

ENERGY POLICIES OF IEA COUNTRIES

Australia

2018 Review



International
Energy Agency
Secure
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Australia

2018 Review

INTERNATIONAL ENERGY AGENCY

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Foreword

The International Energy Agency (IEA) has been conducting in-depth energy policy reviews of its member countries since 1976. As a core activity, the process of review by peers not only supports member countries' energy policy development and mutual learning, but it also encourages exchange of international best practice and experience. In short, by seeing what has worked – or not – in the “real world”, these reviews help to identify policies that achieve objectives and bring results.

In 2016, the IEA decided to modernise the reviews by shifting their focus to key energy security challenges in fast-changing global energy markets and to the transition to a clean energy system.

This report on Australia offers insights into two special focus areas, which were chosen by the Australian government: the transition to a low-carbon energy economy and related challenges, and the role of natural gas in this context.

Natural gas can play a crucial role as a transition fuel to a lower-carbon economy. Australia's gas market reform and the review of the country's emissions reduction policies were actively discussed with reform proposals under way in 2017. The report examines these ongoing reforms and explores new initiatives that Australia could put in place to encourage domestic production, investment and competition.

The special focus chapter on the energy system transformation evaluates opportunities and challenges with regard to increasing the share of variable renewable energy in the power sector and beyond, in industrial heat and transport. The energy transition is under way, and efforts are required to ensure system reliability and improve market integration of renewable energy. The electricity sector is at the heart of the energy system transformation. Therefore, this report provides recommendations for the design of climate policies addressed to this sector, including ways to shape market rules and network regulation, retail market reforms, and wholesale market actions to improve electricity security during the transition.

The primary aim of this report is to support Australia in its quest for a secure, affordable and environmentally sustainable transformation of its energy sector and economy. It is my hope that this country review will guide Australia in its energy transition and its contribution to a cleaner, more sustainable and secure global energy system.

Dr. Fatih Birol

Executive Director

International Energy Agency

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Executive summary

Overview

The energy market and policy environment in Australia have seen rapid changes during the five years since the IEA presented the last in-depth review of Australia in 2012. In line with global energy market trends, Australia's energy system is undergoing a profound transformation, bringing about challenges to the design of energy and climate policies and energy markets.

In this context, the Commonwealth government asked the IEA to review the lessons that Australia can learn from other countries' experiences in transiting to a low-carbon energy market as part of the Finkel Review and this dedicated country review by the IEA. This includes critical topics of safeguarding electricity security and the role that natural gas can play as a lower-emission transition fuel in power generation. The main objective of this IEA review is to present to the Australian government a comprehensive all-energy assessment of the country's energy policy and to provide relevant recommendations to strengthen its position, including at an international level, with regard to the energy system transformation and energy security, which are outlined in Part I and Part II of this report.

Progress and challenges

Well-endowed with energy resources, Australia is a key player in global energy markets. Energy exports are driven by the significant increase in energy demand from emerging economies, such as the People's Republic of China and India. Energy represented nearly 40% of Australia's total export revenues in fiscal year 2015 and exports are growing significantly, making the country the world's largest exporter of coal and a leading exporter of liquefied natural gas (LNG).

Since the 2012 IEA review, the Commonwealth government has proceeded with energy reforms based on the 2015 Energy White Paper (EWP) and its three key priorities with a view to: *i*) enhance competition to improve consumer choice and put downward pressure on prices, *ii*) ensure productive use of energy to lower costs, improve energy use and stimulate economic growth and *iii*) foster investment in innovation and energy resource development to grow exports.

In 2015, the government put forward a target to deliver a 40% improvement in Australia's energy productivity by 2030 under the National Energy Productivity Plan (NEPP). To foster market functioning, the Council of Australian Governments (COAG) Energy Council set in motion a gas market reform programme and is discussing reforms to improve the electricity system's security. Acknowledging the lack of competition, the

Commonwealth government is amending Australia's competition laws and the Australian Consumer and Competition Commission (ACCC) is conducting several inquiries into electricity and gas prices, including the review by the Australian Energy Regulator (AER) of potential generator market power.

Australia has been relying on the paradigm of deregulated and liberalised energy markets. Despite ongoing reforms, the signs of stress in the Australian energy system have grown. Since the last IEA in-depth review, energy prices have remained continuously high against low levels of competition in gas and electricity markets and low consumer choice, pointing to structural challenges. Concerns have been raised that gas supplies may reach a shortage in the east coast market as LNG exports ramp up to 2022, further pushing up power prices. The resilience of the electricity system is being tested at a time of system transformation with old coal plants retiring and more variable renewables entering the system, but unevenly distributed across the common market, the National Electricity Market (NEM). South Australia has the highest penetration of variable renewable energy in the NEM. The South Australia Black System event in September 2016 and heat-waves in early 2017 represented a wake-up call with regard to power system security and prompted several policy reviews.

In 2016-17, the Commonwealth government, including through the COAG (both at leaders' and Energy Ministers' level), has been undertaking a large number of policy reviews. In 2016, the COAG Energy Council requested an Independent Review into the Future Security of the National Electricity Market (NEM) by Chief Scientist Dr. Alan Finkel. Dr Finkel presented a national reform blueprint to maintain security and reliability in the NEM in June 2017 (the "Finkel Review"). Building on its climate pledge under the Paris Agreement in 2015, the Commonwealth government is now also reviewing its climate policies. The NEM market bodies have reviewed market rules and regulations.

Bringing together the outcomes of the reviews and adopting new legislation and new NEM market rules will be a significant task. The energy policy governance in Australia is very complex and fragmented. It suffers from frequent changes of policy direction and institutions at Commonwealth level. The states and territories are implementing energy policies, notably for renewable energy and energy efficiency, but have agreed to common energy market rules in the NEM. At this level, there are three key market bodies (the Australian Energy Regulator, the Australian Energy Market Commission and the Australian Energy Market Operator) which have a role in the oversight of energy markets and networks, and are active in keeping up with and adapting to the country's rapid energy developments and changing markets. There are overlaps in many areas among them and with Commonwealth institutions, such as the ACCC or the Clean Energy Regulator (CER) or Climate Change Authority (CCA), which are not part of the NEM.

A key priority is to ensure that Australia can maintain its competitiveness as a natural resource exporter and embrace the energy transition at home by fostering secure, competitive and clean energy supply for households and industry alike. Markets can most effectively deliver desired investments and outcomes when investors have visibility of government direction. This helps set investment priorities and reduce regulatory and commercial risks. Given the economy-wide importance of the energy sector, Commonwealth government leadership is needed to set a national, integrated energy and climate policy framework for 2030 based on a low-emission development strategy for 2050. Effective co-ordination of energy and climate policies within the common energy market, the NEM, and across the Commonwealth system of government (through the

COAG Energy Council and the energy market bodies) remains an imperative, based on enhanced collaboration, clarified roles and clear accountability. In short, a strategic and enduring policy response towards an orderly energy transition is required. The creation of the new Energy Security Board and the proposed National Energy Guarantee are welcome developments in this regard.

Energy security

Australia is a significant net exporter of coal, uranium and natural gas and has abundant renewable resources. As a net energy exporter, Australia's energy security position has been considered solid for many decades. However, the country is increasingly exposed to new challenges for maintaining security of energy supply, a situation that is markedly different from how energy security was perceived only five years ago. In 2016, the country saw itself confronted with a state-wide blackout in South Australia, several situations of load shedding and gas shortages, and power reliability issues are anticipated under severe climate situations in 2017-18 in Victoria and South Australia. To deal with such multi-sector energy security risks, the Commonwealth government should regularly update and publish the National Energy Security Assessment (NESA); the last one was presented in 2011.

Domestic oil production has declined by 30% along with lower domestic refining capacity, making Australia more and more dependent on imports from global oil product markets to satisfy a growing demand. Oil product imports skyrocketed and are expected to grow by 3.2% per year by 2021-22. Despite having access to a long oil supply chain, Australia is vulnerable to unexpected changes in Asian regional demand patterns and to any disruptions of the main supplies from the Middle East, on which the whole Asian region and Australia are dependent.

A member of the IEA since 1979, Australia neither complies with the oil stockholding obligation of 90 days of net imports nor does it have the capacity to contribute to an IEA collective action. The country's 2017 oil stocks of 49 days are at an all-time low since 2000, as stocks are held on a commercial basis only, with the country having no strategic oil stocks and not placing any stockholding obligation on industry. The government is commended for presenting a compliance plan in 2016 which is expected to lead to full compliance with its international obligations by 2026 over two phases. First, the government aims at purchasing "ticket" contracts with oil stockholders abroad and has introduced mandatory petroleum and other fuel data reporting. During a second phase (2020-26), the government aims to build the necessary stocks based on an implementation plan to be issued by 2020.

Australia has plenty of gas reserves and world-leading expertise in the development of conventional and unconventional gas. However, there are significant concerns about the price and the availability of natural gas amid moratoriums on gas production in the eastern market. Gas prices have been aligning with liquefied natural gas net-back prices and even exceeding them; retail gas prices have almost doubled, driving up household electricity prices, too. This has significant implications for the competitiveness of natural gas in the domestic market and the future of industry and residential demand which have seen the end of their low-cost natural gas contracts. In such a tight market, any disruption, outage or extreme weather event will require an even more robust emergency preparedness and response. The Commonwealth government can play an important role

in supporting the sustainable development of the gas reserves, building on its expertise and international best practices, as reflected in the IEA publication *Golden Rules for a Golden Age of Gas*.

The Commonwealth government is aware of the significant challenges facing the east-coast market and introduced a gas security mechanism in July 2017, involving possible LNG export restrictions. The IEA believes the government should make all efforts to improve gas market competition, liquidity and efficiency through regulatory measures and support the development of more domestic conventional and unconventional oil/gas reserves, while addressing community concerns. The newly introduced gas security mechanism should be used as a tool to improve risk assessments and preparedness. All market-based measures should be used before introducing export restrictions to guarantee the domestic supply. Otherwise, the mechanism risks discouraging upstream investment in new gas production.

Australia's electricity system has a radial and long transmission grid and a weak level of interconnections within the NEM. Simultaneous peak demand, generator outages, or the loss of interconnection capacity, combined with gas supply shortages, can lead to power system disruptions, notably during extreme weather events. Any disruption of an interconnector quickly leads to the isolation of the region. This has been a challenge in the past.

While the NEM wholesale reliability standards are high, the states' reliability levels have been often breached in recent years, as old capacity retires faster than expected and as new variable renewable energy follows different standards. The electricity blackouts and load-shedding events during the storms and heat-waves of 2016/17 illustrated the low physical resilience of the energy infrastructure and the close interplay between electricity and gas security. A more flexible system with new system services, updated technical standards and grid codes, and appropriate network investments, including in new interconnectors across the NEM, remain critical to ensuring electricity reliability.

The NEM is a world-leading, five-minute energy-only market, which has been the cornerstone of power security. However, greater collaboration on energy security within the NEM is needed, including better risk identification and assessments. AEMO's energy outlooks and adequacy reviews are becoming more important and should be better coordinated with AEMC's Reliability Panel. While market-based measures have been effective for maintaining reliability, the energy system transformation presents a set of new challenges which may require a safety net for the system operation during periods of system adequacy risks. Such a safety net could build on AEMO's Reliability and Emergency Reserve Trader (RERT) mechanism as a means to provide for reserves in the short to medium term.

Energy data are collected and reported for different purposes and by different government organisations and under voluntary industry reporting. Under the 2007 National Greenhouse Gas and Energy Reporting Scheme (NGERS) energy consumption/supply and GHG emission data are published by the Clean Energy Regulator (CER) mainly at corporation level, not by facility or sector, as some data remain confidential. The Australian government is aware of these barriers and is working to improve information flows, including between data-collecting authorities through bilateral memorandums of understanding across governments and has introduced mandatory oil and other fuel reporting. The government should continue to improve data

reporting and data sharing across government and agencies to enhance analysis and policy development, and design timely and efficient responses to energy security concerns.

Energy system transformation

Under the Paris Agreement, Australia has increased its international climate change ambitions and aims to reduce greenhouse gas (GHG) emissions by 26% to 28% by 2030 below 2005 levels. Despite stated ambitions of the Paris pledge, the Commonwealth government has not yet come forward with durable climate change policies after 2020 or a long-term emissions reduction goal for 2050, pending a climate policy review in 2017. A stable and longer-term framework is critical to guarantee visibility for investors and consumers alike.

The energy system transformation is happening at a faster pace and scope than expected, driven by rapidly falling technology costs for renewable energy, energy-efficient appliances and batteries, and the closure of the oldest coal-fired power plants. Coupled with rising energy prices and limited energy retail choice, a growing number of consumers have opted for electricity production at home and some have even gone off grid. This has led to the highest in the world national penetration of solar photovoltaic (PV) installations per household.

The growth in wind and solar power has accelerated since 2009, but each still represents less than 1% of total primary energy supply (TPES) for the country as a whole, with large variations across states and territories. In power generation, together with biomass and hydro, total renewable energy sources accounted for 14.7% in 2016, according to the latest IEA data. However, Australia still has 85% of fossil fuels in the power mix, the highest share among IEA member countries in 2016. The share of variable renewable energy (VRE) in electricity generation has reached a nationwide share of 7% but stood at 48% in South Australia in 2016. This places South Australia among IEA members (with Ireland and Denmark) that are confronted with system integration issues.

Australia reduced the energy intensity of its economy (TPES per GDP) by 14% over the decade 2006-16, less than the IEA average (-17%). Energy-related carbon dioxide (CO₂) emissions reached a peak in 2009 and have decreased by 4% since. The main contributing factors are the closure of coal-fired power plants and lower electricity demand as many energy-intensive manufacturing and engineering utilities have closed. These trends strongly contributed to the reduction in carbon intensity of the whole economy and the decoupling of CO₂ emissions from economic growth.

The energy system transformation meant that the share of natural gas and renewable energy sources has increased and that CO₂ intensity of electricity generation has been reduced by 15% since 2005. Nonetheless, the CO₂ intensity of Australia's electricity generation remains the highest among all IEA member countries and almost twice as high as the IEA average. The country is not subject to any effective carbon constraint or rate under the Emissions Reduction Fund and its safeguard mechanism. Current energy efficiency measures and climate mitigation policies are not sufficient. To meet its 2030 target, domestic efforts need to increase. They are being currently considered by the climate change policy review of the Australian government. Commonwealth climate policies have seen great uncertainty with frequently changing decisions around the

emissions trading scheme and the carbon tax, which had applied to large emitters from 2012 to 2014, and was repealed in 2014 by the Clean Energy Legislation (Carbon Tax Repeal) Act. There has been a broad discussion of the optimal emission reduction policy, with support to carbon pricing voiced by industry and a call by regulators for a cost-effective emission intensity scheme, or a Clean Energy Target, as recommended by the Finkel review. In 2017, the Energy Security Board presented advice to the Australian government in favour of a combined scheme, the National Energy Guarantee (NEG), which would require retailers to both meet emission reductions and reliability targets in their electricity sales. COAG Energy Council is expected to adopt the NEG by April 2018. Whichever option the Australian government chooses for the design of the future emissions reduction mechanism for 2030, it should ensure that such support becomes market-based, adapted to the NEM rules and facilitate locational signals.

The NEG could be an effective market-based mechanism if the government can ensure more competition, better interconnection among the NEM regions and stringent rules for the integration of renewable energy capacity into the system. The NEG cannot become a “silver-bullet” and its design should remain compatible with the NEM energy-only market, otherwise, it could create new barriers and windfall profits, if those elements are not considered.

Undoubtedly, the power sector will be at the heart of Australia’s energy system transformation. There is a lack of visibility for business, consumers and policy makers alike with regard to the pace and magnitude of this transformation. International best practice suggests that both energy efficiency and renewable energy are key drivers of the energy transition. The Commonwealth Scientific and Industrial Research Organisation (CSIRO) developed a Low Emissions Technology Roadmap in 2017, which reviewed several pathways. However, the roadmap did not make specific recommendations on no-regret pathways. Building on the CSIRO roadmap, a government-led mid-century low-emission strategy is required to set an emissions reduction goal for the power sector, identify the potential contribution from renewable energy and energy efficiency, and ensure that the retirement of old power plants can be done in a way to ensure competitiveness, security and reliability of supply at minimal cost. Combining a resource-intensive economy with a clean energy sector is feasible and can be an enormous economic opportunity to bolster energy affordability, security and competitiveness, if harnessed in an effective and efficient manner.

The energy system transformation is driven by investment in clean energy technologies. Australia is well placed to demonstrate cutting-edge technologies, including concentrated solar power, battery storage and carbon capture and storage (CCS). Public expenditure in research and development (R&D) has seen sharp cuts since a peak in 2009. The Commonwealth and jurisdictional governments should step up support to technology R&D and commercialisation, including by increasing focus on R&D through the Australian Renewable Energy Agency (ARENA) and the commercialisation of R&D results through the Clean Energy Finance Corporation (CEFC). The Commonwealth government has voiced support for a technology-neutral approach, including the continued use of coal (high efficiency low emission HELE plants). However, without CCS, the continued use of new or old coal plants makes the attainment of Australia’s Paris commitments problematic and may result in carbon lock-in.

Special focus 1: The role of natural gas in the transition

As coal power capacity is being retired over the coming decades, it is expected that natural gas can play a role in the energy transition. However, for this to occur, gas supplies need to be abundant and gas prices more competitive.

Australia's natural gas sector is facing a period of rapid change and has entered an era of relatively high-cost production from unconventional gas, with the expansion of LNG developments in Western Australia and the start of LNG exports from Queensland on the east coast. Gas consumption has grown by 70% over the past decade, notably in power generation. As LNG production is ramping up, the new eastern gas fields have not been able to cover all of the increasing demand. Gas from the domestic market has been utilised to supply export contracts, contributing to price increases and volatility for consumers, both industrial (including electricity generators) and residential, who had grown used to long-term stable and, by international standards, cheap contracts. Current prices make natural gas a less competitive fuel in power generation or, alternatively, drive up electricity prices. These factors have led to tight domestic supplies and to increasing concerns about the adequacy of the gas supply/demand balance in the medium term.

Australia has three distinct gas markets (east, north and west), which are not interconnected and regulation has been light touch. The COAG Energy Council has engaged in a comprehensive gas market reform agenda, based on the Gas Vision 2014, the domestic gas supply strategy, and on reviews by the Australian Competition and Consumer Commission (ACCC), the Australian Energy Market Commission (AEMC) and Dr. Michael Vertigan AC. The aim is to open up the market towards greater transparency on gas pricing and pipeline utilisation. Production from the eastern gas fields has not been able to cover all the export and domestic demand. Competition in Australia's gas markets and transparency levels remain low, despite reform attempts since 2010. The largely unregulated infrastructure is owned by a few companies that are active in production, transmission and wholesale of gas, which results in opaque gas pricing. Commendably, the Commonwealth government continues to proceed with price inquiries by the Australian Competition and Consumer Commission (ACCC) and the COAG Energy Council gas market reforms to improve market operations. Major reforms have led to the creation of new gas hubs and gas bulletin boards, providing more transparent information on prices and pipeline utilisation. Negotiated pipeline access is now in place, but yet uncertainty remains around its ability to create a market place.

Special focus 2: The transition to a low-carbon economy and system integration of higher shares of variable renewables

An electricity system based on higher shares of variable renewable energy (VRE) will be at the heart of the energy system transformation. By 2020, the federal renewable energy target (RET) is set to deliver 33 000 gigawatt-hour (GWh) of large-scale renewable energy. State- and territory-based renewable energy procurement systems have accelerated the uptake of wind and solar energy, notably residential solar energy rooftop

installations. A challenge has been that these policies have lacked co-ordination and led to the concentration of renewables in a few states, leading to system integration challenges within the NEM.

Policies at the level of states and territories are and will likely be evolving, not necessarily aligned to common rules needed in the NEM with higher shares of variable renewables, flexible sources and lower contribution from baseload power plants. There are concerns whether the NEM, as a short-term energy-only market, is able to manage the system transformation. The IEA believes the NEM can remain effective, but policies and market rules need to evolve. The government should continue to foster well-functioning wholesale and retail markets along five key elements. First, such a reform should start at the level of relevant technical standards and grid codes. Second, another priority area is the co-ordinated planning of grid infrastructure, including interconnectors, to optimise grid infrastructure beyond jurisdictional borders. Third, ongoing efforts to improve system operation and expand scope for providing system services should be fully implemented. Fourth, geographically balanced deployment should be improved by providing locational signals and thus smoothing the impact of VRE generation. Fifth, systematically assessing and enhancing the flexibility of the power system is critical, including higher flexibility from existing thermal generation assets, from demand response, storage and improved management of existing and new interconnections.

The COAG Energy Council needs to swiftly embrace and work on the NEM market reform, reflecting its endorsement of the recommendations of the Finkel review and the ongoing initiatives by the rule maker for the NEM, the Australian Energy Market Commission (AEMC) and the market and system operator of the NEM, the Australian Energy Market Operator (AEMO). Key reform actions identified by the Finkel review included recommendations for increasing system stability and reliability in the NEM regions and robust emergency preparedness and response, strengthening the governance of the NEM through the creation of a new Energy Security Board (ESB) and greater strategic policy direction from COAG on energy and climate policy, based on a strategic energy plan and a new Australian Energy Market Agreement. In July 2017, the COAG Energy Council has accepted almost all the recommendations from the Finkel Review and is now implementing a suite of measures. Since, the ESB has been set up and the AEMC rule changes on system security are being implemented.

Moreover, the emergence of variable renewable energy and new technologies (electric vehicles, battery storage, and rooftop solar PV, including advanced metering) provide an opportunity to build more innovative, cost-effective and secure electricity markets throughout Australia, which can deliver benefits for all electricity consumers. However, these developments make the systems even more dynamic and complex to manage in an efficient and secure manner.

As Australia is currently rolling out advanced meters, there is an opportunity to boost the availability of dynamic pricing and demand response. Network operators, retailers and consumers will be at the forefront of managing these challenges. AEMC and the Australian Energy Regulator (AER) are addressing the regulatory challenges associated with those new technologies, in favour of competitive markets, which is welcome. However, network regulation should be revisited, on the basis of a review of economic efficiency, towards considering a TOTEX approach with output based regulation to leave flexibility to network operators between OPEX and CAPEX

investments. The aim should be to strengthen the regulator's competences and to ensure that regulated network operators' activities are strictly geared towards public policy outcomes.

The retail market reforms through the COAG Energy Council should continue towards greater transparency and consumer engagement. After moving to deregulated retail markets, the COAG should now focus on the transformation of distribution systems, including by ensuring harmonised technical standards, interoperability of resources in different states and consistent economic regulatory arrangements. This also requires joint retail market monitoring and reporting by ACCC, AER and AEMC, a high degree of co-ordination between transmission and distribution network operators and new grid planning, which involves the distributed resources, demand response and energy storage. As states and territories have largely deregulated their retail markets since the last IEA review in 2012, such a reform package is timely and can support government efforts in providing customer choice and competitive offers.

Key recommendations

The government of Australia should:

- Design an energy and climate policy framework for 2030 and develop a mid-century low emission development strategy, based on the outcomes of the 2017 review of the climate policies and the Finkel review.
- Improve governance through enhanced collaboration and clarified roles with states and territories through the COAG Energy Council and with market bodies of the NEM.
- Guide the energy transition through an emissions reduction goal for the power sector and provide a market signal to retire older and less efficient generation, while ensuring that plants provide sufficient advance notice of their intention to close.
- Continue to foster well-functioning wholesale and retail electricity markets through the COAG Energy Council in order to ensure efficient and innovative outcomes, to deliver security of supply and to more effectively integrate growing shares of variable renewable energy by:
 - > Reviewing and adapting technical standards and the procurement of ancillary services, including a strategic reserve to increase power system flexibility, resilience and reliability;
 - > Ensuring that low-emission technology support is market-based and guided by locational signals, supported by energy system-wide network planning.
 - > Adapting the distribution network regulation through harmonised technical standards, interoperability of resources in different states and consistent economic regulation.
- Develop competitive, liquid and adequate domestic gas supplies and transportation capacity by swiftly completing the gas market reforms. Support the sustainable development of domestic oil/gas reserves by addressing community concerns.

EXECUTIVE SUMMARY AND KEY RECOMMENDATIONS

- Regularly update the National Energy Security Assessment, in order to identify energy security risks across the energy system, and design measures to reduce or eliminate these risks in a timely and comprehensive manner.
- Foster data reporting and monitoring across all energy sectors and continue to develop data-sharing arrangements across government and agencies to improve energy data quality for analysis, policy development and the deployment of emergency measures.

1. General energy policy

Key data

(2016 provisional)

Energy production: 394.1 Mtoe (coal 74.5%, natural gas 18.8%, oil 4.5%, biofuels and waste 1.4%, hydro 0.3%, wind 0.3%, solar 0.2%) +46% since 2006

TPES: 132.32 Mtoe (coal 34.4%, oil 32.0%, natural gas 27.0%, biofuels and waste 4.1%, hydro 1.0%, wind 0.8%, solar 0.7%), +12% since 2006

TPES per capita: 5.4 toe (IEA average: 4.4 toe)

TPES per unit of GDP: 0.12 toe/USD 1 000 PPP (IEA average: 0.14 toe/USD 1 000 PPP)

Energy intensity: 0.120 toe/USD million PPP (IEA average: 0.109), -13.9% since 2006

TFC (2015): 81.3 Mtoe (oil 52.4%, electricity 22.4%, natural gas 16.6%, biofuels and waste 5.4%, coal 2.9%, solar 0.4%), +13% since 2005

Consumption by sector (2015): transport 40%, industry 34.5%, residential 12.9%, commercial and public services including agriculture, forestry and fishing 12.6%

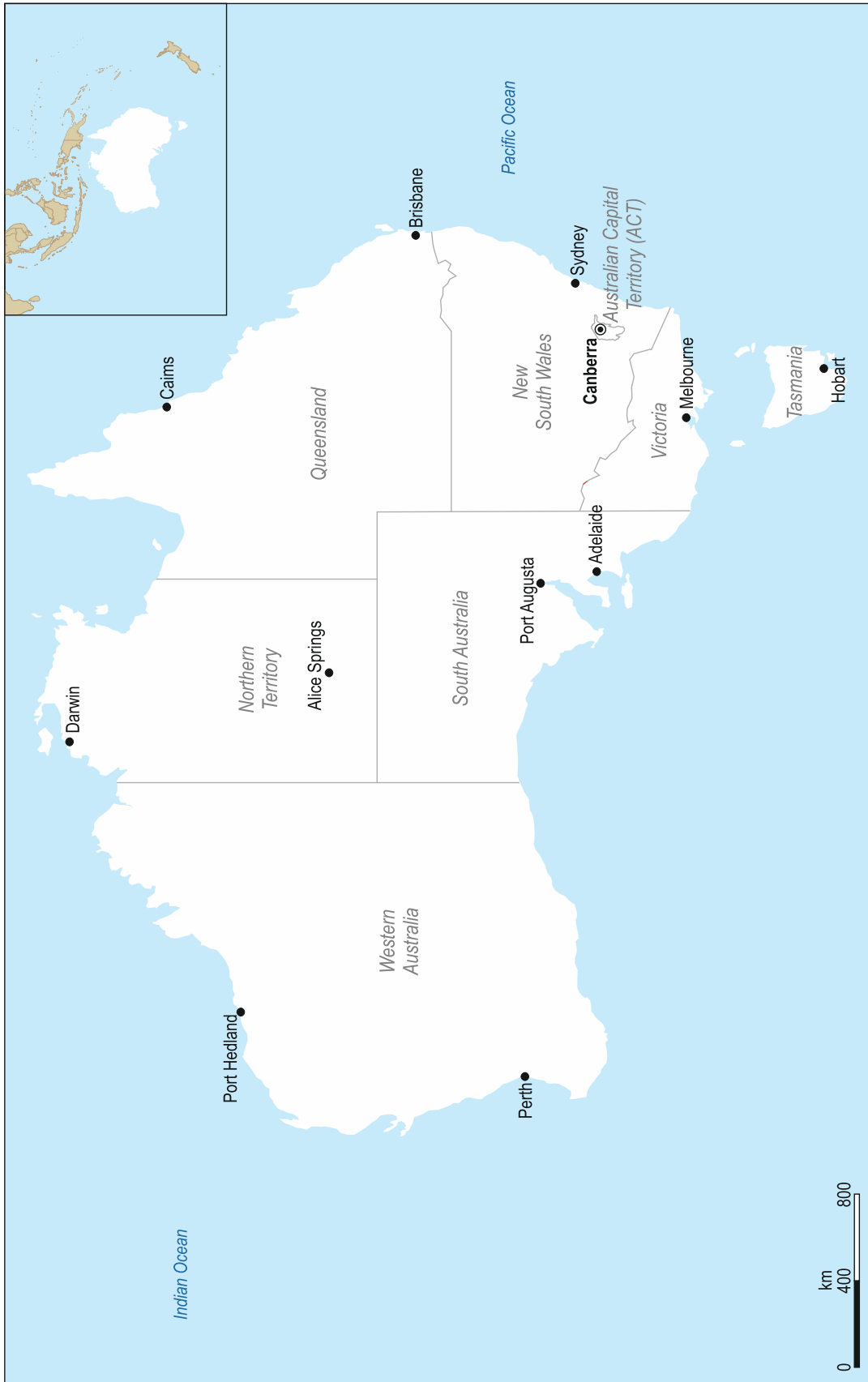
Australian dollar: On average in 2017, AUD 1.30 = USD 1

Country overview

Australia is a federation with six states (New South Wales, Queensland, South Australia, Tasmania, Victoria and Western Australia) and two territories, the Australian Capital Territory (ACT) and the Northern Territory (NT).

Australia is a parliamentary monarchy with Queen Elizabeth II of the United Kingdom, formally the Queen of Australia, as head of state. She is represented by the Governor-General of Australia, Sir Peter Cosgrove. The Commonwealth and all states other than Queensland have bicameral parliaments, consisting of a lower and an upper house. The ACT and NT have unicameral parliaments. The executive branch of the Commonwealth is led by the Prime minister. The legislative branch is composed of the Parliament of Australia's House of Representatives and of the Senate. The judicial branch consists of the Commonwealth, states and territory courts. Over the past decades, Australia saw the government alternating between the Liberal and the National Party Coalition (currently in government) and the Australian Labor Party.

Figure 1.1 Map of Australia



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Australia has seen strong growth of its population, reaching 24 million in 2017. It has experienced 25 years without recession, achieving a GDP per capita of USD 47 770 (OECD, 2017). Australia has seen a recent slow-down in its economic growth, with declining resource-sector investment, weak commodity prices and hesitant investment elsewhere in the economy, although the exchange-rate depreciation is helping the economy to adjust. Productivity growth remains weak, despite a business environment favourable to entrepreneurship, in addition to flexible labour markets. Boosting productivity requires common structural weaknesses to be addressed, notably the tax revenue structure, housing market and public infrastructure. GDP growth is projected to strengthen to about 3% by 2018, thanks to liquefied natural gas (LNG) production which will boost exports and helps offset the negative effects from shrinking mining investment. Rebalancing towards non-mining sectors can drive the future pick-up of overall activity, helped by supportive macroeconomic policies (OECD, 2017).

Employment growth is expected to result in the further decline in the unemployment rate. Household consumption growth is expected to remain solid, aided by further downward adjustment in households' saving ratio to the historical average. The pick-up in aggregate demand is not projected to generate significant inflationary pressure, owing to remaining economic slack. Commodity market developments, particularly those linked to the Chinese economy, remain an important source of uncertainty and risk. Domestically, non-resource investment is only slowly growing, dampening growth prospects. The housing market remains a risk, as price acceleration could weaken consumption and construction activity.

Major markets for Australia's natural resources are the People's Republic of China, Japan, India, Korea and Chinese Taipei. The resources sector is critical to Australia's economy. In 2015, Australia overtook Indonesia as the world's largest coal exporter and became the second-largest LNG exporter, after Qatar. The coal-mining industry employed around 49 000 people in 2015/16. Australia is expected to maintain its market leadership in the coming decades given its abundant high-quality coal reserves, proximity to the Asian region where coal demand is projected to increase in the period to 2040, and the relative cost competitiveness in the production and supply of coal. LNG development is ramping up fast to 2020 and will boost Australia's position in the global LNG trade to the top LNG exporters together with the United States and Qatar (IEA, 2017).

Supply and demand

Primary energy supply and production

Large domestic energy production allows Australia to be a world leading energy exporter. Total energy production is three times higher than total primary energy supply (TPES¹) - coal production is nearly six times the domestic coal demand. Large coal (black and brown) production dominates Australia's energy system. Cheap access to domestic supply has also made coal the fuel most used in Australia's energy supply. Natural gas comes second in energy production, which is increasingly

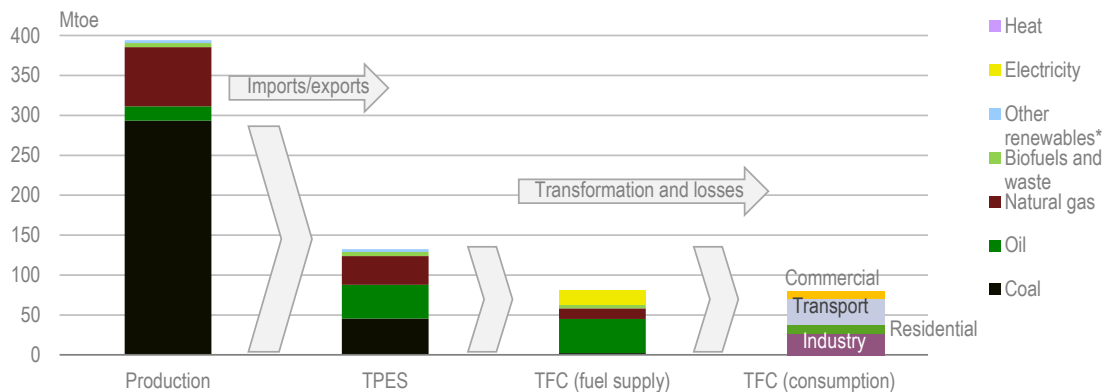
¹ TPES is made up of production + imports – exports - international marine and aviation bunkers ± stock changes. This equals the total supply of energy that is consumed domestically, either in transformation (e.g. power generation and refining) or in final use.

exported with the start of LNG exports in 2015. Oil products are mostly imported - crude oil production only covers 42% of supply and is declining. Thus, Australia has remained a net importer of crude oil and oil products.

Australia's TPES is dominated by fossil fuels. Coal and oil accounted for roughly one-third of TPES each, followed by a growing share of natural gas, which accounted for over one-quarter in 2016 (see Figure 1.2).

Coal is mainly used in power generation; nearly two-thirds of electricity generation comes from coal-fired power. However, the role of coal in overall energy supply has declined by 12% over the ten years from 2006 to 2016, whereas natural gas has gained a greater role, more than doubling in power generation and increasing by 55% in TPES. Oil supply increased by 16% as a result of growing demand for oil in transport and mining sectors over the same period. Hydro energy has been stable at around 1% of TPES, while wind and solar have grown rapidly. However, they only accounted together for 1.5% of TPES in 2016.

Figure 1.2 Overview of Australia's energy system, 2016

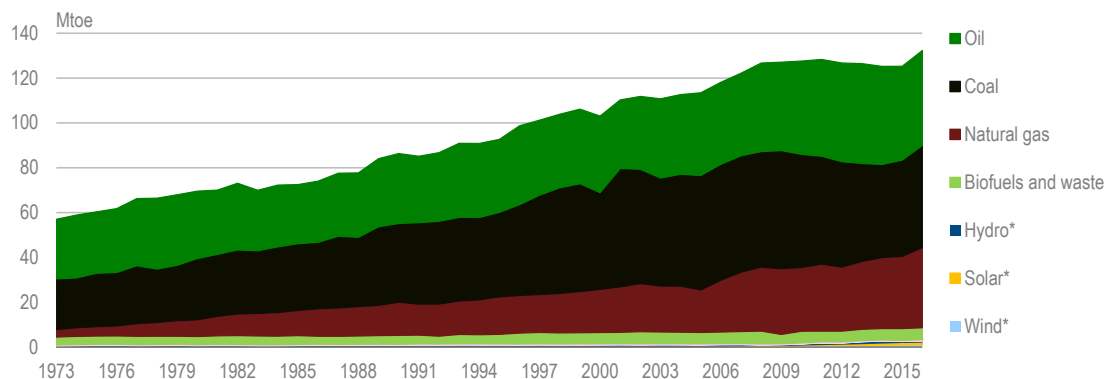


*Other renewables include hydro, wind and solar.

Note: Consumption (TFC) data are for 2015, supply data are provisional for 2016.

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 1.3 Total primary energy supply by source, 1973-2016

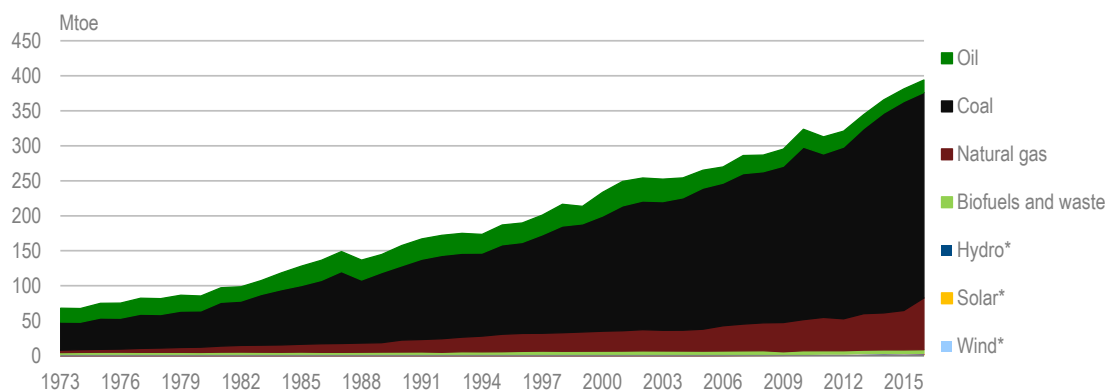


* Negligible.

Note: Data are provisional for 2016.

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 1.4 Energy production by source, 1973-2016



* Negligible.

Note: Data are provisional for 2016.

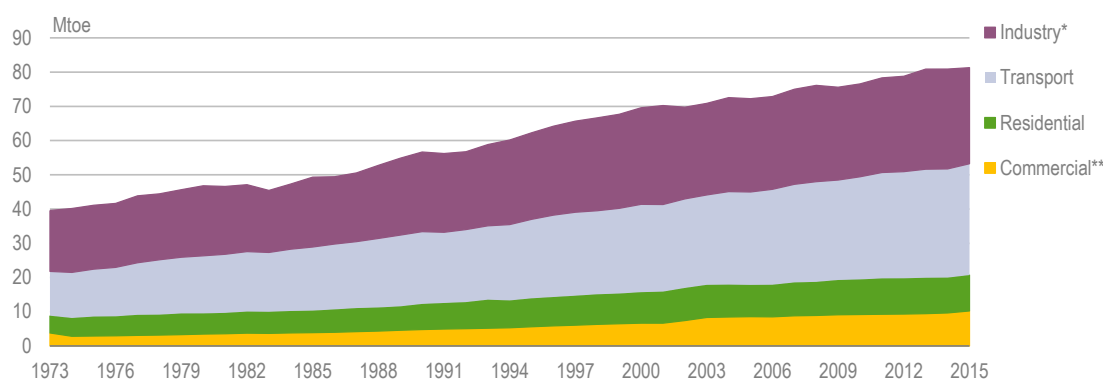
Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

Energy consumption

Australia's total final energy consumption (TFC²) is driven by the activities in the transport and industry sectors, which accounted for 40% and 35% of TFC, respectively. Unlike in other countries, residential and commercial sectors are relatively small energy consumers, with less than 13% of TFC each. In terms of fuels, oil products accounted for over half TFC, which is a result of large oil demand in both sectors (see Figure 1.5).

Transport is almost entirely dependent on oil products, with minor shares of gas, biofuels and electricity. The industry sector also uses large shares of oil, both as fuel in mining and as feedstock in industrial processes. Electricity is the second-largest fuel in TFC and accounted for the main part of energy consumption in the residential and commercial sectors. Natural gas is the third-largest fuel in TFC, mainly consumed in industry and the residential sectors.

Figure 1.5 Total final consumption by sector, 1973-2015



* Industry includes non-energy use.

** Commercial includes commercial and public service, agriculture, forestry and fishing.

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

² TFC is the final consumption of fuels (e.g. electricity, heat, gas and oil products) by end-users, not including the transformation sector (e.g. power generation and refining).

Institutions

The federal (or Commonwealth) government has exclusive responsibility for trade, foreign relations (including climate change), defence and immigration. States are responsible for energy production (including from renewable and non-renewable sources), land use, forestry, transport, mineral rights, environmental assessments (except offshore), while justice, health, education and consumer affairs are shared responsibilities. Most of the policies on energy and environment, and on wholesale/retail energy markets (electricity and natural gas) require collaboration. The **Council of Australian Governments (COAG)** brings together the federal government (prime minister) and the states and territories (state premiers, territory chief ministers and the president of the Australian Local Government Association).

Following the July 2016 elections, the responsibility for energy matters was transferred from the **Department of Industry, Innovation and Science (DIIS)** to the newly created **Department of the Environment and Energy (DoEE)**. Next to energy and environmental legislation, DoEE has competences on energy security. A new Energy Security Office has been created as part of DoEE. The DoEE also oversees the activities of several government agencies for clean energy: the **Australian Renewable Energy Agency (ARENA)**, the **Clean Energy Finance Corporation (CEFC)**, the **Clean Energy Regulator (CER)**, and the **Climate Change Authority (CCA)**.

- ARENA has been established by the *Australian Renewable Energy Agency Act 2011*. Its mandates are to improve the competitiveness of renewable energy technologies and to increase the supply of renewable energy. It provides grants for R&D programmes in the area of renewable energy technologies, and invests in related research and development (R&D) and early-stage commercialisation.
- Created by the *Clean Energy Finance Corporation Act 2012*, CEFC aims to facilitate and increase flows of finance into the clean energy sector – renewables, energy efficiency and low-emission technologies: to date excluding carbon capture and storage (CCS) and nuclear by legal mandate³. CEFC makes commercial investments in these technologies on the basis of the CEFC Investment Mandate Direction and DoEE, and the Ministry of Finance which provides high-level policy direction and articulates the government's broad expectations of how the CEFC will invest and be managed.
- The CER was established in 2012 by the *Clean Energy Regulator Act 2011* and is responsible for administering legislation that will reduce carbon emissions and increase the investment in and use of clean energy. CER administers the carbon mitigation mechanisms, the national greenhouse gas- and energy-reporting (NGER) scheme, the voluntary Emissions Reduction Fund and its Safeguard Mechanism, and the Renewable Energy Target. CER publishes data on energy use and emissions at corporate level.
- The CCA advises government on climate change mitigation policies and initiatives, through reviews and recommendations based on the *Climate Change Authority Act 2011*.

³ On 31 May 2017 the Australian government introduced a bill to Parliament to remove the prohibition on the CEFC investing in CCS projects.

The **Department of Industry, Innovation and Science (DIIS)** leads on upstream (oil/gas/coal) and mining regulation and buildings as a separate branch. The **National Offshore Petroleum Titles Administrator (NOPTA)** is responsible for the administration of petroleum and greenhouse gas titles in Commonwealth waters. The **National Offshore Petroleum Safety and Environmental Management Authority** is the national regulator for certain aspects of offshore oil and gas operations.

The **Department of Foreign Affairs and Trade** is responsible for international climate change policies and for overseeing investment and trade settings which support Australia's economic competitiveness, including in the resources and energy sectors. The **Department of Infrastructure and Regional Development** is responsible for transport policies. The **Department of Defence** is in charge of energy security, energy efficiency and resilience in developing the Australian Defence Force's capabilities and managing the Defence Estate. It also undertakes energy research and innovation activities, including renewable energy projects, for national defence purposes.

Constituted by the *Science and Industry Research Act 1949*, the **Commonwealth Scientific and Industrial Research Organisation (CSIRO)** is the national scientific research agency. Other bodies are involved in climate science, including the Bureau of Meteorology which advises on climate change impacts and science, and the DoEE-supported National Climate Science Advisory Committee (jointly with DIIS).

The **Australian Competition and Consumer Commission (ACCC)** is an independent Commonwealth statutory authority whose role is to enforce the *Competition and Consumer Act 2010* and a range of additional legislation, promoting competition, fair trading and regulating national infrastructure through the **Australian Energy Regulator (AER)** in the energy sector (gas and electricity), which is a constituent part of the ACCC while being independent in its financial and executive decisions by the board. However, the **National Competition Council (NCC)**, a research and advisory body, deals with the regulation of third-party access to services provided by monopoly infrastructure.

In the area of energy, the **COAG Energy Council** enables co-ordination between the state and territory jurisdictions and the Commonwealth government on energy policy. It supports the national rule-making under the National Electricity Law, the National Gas Law, and the National Energy Retail Law, among others. "National" refers not to the entire Commonwealth but to the interconnected National Energy Market (NEM), which brings together five regional market jurisdictions – Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania. Western Australia and the Northern Territory are not connected to the NEM.

The Commonwealth has provided for the self-governance of the national electricity and gas markets through independent authorities. Energy markets are overseen by three main market authorities with overlapping competences and areas of responsibility (see Chapter 4 on Electricity): the AER oversees wholesale/retail energy markets and the federal economic regulation of energy networks. The **Australian Energy Market Commission (AEMC)** is the supervisory body of electricity and gas markets, independent from Commonwealth or state governments. The AEMC is the rule maker for the NEM. The **Australian Energy Market Operator (AEMO)** operates Australia's largest gas and electricity markets and power systems – 10 gas hubs and the NEM, and the Wholesale Electricity Market (WEM) and the power system in Western Australia. AEMO is 60% government-owned and 40% privately owned, but funded through fees.

On 14 June 2017, the COAG Energy Council established the **Energy Security Board** with Dr Kerry Scott AO as independent chair, Ms Clare Savage as deputy chair and the heads of the AEMC, AER and AEMO. Its main task is to foster co-ordinated rule making across the NEM with regard to reliability, security and emission reduction policies.

Energy strategy and targets

Based on the priorities of the COAG Energy Council of 2015, the Commonwealth energy strategy was outlined in the *Energy White Paper* (EWP) of 8 April 2015 (Australian Government, 2015a). The EWP sets out the government's vision for the energy sector along three main directions: *i)* greater competition in energy markets to improve consumer choice and to put downward pressure on prices, *ii)* more productive use of energy to lower costs with a view to improve energy use and stimulate economic growth and *iii)* investment to encourage innovation and energy resources development and to allow jobs and exports to grow.

Building upon the EWP, the government presented the National Energy Productivity Plan (NEPP) 2015-2030 (Australian Government, 2015b). The EWP and related energy policies mainly run to 2020 and do not yet reflect the government's climate change pledge for 2030 under the Paris Agreement on Climate Change, which aims at a nationally determined contribution of reducing 26% to 28% of greenhouse gas (GHG) emissions below 2005 levels. In 2017, the Commonwealth government has been reviewing its climate change policies, including a long-term emissions reduction goal. Australia's states and territories have ambitious energy and climate targets. Six of them – the Australian Capital Territory, Victoria, New South Wales, South Australia, Queensland and Tasmania – have adopted targets of zero net emissions by 2050.

The **main Commonwealth energy and climate policies and targets** are as follows:

- **40% of energy productivity improvement** by 2030 over 2015 levels under the NEPP
- **GHG emissions reduction targets:** 26% to 28% (below 2005 levels) by 2030 and 5% by 2020 (below 2000 levels)
- **Renewable Energy Target (RET)** is a green certificates scheme, made up of the large-scale RET (LRET) and small-scale renewable energy scheme (SRES). In 2015, the Commonwealth government reviewed the LRET (adjusting it downwards from 41 000 gigawatt-hours (GWh)) to deliver 33 000 GWh of large-scale renewables, so that 23.5% of Australia's electricity in 2020 will be generated from renewables. The LRET is capped at 33 000 GWh and remains in place until the legislated scheme ends in 2030. The SRES runs up to 2020 and creates incentives for home-owners and small businesses to install eligible small-scale renewable energy systems and solar water-heating systems. The RET has been in place since 2001.
- **Emissions Reduction Fund (ERF)** is a voluntary scheme which credits and purchases abatement from eight family-type methods and 33 individual methodologies of domestic emissions reduction. Its *safeguard mechanism* places an emissions limit (baseline) on facilities with emissions above 100 000 tonnes of carbon dioxide-equivalent (CO₂-eq) per year. The *safeguard mechanism* applies to up to 340 facilities, including around 60 grid-connected electricity generators. It covers around half of Australia's emissions. Facilities covered by the *mechanism* are required to reduce emissions or purchase carbon units

(i.e. carbon offsets) to ensure net emissions remain below the baseline. CER publishes data of participating companies at corporate level.

- **Technology development and deployment support** mainly through the Australian Renewable Energy Agency (ARENA), the Clean Energy Finance Corporation (CEFC) and other agencies, including the CSIRO and the Australian Research Council (ARC).

Energy data

In Australia, energy data are collected and published by a number of government agencies at federal and state/territory level of government and also by the market bodies of the National Electricity Market (NEM).

The Office of the Chief Economist in the Department of Industry, Innovation and Science (DIIS) previously collected and produced the Australian Energy Statistics including state-based statistics on an annual basis. **State and territory governments** collect statistics on coal, oil, gas, and biofuels production. The market bodies **AEMC**, **AER** and **AEMO** produce gas/electricity market data (with different coverages). The **Australian Competition and Consumer Commission (ACCC)** processes confidential information during inquiries into energy market prices, sales and competition, and energy infrastructure throughput and storage. The **Australian Bureau of Statistics (ABS)** releases energy trade (import, exports), energy accounts, energy expenditure and price indexes, industry activity and exploration expenditure. Data on offshore production and stocks are collected by the **National Offshore Petroleum Titles Administrator (NOPTA)**, under the *Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 (RMA Regulations)*. The **Australian Taxation Office** collects customs duty and excise data on a weekly basis as part of its administration of the fuel excise regime. The **Department of Infrastructure and Regional Development** holds data on energy use and activity in the transport sector. The **Clean Energy Regulator (CER)** collects annual energy production and consumption data, including renewable energy data for small- and large-scale renewables, under the *National Greenhouse and Energy Reporting Scheme (NGERS)* and the Renewable Energy Certificate Registry. The **CSIRO** is developing an energy use data model.

Energy data used to be collected by the Bureau of Resources and Energy Economics (BREE), formerly housed in the Office of the Chief Economist in DIIS. In 2014, BREE was dismantled. In 2016, the energy data and analysis function of BREE was placed in the DoEE. However, DIIS maintains coal and uranium production statistics, energy trade statistics and related forecasting, as well as the natural resource database. The **Energy Statistics and Analysis (ESA)** section is now integrated in the Economics Branch of DoEE which will allow for a better interaction with energy and climate change data and policies. The ESA section, which is in charge of reporting to the IEA, prepares the annual Australian energy balance, the energy efficiency data, and the monthly Australian petroleum statistics. ESA has put in place a number of data-sharing agreements in recent years; however, gaps remain in the reporting of several fuel statistics to the IEA owing to limited data sharing within the Australian government: ESA does not report to the IEA coal data by type and energy content (notably steam and coking coal); natural gas production, storage; and prices in power generation, coal, electricity and gas (household/industry) and for several petroleum fuels (diesel for commercial users, light

fuel oil for industry). In addition, energy demand data are insufficient to properly assess how and why energy is being used, notably as the NGERS is not covering the entire energy-related sector activities. Data on households' electricity prices reported to the IEA do not include values during 2005-11. For household electricity prices, ESA uses data from the Australian Energy Market Commission's annual report on residential electricity price trends at a national average price, with a goods and service tax (GST) added, and produces a weighted average based on the number of household connections in each jurisdiction.

Energy statistics legislation

In 2012, the Clean Energy Regulator took over the administration of the *NGERS* which was introduced by the *National Greenhouse Gas and Energy Reporting Act 2007*⁴ to provide data and accounting in relation to GHG emissions, energy consumption and production under a single national framework. DoEE has formal oversight of NGERS and NGER Act and responsibility for fulfilling Australia's international GHG inventory reporting obligations, tracking progress in Australia's international emissions reduction commitments and informing public and private research and policy making. The *NGERS* provides a national framework for reporting and disseminating company information about GHG emissions, and energy production and consumption. Data are also collected to inform the Safeguard Mechanism and for the administration of the Emissions Reduction Fund (ERF), some of which are published online in the contract and project register by CER at corporation level, without providing details by sector or facility.

The Australian government collects monthly oil data from individual companies on a voluntary basis, and publishes aggregate statistics in the Australian Petroleum Statistics (APS). However, the rate of participation in this voluntary reporting scheme has been in decline since the early 2000s as the market has evolved to include a greater number of participants. Around 30 companies participate (as of March 2017), including many petroleum refiners, producers and wholesalers, some of which have participated since the APS began. However, there are at least 15 other companies that do not participate in this voluntary scheme and recent new entrants into the petroleum industry are unaware of or unfamiliar with the nature of the APS.

To address this situation, the government introduced the *Petroleum and Other Fuels Reporting Bill 2017* to establish the framework for a mandatory reporting requirement on 30 March 2017. This Bill has passed through the Australian Parliament and a mandatory reporting obligation will apply from 1 January 2018. The *Petroleum and Other Fuels Reporting Bill 2017* will enable DoEE to report more accurate statistics to the IEA. This legislation covers the following fuels: crude oil, condensate, liquefied petroleum gas, natural gas liquid, gasoline, diesel, kerosene, fuel oil, heating oil, naphtha, oil, lubricant or grease, paraffin wax, petroleum-based solvent, petroleum coke, bitumen, biofuel, hydrogen or related fuels if associated in the following activities: production, refining, wholesaling, importing, exporting, stockholding or any other activity deemed appropriate by the minister and prescribed in subordinate legislation (*Petroleum and Other Fuels Reporting Rules 2017*). It does not include compressed or liquefied natural gas.

⁴ www.legislation.gov.au/Details/C2017C00054

Assessment

Energy markets in Australia have changed significantly since the creation of the National Electricity Market in 1998. The institutional structure of the NEM remains complex as the Commonwealth government delegated the governance of the energy market to independent market bodies (AEMC, AEMO and AER) which work along Commonwealth agencies, and under the COAG Energy Council. These bodies also produce a wide range of analysis and data on energy wholesale and retail markets for the NEM, sometimes with overlapping or different methodologies and objectives.

In 2015, the *Review of Governance Arrangements for Australian Energy Markets* (the “Vertigan Review”) (Vertigan, 2015) and in 2017, the *Independent Review into the Future Security of the NEM* (the “Finkel Review”) both highlighted the need for institutional reform and provided recommendations for streamlining and improving the NEM governance. While the reviews found that the institutions of the NEM are sound thanks to their independence and analytical strength, their structured collaboration could be improved. In this context, the Finkel Review proposed an Energy Security Board (ESB) as a new self-co-ordination body which should, among others, develop a data strategy for the NEM (Finkel, 2017). With regard to energy analysis and energy data, the IEA believes that joint monitoring and reporting based on joint data collection could foster transparency on price data and provide essential market data (see also Chapter 4 on Electricity which provides an overview of the retail market monitoring as an example). The new ESB should help to bring together analysis, data and policy advice for more streamlined rulemaking in the NEM. The national energy guarantee proposed by the ESB for the NEM will be the litmus test in this regard.

On the other hand, covering the entire country (NEM does not cover the Northern Territory and Western Australia), the Commonwealth government’s energy data have shortcomings in quality, time series gaps and a lack of reporting from industry, notably on prices, production and energy infrastructure capacity and usage. Within the Commonwealth government, data are collected for different purposes and by different government organisations and a high level of data confidentiality is imposed under legislation or administrative statutes.

At the level of the Commonwealth government, the energy data function, the Energy Statistics and Analysis (ESA) section, has been transferred to DoEE which is a welcome development in support of the further integration of energy and climate data. ESA has been active in establishing a range of data sharing arrangements with other government departments and related agencies. That marks strong progress. The IEA encourages the government to continue its efforts in improving and streamlining information flows within the government, noting that there are often significant legislative barriers to sharing commercially sensitive or personal information between agencies. The IEA encourages the DoEE to continue developing data-sharing agreements with other federal government departments and authorities collecting or holding data that could help fill remaining gaps in the energy statistics and complement the mandatory data-reporting scheme.

To address the current gaps with regard to ESA reporting to the IEA, the IEA recommends that the Commonwealth government gives priority to a comprehensive data-sharing agreement, notably with the Competition and Consumer Commission and the Department of Industry, Innovation and Science, in particular to obtain

authorisation to use the price data and report on them. ESA should also continue to build strong data-sharing arrangements with the states and territories on electricity and primary production data. This will enable the full understanding of the market and will allow Australia to make meaningful comparisons with prices in other countries, data which the IEA collects from all member countries.

Non-reporting in voluntary surveys of the petroleum statistics may lead to under-reporting of energy data, including the commercial stockholdings that Australia reports to the IEA. Analysis commissioned by DoEE estimated that between 10% and 20% of stocks of products are not reported in the monthly data – the equivalent of at least 3-days of net oil imports each month. The government should work with industry to conduct a formal audit of capacity of domestic oil storage infrastructure before end-2019 so that the information can be taken into account during Phase-2 of the plan to return to compliance. The IEA considers that the information on oil storage capacity will complement the higher-quality oil data expected to be obtained under the mandatory data-reporting scheme. In general terms, data for monitoring energy security could be further streamlined and strengthened, amid the creation of the Energy Security Office in DoEE. This would align with a regular update of the Australian National Energy Security Assessment (NESA), a subject that is further discussed in Part I of this report. With proper monitoring, analysis and planning, notably on oil, gas and electricity supply-demand balance, and on oil, gas and electricity storage data, emerging and potential energy security issues could be identified earlier, enabling policy remedies to be developed in advance.

Reporting obligations are introduced by the *Petroleum and other Fuels Reporting Bill 2017*, which were adopted by the Australian Parliament in 2017. However, the new mandatory reporting scheme mainly covers liquid fuels and does not help address the existing gaps in relation to natural gas data (particularly with regard to production and storage) and to coal data by type and energy content at this stage.

Australia is a leading coal exporter and is becoming a major gas exporter but the weakness of data remains a concern, including for assessing gas supply adequacy and energy security. Data on natural gas capacity has partly become available online in the *Natural Gas Bulletin*. This and the creation of the natural gas hubs and the planned gas price index by ABS are all positive examples of moving towards greater market transparency. However, if results are not sufficient, the government should continue improving data reporting by industry in areas where market transparency efforts do not lead to open access to data. At present, some natural gas producers decline to participate in the voluntary data-reporting system. However, other natural gas producers do participate in mandatory reporting obligations at state level. A review of the mandatory reporting legislation is scheduled for 2021. This presents a good opportunity to review the appropriateness of expanding mandatory reporting to natural gas. Given the strong development of gas in Australia, efforts to bring this date forward would be beneficial.

Data on energy demand remain a challenge. The Australian government aims at expanding and refining its data collection on energy end-use at a national level through expanding the electricity work of CSIRO with ESA and AEMO. However, data on energy use in buildings, appliances and commercial sectors remain a challenge, as the Clean Energy Regulator only provides information on participating companies at corporate level, not by sector or facility. The Commonwealth government is

encouraged to expand the breakdown of the GHG and energy reporting (NGERS), including through international collaboration, bilaterally with the IEA and by joining the G20 energy end-use metrics initiative of the IEA and ADEME, the French agency on environment and energy, which started in 2017.

Recommendations

The government of Australia should:

- Strengthen the National Energy Market governance, taking up the recommendations in recent reviews, including the Vertigan and Finkel reviews, and establish joint reporting, monitoring and analysis across the NEM institutions.
- Increase transparency and analysis of greenhouse gas and energy end-use data reporting and collection through the NGERS scheme towards sector and facility information through close collaboration with CER, DoEE, CSIRO and AEMO, including by making use of international collaboration in that area in order to improve long-term energy supply, demand and emission scenarios.
- Strengthen resources to consolidate the energy statistics function at DoEE and foster data quality and cross-government data sharing.
- Improve energy demand-side data collection and evaluations for policy analysis, building upon the energy end-use data models of CSIRO and AEMO, and join international collaboration to build robust energy consumption metrics.
- Implement mandatory reporting for liquid fuels and consider its extension to natural gas, and all other sources of energy.
- Continue to develop data-sharing arrangements across government and agencies to improve data quality.
- Seek to improve price data to ensure transparency of energy cost and price drivers and to ensure that full international comparisons can be of benefit to Australians.

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Summary of Part I

Australia is well endowed with energy resources. The country is an oil producer, and although production is in decline, the country is still nearly 40% self-sufficient. Australia became a net exporter of gas in 1989, but natural gas production and exports have increased rapidly since 2015 to turn Australia into a rival to Qatar as the global leader in LNG exports by 2022. Coal is available in large quantities, with about 10% of the total coal production used domestically and 90% exported, making Australia the largest coal exporter worldwide. Uranium is exported from large resources; however, Australia has not invested in nuclear energy and in the absence of the regulatory framework there is a low prospect of building new plants. The country has large renewable resources, like wind, solar, some biomass and hydro, a source of energy security and affordability for a country that is so geographically remote from global markets. However, Australia is struggling with a set of complex energy security challenges in the short to medium term.

- Oil stock levels are low by international comparison, resulting in a tight supply chain in a country where distances are long and considerable efforts are needed to respond to unpredicted fluctuations in demand.
- The largest gas reserves are in the west and north of the country, while the major demand centres are in the east. And although gas production in the east is almost three times higher than domestic demand in that region, most of this is earmarked for contracted LNG exports, leaving the east with a potential gas shortfall in the near future.
- The coal-fired power fleet is ageing and a sizable portion will retire in the coming decade in the absence of significant investments. New plants may not be built, unless carbon capture and storage technology is deployed, if the country is to comply with its national emissions reduction target. Substitution of coal with gas-fired power would fit that target better; however, gas prices are very high and gas availability is tight, resulting in potentially constrained electricity generation.
- Recurring extreme weather events, including heat waves, bushfires, and cyclones, are an ongoing concern for Australia and there are large areas of the continent with exposure to droughts. As around 85% of the Australian population live in coastal areas, the country's infrastructure is vulnerable to climate change impacts from tropical cyclones, sea-level-rise, flooding and inundations.
- So far, the potential of wind and solar remains largely untapped for the country as a whole and installed capacity is unevenly distributed among the states, with a prominent penetration in South Australia. The National Electricity Market (NEM) has a stretched power system with bottleneck interconnectors between the states. Electricity transmission costs are high. The integration of greater shares of variable renewable energy remains challenging with given NEM's low levels of interconnection and declining baseload capacity.

In short, the country is in a paradoxical situation: while Australia is well endowed with natural resources, energy security risks across several sectors have increased. This is markedly different from the way the situation was perceived only five years ago. In 2016, the NEM was confronted with a statewide blackout in South Australia, several situations of load shedding, and gas shortages; and reliability issues have become a concern under extreme situations. This was exacerbated by unclear policy directions from changing administrations with fundamentally different views on how to reduce emissions.

Part I of this report focuses on energy security and addresses short- and long-term energy security issues. In general, short-term issues result in direct government intervention or use of emergency powers, preferably law-based and informed by accurate data.

Data are collected and reported for different purposes and by different government organisations. Industry reporting requirements are mostly voluntary and data are confidential at facility level in the energy sector. The Australian government is aware of these barriers and is working to improve information flows, including between data-collecting authorities through bilateral memorandums of understanding across government. A general data-sharing and transparency initiative is critical to support these efforts, in order to enhance analysis and policy development. With proper monitoring, analysis and planning, security issues could have been signalled earlier and remedies could have been applied. Energy data are essential for the government regularly to examine the vulnerabilities in the energy system.

One example is the gas sector, where insufficient reliable and transparent data on gas supply, storage, transportation and gas consumption by power generation are hampering the analysis of gas security challenges. The Australian government has decided to act on those shortcomings and made gas security a priority, notably through the introduction of the Australian domestic gas security mechanism, which came into effect on 1 July 2017. Greater transparency is expected from the work of the price inquiries by the Australian Competition and Consumer Commission (ACCC), the Gas Bulletin Board and the changes in the National Gas Rules and Laws by the COAG Energy Council.

Australia hosted the IEA Unconventional Gas Forum in Brisbane in February 2017. Queensland has been a leader in its engagement in environmental, safe and sustainable development of unconventional oil and gas reserves, much in line with the IEA golden rules.¹ Other states/territories can learn from this experience. The COAG Energy Council is implementing a gas supply strategy to improve collaborative efforts between jurisdictions on scientific and regulatory issues associated with onshore gas. The Australian government's Department of Industry, Innovation and Science supports the implementation of this work.

However, Australia's exposure to international gas prices through massive LNG exports may require a structural adaptation of the economy. Contracts of domestic gas users on the east coast market that had a comparative advantage, before LNG exports commenced in Queensland, can no longer benefit from prices that are below international prices, when long-term industry contracts expire in the coming years. Under these new circumstances, gas markets need to be redesigned to safeguard competition

¹ IEA (2012), *World Energy Outlook, Special report, Golden Rules for a Golden Age of Gas*.

in the domestic market, and, for future security, new gas production needs to be opened to foster a more liquid and competitive gas market in eastern Australia.

The implementation of the Paris Agreement will also have consequences for energy security. An emissions reduction target for the country as a whole has been established (26% to 28% by 2030 and the government is reviewing its policies in 2017 to ensure they remain effective in meeting this target and the Paris Agreement commitments. Ongoing uncertainty about future climate policies can become an investment barrier, as illustrated in the recent years. Amid rising concerns related to electricity and gas security during 2016, the COAG Energy Council, the Australian government, all NEM market bodies and the system and market operator AMEO have been conducting a number of reviews of Australia's electricity and gas security throughout 2016-17.

Following the system-wide black out in South Australia on 28 September 2016, which left the entire state without electricity following severe storms and heat waves, the COAG Energy Council commissioned an 'Independent Review into the Future Security of the National Electricity Market (NEM)' - the Finkel Review. The black system event prompted a wider assessment of the energy market design and security in the NEM amid the rise of renewable energy and exit of thermal power capacity. Key reform actions identified by the Finkel Review were presented as 50 recommendations for increasing the system's stability and reliability in the NEM regions; robust emergency preparedness and response; strengthening the governance of the NEM through the creation of a new Energy Security Board; greater strategic policy direction from the COAG on energy and climate policy, based on a strategic energy plan; and a revised NEM agreement. In July 2017, the COAG Energy Council accepted 49 out of the 50 recommendations. The National Guarantee Scheme is designed to respond to the fiftieth recommendation.

The uncertainty about the emissions pathway in the power sector has certainly impacted the outlook – all new investment came from renewable energy. In 2017, the review of climate change policies was carried out and the Energy Security Board has recommended the creation of a national guarantee scheme, with a reliability standard and an emissions reduction standard. At the same time, states have developed their own policies, mostly aimed at increasing energy efficiency and renewable energy deployment. While this is a commendable development, such an unco-ordinated approach will most likely result in a sub-optimal outcome in terms of costs and energy security, as recent developments in South Australia have shown. Likewise, as retiring large-scale coal-fired generation can have a major impact on the generating capacity of a region, it is advisable to require that such capacity be withdrawn from the market, only with sufficient notice, so that the market can prepare itself for such retirement. The Finkel review has recommended at least three years notice, which is being implemented. Long-term energy outlooks, as now prepared by the energy market operator AEMO can guide the energy security assessments and should be based on a mid-century low-carbon strategy which would also show the contribution from energy efficiency and present an evaluation of supply/demand forecasts and impacts of current and future policies.

In May 2017, the Australian government proposed an energy security budget commitment and a legislative package of measures, including the Australian domestic gas security mechanism. While many of these actions are focusing on solving short-term issues, a more strategic view of oil/gas/electricity security on the basis of a comprehensive risk assessment in form of an updated National Energy Security Assessment (NESA) remains critical.

2. Oil

Key data

(2016 provisional)

Crude oil production: 16.9 Mt*, -23% since 2006

Net imports of crude oil: 4.5 Mt* (15.6 Mt imported, 11.2 Mt exported)

Oil products production: 20.8 Mt*, -31.5% since 2006

Net imports of oil products: 24.9 (26.4 Mt imported, 1.5 Mt exported)

Share of oil: 32% of TPES and 53% of TFC (2015)

Consumption by sector (2015, energy unit):** 42.6 Mtoe (transport 74.1%, industry 18.2%, commercial and public services, including agriculture 6.9%, residential 0.9%,)

*Supply data are presented in volumes (Mt), whereas the energy balance data tables in the Annex B are in energy units (Mtoe).

**Demand data are presented in energy units to be comparable over different fuels and sectors. TFC excludes energy transformation.

Overview

Oil accounts for over half of Australia's total final energy consumption (TFC) and about one third of total primary energy supply (TPES). Oil production has been declining for decades, while natural gas production has increased significantly; with the lion's share destined for exports. Oil product consumption on the other hand has increased along domestic refinery closures and a rapid growth in imports from Asia, increasingly from Korea. Low tax levels provide Australian consumers with relatively cheap fuels. On the other hand, lower oil (but higher natural gas) production has also reduced government revenues from royalties and taxes at the Commonwealth and state levels. Fuel quality standards for gasoline and diesel sold in Australia can vary, and the government is looking into aligning and improving the country's fuel standards, in conjunction with the tightening of vehicle emission standards.

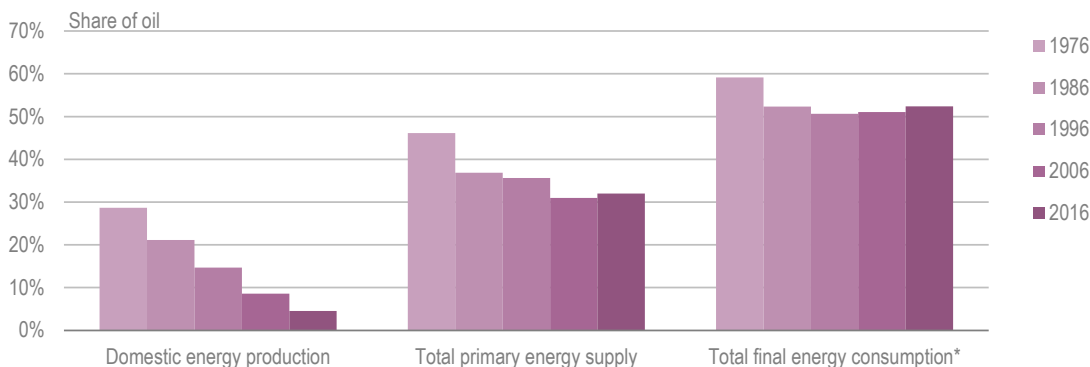
Supply and demand

Oil is the second-largest primary energy source in Australia, just behind coal in TPES, and the largest in TFC. Transport is the biggest oil-consuming sector, accounting for 74% of total oil consumption and growing demand has led to increasing imports of oil products.

Production and imports

Australia's domestic crude oil production has declined by 23% in the past decade to 17 million tonnes (Mt) in 2016, the lowest level since the IEA began recording in 1973. Crude oil production peaked at 33 Mt in 2000/01, when it covered almost the entire domestic consumption. In 2016, Australia's oil import dependence stood at around 67%.

Figure 2.1 Share of oil in Australia's energy system, 1975-2016



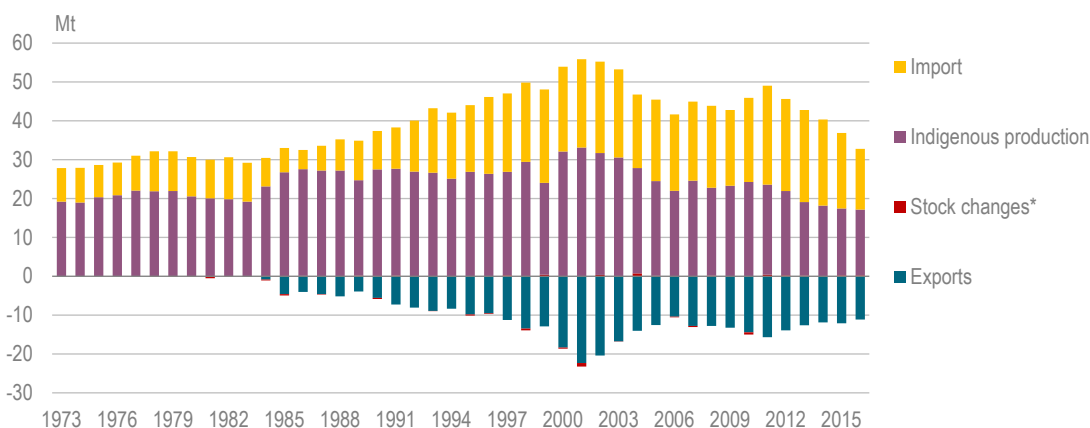
*The latest consumption data are for 2015.

Note: Data are provisional for 2016.

Source: IEA (2016), *Energy Balances of OECD Countries 2016*, www.iea.org/statistics/.

Production has been falling and there have been no significant oil discoveries since 2000. Australia has 14 years of reserves remaining at current rates of production (GA, 2014), mostly unconventional reserves. Around 80% of crude production is exported. Rising condensate production from the north-west is suitable to Asian refineries and Australia's consumption and refining centres are mainly located in the south. Domestic crude oil production (including condensate) averaged 322 thousand barrels per day (kb/d) in 2015, as mature fields continue to decline. Production is projected to increase to around 390 kb/d in 2018-19 with additional condensate production associated with the natural gas projects in Gorgon, Prelude and Ichthys. It is expected to tail off again – declining to an average of 338 kb/d by 2021.

Figure 2.2 Crude oil supply by source, 1973-2016



*Negligible.

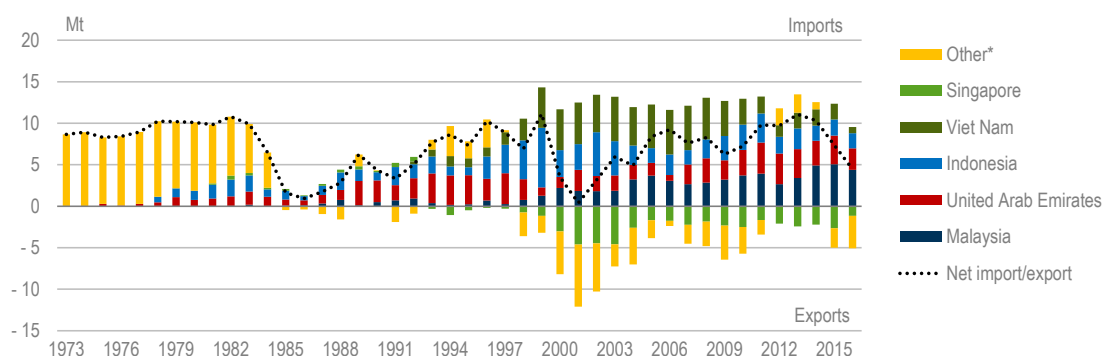
Notes: Crude oil including natural gas liquids and feedstock. 2016 data are provisional.

Source: IEA (2017a), *Oil Information* (database), www.iea.org/statistics/.

According to industry, the only way to reverse the country's declining production levels in the long term is to develop new fields. Although oil exploration activity is continuing, notably in the southern Great Australian Bight and in the north-west (see Figure 2.8), few sizeable oil discoveries have been made in recent years. Because of geological and other factors, there are few opportunities to utilise enhanced oil recovery or similar initiatives to slow or reverse the decline of Australia's existing oilfields. The recent decline in upstream investment due to lower oil prices will contribute further to the long-term declining trend. Australia's petroleum exploration expenditure by industry was AUD 355 million in Q3 2016, down by 39% from the previous year.

Australia exports a large share of its crude oil production, mainly to Thailand, followed by Singapore and the People's Republic of China (hereafter "China") (included under "Other" in Figure 2.3). In 2016, Malaysia was the largest crude oil exporter to Australia, accounting for 28% of Australia's total imports, followed by the United Arab Emirates (17%), Indonesia (12%) and Viet Nam (5%).

Figure 2.3 Crude oil imports and exports by country (net), 1973-2016



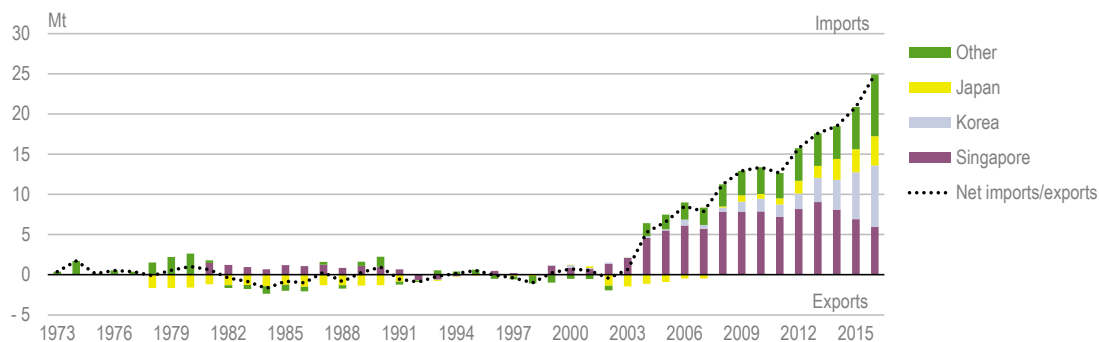
*Other includes exporting countries, e.g. New Zealand and Gabon, and importing countries, e.g. China and Thailand.

Note: Crude oil including natural gas liquids and feedstock. Data are provisional for 2016.

Source: IEA (2017a), *Oil Information* (database), www.iea.org/statistics/.

Australia produced 20.8 Mt of oil products in its refineries in 2016, which covered just over half the domestic demand. Net imports were 24.9 Mt, which represents an increase by nearly three times in ten years since 2006. Korea accounted for 29% of total oil products net imports, followed by Singapore with 23% and Japan with 14%; other small oil product exporters to Australia include India (9%), China (8%), Malaysia (7%), and the United States (3%), altogether referred to as "Other" in Figure 2.4.

Australia's sources of petroleum product imports are well diversified. Dominated by Singapore until 2011-12, diversification (primarily from the Asian region) has increased as Australia's reliance on imports has also increased. Oil product imports from Singapore declined from a 52% share of total imports in 2006 to a 23% share (on average) in 2016, while those from East Asian countries, namely Korea and Japan, have increased sharply. In 2016, the volume of imports from Korea exceeded that from Singapore, and Korea became the largest source of oil products for Australia.

Figure 2.4 Oil products imports and exports by country (net), 1973-2016

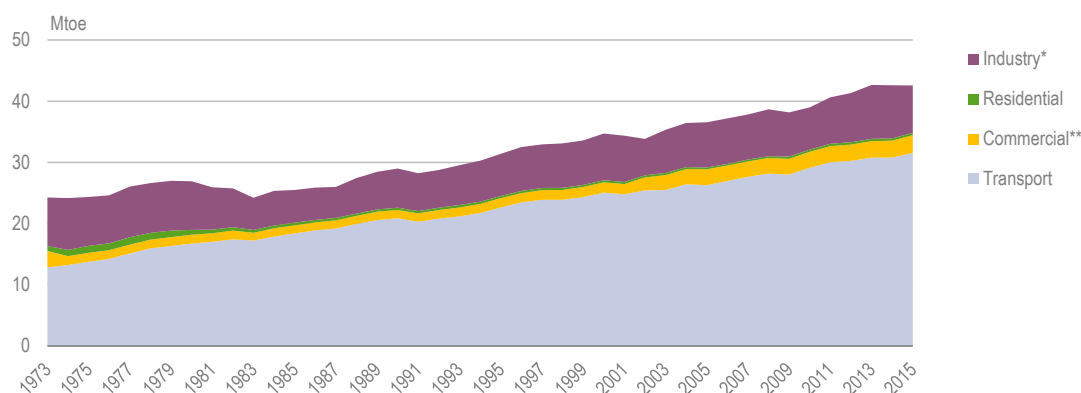
Note: Data are provisional for 2016.

Source: IEA (2017a), *Oil Information* (database), www.iea.org/statistics/.

Consumption

Australia's oil consumption has increased by 19% from 2005 to 2015 (see Figure 2.5). While total consumption has increased over several decades, thus increasing oil import needs, the shares of consumption by sector have been relatively stable.

The transport sector is the largest consumer, accounting for 74% of total final oil consumption in 2015¹. Oil consumption has increased by 20% in the sector, similar to the growth in total oil demand. Road transport accounts for the largest share and over half the total oil consumption in the country (see Figure 2.6). The industry sector accounts for 18% of oil consumption, of which almost half is for non-energy purposes such as feedstock in petrochemical industries' processes. Mining and quarrying is the largest oil-consuming industry. The commercial sector, including agriculture, accounts for 7% of oil consumption, and the remaining is a small share in the residential sector.

Figure 2.5 Oil demand in TFC by sector, 1973-2015

* *Industry* includes non-energy use.

** *Commercial* includes commercial and public services, agriculture/fishing and forestry.

Note: TFC by consuming sector for crude oil (plus refinery feedstock, natural gas liquids, additives and other hydrocarbons) and oil products, but excluding energy transformation and international aviation.

Source: IEA (2017b), *World Energy Balances 2017*, www.iea.org/statistics/.

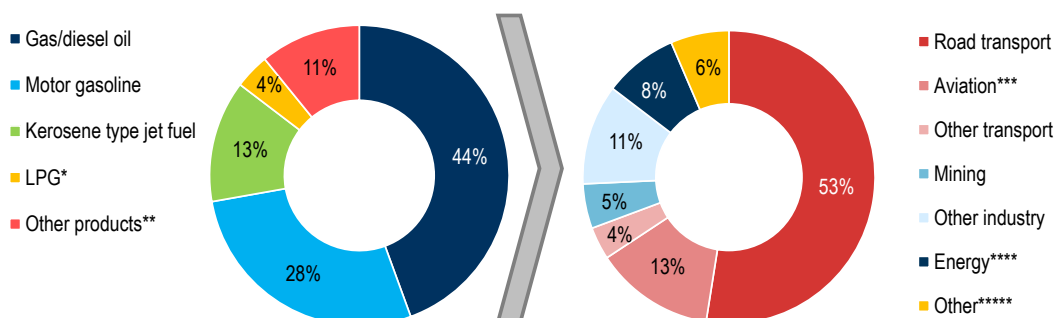
¹ This means the share of oil in TFC per consuming sector, excluding energy transformation.

Diesel oil has been the most consumed oil product in Australia since 2005 and consumption increased by 50% by 2015. Diesel is consumed mainly in the road transport sector but is also an important fuel in agriculture and in mining.

Motor gasoline is the second-largest oil product, consumed almost entirely for road transport. Unlike diesel fuel, gasoline use has declined slightly by 4% in the last decade.

Consumption of kerosene-type jet fuel used in aviation has increased by 72% from 2005 to 2015. International aviation accounted for over half total kerosene consumption, but consumption in the domestic aviation sector has increased at a faster rate in the last decade, with more than a doubling in kerosene consumption for domestic flights since 2005.

Figure 2.6 Oil supply by fuel and consumption by sector, 2015



* LPG = liquefied petroleum gases.

** *Other products* include petroleum coke, fuel oil, ethane, bitumen, lubricants and other oil products.

*** *Aviation* includes international aviation fuel, which is not included in TPES.

**** *Energy* includes electricity generation and energy industry's own use.

***** *Other* includes residential, commercial and public services, agriculture and forestry.

Note: Data are in volumes.

Source: IEA (2017b), *World Energy Balances 2017*, www.iea.org/statistics/.

Infrastructure

Refining

Australia has four operational refineries – down from seven in 2012. The impact of the closure of three of Australia's seven refineries has been a reduction in crude oil imports and an increasing reliance on imported product to satisfy market demand. Australia's combined refining capacity currently stands at 447 thousand barrels per day (kb/d).

The four remaining refineries include the 146 kb/d Kwinana refinery in Western Australia (owned by BP); the 109 kb/d Lytton refinery in Queensland (owned by Caltex); the 80 kb/d Altona refinery in Victoria (owned by ExxonMobil); and the 112 kb/d Geelong refinery in Victoria (owned by Viva).

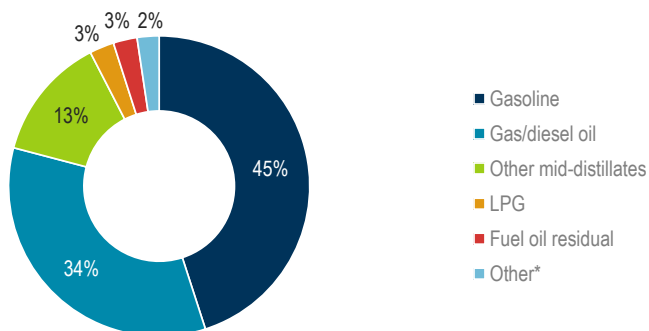
Recent and planned investments to boost Australia's domestic refining capacity included a Viva commissioned 100 million-litre super crude tank in 2017 which will provide capacity to store additional crude to boost peak refining capacity at the site. Viva also invested in AUD 23 million fuel pumping station between the Geelong refinery and the Newport terminal, providing for additional transport capacity between the facilities,

equivalent to 100 trucks per day. In 2016, ExxonMobil announced a major expansion of the Altona refinery's diesel and jet fuel production capacity from 80 kb/d to 90 kb/d. The expansion will result in an increase in the quantity of domestically produced crude that can be processed by the refinery.

Australian refineries face considerable competition from mega-refineries in Asia, with Singapore product prices largely determining their profitability. Australian refineries use both domestic and imported crude, primarily from the country's Bass Strait production in the south and from Southeast Asian producers. However, for much of the past decade, the country's refineries have steadily increased their reliance on imported crude. Around 78% of Australia's refinery feedstock was imported in 2015-16. This situation has arisen for a number of reasons. Australia's recent oil discoveries have increasingly been in the north-west of Australia, a region that is geographically distant from much of the country's existing refining capacity, but relatively close to Asian refining centres. In many instances, the quality characteristics of domestically produced oil (e.g. condensates) are also more suited to offshore Asian refineries than to those in Australia. As a result, even despite the decline in domestic oil production, around three-quarters of domestic crude production is exported overseas.

The domestic refiners produce mostly gasoline and middle distillates, as well as smaller volumes of bitumen and liquefied petroleum gas (LPG). In 2016, gasoline accounted for 45% of refinery output, diesel for 34% and jet fuel and kerosene for 13%.

Figure 2.7 Refinery output, 2016



* Other includes petroleum coke, naphtha and other oil products.

Source: IEA (2017b), *World Energy Balances 2017*, www.iea.org/statistics/.

Three refineries – Clyde (Sydney), Kurnell (Sydney) and Bulwer (Brisbane) closed in 2012, 2014 and 2015, respectively – have been accompanied by the conversion of these facilities to product import terminals to provide the necessary infrastructure for maintaining domestic supply. For example, the Kurnell refinery was converted into a 750 million litre capacity terminal.

Pipelines

As Australia is an island continent, 100% of its oil imports are delivered by crude oil tanker. The country has four key pipelines for transporting oil and oil products domestically:

- Santos operates the 659 km Moomba-Port Bonython crude oil pipeline in South Australia

- Esso/BHP Billiton operates the 185 km Longford-Long Island crude oil pipeline in Victoria (south-east of Melbourne)
- Caltex operates a 211 km Sydney-Newcastle petroleum product pipeline in New South Wales
- There is also a 269 km Mereenie-Alice Springs crude oil pipeline in the Northern Territory, owned by Central Petroleum and the Macquarie Group, but this pipeline is currently not in service.

Ports

Australia reportedly has oil port import capacity of around 35.5 million tonnes per year (Mt/y). The oil ports are geographically widely distributed around the country, with the largest being the Port of Brisbane with nameplate import capacity of 10.5 Mt/y. During the mining boom, there was significant investment in import terminals, particularly in Queensland and Western Australia, where the market grew rapidly to meet increased demand stemming from intensified mining activity. Across Australia, there are over 30 metropolitan and regional centres with storage terminals which supply petroleum products to their local region.

Storage capacity

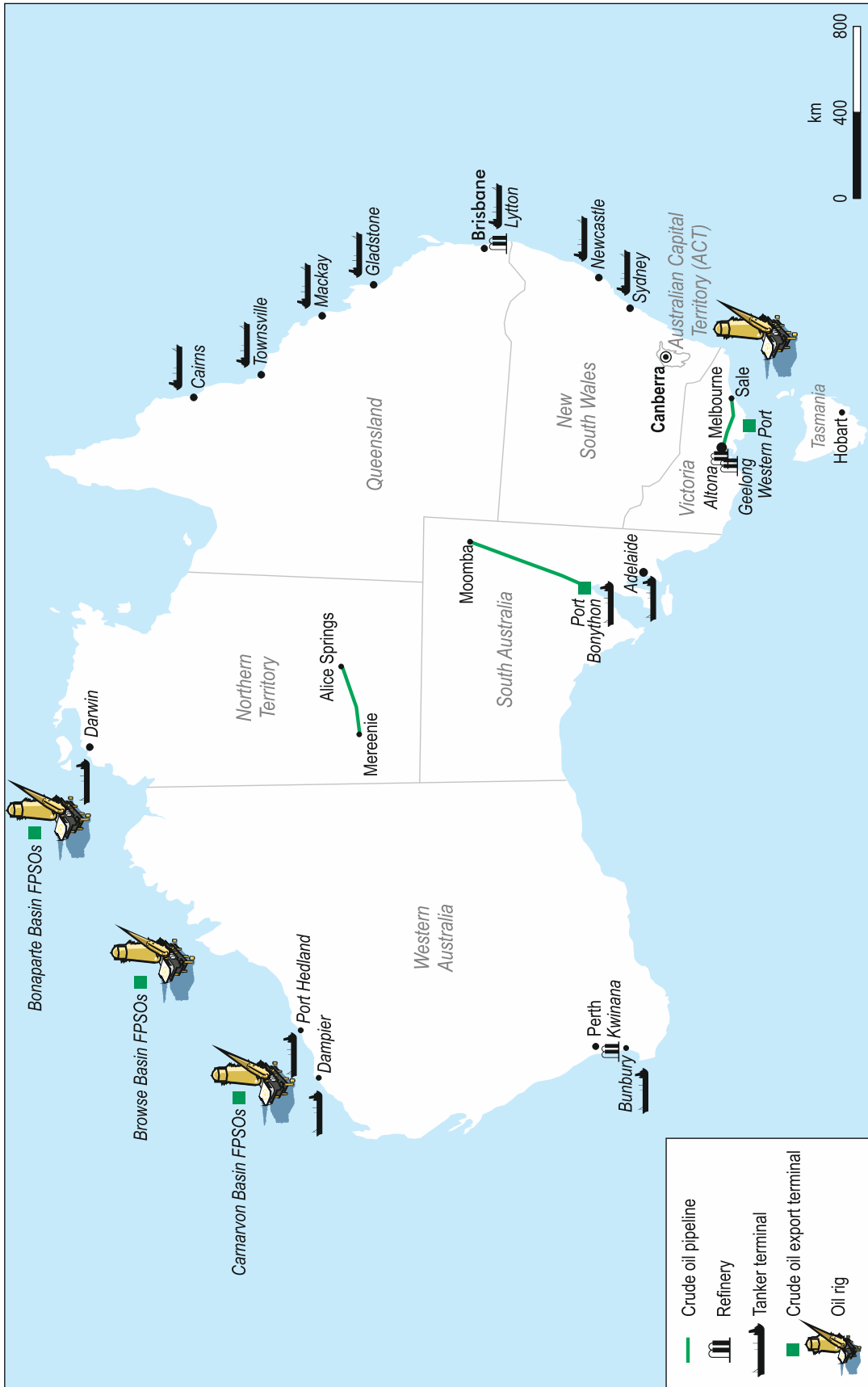
Australia has about ten main oil storage facilities geographically distributed throughout the country (with at least one per state or territory). In 2016, total crude oil storage capacity stood at 26 million barrels (mb), while refined product storage capacity totals 35.3 mb. Total reported oil storage capacity is 61.3 mb. The reported oil storage capacity significantly exceeds the reported crude oil and product stock levels (which are 9 mb and 21 mb respectively as of end November 2016) by more than 100%.

Market structure

Over the past five years, there have been significant changes in Australia's downstream petroleum industry with one oil major, Shell, exiting all aspects of the Australian downstream petroleum market (including the aviation business which was purchased by Viva Energy Australia). The second oil major, Chevron, divested its share in Caltex Australia. Another recent development in the Australian oil market is the entry of Vitol and Trafigura (international commodity trading companies), through the acquisition of supply chain infrastructure and existing marketing businesses.

In 2014, Vitol launched Viva Energy Australia following the acquisition of Shell Australia's downstream assets, including its Geelong refinery and 850 retail sites. Viva Energy operates as a Shell licensee. In late 2014, Viva Energy acquired independent wholesaler Liberty Oil. Puma Energy Australia, which is part-owned by Trafigura, entered the Australian market in 2013 with the acquisition of small independent wholesalers Ausfuel Gull, Neumann Petroleum, Matilda and the Central Combined Group. Puma Energy operates over 270 retail sites and has since acquired the bitumen businesses of Caltex Australia and BP Australia. The volume of retail sales by brand in the financial year 2013/14 was shared as follows: BP (13%), Caltex (18%), Coles Express/Shell (24%), Shell (2%), Woolworths/Caltex (24%) and other retail chains (19%).

Figure 2.8 Oil infrastructure in Australia



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Institutions

The Australian Institute of Petroleum (AIP) represents (primarily) the midstream and downstream participants in the domestic oil industry. It has around 31 members – all of which are companies involved in refining and/or marketing petroleum. This includes the four largest players: BP, Caltex, Mobil and Viva.

The AIP provides a key link between industry and government. It also promotes industry's self-regulation and facilitates the development and implementation, by its member companies, of common policies and programmes. The AIP also represents Australia's oil industry on the IEA Industry Advisory Board (IAB).

The Australasian Convenience and Petroleum Marketers Association (ACAPMA) represents the interests of the petroleum distribution and retail industry. ACAPMA members comprise 95% of Australia's fuel distribution and storage businesses, which supply fuel to approximately 4 800 retail fuel outlets in Australia.

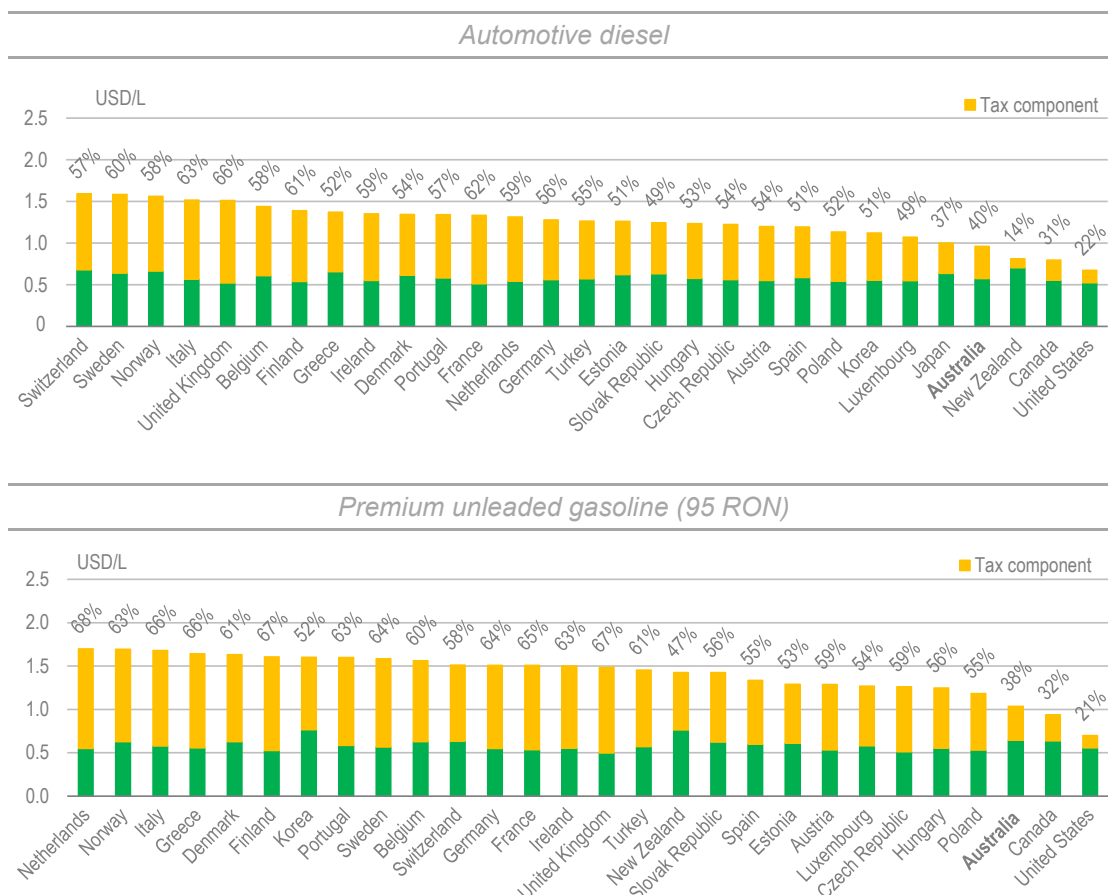
Prices and taxes

Australia has low oil fuel taxes compared to many IEA member countries, resulting in relatively cheap fuels. In the second quarter of 2017, the household price for automotive diesel was USD 0.96 per litre, the fourth-lowest among IEA member countries. Taxes accounted for 40% of the total price. The gasoline price was slightly higher at USD 1.01 per litre, of which 38% was taxes. Australian households paid the third-lowest gasoline price among IEA members, with only the United States and Canada being cheaper.

Australia has a fuel excise tax on most fuel products, with petrol and diesel taxed at 40.1 cents per litre as of 1 February 2017. There is a full rebate on the excise tax for petrol and diesel used in various business activities – including for use in vehicles or machinery that is not used on the road. The rebate is offset by a road user charge for otherwise eligible heavy vehicles used on the road which is set at 25.8 cents per litre as of 1 July 2017.

There are also three different taxes that apply to upstream oil and gas activities:

- A petroleum resource rent tax (PRRT) of 40% on the taxable profit of a petroleum production project (netted government revenue of AUD 950 million in the 2016/17 financial year).
- Royalties at the Commonwealth, state and territory levels set at 10% to 12.5% of wellhead value (netted government revenue of AUD 1.3 billion in the 2015/16 financial year – down from AUD 2.6 billion in 2013/14).
- A crude oil excise tax imposed on eligible crude oil and condensate production from coastal waters, onshore areas, and the North West Shelf project area in Australian maritime territory (netted government revenue of AUD 353 million in 2015/16, down from AUD 518 million in 2014/15 and projected to fall another AUD 200 million in 2016/17).

Figure 2.9 Fuel prices in IEA member countries, second quarter 2017

Note: No data available for Japan (gasoline).

Source: IEA (2017c), *Energy Prices and Taxes second quarter 2017*, www.iea.org/statistics/.

Resource taxation

Under the *Petroleum Resource Rent Tax Assessment Act 1987*, the Petroleum Resource Rent Tax (PRRT) is designed as a profit-based tax which is levied on a petroleum project. Such a project can involve the recovery of all petroleum products from Australian Government waters (including crude oil, natural gas, liquid petroleum gas (LPG) condensate and ethane), except for petroleum products extracted from the Joint Petroleum Development Area, and value added products such as liquefied natural gas (LNG). From 1 July 2012, the PRRT was extended to apply to all Australian onshore and offshore oil and gas projects, including the North West Shelf, oil shale and coal seam gas projects. Initially designed to apply to oil production, the context of the PRRT has changed with the growing dominance of liquefied natural gas (LNG) and declining oil production. The PRRT is applied to the gas used to produce LNG but not to the final product.

During 2016/17, the Treasury reviewed the PRRT, and commissioned an independent review by expert Michael Callaghan (2017) into the design and operation of the PRRT, crude oil excise and associated Commonwealth royalties that apply to the onshore and offshore oil and gas industry. The Callaghan Review report of April 2017 found that the current PRRT is not discouraging investments, that the delay in PRRT payments until

projects become cash-positive was a deliberate design feature and ensured that investment would not be discouraged (Callaghan, 2017). The review recommended prioritising the stability of the fiscal environment by ensuring that an updated PRRT design is applicable only to new projects and that improvements and modernisation of the administration of the tax are available to both existing and new projects. While PRRT arrangements should be updated to be more compatible with the current state of the Australian petroleum industry, which is now dominated by gas, Mr Callaghan made allowance for the large recent investments and recommended that any new regime apply to new projects after a date to be specified.

Fuel quality standards

In December 2016, the Australian government released a discussion paper titled *Better Fuel for Cleaner Air* to seek stakeholder views on potential revisions to the country's fuel quality standards, which are set out in the *Fuels Quality Standards Act (FQSA)*. The discussion paper looked at a variety of elements relating to fuel quality standards, not only sulphur levels. Proposed changes to these standards are being considered in conjunction with the tightening of vehicle emissions standards.

While diesel sold in Australia is already subject to a 10 parts per million (ppm) standard, gasoline has much higher levels (up to 150 ppm in regular unleaded and 50 ppm in premium). The introduction of 10 ppm sulphur gasoline has not been implemented. Australia's fuel quality standards are relatively outdated and have not kept pace with world best practice and changes in the oil industry and global markets.

A key proposal in the discussion paper *Better Fuel for Cleaner Air* is to limit sulphur levels in gasoline to 10 ppm. A rigorous cost-benefit analysis is being undertaken by the government to examine the implications of low-sulphur gasoline for air quality (health benefits), gasoline prices, refining costs and greenhouse gas (GHG) emissions (vehicle versus refining). Some members of the refining industry are of the view that the proposed 10 ppm sulphur limit for gasoline will cost the Australian refining sector up to AUD 979 million to implement and that it should therefore be phased in over a period of 10 years (by 2027). The government discussion paper estimates a cost of AUD 1 billion.

The Australian Institute of Petroleum (AIP) has its own, higher fuel quality standards which its members – including the four main oil companies – have voluntarily adhered to, when it comes to additives. However, in recent years, there have been a number of new entrants to the Australian market who opted to adopt the lower government standards rather than those of the Institute. This means that fuel quality standards for gasoline and diesel sold in Australia can vary, notably with regard to additives and aromatics.

Oil supply security and emergency preparedness

Stockholding regime

Australia is the only IEA country which is a net oil importer and solely relies on the commercial stockholding of industry to meet its minimum 90-day stockholding obligation under the International Energy Program. The country does not have public stockholdings and does not place a minimum stockholding obligation on its domestic oil industry.

Compliance with the IEA stockholding obligation

All IEA countries have two obligations: *i)* to hold emergency stocks equivalent to 90-days of net imports; and *ii)* to have effective policies in place in order to be able to contribute to an IEA collective action. Australia meets neither obligation.

In 11 out of the 12 months of 2012, and for all of 2013 to 2017, end-month stock levels were below the 90-day level. Stock levels as of 1 October 2017 were equivalent to only 48 days of net imports. This was Australia's lowest reported monthly stock level in terms of days' cover since 2000, the year in which its domestic production peaked.

The stock decline is confined to crude oil stocks and has arisen from the decline in domestic oil production and the closure of three of Australia's seven refineries between 2012 and 2015. Days' cover of refined petroleum products has remained stable in recent years.

In addition to not meeting its international obligations, this situation leaves Australia more vulnerable in the event of a significant external supply shock. Although the long supply chain provides Australia with additional time to implement domestic measures in response to a supply shock, low stock levels limit the country's options for addressing such a disruption. A long supply chain also presents challenges in responding to unexpected fluctuations in domestic demand – challenges, which may be exacerbated by the relatively low stock levels.

The government is now committed to addressing this situation and in June 2016 presented a plan to return to compliance by 2026. To date, Australia has made good progress with the plan's implementation although it has further work to do. The government plan to return to compliance with its oil stockholding obligation under the Agreement on an International Energy Program in June 2016 (DOEE, 2016) includes two phases. During 2016-20, Australia will establish an initial ticketing commitment of 400 kilotonnes (kt) to ensure that the country can contribute to an IEA collective action while it implements longer-term measures for full compliance. As part of phase 1, Australia aims to start purchasing tickets in July 2018, establish mandatory petroleum and other fuel data-reporting requirements and establish a new Energy Security Office (ESO) in the government (the ESO was established from 1 July 2016 and is responsible for Australia's return to compliance). In its 2016/17 budget, the government allocated AUD 23.8 million over four years to support this first phase of work. In the second phase during 2020-26, Australia aims to build the necessary stocks (seeking a combination of physical stocks and tickets) to return to full compliance. It also committed to developing an implementation plan for the second phase of the stockholding arrangements by 2020. No decisions on budget allocations for the second phase had been announced at the time of writing the report.

Emergency response policy

In the first instance, Australia's oil security policy is based on ensuring the operation of an efficient and flexible oil market. This policy is underpinned by various policy and emergency response measures, regular vulnerability assessments and international advocacy for open and effective global energy markets. Accordingly, the country's liquid fuels market is largely unregulated during business-as-usual – with the exception of being subject to fuel quality standards and competition and consumer laws.

Australia's focus on ensuring that the oil market operates efficiently and flexibly during business-as-usual is a sound policy position. However, it is less clear how the country would respond in the event of a serious oil supply disruption leading to market failure. Although the government has very well-defined and organised structures for responding to an oil supply disruption, the physical tools, like emergency stocks, available to the government (and industry) for addressing a serious disruption are limited.

There are no distinctions either legally or administratively as to how the government would respond to an international disruption compared to a domestic one.

The *Liquid Fuel Emergency Act 1984* (LFE Act) and associated Guidelines gives the government broad powers to control the production, distribution, sale and use of liquid fuel stocks across Australia in the event of a domestic oil supply disruption or in response to an IEA collective action request. The relevant ministers in the states and territories have similar legislative authority in the event of more localised emergency events. To date, the LFE Act has never been invoked as the government's policy is to allow industry to manage fuel supply shortfalls without government intervention where possible. Under the Australian Constitution, responsibility for energy resides with state and territory governments. Each state and territory has its own legislation to address liquid fuel shortages within their jurisdiction. Co-operation between states and territories is set out in an Intergovernmental Agreement formalising planning and contingency powers under the LFE Act. These powers are for use in the event of a widespread disruption to supply across multiple jurisdictions (i.e. a liquid fuel shortage with national implications). In such an event – following consultation with state and territory ministers, Cabinet, the Department of the Environment and Energy (DoEE) and other advisors – the federal minister responsible for energy may request the Governor-General to declare a national liquid fuel emergency under the LFE Act.

National Emergency Strategy Organization (NESO)

Australia's NESO, chaired by the Minister for Energy, is comprised of the DoEE Executive; Energy Security Office (within DoEE); and NOSEC. The members of the DoEE Executive include the Secretary of the Department; the Deputy Secretary responsible for Energy; the Head of the Energy Security Office (ESO) Division; and the Heads of the Energy International Implementation Branch and the Energy Security Policy Branch in the ESO.

Assessment

Australia's oil sector is experiencing declining domestic crude oil production and refining capacity, and steadily increasing demand – leading to rising product imports. Oil is the second-largest energy source (after coal) in Australia, standing at 32% of total primary energy supply in 2016.

Australia's oil demand has increased steadily over the long term, reaching an all-time high of 42.6 million tonnes of oil-equivalent (Mtoe) in 2015. Diesel surpassed gasoline as the single largest component of Australia's oil demand in 2010. In 2015, diesel accounted for 44% of total demand (up from 31% in 2001), while gasoline represented 28%.

As in many OECD countries, the use of oil in Australia has become increasingly concentrated in the transport sector. In 2015, the sector accounted for 74% of the country's oil consumption, followed by the industry sector (including mining) 18%.

Structural changes in the Australian economy have impacted overall oil demand and the use of specific refined products. Diesel demand has increased in the road transport sector, but slightly declined in mining in recent years. Jet fuel growth has also been strong, averaging 6% per year over the past three years. The government expects continued economic growth, pushing up oil demand in the medium term.

Australia has significant but declining crude oil production levels – with crude oil and condensate production having declined by around 30% over the past decade, the lowest level since 1972. The recent decline in upstream oil investment due to lower oil prices will contribute further to the long-term declining trend in oil production, although investment has increased in LNG production. According to industry, the only way to reverse Australia's declining production levels in the long term is to develop new fields. Although oil exploration activity is continuing, notably by Chevron off the coast of the Great Australian Bight, there have been no significant oilfield discoveries in recent years. Because of geological and other factors, there are thought to be few opportunities to utilise enhanced oil recovery or similar initiatives to slow or reverse the decline of Australia's existing oilfields.

In November 2016, the government reviewed the operation of the petroleum resource rent tax (PRRT) through a report commissioned from expert Michael Callaghan. The purpose of the review was to determine whether the country's oil and gas taxes and royalties are providing a fair return to the government from the extraction and sale of oil and gas resources without discouraging investment in exploration and development. The focus of the review was to assess options to adapt the regime to the new realities of Australian oil/gas production with the start of LNG and unconventional gas production rising. From an IEA perspective, it is critical that the outcomes of the PRRT review do not result in policy changes that negatively impact the outlook for new investments in oil exploration, a point also reiterated by the Callaghan review.

In 2016, Australia's oil import dependence stood at around 67%. According to IEA data, the country's net products imports increased by 56% in the period 2010 to 2015, reaching 45% of domestic demand. The government projects that volumes of imported products will increase by a further 3.4% per year in the period to 2021.

As emphasised by the government and the oil industry, Australia's sources of oil products are well diversified. Dominated by Singapore until 2011/12, diversification of import sources (primarily from the Asian region) has increased in step with the country's growing reliance on product imports. While the diversity of petroleum product suppliers is a positive development, the risk remains that Australia's regionally sourced supplies would be affected as a consequence of a crude oil supply disruption affecting the Asian region, which is heavily dependent on Middle Eastern crude oil supplies. This situation is exacerbated by the fact that the country holds relatively low levels of petroleum stocks domestically, and is currently non-compliant with its IEA obligation to hold a stock equivalent to 90 days of net imports. In 2016, the government announced a plan to return to compliance by 2026, and is in the process of implementing it.

The sources of Australia's imports will continue to evolve in coming years in response to global market developments. For example, some projections show that the Asian region

will become a gasoline net importer from 2017, with supplies increasingly sourced from the Middle East and North America. As part of the Asian region, Australia is likely to become more reliant on longer supply chains for gasoline imports as it is already for crude oil imports. Gasoline comprised over 20% of Australia's total petroleum product imports in 2015/16. The country may, therefore, be more vulnerable than other IEA member countries to the effects of a major crude oil supply disruption to the Asian region, should such a disruption occur in the short to medium term.

The government released a discussion paper titled *Better Fuel for Cleaner Air* in December 2016 to seek stakeholders' views on potential revisions to the country's fuel quality standards. A rigorous cost-benefit analysis is being undertaken to examine the implications of low sulphur gasoline for air quality (health benefits), petrol prices, refining costs and GHG emissions (vehicle versus refining). A key proposal in the discussion paper is to limit sulphur levels in gasoline to 10 ppm. While diesel sold in Australia is already subject to a 10-ppm standard, gasoline has much higher levels (up to 150 ppm in regular unleaded, and 50 ppm in premium). Some members of the refining industry are of the view that the proposed 10 ppm sulphur limit for gasoline will cost the Australian refining sector up to AUD 979 million to implement, and that it should therefore be phased in over a 10-year period. Reducing gasoline sulphur levels and increasing minimum octane levels is important, but it is also critical that Australia swiftly considers the modernisation of standards relating to other harmful substances used in vehicle fuels such as octane-enhancing additives, like monomethylaniline (MMA) or aromatics, which have already been restricted or banned in other countries.

Recommendations

The government of Australia should:

- In conjunction with its plan to return to compliance with the 90-day IEA stockholding obligation, use part of this obligation to increase the level of buffer stocks in the domestic oil supply chain to reduce the potential economic and social impact of a major supply disruption.
- Implement improvements to fuel quality standards, including a 10-ppm standard for sulphur levels in gasoline, and restrictions on the use of octane-enhancing fuel additives, in line with modern environmental best practice.

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3. Focus area 1: Natural gas market design

Key data

(2016 provisional)

Natural gas production: 88.2 bcm, +106% since 2006

Net exports: 40.9 bcm (7.2 bcm imported, 48.1 bcm exported)

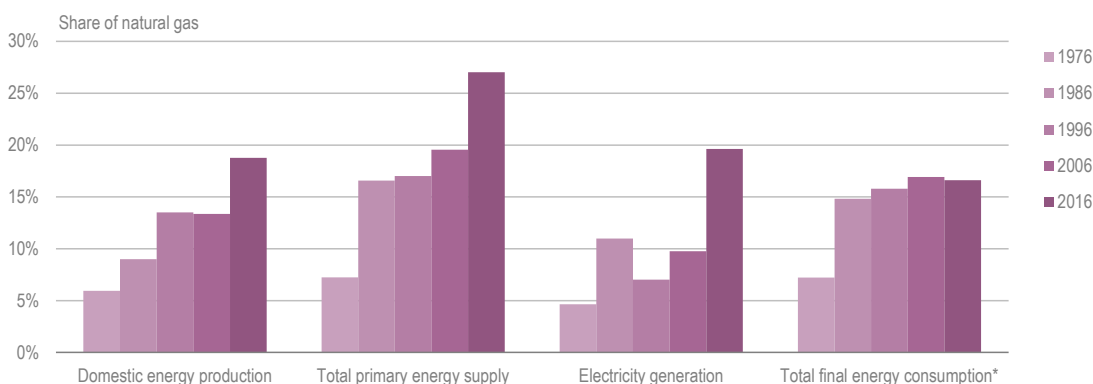
Share of natural gas: 27% of TPES and 19.6% of electricity generation

Consumption by sector (2015): 39.8 bcm / 32.2 Mtoe (power generation 36.4%, industry 26.1%, other energy industries 22.3%, residential 10.7%, commercial and public services, including agriculture and fishing 3.8%, transport 0.8%)

Overview

The role of natural gas has been growing steadily in Australia, in terms of both production and consumption (Figures 3.1 and 3.2). In 2016, gas accounted for over one-quarter of the total primary energy supply (TPES) and has become an important fuel in electricity generation. Australia has large natural gas resources, which enable the country to be self-sufficient in gas supply as well as a leading exporter of liquefied natural gas (LNG). LNG exports have rapidly increased in recent years, as a result of new LNG terminals being constructed across Australia, including in the eastern market previously a centre of domestic consumption. The country has three distinct gas markets, located in the west, north and east. Interconnections are being planned between the markets, but at present there are no interregional gas flows between the gas systems.

Figure 3.1 Natural gas share in different energy supplies in Australia, 1976-2016



* The latest consumption data are for 2015.

Note: Data are provisional for 2016.

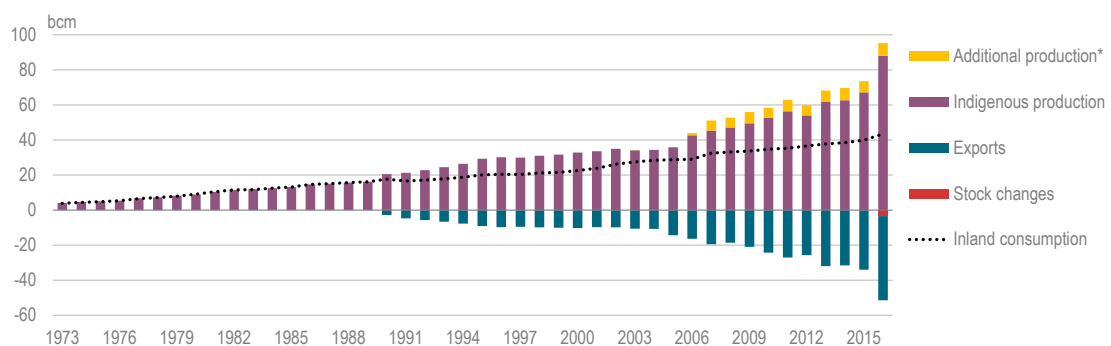
Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Gas production from new eastern fields has not been able to ramp up quickly to cover the increase in LNG demand. Gas from the domestic market has been utilised to meet export demand, causing price increases and volatility for Australian consumers, both industrial (including electricity generators) and residential, who had grown used to long-term stable and, by international standards, cheap contracts. Rising and increasingly volatile gas prices make natural gas a less competitive fuel in power generation and drive up electricity prices. At the same time, gas in power generation becomes more important for balancing an increasing share of variable renewable energy (VRE) sources on the grid. Australia's gas market competition and transparency levels are unsatisfactory, despite recent policy attention, with largely unregulated infrastructure owned by a few companies active in both transmission and wholesale markets, resulting in opaque gas pricing. Since 2014, the government has been implementing gas market reforms to improve market operations, including the creation of new gas hubs and bulletin boards providing more transparent information on prices, pipeline utilisation and commercially negotiated access. In 2017, these reforms were complemented by a gas security mechanism which provides for potential export restrictions to guarantee the domestic supply, based upon a robust adequacy assessment.

Supply and demand

In 2016, Australia's natural gas production reached 88 billion cubic metres (bcm), which was the fourth-largest in the IEA after the United States, Canada and Norway. Australia has doubled its gas production over the last 15 years, which has enabled both growth in domestic consumption and increased gas exports (see Figure 3.2). Gas production began in the Cooper Basin in South Australia almost fifty years ago but the largest production fields and reserves are found in fields of conventional gas in Western Australia and unconventional gas in the eastern states (see Figure 3.3 and Table 3.1). LNG exports have increased rapidly as several new liquefaction plants have been opened in Australia in 2015/16, and export growth is expected to continue. In the New Policies Scenario (NPS) from the IEA *World Energy Outlook 2016*, Australia's natural gas production increases to 152 bcm in 2025 and to 197 bcm in 2040 (IEA, 2016).

Figure 3.2 Natural gas supply by source, 1973-2016



* Production in the Joint Petroleum Development Area.

Source: IEA (2017b), *Natural Gas Information* (database), www.iea.org/statistics/.

Beginning in the 1960s, the first gas markets developed in the populated east coast area, often based on using associated gas from oil production. Gas was sold on long-term

wholesale contracts with low and stable prices to domestic industries, households and utilities. Since the 1980s, gas reserves offshore western and northern states have been developed for export via liquefied natural gas (LNG).

Natural gas resources in Australia

Australia has large reserves and resources of conventional and unconventional gas, including coal seam gas (CSG, also named coal bed methane). As of the end of 2014, total remaining resources were estimated at around 7 000 billion cubic metres (bcm), roughly six times as much as the total historical production. Largest resources are found as conventional gas in the Carnarvon and Browse Basins on the west coast, the Bonaparte Basin in the north and the Gippsland Basin in the south-east, and in unconventional CSG fields in the Surat/Bowen Basins (most of which are in Surat) on the east coast (see Figure 3.3 and Table 3.1). These four basins together account for almost 90% of total estimated resources in Australia.

In addition to recoverable reserves, Australia has very large prospective gas resources, estimated around 25 000 bcm, of which 17 500 bcm is shale gas, 6 100 bcm conventional gas, 1 300 bcm tight gas and 200 bcm CSG (GA, 2016).

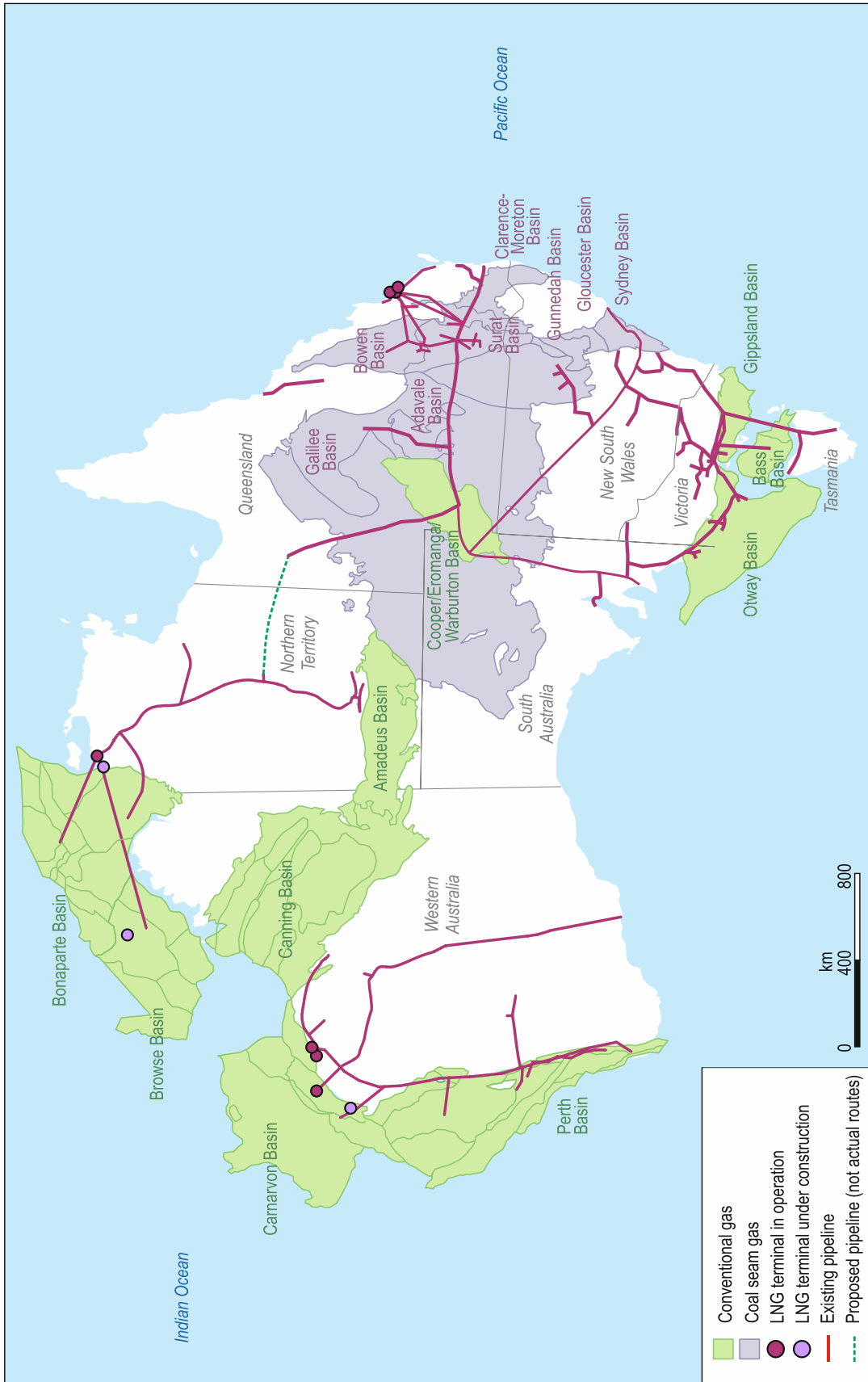
Table 3.1 Estimated recoverable resources and production by field, 2014 (bcm)

Basin (*)	Conventional gas	CSG	Total resources
Carnarvon (W)	2 599	0	2 599
Perth (W)	54	0	54
Canning/Roebuck (W)	5	0	5
Browse (W)	1 169	0	1 169
Bonaparte (W and N)	598	0	598
Amadeus (N)	10	0	10
Surat/Bowen (E)	3	1 676	1 679
Gippsland (E)	220	0	220
Cooper/Eromanga (E)	91	12	103
Bass/Otway (E)	44	0	44
Clarence/Moreton (E)	2	150	152
Gunnedah (E)	0	98	98
Gloucester (E)	0	74	74
Galilee (E)	0	68	68
Sydney (E)	0	45	45
Adavale (E)	1	0	1
Total	4 794	2 122	6 917

Note: Basins: W: Western; N: Northern; E: Eastern.

Source: GA (2016), "Gas", webpage, www.ga.gov.au/aera/gas.

Figure 3.3 Natural gas resource basins in Australia



Australian gas reserves and resources are thus significant, but much is located offshore, remote or otherwise undeveloped. Coal seam gas (CSG) exploration and production require continuous investments in new wells, as gas production levels in each well deplete relatively quickly (with smaller production levels available for longer periods). In 2016, 70% of the gas in the eastern market was supplied by the Surat/Bowen Basins, which increased production by 83%, but did still not cover the increasing demand from the exporting LNG terminals coming on line. Offshore gas production in the Otway Basin in Victoria declined by 15% in 2016, and new onshore drilling by Australia's petroleum industry overall fell by 70% in one year. Despite having large reserves, Australia is thus not guaranteed to keep up high production levels in a low-price environment, unless recently developed production improves (AER, 2017a).

Unconventional gas development and regulation

CSG is the main source of unconventional gas production in Australia. The country is the third-largest producer of CSG globally, with an output of 8 bcm in 2014, behind the United States (33 bcm) and the People's Republic of China (hereafter "China") (13 bcm). Commercial production started in 1996 in the Surat/Bowen Basin in Queensland (QLD), and it is still the main CSG field, accounting for 98% of total production in 2014 and 79% of identified CSG resources (see Table 3.1). CSG is projected to continue to grow in importance in Australia. In the *World Energy Outlook (WEO) New Policy Scenario (NPS)*, Australia becomes the world leader in CSG production by 2025, with an output of more than 60 bcm – almost half of the world's total CSG supply, and production continues to grow to reach a projected 90 bcm in 2040. New LNG plants have been the primary driver for the growth in CSG production in eastern Australia. The combined capacity of LNG plants on the east coast is 34.4 bcm and exports in 2016 were 24 bcm.

CSG production in Australia has raised social and environmental concerns with regard to impacts on aquifers, land access and public health. As a result, unconventional gas exploration has been banned in several states. The Victoria (VIC) state government decided on CSG exploration restrictions which eventually became a ban of all onshore gas exploration in the *Resources Amendment Legislation Act*, following Parliamentary approval in March 2017. The act contains a ban on hydraulic fracturing and prevention of exploration for coal seam gas. Furthermore, it imposes a moratorium on any onshore petroleum exploration and production until July 2020 (VSG, 2017). Similarly, the Tasmanian (TAS) government adopted a moratorium on fracking until 2020 and the Northern Territory (NT) government has a moratorium on unconventional gas exploration pending the outcome of an independent scientific inquiry investigating environmental, social and economic risks and impacts of hydraulic fracturing in the state (HFT, 2017). New South Wales (NSW) does not have a moratorium on unconventional gas exploration, and the government of the state is currently assessing new gas exploration projects, through an approach set in the NSW Gas Plan. South Australia (SA) and Queensland (QLD) provide incentives for gas exploration. QLD government made land available for domestic gas production only, and SA has proposed that 10% of the revenues from gas royalty will go to land-owners who allow access to their resources.

The Australian government is working to address community concerns by assessing the impacts of unconventional gas through different programmes and working groups such as the *Bioregional Assessment Programme*, the *Gas Industry Social and Environmental Research Alliance* (GISERA) and *Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development* (IESC). Specific focus has been on regulating water management to enable a sustainable model for CSG production,

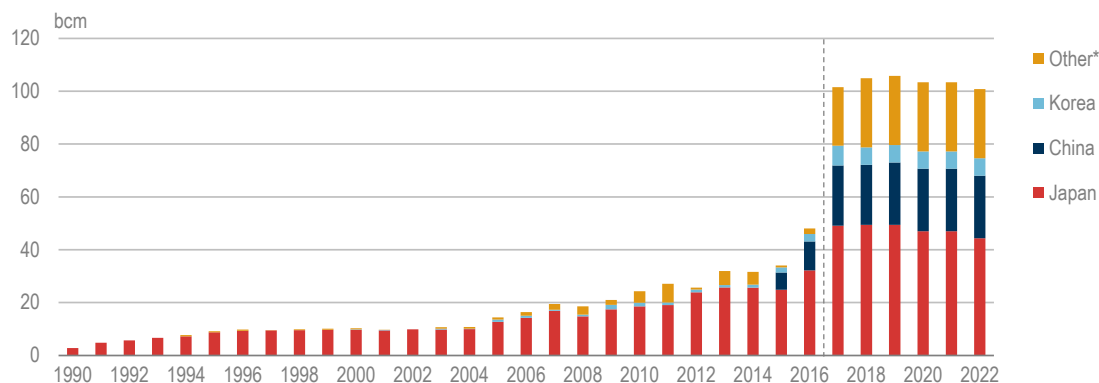
through action at both Commonwealth and state levels, and providing transparent scientific information to better understand the potential impacts of CSG and coal mining developments on water resources and water-dependent assets. The Australian government has funded AUD 100 million for an independent expert scientific committee to do research on water-related issues. Furthermore, a *Gas Acceleration Programme (GAP)* of AUD 26 million is being established to accelerate the development of known significant gas resources. This programme will support projects with the greatest likelihood of securing new and significant gas supplies for the eastern gas market from onshore gas fields.

The IEA has previously developed golden rules for gas that provide further guidance in addressing environmental and social impacts when developing unconventional gas resources (see Box 3.1).

LNG exports

Australia has been exporting liquefied natural gas (LNG) since 1989, initially from developing gas reserves offshore western and northern Australia. Export volumes were stable around 10 bcm per year from the mid-1990s until 2004, when they began to increase and doubled in five years. The Australian LNG export market changed even more significantly in 2009 to 2011, when commitments to build seven more large LNG plants with total investments of more than USD 150 billion were announced. The new plants were planned to become operational over the period 2015-19, and to increase total export capacity to nearly 120 bcm. This rapid growth has made Australia the second-largest LNG exporter in the world after Qatar. Three of the new LNG terminals are located in QLD, supplied by CSG from the Surat/Bowen Basins and conventional gas from the Cooper Basin. Japan is the largest importer of LNG from Australia, with annual imports of around 25 bcm, accounting for nearly three-quarters of Australia's total exports in 2015 (see Figure 3.4). The country exports LNG mainly through long-term contracts, and the contracted volume is set to almost triple by 2017 compared to 2015, to around 100 bcm. Exports to Japan will grow to almost 50 bcm in the coming years, but exports to China will increase more rapidly to around 24 bcm annually in 2019-22. Japan, however, will continue to be the largest importer of Australian LNG, accounting for 44% of total contracted volumes in 2022.

Figure 3.4 LNG exports and contracted exports by country, 1990-2022



* *Other* includes non-specified exports and contracts to Chinese Taipei, Malaysia and India.

Note: Export volumes 1990-2015 and contracted LNG exports 2016-22.

Source: IEA (2017b), *Natural Gas Information* (database), www.iea.org/statistics/ (contracted LNG volumes from IEA gas contracts database).

Box 3.1 Golden rules for a golden age of gas

Recent North American experience shows that unconventional gas, notably shale gas, can be exploited economically and many countries hope to emulate this success. In many cases, governments are hesitant, or even actively opposed, responding to public concerns that production could involve unacceptable environmental and social damage.

In 2012, as part of the *World Energy Outlook* series, the IEA developed its *Golden Rules for a Golden Age of Gas*, which suggested principles that can allow policy makers, regulators, operators and others to address these environmental and social impacts.

Application of these rules can bring a level of environmental performance and public acceptance that can maintain or earn the industry a “social licence to operate” within a given jurisdiction, paving the way for the widespread development of unconventional gas resources on a large scale.

Measure, disclose and engage

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting before exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.
- Establish baselines for key environmental indicators, such as groundwater quality, before commencing activity, with continued monitoring during operations.
- Measure and disclose operational data on water use, on the volumes and characteristics of waste water, and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.
- Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.
- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.
- Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas-bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.

- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.
- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.
- Treat water responsibly
- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.
- Store and dispose of produced and waste water safely.
- Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimise flaring and other emissions

- Target zero-venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse gas emissions during the entire productive life of a well.
- Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.
- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.
- Find an appropriate balance in policy making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.
- Ensure that emergency response plans are robust and match the scale of risk.
- Pursue continuous improvement of regulations and operating practices.
- Recognise the case for independent evaluation and verification of environmental performance.

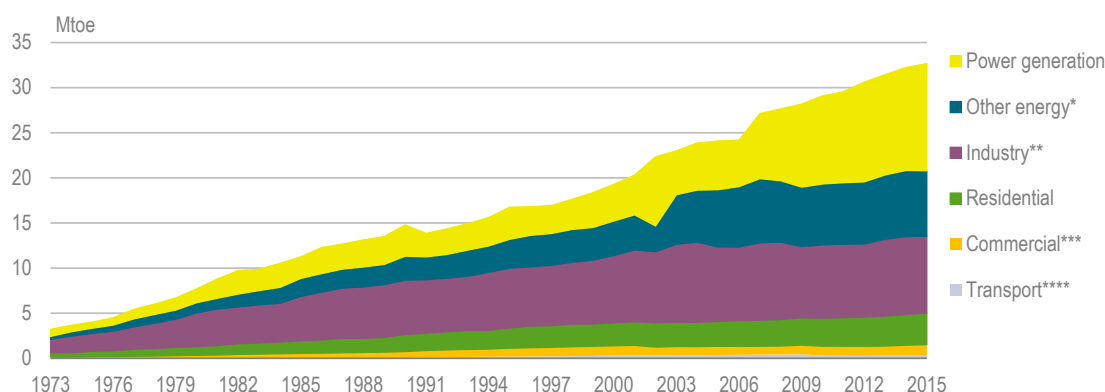
Source : IEA (2012), *World Energy Outlook 2012 SR: Golden Rules for a Golden Age of Gas*, OECD/IEA, Paris.

Consumption

Natural gas consumption has increased steadily in Australia for decades, with the exception of a small decline in 2005. In 2015, total consumption reached a record high at 32.2 Mtoe, an increase by 70% over the last decade (see Figure 3.5).

The power sector has become the largest gas consuming sector in Australia since 2009, overtaking the industry sector, and its consumption has increased rapidly in the last decade. In 2015, natural gas consumption in power generation reached a new peak at 11.9 Mtoe, which was an increase of 120% over 2005 and accounted for over one-third of total gas consumption. Gas power represented 21% of total electricity generation in 2015, a share that has doubled since 2005. Queensland and Western Australia are the states with the largest electricity generation from natural gas in the country, together accounting for 73% of total gas power generation (Australian government, 2015).

Figure 3.5 Natural gas demand by sector, 1973-2015



* *Other energy* includes oil and gas extraction, LNG liquefaction and petroleum refineries.

** *Industry* includes non-energy use.

*** *Commercial* includes commercial and public services, and agriculture/forestry.

**** Negligible.

Note: Final consumption by consuming sector and including gas consumption in energy transformation.

Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

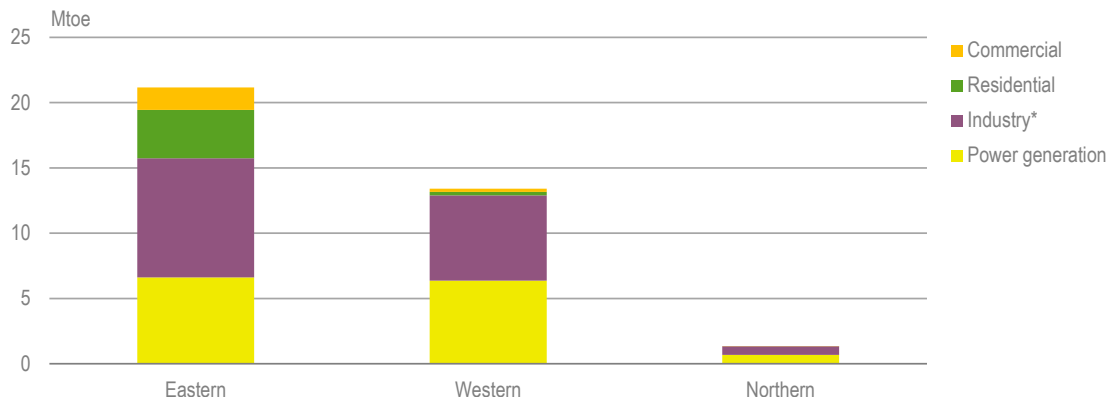
In 2015, the industry sector was the second-largest gas consuming sector, accounting for one-quarter of total consumption, with levels around 8-9 Mtoe in the last decade. Non-ferrous metals industry (notably alumina mineral) consumed 40% of total industrial consumption. Other large natural gas consuming industries were chemical and petrochemical (which includes LNG gas processing), non-metallic minerals, and food and tobacco industries. The industry consumption included natural gas used for non-energy purposes in industrial processes, which accounted for around 10% of total industry consumption.

Other energy-related consumption accounted for the third-largest share of natural gas consumption in Australia, reaching 7.3 Mtoe in 2015. A majority of this was consumed in oil and gas extraction and another third was used in liquefaction plants for LNG production, supporting the gas export industry. This consumption increased by 14% over the decade 2005-15. The LNG sector is, as noted above, growing at an extraordinary pace. In the eastern and south-eastern markets alone, the demand for natural gas to LNG production increased to 24 Mtoe in 2016 and its growth is expected to continue in the coming five years to 34 Mtoe in 2021 (AEMO, 2016a).

The residential and commercial sectors together consumed 4.7 Mtoe of natural gas in 2015, accounting for 15% of total gas consumption. This represented an increase by 26% in the residential sector and 29% in the commercial sector over the last decade. There is also a small share of natural gas consumed in the transport sector.

Western Australia is the state with the highest natural gas consumption, mainly used in industry and power generation. The east-coast market includes the five south-eastern states and the capital region. It is the largest gas market, accounting for almost 60% of Australia’s total gas consumption (see Figure 3.6).

Figure 3.6 Natural gas consumption by market area and sector, 2015-16



*Industry includes manufacturing and mining. The data do not separate consumption in energy industry other than power generation (e.g. consumption in oil and gas extraction or in refineries), and the category *Other energy* in Figure 3.5 is here mainly included in *Industry*.

Source: AG (2015), “Energy in Australia”, Department of Industry, Innovation and Science, Canberra.

Institutions and regulatory framework

The Energy Council of the **Council of Australian Governments (COAG)**, chaired by the Australian government, is the federal/state ministerial forum responsible for developing an overall energy policy for Australia’s electricity and gas markets. The Energy Council provides a platform for collaboration. It works around six strategic themes, of which natural gas is one, and has presented several gas reforms in recent years, including a Gas Market Reform Package in 2016. One part of the reform package is the COAG Energy Council Gas Supply Strategy.

Australia’s *Domestic Gas Strategy* of 2015 set out the role of the Commonwealth government policy and actions to meet expectations of state and territory governments and industry in developing conventional and unconventional gas. Gas resources onshore and in coastal waters (the first three nautical miles from the coastline) are managed by the state and territory governments. The Commonwealth government is responsible for petroleum rights beyond coastal waters and decisions are carried out together with the state governments.

Gas producers in Australia pay a profit-based *petroleum resource rent tax (PRRT)*. From 2012, the PRRT applies to all Australian onshore and offshore oil and gas projects, including oil shale and coal seam gas projects. PRRT is levied at 40% of a project’s net cash flow (after allowing for carrying forward deductions in the

exploration and development phases). PRRT payments are deductible for company income tax purposes (Australian Government, 2017). Furthermore, onshore gas producers pay royalties to state governments in the range of 10% of net well-head value (see also Chapter 2 on Oil).

The **Australian Energy Regulator (AER)** is the main regulatory body for natural gas transmission pipelines in eastern and northern Australia that are covered by regulation. AER is responsible for enforcing and monitoring compliance with the National Gas Law (NGL) and National Gas Rules (NGR) in all jurisdictions except Western Australia, which is regulated by that state's **Economic Regulation Authority (ERA)**.

The **National Competition Council (NCC)** has the main function to recommend on the (light/full) regulation of third-party access to services provided by monopoly infrastructure, including regulated gas pipelines, under the NGL.

The **Australian Energy Market Operator (AEMO)** is responsible for operating the country's largest gas and electricity markets. Its functions are prescribed in the NGL. AEMO operates the wholesale trading markets, gas supply hubs and retail gas markets. AEMO is also operating gas bulletin boards overlooking the major gas production fields, demand centres and transmission pipeline flows on the eastern and western markets.

The **Australian Energy Market Commission (AEMC)** has the power to make and amend the national gas rules and regulations based on the NGL.

The **Australian Competition and Consumer Commission (ACCC)** is responsible for enforcing competition and consumer protection in energy markets. In April 2017 the government directed the ACCC to publish regular supply and price information. For the next three years, the ACCC will publish reports every six months that monitor competition and pipeline access, retail gas prices and LNG prices. Two interim reports have been published since the inquiry started (ACCC, 2017a and 2017b).

Gas infrastructure and network regulation

Australia's natural gas system consists of three separate gas networks located in Western Australia, the Northern Territory and the south-east states (see Figure 3.7). These networks are geographically isolated from each other, and transportation of gas between markets has generally been considered uneconomic. As a result, there is currently no pipeline interconnection between the three markets, and produced gas is therefore either consumed within each market or exported as LNG.

The Australian gas pipeline regulation is a patchwork of different regulatory regimes; some lines are subject to full economic regulation, others are lightly regulated, and some are not regulated at all. Transmission networks are often not regulated at all, while most distribution networks are either fully or lightly regulated. NCC makes recommendations on whether a network should be regulated. The jurisdictional minister then takes the decision. Federal natural gas legislation is the responsibility of the Department of Industry, Innovation and Science (DIIS).

Transmission networks

Australia has over 47 000 km of high-pressure pipelines that are used for natural gas transmission. The gas transmission is dominated by three pipeline operators: APA Group (which has the largest market share); Jemena (jointly owned by State Grid Corporation of China and Singapore Power); and Epic Energy (South Australian company). APA Group owns and operates transmission pipelines in all three Australian gas markets, while Jemena and Epic Energy are present in the eastern market.

Gas infrastructure can be subject to no, full or light regulation. Only four out of fifteen transmission pipelines under the Australian Energy Regulator's AER jurisdiction are covered by full regulation, and another three are covered by light regulation (see Table 3.2). The remaining nine transmission lines are not regulated. Under the NGL, the owner or operator of a pipeline that is covered by regulation must submit an access arrangement, including tariffs and other terms and conditions for third-party access to the pipeline. The access arrangement needs to be approved by the regulator. Under light regulation, the pipeline provider determines its own tariffs. For unregulated pipelines, third-party access is a matter for commercial negotiation between the access provider and the access seeker, without regulation.

Table 3.2 Gas transmission lines and regulation (excluding Western Australia)

Transmission pipeline	Owner	State	Regulation
Amadeus pipeline	APA	NT	Fully regulated
Central ranges pipeline	APA	NSW	Fully regulated
Roma Brisbane pipeline	APA	QLD	Fully regulated
Victorian transmission system	APA	VIC	Fully regulated
Carpentaria pipeline	APA	QLD	Lightly regulated
Central West pipeline	APA	NSW	Lightly regulated
Moomba Sydney pipeline	APA	NSW	Lightly regulated
Eastern gas pipeline	Jemena	NSW/VIC	Not regulated
Queensland gas pipeline	Jemena	QLD	Not regulated
Moomba Adelaide pipeline	Epic	SA	Not regulated
South East pipeline	Epic	SA	Not regulated
Berwyndale Wallumbilla pipeline	APA	QLD	Not regulated
Bonaparte gas pipeline	APA	NT	Not regulated
SEA gas pipeline	APA	VIC/SA	Not regulated
South West Queensland pipeline	APA	QLD	Not regulated
Tasmanian Gas Pipeline	TGP Pty Ltd	TAS	Not regulated

Sources: AER (2017c), *Gas 2017: Analysis and Forecasts to 2022*; APA Group (2017), "Gas transmission". Bloomberg Finance LP.

The situation of three separate gas systems is changing as new transmission pipelines are completed. This includes the 622 km Northern Gas Pipeline which will link the eastern and northern markets (see Figure 3.7). The contract to construct and operate the

Northern Gas Pipeline was awarded to Jemena, and is expected to be completed in 2018. As the market has evolved, more flexibility and services are requested from gas pipelines besides simply transporting gas from a supply source to a demand centre. To meet new demand, gas pipeline operators have started to offer bidirectional flows, park and loan services, capacity expansions, and interconnection with other pipelines.

Distribution networks

The distribution networks consist of high, medium and low-pressure pipelines, bringing gas from the transmission lines to the end consumers. The NGL provides a regulatory framework for gas distribution and the AER regulates all distribution networks except in Western Australia where the state's Economic Regulation Authority (ERA) is the regulator.

Unlike gas transmission lines, most gas distribution networks are subject to full economic regulation, which requires the network operator to prepare an access arrangement for third parties to access the pipelines (AEMC, 2017).

LNG terminals

LNG exports began in Australia from the Northwest Shelf terminal in 1989, which subsequently expanded from three LNG trains to five. For many years, this was the only LNG terminal in the country, before the Darwin LNG plant was constructed in the Northern Territory and started its operations in 2006, and later the Pluto terminal in Western Australia (see Figure 3.7). In 2009-11, commitments to build seven more large LNG plants were announced. These plants will progressively enter production between 2015 and 2019. By end of 2017, Australia had nine operating LNG terminals and two more under construction (see Table 3.3). The terminals are located strategically close to the largest gas production fields (see Figure 3.3). Three terminals are situated close to the Carnarvon Basin on the west coast, with the Gorgon LNG terminal being the most recent. A fourth terminal, the Wheatstone LNG train 1 has started operations in 2017 and train 2 is under construction. On the north coast, close to the Bonaparte and Browse Basins, the new Ichthys LNG terminal is being constructed next to the Darwin plant.

Gorgon LNG, with a total capacity of 21.2 bcm per year in three production trains (see Table 3.3), is one of the world's largest natural gas projects and the largest single resource development in Australia. Operation of the first two trains began in 2016, and the third train started in March 2017. Of total export capacity from Gorgon, 75% is booked under long-term contracts to Japan, Korea, China and India. The rest of the export capacity is handled by the portfolio players such as Chevron, Shell, BP and ExxonMobil. The three east coast projects are Queensland Curtis LNG (QCLNG), Gladstone LNG (GLNG) and Australia Pacific LNG (APLNG), containing two LNG trains each. QCLNG was completed in 2015 and is operated by Shell. GLNG, which is operated by Australian company Santos, started its two trains in 2015-16. Almost 90% of its export capacity is committed to Malaysian Petronas and Korean KOGAS on 20-year long-term contracts starting from 2016. APLNG, the third CSG-fed LNG project shipped its first cargo to China in January 2016, with almost 95% booked under 20-year contracts.

On a global level, massive investments have been made in new LNG production capacity in recent years, first in Australia and, more recently, in the United States. In 2016, new LNG projects in Australia accounted for 75% of all new LNG export capacity worldwide, and in the United States for the remaining 25% (IEA, 2017c). Australia and the

United States continue to be the leaders in bringing on stream new LNG export capacity. In 2018, production will commence at Wheatstone, Ichthys in Darwin and the Prelude floating LNG project. Australia plans to add 29 bcm per year in LNG capacity, and could overtake Qatar in terms of total capacity by 2019.

Table 3.3 Constructed and planned LNG projects in Australia

Project name	Major participants	State	Capacity (bcm/year)	Status
QCLNG (T1-T2)	BG Group	QLD	11.6	Operational in 2015
APLNG (T1)	Origin Energy, ConocoPhillips, Sinopec	QLD	6.1	Operational in 2016
APLNG (T2)	Origin Energy, ConocoPhillips, Sinopec	QLD	6.1	Operational in 2016
GLNG (T1)	Santos, Petronas, Total, KOGAS	QLD	5.3	Operational in 2015
GLNG (T2)	Santos, Petronas, Total, KOGAS	QLD	5.3	Operational in 2016
Gorgon LNG (T1)	Chevron, ExxonMobil, Shell	WA	7.1	Operational in 2016
Gorgon LNG (T2)	Chevron, ExxonMobil, Shell	WA	7.1	Operational in 2016
Gorgon LNG (T3)	Chevron, ExxonMobil, Shell	WA	7.1	Operational in 2017
Wheatstone LNG (T1)	Chevron, KUFPEC, Woodside	WA	6.1	Operational in 2017
Wheatstone LNG (T2)	Chevron, KUFPEC, Woodside	WA	6.1	Expected operation in 2018
Ichthys LNG (T1-T2)	Inpex, Total	NT	12.1	Under construction

Source: IEA (2017c), *Gas 2017: Analysis and Forecasts to 2022*. Santos (2014), "About Santos GLNG", Brisbane.

Storage capacity

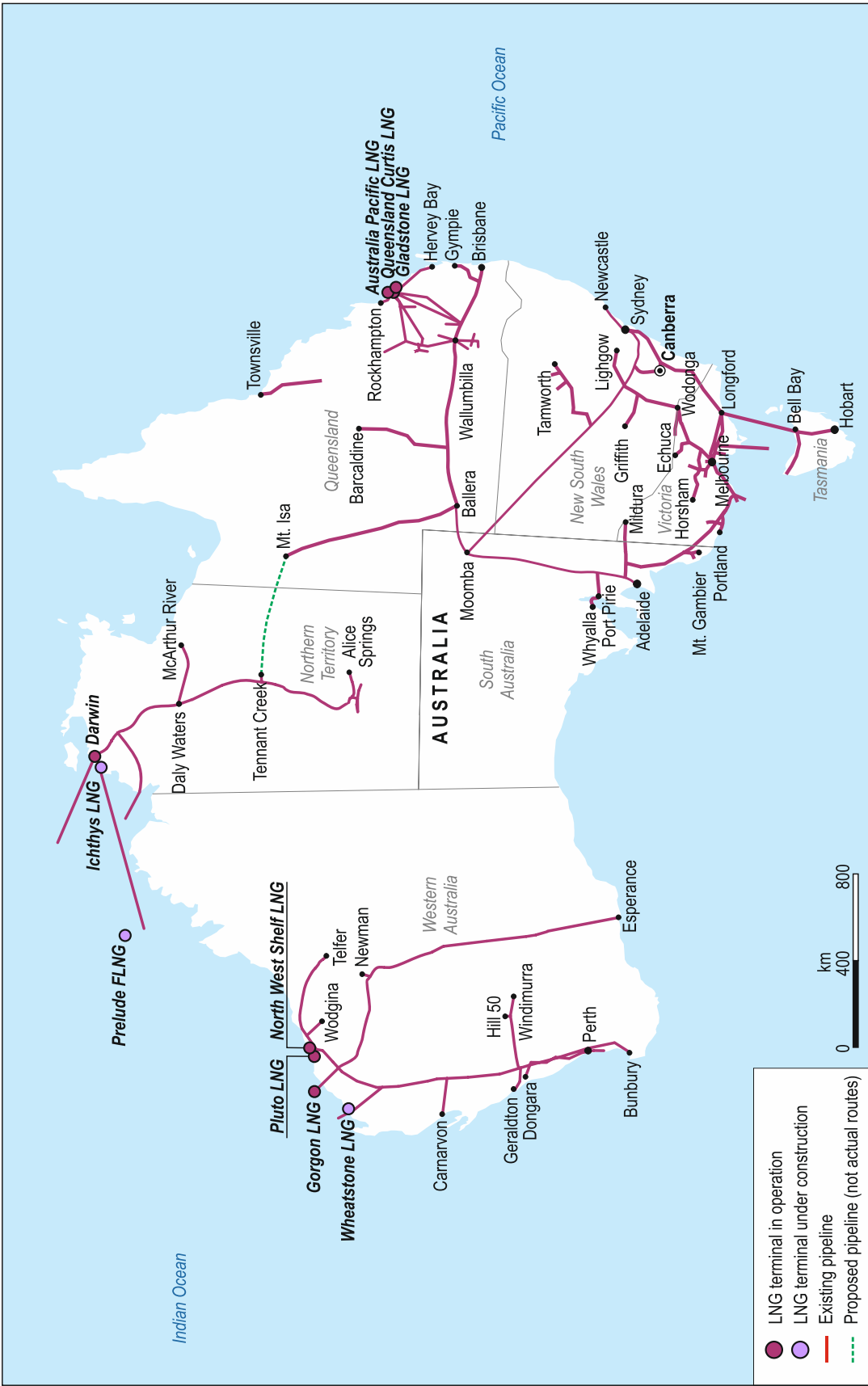
Natural gas storage facilities are located close to gas production hubs, mainly in the eastern market (see Table 3.4). Furthermore, there are two small LNG storage facilities in Newcastle and Dandenong, which provide peak demand management capabilities for the large Sydney and Melbourne markets. There are large storage tanks at all the country's LNG export facilities, all without regasification capabilities.

Table 3.4 Gas storage facilities in Australia

Storage facility	Operator	State	Storage capacity (PJ)
Moomba gas storage	Santos	SA	85
Roma underground storage	GLNG	QLD	70
Silver springs gas storage	AGL	QLD	35
Iona storage facility	Energy Australia	VIC	26
Mondarra gas storage facility	APA	WA	15
Ballera gas storage	Santos	QLD	10
Newstead gas storage	Origin Energy	NSW	2
Dandenong LNG storage	APA	VIC	0.7

Sources: AER (2017a), "State of the energy market, May 2017"; AEMO (2016b), "Gas statement of opportunities for Western Australia".

Figure 3.7 Natural gas infrastructure in Australia



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

There is no public storage held by the Australian government and no new storage facilities are planned. Possibilities of using depleted gas fields are being considered in Western Australia (Tubridgi field), South Australia (Katnook) and Queensland (Surat).

Market operation and prices

The energy market operator AEMO operates the eastern wholesale trading markets, gas supply hubs, bulletin boards and the retail gas markets in Victoria, Queensland, South Australia, Western Australia, New South Wales and the Capital Territory.

Wholesale markets and hubs

Wholesale markets are on the east coast where the gas market has two trading markets and two additional supply hubs.

Victorian gas market

Victoria's Declared Wholesale Gas Market (DWGM) was launched in 1999, as a way to manage flows in the Victorian transmission system and to introduce gas spot-market trading. The DWGM has around 17 participants, and like the short-term trading market (see below), they do not use the market as the main way to trade gas. AEMO operates the financial settlements on the DWGM and also manages the physical balance. On the DWGM, financial instruments are available in terms of futures and options that are traded on the stock exchange, the Australian Securities Exchange (ASX).

Short-term trading market

The short-term trading market (STTM) is a wholesale gas market operating at three defined gas hubs in Sydney, Adelaide and Brisbane. The hubs are transfer points through which gas is transmitted before being delivered to the distribution networks. STTM was first launched in Sydney and Adelaide in September 2010 and later in Brisbane in December 2011. AEMO operates the STTM but not the physical pipeline or network assets. There are around 30 participants on the STTM, which have to register with AEMO. Participation is voluntary and none of the participants use the STTM for a majority of their gas purchases or sales. The operator has no knowledge of the supporting contractual arrangements between gas producers and buyers. Gas is traded on a day-ahead market and AEMO sets the day-ahead price at each hub. There is no derivatives market in the STTM for trading with financial instruments on the Australian stock exchange market (ASX).

Western Australia wholesale market

Western Australia is the largest gas consuming state in the country, with large consumers in mining, manufacturing and electricity generation accounting for two-thirds of total consumption. Most customers are supplied directly through the transmission network, whereas only 8% are supplied on a retail market through distribution networks. In most of the gas supply transactions, gas producers sell ex-plant and the large industrial customers arrange their own gas transport agreements with the relevant transmission pipeline. Unlike the eastern market, there is no short-term gas trading market in Western Australia.

Gas supply hubs

New gas trading markets and supply hubs have been established to improve transparency on Australia's east coast markets. The market operator launched a gas supply hub at Wallumbilla, Queensland, in 2014. The hub is a pipeline interconnection point for the Surat/Bowen and Cooper Basins, linking gas markets in Queensland, South Australia, New South Wales and Victoria. In 2016, a new hub was launched at Moomba, South Australia, in another major junction linking gas basins and markets in southern and eastern Australia.

Participation in trading on the hubs is voluntary, and the traded volumes are still very low. Participants can trade gas up to several months in advance of physical delivery, and on a weekly, monthly and quarterly basis, compared to the daily-basis-only at the other markets. The AER monitors the hubs, reporting weekly on activity (AER, 2017b).

Gas Bulletin Board

As a way to improve transparency and information available on the eastern gas market, AEMO established the Gas Bulletin Board (www.gasbb.com.au) in 2008. The Gas Bulletin Board is an electronic platform that provides current information on gas production, storage, transmission pipeline capacity and flow in eastern Australia.

Pipeline operators, gas producers and storage facility owners are obliged to submit information to AEMO, which operates the bulletin board, and the AER monitors participants' compliance. The Gas Bulletin Board covers most of the major production, storage and pipeline capacities in the eastern gas market, with some exemptions for some smaller pipelines that do not transport gas between different zones, and related production and storage facilities.

The Western Australia wholesale market also includes a gas bulletin board, operated by AEMO, showing information on gas production, consumption and capacity outlooks.

Wholesale prices

Most gas used in Australia is sold via gas supply agreements (GSAs), bilateral agreements guaranteeing a fixed price over a set period, which used to last up to 40 years. The long-term GSAs have changed in recent years as a number of the legacy gas contracts for domestic supply have come to the end of their lifetimes. From 2010 to 2016, many GSAs expired and were replaced by shorter and more expensive contracts, affecting the overall wholesale and retail prices.

While the northern and western markets were exporting the vast majority of production to Japan, the east coast market was focused on domestic consumers. This arrangement began to change in 2009 to 2011, with the commitments to build three plants in Queensland, connecting the east coast market with export markets for the first time. East coast LNG export started in 2015, but gas producers had begun to sign supply contracts in 2010 with major export markets in Asia, and wholesale prices have continuously increased since.

In 2015, the average wholesale gas price for large industrial customers¹ on the east coast of Australia was AUD 8 per gigajoule (or USD 6/GJ), a more than 50% increase from just over

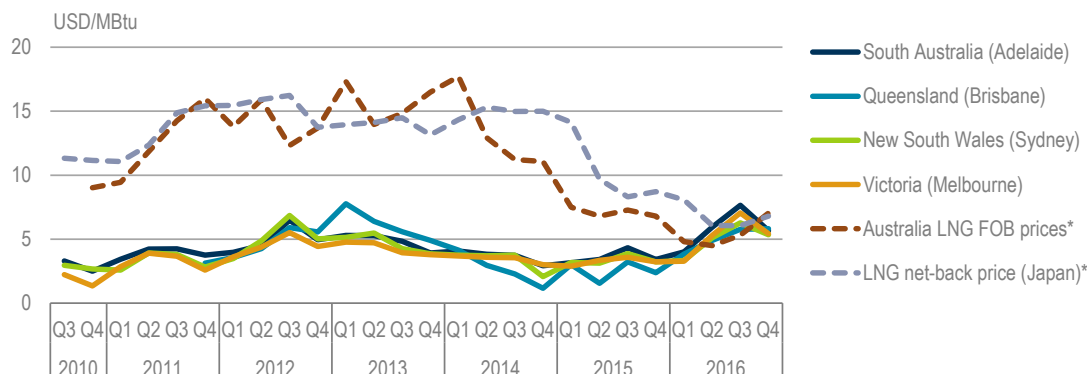
¹. Consuming over 1 PJ per year, or equivalent to around 25 mcm per year.

AUD 5/GJ in 2010 (OG, 2016). Some buyers have seen similar or even larger increases over shorter time frames. Domestic residential and industrial consumers compete with the LNG plants and power generators for gas, which could continue to put upward pressure on gas prices.

Gas prices on the domestic market hubs are aligning with LNG netback prices, and occasionally even exceeding them (see Figure 3.8). Because contracts are usually confidential between the parties, the Australian gas markets have to deal with a lack of price transparency, and some assessments have reported domestic contracted prices significantly above the LNG netback prices (AER, 2017a).

There is also a disparity between the information available for market participants based on size, where large incumbents benefit in price negotiations compared with smaller consumers (AER, 2017a). There is also a lack of transparency and monopoly pricing in natural gas transmission. In a 2016-inquiry into the east coast gas market, the ACCC found evidence of charges for the transmission pipelines that were significantly above competitive tariffs (ACCC, 2016).

Figure 3.8 Wholesale natural gas prices in trading hubs in Australia's eastern gas region and prices for LNG exports, 2010-16



*FOB (free on board) prices include spot LNG prices to the world. Netback prices include spot and contracted LNG (minus cost of transport) to Japan.

Note: The trading hub prices only represent a small share of the total gas sold on the domestic market, but provide an indication of the domestic price development. Estimated average east coast wholesale price for large industries in 2015 was USD 5.7 per million British thermal unit, according to OG (2016), which would be higher than what the trading hub prices indicate.

Sources: IEA (2017c), *Gas 2017: Analysis and Forecasts to 2022*, IEA/OECD, Paris. AEMO (2017a), "STTM Price and Withdrawals". Wholesale prices: IEA analysis based on AER (2017b), "Wholesale statistics, gas prices"; Australia LNG free on board (FOB) prices: ICIS (2017), *ICIS LNG Edge*; Japan LNG contract: Bloomberg Finance LP.

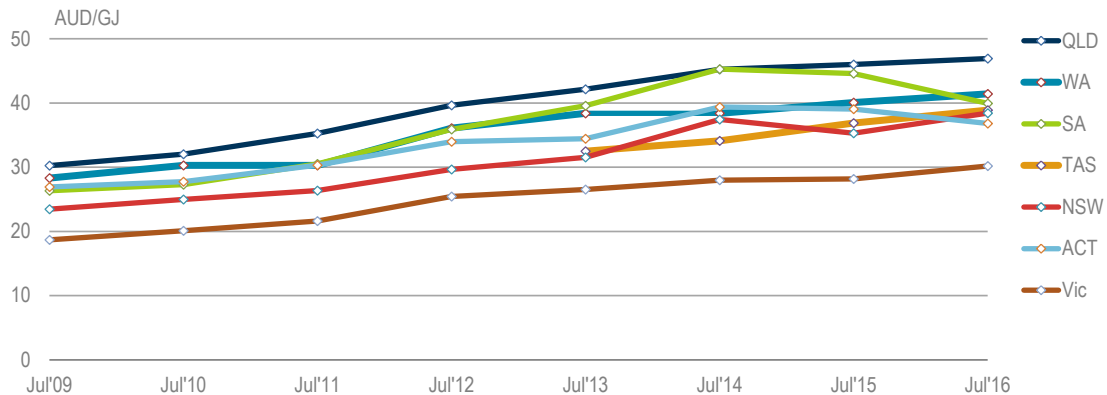
Retail markets and prices

The biggest retail markets for gas are in the populated areas in the south-east of Australia. Victoria had the highest residential gas consumption of 107 petajoules (PJ) in 2013-14, which was two-thirds of total national residential consumption (OG, 2016). The retail gas price is determined by the wholesale price, transmission and distribution costs, and the retailers' margin. Australian consumers pay no energy tax on natural gas, but a goods and service tax (GST) of 10%. In most states, distribution network charges were the largest cost component, accounting for 30% of the total retail price in Victoria and up to 69% in South Australia in 2015 (OG, 2016).

In July 2016, retail prices varied from 30 AUD/GJ in Victoria to 47 AUD/GJ in Queensland (see Figure 3.9). The average east coast price was 39 AUD/GJ, slightly below the retail price in Western Australia at 41 AUD/GJ (St Vincent, 2016). Australia's weighted average retail price is the sixth-highest among IEA member countries that have available price data (see Figure 3.10).

No gas prices for industry are reported by Australia to the IEA. Commercial and industrial consumers have signalled difficulties in obtaining quotes from retail gas suppliers, with sometimes no more than one or two suppliers responding. They have reported steep price increases, severely impacting their competitiveness.

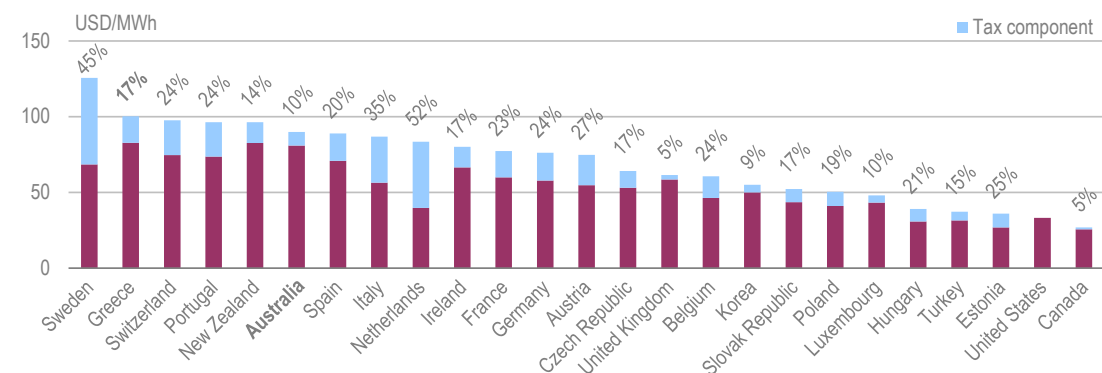
Figure 3.9 Natural gas retail prices, by state



Note: Prices include a goods and service tax. Retail prices calculated from estimated annual bills for customers consuming 30 GJ per year.

Source: IEA analysis based on St Vincent de Paul Society and Alvis Consulting (2016).

Figure 3.10 Natural gas prices for households in IEA member countries, 2016



Note: Data not available for Finland, Denmark, Japan and Norway. Australian data are the weighted average of retail prices in Figure 3.9, based on consumption data for the residential sector 2014/15, and the 10% GST added.

Source: IEA (2017d), *Energy Prices and Taxes Q4 2016*, www.iea.org/statistics/; Department of Industry (2017), "Australian energy statistics, Table F".

Gas market reform

The gas infrastructure on the east coast is dominated by a few market players, exemplified by the APA group owning a large majority of the transmission lines (see Table 3.2). Furthermore, publicly available information regarding storage capacity and withdrawal rates is scarce or non-existent. The federal government does not collect

comprehensive data on gas storage levels, and any data collected by state or territory governments is not published as it is considered commercially sensitive, in contrast to practice in most other IEA jurisdictions.

The Gas Bulletin Board with information on storage and flow, and the creation of a gas price index and harmonisation of the gas trading at hubs may improve transparency, but further measures are being considered.

Several recent reports looked into issues with competition, market liquidity and transparency. In 2015, the ACCC conducted an inquiry into the competitiveness on the east coast wholesale gas market, resulting in a number of recommendations on how to avoid supply shortages, strengthen pipeline regulations and improve market transparency. Following the inquiry, the AEMC, the market commission, released a review of the east coast wholesale gas markets and pipeline framework in 2016. The review makes recommendations on new trading hubs and pipeline capacity trading. Based on the ACCC inquiry and the AEMC review, the COAG Energy Council released a gas market reform package in 2016. The reforms aim to increase the supply of natural gas in the market, reduce barriers to competition, provide for easier access to transport infrastructure and improve pipeline capacity trading. Furthermore, the reforms should enhance price transparency and information on gas supply, enable market players to trade gas in the market more efficiently, and take informed investment decisions.

The COAG Energy Council set up a new Gas Market Reform Group (GMRG) to implement the inquiry's and review's recommendations. It also appointed Dr. Michael Vertigan to chair the GMRG and examine gas pipeline issues, which resulted in a recommendation in favour of a gas pipeline arbitration framework (see Box 3.2), instead of full regulation of all pipelines. The reform package comprises 15 new measures along three core priorities of:

- Reforming gas spot markets, concentrating trade to two new trading hubs; a northern hub located at Wallumbilla and a southern hub located in Victoria, with improved and unified market designs.
- Introducing a secondary capacity trading platform and day-ahead auction. The Reform Group consulted stakeholders in May 2017 on how to set up the platform.
- Improving gas transmission pipeline regulation with the new gas pipeline arbitration framework (see Box 3.2) and making gas market information available through the Gas Bulletin Board.

In 2017, the Australian Competition and Consumer Commission (ACCC) added significant transparency through the gas market inquiry 2017-20. The first interim report of the inquiry (ACCC, 2017a) raised concerns that market participants could not be able to gain access to pipeline capacity at reasonable prices, that some pipelines are contractually congested and that a large number of major pipelines are using their market power to engage in monopoly pricing. Although the pipeline regulatory framework has been updated (see Box 3.2), ACCC believes its implementation may take some time to have an effect on prices and that there is a limit to how much gas can be swapped between locations to ease congestion in south-east Australia. The second interim report (ACCC, 2017b) also highlighted that access to pipeline capacity to transport Queensland gas to the southern states remains critical for the east coast market. Transportation costs for the direction Queensland to southern states were around AUD 1.85–2.45/GJ, while

the cost of transporting gas from the Northern Territory would be in excess of AUD 5/GJ. An LNG regasification terminal could be an alternative. Investment in new north-south pipeline capacity in the East Coast market is not developing due to lack of gas supply developments in the south, high gas prices and the short-term focus of retailers.

Box 3.2 Gas pipeline arbitration framework

Between August and December 2016, the chair of the Gas Market Reform Group (GMRG), Dr Michael Vertigan, examined the current regulatory test for the regulation of gas pipelines on request from the Council of Australian Governments (COAG) Energy Council. In consultation with stakeholders, Dr Vertigan noted that there was no widespread industry support for increasing the extent of regulation of the pipeline industry. He concluded that the “principal problem that shippers face when seeking access to pipeline services is an imbalance in bargaining power”.

To address this imbalance, the examination recommended enhancing the transparency of pipeline service pricing and contract terms, and to introduce a framework for binding arbitration. Pipeline operators will be made to publish information required for gas suppliers to take informed decisions on pipeline shipping, and an arbitration mechanism will be introduced in the Natural Gas Law to use when commercial agreements cannot be reached.

In December 2016, the Council endorsed these recommendations and asked Dr Vertigan to bring forward his detailed design work to enable the new framework to commence on 1 May 2017. Final design recommendations were presented by the GMRG in June 2017. The arbitration framework rules came into effect on 1 August 2017.

Source: GMRG (2017), “Gas pipeline information disclosure and arbitration framework: Final design recommendation”, GMRG / Australian Energy Market Commission, Sydney.

Security of supply

Concerns with supply and demand adequacy that also have potentially strong effects on electricity security have led to the development of a new gas security mechanism, to ensure domestic supply on a short-term basis until long-term gas supply has improved.

Supply and demand adequacy

In Western Australia, the state government has for some decades obliged gas exporters to develop a domestic gas market and to reserve around 15% of production for that market. The domestic market also provided an important source of cash flow to LNG development in the early stages. Gas supply in the western market is expected to remain higher than forecast gas demand over the next five years (AEMO, 2016b).

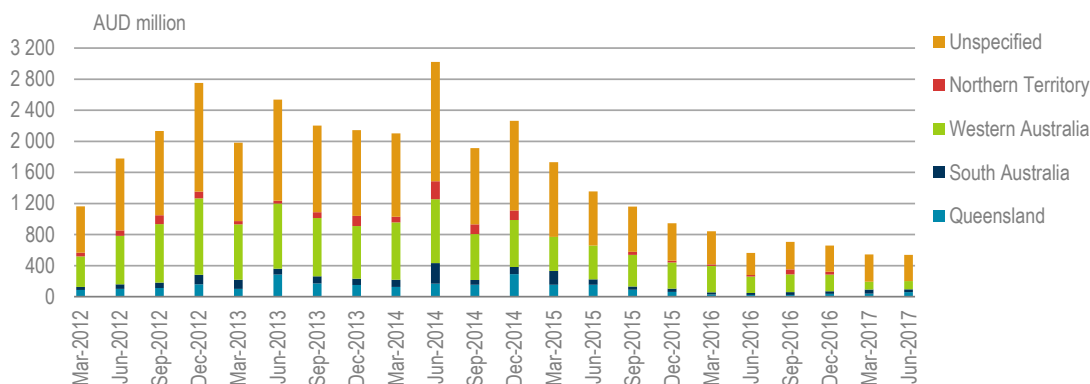
The east coast gas market never had such arrangements, and the market is in a situation of rapidly growing demand from the LNG projects, which has not fully been met by increased production, leaving the domestic market exposed to a risk of being undersupplied. This is related to both supply and demand challenges.

On the supply side, Surat and Bowen Basins accounted for 70% of all gas production in the eastern market in 2016. To keep up with the growing LNG exports, gas

production in these basins increased by 83% from the year before (AER, 2017a). However, this has not been enough to meet LNG requirements. The energy regulator concluded that the gas-well development by the Santos's Gladstone LNG project has been slower than expected, which has disrupted the domestic market (AER, 2017a). Because the project lacks sufficient resources to meet its LNG requirements, it is sourcing around 50% of its gas from elsewhere, much of it from the Cooper Basin in central Australia but also gas from Victorian production sources (AER, 2017a).

At the same time, gas production has been declining in conventional fields in Victoria and new exploration and development of gas reserves is slowing down as a result of a global low-price environment and of gas production restrictions put in place in several states (e.g. Victoria and Northern Territory). Total expenditure on petroleum exploration fell by 70% between 2014 and 2016 (see Figure 3.11). The absence of LNG imports or additional supply has created a tight domestic market, while the lack of transparency and competition worsened the situation in 2016/17. The market operator has highlighted that without new gas supply developments there is a risk of gas shortages in 2019-24 (AEMO, 2017b).

Figure 3.11 Petroleum exploration expenditure by state and territory, 2012-17

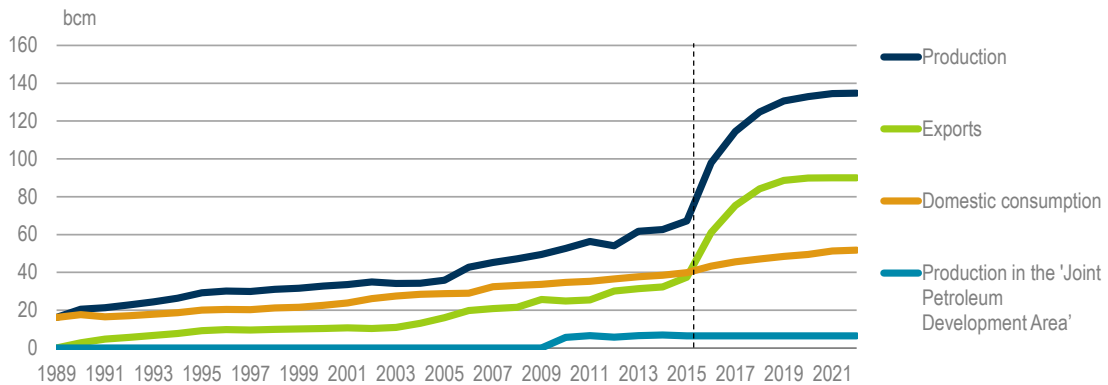


Source: ABS (2017), "8412.0 - Mineral and Petroleum Exploration, Australia, Jun 2017", <http://abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/8412.0Jun%202017?OpenDocument>.

Gas shortages can affect electricity supply, since the power sector is the largest gas consumer, and gas power contributes to meeting peak demand and provides supply flexibility. Gas power generation has increased significantly in Australia, from 24 terawatt-hours (TWh) in 2005 to 52 TWh in 2015. In the last years, however, a decline has been apparent, especially in some east-coast states where plants were mothballed. Victoria's gas power generation fell by 43% over the two-year period 2013/14-2015/16 and South Australia's gas power generation fell by 17% over the same period (DoEE, 2017). A decline in natural gas power can partly be explained by growth in wind power generation, but also by increases in coal power generation in these states. In the absence of carbon pricing mechanisms, which were abolished in 2014, gas power struggles to compete, despite the need for flexible power generation to balance variable renewable sources increases.

In conclusion, IEA analysis expects a tight gas market in Australia, as domestic consumption is expected to grow, while production and exports are going to stay flat in the medium term (Figure 3.12).

Figure 3.12 Projected gas supply and demand on the east coast market, 1989-2021



Source: IEA (2017c), *Gas 2017: Analysis and Forecasts to 2022*, IEA/OECD, Paris. Historical data based on IEA (2017b), *Natural Gas Information* (database), www.iea.org/statistics/.

Australian Domestic Gas Security Mechanism

On 1 July 2017, the government introduced the new **Australian Domestic Gas Security Mechanism** (ADGSM) as a way to address potential gas shortages. The ADGSM establishes a framework for assessing supply/demand adequacy and implementing restrictions on LNG exports in case of a shortage, with the intention to ensure a secure supply to the domestic market. The ADGSM is intended to be a temporary and short-term solution during a five-year period. This is considered to be long enough to address inefficiencies in the market without discouraging new gas developments, which are required to secure long-term supply.

Export restrictions can be introduced by the Federal Minister for Resources and Northern Australia, after an assessment in consultation with different stakeholders. The process begins each year in July with the minister issuing a declaration of intent to determine if the following year risks a shortfall of gas. This will be assessed on the basis of available information from relevant market bodies and organisations, such as the LNG projects and the market operator AEMO. If the minister determines that the following year is a shortfall year, the next step is to determine the *total market security obligation* (TMSO), the amount of gas that needs to be supplied through LNG export restrictions. The minister further determines each LNG project's *exporter market security obligation* (EMSO), based on the net-deficit if more gas is used in LNG exports than what is produced from the gas wells that are supposed to support the project. Finally, the minister grants LNG exporters their export permissions, which can be unlimited volumes (in case of no net-deficit) or an allowable volume (export capacity minus the EMSO).

The mechanism has been criticised for causing uncertainty in the business environment, already affected by the low global oil and gas prices. New investments are required to meet the LNG and domestic gas demand in the future, and uncertainty around possible export restrictions can discourage such investments. However, others have assessed that the gas security mechanism should not have a large impact on total exports, as the export volumes are significantly larger than domestic consumption (Smyth and Sheppard, 2017).

Unlike the LNG development in Western Australia, east-coast LNG was developed without a gas reservation policy or any assessment of the public interest of exports and their likely impact on domestic gas prices and consumption. This has been done in the

United States and Canada, among others. In Australia, a state-level gas reservation policy is in place in Western Australia and is now also tested by the Queensland government. In January 2017, it released a 58 square kilometre area for onshore gas exploration in the Surat Basin, with the condition that the gas has to be reserved for the domestic market. This policy has been met with some positive remarks from the industry as a more market-friendly approach compared to the moratoriums imposed in other states (ERIC, 2017). It was built on the experience in Western Australia. Gas reservation policies exist in many countries, including in Israel, Indonesia and Egypt where domestic gas use in power generation remains critical to power security. Canada and the United States have some sort of test of public interest in place to approve exports of natural gas.

On the basis of the short-term supply/demand adequacy assessments by the competition commission ACCC and the market operator AEMO in September 2017, the Australian government reached an agreement with LNG exporters (a sort of voluntary export restriction) to supply the domestic market in 2018/19. In October 2017, major east-coast LNG exporters agreed to dedicate additional supply to the domestic market for the next two years, thus saving the government from issuing the declaration of intent as required in the gas security mechanism. A formal Heads of Agreement was signed by the Prime minister and representatives from the three east-coast LNG exporters. The agreement reached meant that the forecast shortfall of gas for the domestic market would be provided by the LNG exporters on reasonable terms and that any uncontracted gas would be first offered to the domestic market (ACCC, 2017b, see also IEA, 2017d).

Other security of supply aspects

The United States is rapidly entering the LNG market and, together with Australia and Qatar, it will create overcapacity on the global LNG market over the next decade. As nuclear power increasingly re-enters the key LNG market of Japan, this situation will worsen. Oversupply in the LNG market will keep downward pressure on global gas prices, since the United States supply is priced against the cheaper North American hub prices. This can even put pressure on long-term oil-indexed supply contracts, with some Asian buyers increasingly concerned that such contracts do not reflect gas market supply and demand fundamentals. Price pressure will dampen investment in gas supply, particularly for LNG, and greenfield project commencements have collapsed in recent years.

Supply and demand flexibility

On the supply side, Australia could explore options to increase domestic production, start imports of gas (even by constructing an LNG import terminal), or redirect LNG from the west and north to eastern markets. On the demand side, increased storage or improved demand-response systems plus associated measures in power markets are potential measures to ensure security of gas supply. These measures are particularly important for the east coast gas market.

Australia has large resources of both conventional and unconventional gas. On the eastern market, the main resources are coal seam gas in the Surat/Bowen Basins, which require continuous investments to increase or even to maintain current production levels. Production has so far been lower than expected and costs higher, which has contributed to the domestic gas supply shortage. Moratoriums on unconventional gas extraction further exacerbate the potential shortage, as LNG projects ramp up.

Increasing the gas supply through LNG rerouting or imports is a possibility that has been considered as a short-term solution (AGL Energy announced plans to locate an LNG

import terminal in Victoria). However, the liquefaction process is costly. The cost of supplying the domestic market with (imported) LNG, while exporting LNG from domestic production, would depend on the transportation cost of moving gas across Australia and/or re-routing it from Asian markets.

Increasing gas storage capacity can improve the capacity of coping with peak demand in the domestic market, especially from the power sector, but no new storage investments are planned. Building competitive markets and interlinking the three gas markets to increase liquidity and price information is another way of increasing supply-side flexibility.

Furthermore, fuel switching in the power sector in times of peak gas demand can further add demand side flexibility to secure gas supply. However, as the share of variable renewable electricity increases, natural gas power becomes more important as a flexible power source, which can be difficult to supply from coal or other less flexible fuels, especially as many existing power plants are old.

Network adequacy

Existing infrastructure, including the number and location of pipelines and storage facilities is considered sufficiently robust to meet any N -1 contingency event (when the disruption of one large part of an infrastructure still allows the gas system to function) in any of the three gas markets.

In the eastern market, most major cities are connected with at least two pipelines and the two largest cities of Sydney and Melbourne have multiple pipeline connections to gas sources. The western market has historically had a diversified supply from the North West Shelf Joint Venture and from former Apache Energy operated offshore gas fields. New domestic gas supplies from the Gorgon and Wheatstone LNG projects and from onshore Perth Basin developments will further diversify supply and mitigate any N-1 event in the western market. In the northern market, operation in an N-1 context would not have a large impact because of relatively low levels of domestic consumption. However, the export market would be significantly impacted by such an event in this region. However, despite technically available capacity, firm gas transportation capacity will determine the actual flexibility and adequacy. There are concerns that the Australian pipeline business is a market where market power can be exercised and where the potential impact of monopoly pricing can be significant. The Competition and Consumer Commission's inquiry into the east-coast gas market (ACCC, 2016) found that the current National Gas Law test for regulating pipelines, modelled on the Australian competition rules, is not designed to provide third-party access to transmission pipelines, notably where there is a concern about monopoly pricing. This is a major obstacle to gas security and market development when major connecting gas hub interconnections are not fully regulated in the third-party access regime, but only lightly regulated (the Moomba Sydney pipeline or the future Northern Gas pipeline).

The east coast market has now bidirectional capacity on key pipelines and new planned connections of the eastern and northern markets further strengthens their resilience in an N-1 event. The point-to-point pipeline system has changed into a fully integrated grid. The Iona underground storage, one of the few east coast storages is being expanded. The Northern Gas Pipeline (see Figure 3.7) which is under construction will assist in reducing supply constraints in the eastern market, improve competition and stimulate investment in new gas exploration and production in the Northern Territory.

Box 3.3 Gas and electricity security

- Gas can support the system flexibility needed for the integration of variable renewable energies, along with battery storage and pumped hydro. However, the economics of gas-fired power plants are being challenged by high gas prices and tight supply. Recently, gas-fired power plants have been mothballed and are not available to support power markets. However, gas will play a stronger role as the retirement of coal-fired power capacity will likely make gas-fired power plants the marginal-cost power plants in the NEM merit order. Greater gas use in power generation at current prices will put stress on wholesale electricity prices. High and rising gas and electricity prices may threaten the financial viability of some energy-intensive commercial and industrial customers, but also residential consumers.
- In the 2017 *Gas Statement of Opportunities* (AEMO, 2017b) and the updated short-term outlook published in September 2017 (AEMO, 2017d; ACCC 2017), AEMO highlighted that in the absence of new gas supply developments, rising domestic gas demand from power generation in South Australia, Victoria and New South Wales after the closure of large coal-fired power plants, the NEM faces a potential shortage of gas supply between 2019 and 2024 and will see an increasing interaction between gas and electricity supply, and strong variations in gas production and LNG gas demand. Notably in the short term, gas supply will remain tight in eastern and south-eastern Australia in 2018 and 2019, and there remains a risk of a supply shortfall.
- New gas developments are expensive and increasingly under pressure to obtain a social licence with moratoriums in Victoria and South Australia. Declining gas production may result in insufficient gas to meet the projected demand for gas of gas-fired power plants. While it is expected that the electricity reliability standard will be met under normal conditions, risks of shortfalls could occur in Victoria, New South Wales and South Australia in case there are failures or limitations on generation or transmission; or low wind and solar PV generation coinciding with very high demand across South Australia and Victoria at the time of peak demand in the day (AEMO, 2017c). Such shortages are impacting the cost and reliability of electricity supply.
- Market responses can alleviate the risk in forecasting gas. The short-term increase in gas production and fuel switching could mitigate the risk of gas supply shortfalls. The Australian Energy Market Operator (AEMO) is responsible for operating Australia's largest gas and electricity markets and power systems. However, unlike for electricity, AEMO has no powers to direct the flow of gas in the National Electricity Market (NEM) and does not have full visibility of power generators' actual gas supply arrangements. Maintaining system security is becoming more challenging, which is increasing the risk of supply shortfalls in both gas and electricity
- After the South Australia Black System, the Finkel review suggested AEMO should be given greater visibility on gas contracts to plan responses to shortages. AEMO guidelines for the new Gas Supply Agreement came into force on 1 December 2017 as a temporary measure which will expire on 31 March 2020. The new Gas Supply Agreement builds on the commitments made by producers and pipeline operators in March 2017 to the Commonwealth Government to make gas available to meet peak demand periods in the National Electricity Market (such as during heat waves) through facilitated markets or contractual arrangements during peak NEM demand periods.

Emergency response

Emergency response policy

Under the Australian Constitution, the responsibility for natural gas emergency response actions lies with the state and territory governments – each of which has its own emergency management agency. Management of temporary gas shortfalls is undertaken by gas market participants and jurisdictional governments in the first instance, depending on the nature and size of the event. For more significant events, each state and territory has legislation conferring powers for use in emergency situations that only affect one jurisdiction.

The Energy Council within the Council of Australian Governments (COAG) is the core of Australia's gas National Emergency Strategy Organization (NESO) and is in turn advised by the National Gas Emergency Response Advisory Committee (NGERAC). In more extreme circumstances the Australian Government Crisis Committee and the National Crisis Committee (NCC) may also be activated. NGERAC is chaired by a federal government representative (the Director of the Energy Security Section in DoEE) and is made up of government officials from each jurisdiction as well as industry representatives.

In 2005, the Energy Council signed a memorandum of understanding between the Australian government and the state and territory governments (which have regulatory authority). The memorandum sets out a National Gas Emergency Response Protocol which was updated in 2016. The Protocol provides for the management of major natural gas supply disruptions threatening several jurisdictions to minimise their impact on the economy and the community, thereby contributing to the long-term objective of a safe, secure and reliable gas supply.

For emergency situations of national significance – those affecting more than one jurisdiction – NGERAC will be activated to assess the situation and advise the Energy Council ministers. The ministers are then able to enact the emergency powers within their own jurisdictions in co-ordination with others. These powers may include issuing directions for the production, transmission, distribution and/or allocation of natural gas. In practice, the Advisory Committee has rarely been activated since the management of temporary gas supply disruptions is undertaken primarily by market participants, natural gas system operators and state and territory governments.

A recent example of the Advisory Committee having to be convened was during a period when the country was facing a potential complete shut-down of the Longford Gas Plant in Victoria (affecting both its offshore and onshore facilities) because of the threat of industrial action from 9 December 2016 to 1 March 2017. The reason the Committee was convened in this case was that several jurisdictions would potentially have been affected – including the loss of supply to gas-fired power stations in New South Wales and Victoria. In the end, the industrial action did not occur and the plant remained operational.

There are currently four categories of “gas advisable incidents”:

- Level 1: Incident that can be addressed at the local level without any assistance from the National Gas Emergency Response Advisory Committee.

- Level 2: Could involve distribution of gas supply in any one jurisdiction, and has potential to affect further jurisdictions.
- Level 3: Requires curtailment and/or a multi-jurisdictional response.
- Level 4: Requires the declaration of emergency powers in one or more jurisdictions.

Government intervention in the market would occur only as a last resort.

Emergency response measures

Australia's gas storage is held on a purely commercial basis, and the country has no strategic or government stocks. Accordingly, there are no requirements on grid owners, system operators or other industry participants to hold minimum reserves of natural gas.

During a gas crisis, electricity generators and large industrial customers can use a number of strategies, including fuel switching. The government does not regularly collect data on fuel-switching capabilities of individual gas consumers (including gas-fired electricity generators) from gas to oil products, nor does it have policies to promote fuel switching in the event of a crisis. It is therefore difficult to determine to what extent large consumers would engage in this in the event of a crisis. For registered generators in the National Electricity Market, the energy market operator has a register of fuel-switching capabilities (although any decision by gas-fired plant operators to maintain or secure the ability to access alternate fuels remains a purely commercial one). Gas power generation represents around 22% of installed capacity in the electricity market; this is a significant amount of fuel-switching capacity, provided that alternative sources are available (coal, diesel, renewables, etc.).

NGERAC is in the process of commissioning modelling to inform the levels of baseload gas necessary to ensure system security and gas supply to essential services. This information will be used to advise the Energy Council and state jurisdictions in the event of a natural gas supply emergency. Gas supply companies also develop contingency plans to deal with unexpected issues that may have an impact on gas supply in (or into) their networks. This includes the use of interruptible contracts for large commercial and industrial customers. Interruptible contracts allow these customers to avoid the capacity reservation fee charged for non-interruptible supplies.

During an event where normal market operations are considered unlikely to balance supply and demand in one of the short-term trading market hubs in Sydney, Brisbane and Adelaide, the market operator may call for the supply of additional "contingency" gas over a specific period. Contingency gas may be offered by shippers, who can increase the supply to the hub, and by users who can reduce withdrawals from the hub in cases of under-supply. If scheduled to provide contingency gas, a shipper will be paid a higher price than the *ex ante* market price for the additional gas it sells, and a user will be paid for gas it "sells back" at a higher price than the *ex ante* market price.

As a last resort, in scenarios involving a threat to or a breach of system security, the operator AEMO may give directions to market participants to curtail gas load only in the Victorian system. For Queensland, New South Wales or South Australia, this will be done by the transmission and distribution network operators. Curtailment directions are only issued as a last resort after due consideration of alternate gas supply sources and are limited to the extent required to maintain or restore system security. Accordingly, for

Victoria, the AEMO has developed “curtailment tables” which are used to prepare emergency curtailment lists. The lists are made available to market participants through the Market Information Bulletin Board (MIBB). The curtailment tables specify the order and extent of curtailment of categories of gas customers with the objective of providing the required level of load shedding within the limited time available before system security is breached as defined in the System Security Procedures.

The order of curtailment is primarily driven by the requirement to shed load at the fastest possible rate and, in practical terms, this means that the largest loads are shed first. The order of curtailment is therefore in descending order of load size, with exceptions for certain classes of priority users, such as essential and critical services and uninterruptible processes. Utilities are not on the list of priority users. However, in instances where curtailment of gas-fired generation is required, due consideration will be given to the level of power generation reserve available. AEMO is currently reviewing the natural gas curtailment guidelines for Victoria as these were last updated in May 2010.

Assessment

Increasing LNG exports have created a tight supply in Australia’s eastern market, which is characterised by weak regulation, poor transparency and low liquidity.

The east-coast market in Australia is being transformed, from a domestic market supplied by long-term contracts with low prices, to a high-price market characterised by LNG exports. The three large new LNG facilities coming online on the east coast have contributed to export capacity being double the domestic demand. Opening up the market to international trade has created a link between prices on the domestic wholesale market and international prices. At the same time, LNG development has seen rising costs of production as it entered higher-cost areas (deeper waters, further from market, CBS), with an increasingly constrained gas exploration outlook due to moratoriums and bans in some regions. Much of the gas production investment in Queensland is underpinned by large, long-term LNG export contracts. However, production connected directly to the Queensland LNG terminals has not been able to cover total LNG demand. Some non-contracted gas has been redirected from domestic consumption to exports, which has reduced domestic gas availability.

The gas trading markets are poorly developed, and most gas is sold on bilateral supply agreements, of which many have come to the end of their term. When looking for new contracts, consumers are confronted with shorter contracts with considerably higher prices. While this should not be considered abnormal under such circumstances, different causes for concern have materialised. Because contracts are usually confidential between the parties, the Australian gas markets have to deal with a lack of price transparency. Reports have indicated that domestic prices have been significantly above the LNG net-back prices, which indicates significant market inefficiencies. LNG exports, on the other hand, are still mostly based on longer-term contracts.

Australia’s gas markets have a high level of market concentration, with a few commercial actors, operating largely unregulated transmission pipelines. There is a general lack of transparency on gas storage and on the utilisation of gas pipelines, as well as on commodity and transportation prices, and evidence of monopoly pricing in gas transportation has been reported. In the retail sector, industry and business consumers

have signalled steep price increases, well beyond international net-back prices, severely impacting their competitiveness. Market players have severe problems in hedging their exposure to gas prices, as the emerging gas futures market has very limited liquidity and very short time frames. Especially industry and smaller consumers suffer from this situation. Market inefficiencies need to be addressed swiftly and transparency improved rapidly for domestic consumption and LNG exports to successfully coexist on the gas market.

The Australian government is aware of the challenges facing the east-coast market and has introduced strong policy measures to secure short-term domestic supply.

The COAG Energy Council has engaged in a comprehensive gas market reform agenda in an effort to make the market more liquid and transparent. This involves efforts to increase available supply, concentrate trading on two primary trading hubs, optimise the allocation of transportation capacity, and enhance transparency as well as consumer information. Following the release of an inquiry by the Australian Competition and Consumer Commission (ACCC) and a review by the Australian Energy Market Commission, reforms are now well under way, in particular with the establishment of a Gas Market Reform Group (GMRG) that assembles the main stakeholders. These structural measures should be taken swiftly, before imposing more drastic regulations such as export restrictions.

Recently created financial hedging products at the Australian Stock Exchange lack market liquidity. The concentration of physical trading on two hubs as well as the reflections on the market design of the hubs, should contribute to the development of a more liquid futures market. This should be carefully monitored as it appears to be an important precondition for the development of a more competitive Australian gas market and for encouraging additional production.

As a response to the evidence of monopoly pricing in gas transportation, the chair of the Gas Market Reform Group has proposed a new commercial arbitration framework and information disclosure requirements to enhance the disclosure and transparency of pipeline service pricing and contract terms and conditions. The arbitration framework will be available to all open-access pipelines in the event parties are unable to reach a commercial agreement. It has been agreed to introduce this framework into the *National Gas Law* (NGL). The Australian government should swiftly review the first results of the arbitration regime and introduce regulation on those pipelines which are vital for market operations (connecting the gas hubs) and security of supply. This would ensure that sufficient liquidity is available for the market to grow.

The new Domestic Gas Security Mechanism gives the federal Minister of Resources the power to introduce export restrictions on LNG producers that extract more gas from the domestic market than they produce. The restrictions can only be imposed in years of gas shortfall, which has to be determined together with stakeholders. This keeps the industry involved in the process, but the final decision lies with the minister. The threat of export restrictions could bring uncertainty to the industry and potentially undermine investments in new gas supply. The security mechanism should therefore be considered as a last resort, and on a longer term be replaced with more market-based supply and demand measures. Structural measures to improve market operations should also be prioritised.

Gas has an important role to play in Australia's energy system, and further measures are required to improve the gas market design and efficiency.

In the medium term, gas will have a role to play in Australia's energy transition, as one of the options to decarbonise coal-dominated power generation and as a complement the ambitious development in variable renewable power sources. This will only be possible, however, if sufficient gas supplies are available. Maintaining supply-demand balance will be a challenge given that production from existing reserves is declining, while exports increase. Building on the review of climate change policies in 2017, developing a power sector emissions and reliability outlook will be instrumental in ensuring sufficient visibility for market players.

Australia has significant onshore and offshore gas projects. However, continuous investments are required to sustain and increase gas production to meet LNG export requirements, especially in coal seam gas supplies. The situation has been exacerbated as growing community concerns have prompted some states and territory governments to implement moratoria or bans on both unconventional and conventional gas, reducing the opportunities for further gas developments. The IEA's *Golden Rules* for unconventional gas can be used as a framework for how to address environmental and social concerns regarding unconventional gas utilisation.

On top of the implementation of the Gas Supply Strategy decided by the Energy Council, supply and demand adequacy will require careful monitoring, based on a comprehensive gas data collection. This is critical to exploring both the options to bring more gas to the domestic market and flexibilities on the demand side. In a tight market, any disruption or outages or extreme weather events will require even more robust emergency preparedness and response. Supply and demand adequacy measures should also take into account the elasticity and substitutability effects in gas-powered generation. In case of gas shortage or disruption, the power system has some flexibility through fuel switching. However, in the longer term, gas will become more important to balance peak power demand and variable renewable power sources, potentially raising power sector issues if gas availability is constrained over a short or medium time frame. Hence, additional gas supply and better functioning markets are both needed.

Australia has comprehensive arrangements for natural gas emergency response. However, the lack of reliable and transparent data on gas supply, storage and transportation is hampering the government's ability to conduct timely analysis of current and emerging gas security challenges. With proper monitoring, analysis and planning, security issues can be signalled earlier and remedies can be developed in a timely way. Such constraints no doubt reduce the potential effectiveness of emergency response planning and procedures. Improved data-collection capability and analysis are therefore urgent, in parallel with market reform efforts.

New transmission pipelines are currently under construction or being planned, including a pipeline connection between the eastern and northern markets. This pipeline will assist in reducing supply constraints in the eastern market, improve competition and stimulate investment in new gas exploration and production in the Northern Territory. It should be supplemented by further measures to increase transparency and liquidity on the Australian gas markets.

Recommendations

The government of Australia should:

- Continue to strengthen transparency, liquidity and competition in the gas market, including the optimal use of pipeline capacity and facilitate the development of financial hedging products, in support of a more competitive gas market.
- Ensure an effective control of market power in the gas market, be it on production, transportation or storage, so as to limit its impacts on competition, and ultimately on the prices paid by consumers. In the light of competition inquiries, and a review of the first results of the framework for binding arbitration in gas transportation, consider further regulation of the gas pipeline activities.
- Establish a regular monitoring and publication of gas prices, both on the wholesale and retail markets in order to allow transparent and comprehensive assessment of trends in prices and cost.
- Strengthen the risk assessments in the east-coast gas market by building robust gas data, including information on fuel switching, swing demand, line pack to assess supply-demand adequacy, exploring both the options to bring more gas to the domestic market and the flexibilities on the demand side, including in residential gas use and gas-powered generation. Any additional supplies should in priority contribute to the liquidity of the hubs.
- Use the export restrictions in the gas security mechanism only as a last resort after involving industry stakeholders in a transparent assessment process, to avoid reducing the incentives for investments into new gas production.

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4. Electricity

Key data

(2016 provisional)

Total electricity generation: 257.5 TWh, +11% since 2006

Electricity generation mix: coal 63.4%, natural gas 19.6%, hydro 5.9%, wind 4.7%, solar 2.7%, oil 2.3%, biofuels and waste 1.4%.

Installed capacity (2017): 67 GW - NEM installed capacity: 47 GW

Peak load: 38.8 GW – NEM peak load (historic peak load – in winter 2008: 34.4 GW – in summer 2009: 35.5 GW)

Electricity consumption (2015): 225 TWh - industry 34%, commercial and other services including agriculture 31.0%, residential 26.3%, energy industry 6.1%, transport 2.4%.

Overview

Australia's electricity markets are undergoing a significant transformation. In 2015, 85% of the inputs to Australia's total electricity generation were fossil fuels, the highest share of all IEA member countries (with Poland and Estonia), making the power sector responsible for 50% of energy-related in carbon dioxide (CO₂) emissions.

Three key trends shape the pace of the energy system transformation: *i)* the rapid and uneven growth of variable renewable energies in several regions, *ii)* the ongoing closure of the oldest coal-fired power plants, combined with *iii)* concerns around the availability and affordability of natural gas supplies in the east coast market. These trends have created significant challenges for the functioning of the National Electricity Market (NEM), one of the world's largest interconnected power systems linking five regional market jurisdictions (Queensland, New South Wales, including Australia Capital Territory, Victoria, South Australia and Tasmania). Western Australia and Northern Territory are not connected to the National Electricity Market (NEM).

Affordability remains a key concern, amid rapidly rising retail and wholesale electricity prices, driven by a lack of competition and increasing domestic gas prices among others. Electricity consumers are investing in decentralised energy resources, notably solar photovoltaic (PV).

The twin challenge of maintaining electricity security and affordability as the sector is undergoing a deep transformation has risen to the top of the political agenda following the state-wide blackout in South Australia of September 2016. The event prompted an Independent Review into the Future Security of the NEM (the "Finkel Review").

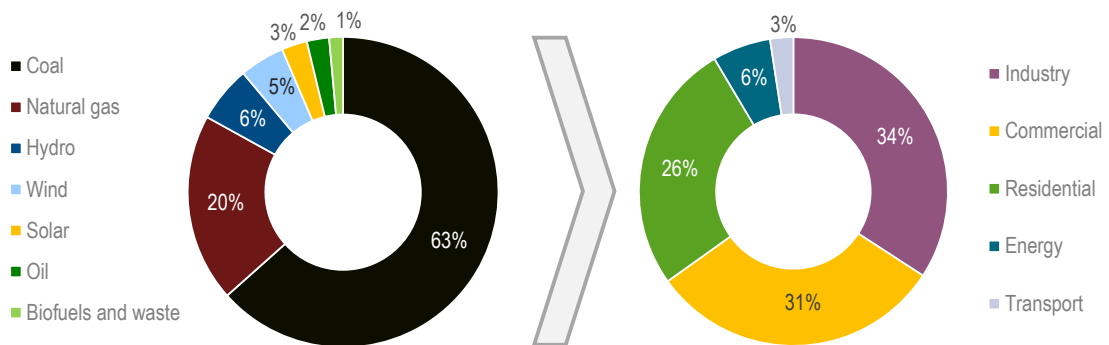
4. ELECTRICITY

Key reform actions identified by the Finkel Review in 2017 included 50 key recommendations for increasing the system’s stability and reliability in the NEM regions; robust emergency preparedness and response; strengthening the governance of the NEM through the creation of a new Energy Security Board; greater strategic policy direction from the Council of Australian Governments (COAG) on energy and climate policy based on a strategic energy plan; and a new Australian Energy Market Agreement. In July 2017, the COAG Energy Council agreed to 49 out of the 50 recommendations from the Finkel Review and is looking to implement the fiftieth recommendation with a new scheme.

Electricity supply and demand

For Australia as a whole, coal (black and brown) accounted for 63% or almost two-thirds of total electricity generation, followed by growing shares of natural gas (20%) and renewable energy sources (see Figure 4.1). Electricity is evenly consumed in all sectors, industry, commercial and residential.

Figure 4.1 Electricity generation by source and consumption by sector, 2016

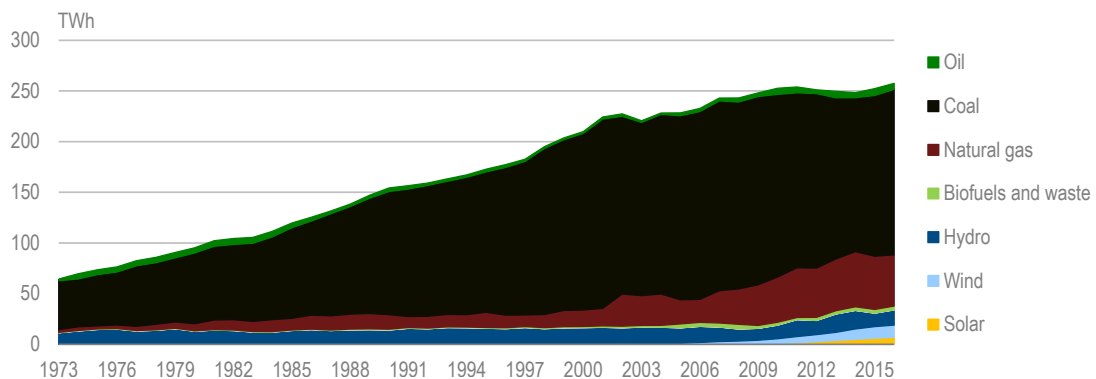


Note: Breakdowns per sector are from 2015 data.

Source: IEA (2017a), *Electricity Information* (database), www.iea.org/statistics/.

Electricity generation

Figure 4.2 Electricity generation by source, 1973-2016



Note: Data are provisional for 2016.

Source: IEA (2017b), *World Energy Balances 2017*, www.iea.org/statistics/.

Power generated from coal had increased for several decades until it peaked at 187 TWh in 2007. Since then, the role of coal declined by 13% as a result of lower electricity demand and growth in other power generation sources. Electricity generation from natural gas has more than doubled since 2006, reaching 20% in 2016. However, the growth has recently stalled: gas-fired generation declined for the first time in a decade in 2015 and dropped further in 2016, being 7% lower than the peak in 2014. Renewable energy sources accounted for 14.7% of total electricity generation in 2016. Located mainly in Tasmania, hydropower remains the largest renewable source, but variable renewable energy (VRE), in the forms of wind and solar power generation, has increased rapidly since 2009 to reach 7.4% of total electricity generation in 2016. By international comparison, Australia as a whole has the highest share of fossil fuels in electricity generation among IEA member countries, with 85% in 2016 (see Figure 4.6). (This reflects the high average share of nuclear and hydropower in IEA countries, whereas Australia does not have nuclear energy and limited hydro contributions.)

Looking at installed power generating capacity, in 2015, coal power capacity accounted for 43% in Australia as a whole (see Table 4.1). Natural gas power capacity has increased significantly from a few gigawatts (GW) in the 1990s to 18 GW in 2015.

Table 4.1 Installed power generating capacity in Australia, 1990-2015

(GW)	1990	1995	2000	2005	2010	2011	2012	2013	2014	2015
Coal	24.04	26.48	26.73	29.01	29.69	29.90	29.90	28.91	28.97	28.17
Natural gas	3.23	4.25	5.50	8.38	15.86	16.37	16.95	17.27	17.80	17.55
Other fuels*	2.86	2.89	4.72	3.42	4.03	3.78	3.53	3.99	3.94	3.99
Hydro**	8.32	8.56	9.20	9.21	9.45	9.46	9.47	8.71	8.72	8.72
Wind	0	0.002	0.03	0.74	1.86	2.13	2.56	3.22	3.80	4.23
Solar	0	0.01	0.03	0.05	0.40	1.40	2.44	3.26	4.01	4.36
Total capacity	38.45	42.19	46.20	50.82	61.29	63.03	64.84	65.36	67.23	67.03

*Other fuels includes liquid fuels and refinery gas, liquid/ as and solid/liquid gas combined plants, and biofuels.

**Hydro includes pumped hydro storage capacity.

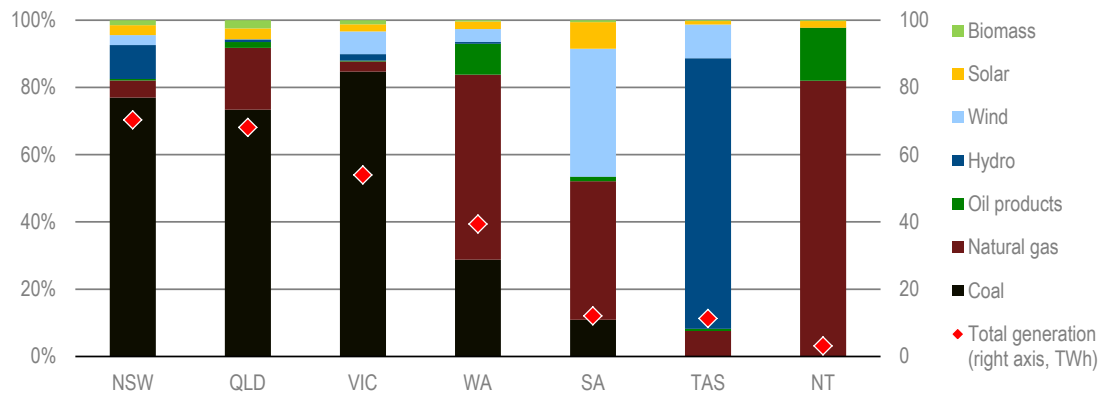
Source: IEA (2016), *Electricity Information*, www.iea.org/statistics/.

In 2015, Australia also had the highest carbon intensity of power generation with 740 grams of CO₂ per kilowatt-hour kWh. The CO₂ intensity fell during 2012-14 (see Figure 4.4), when the carbon tax was applied and several old coal plants were closed in recent years. Coal has been a major source of electricity for decades, but its contribution is declining. In 2016, 63% of Australia's electricity was generated in coal power plants, down from 80% ten years earlier. Black coal accounted for over two-thirds of coal power generation (Figure 4.5), while brown coal (lignite) is only used in power plants in Victoria.

The power mix is quite diverse across the NEM jurisdictions (see Figure 4.3). Coal dominates the electricity generation in the three largest power markets (Queensland, New South Wales and Victoria). There is some solar in other states. Wind power is concentrated in the southern states (South Australia, Tasmania and Victoria). Tasmania stands out as the main producer of hydropower, which accounts for 86% of the state's electricity generation. Natural gas accounts for the major share in the less populated northern and western parts of the country, in Western Australia (WA) and Northern Territory (NT), which produce gas, but are however all outside the NEM. Solar power is mainly concentrated in South Australia.

4. ELECTRICITY

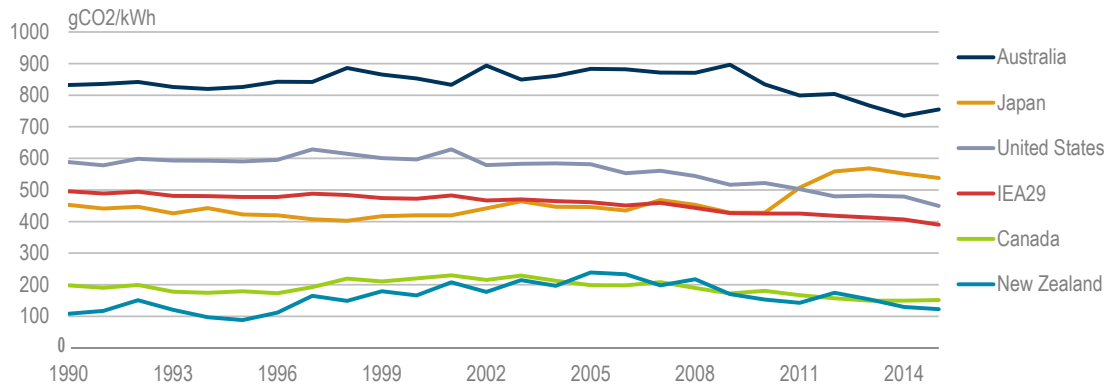
Figure 4.3 Electricity generation by fuel and state, 2016



* *Biofuels* include biogas and wood fuels.

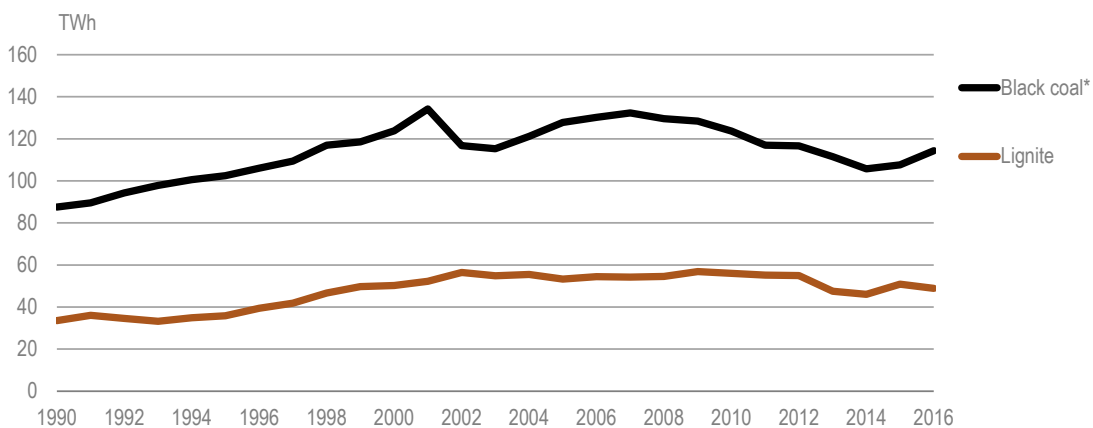
Source: DoEE (2017), "Australian energy statistics, Table O", www.environment.gov.au/energy/publications/australian-energy-update-2016.

Figure 4.4 CO₂ emissions per kWh heat and power in Australia and in other selected IEA member countries, 1990-2015



Source: IEA (2016), *CO₂ Emissions from Fuel Combustion 2016*, www.iea.org/statistics/.

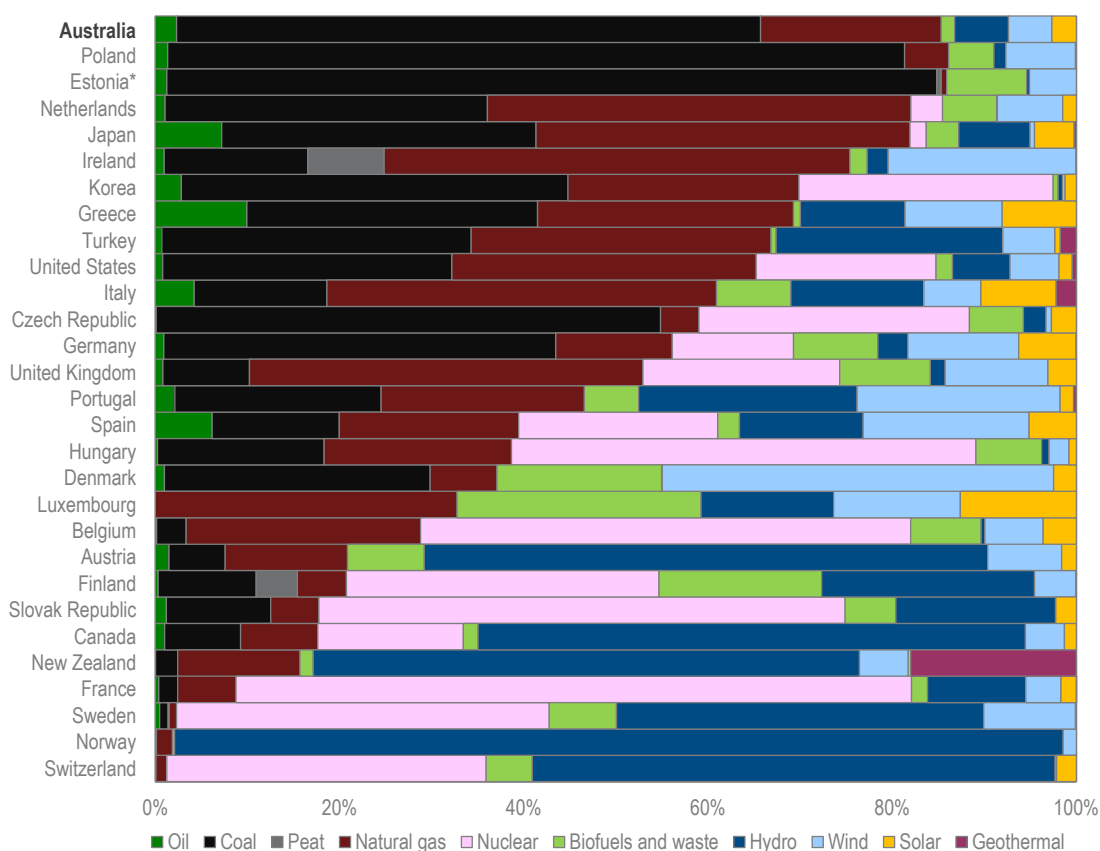
Figure 4.5 Electricity generation from hard coal and brown coal, 1973-2015



*Black coal includes sub-bituminous and other bituminous coal.

Note: 2016 data are provisional.

Source: IEA (2017b), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 4.6 Electricity generation by source in IEA member countries, 2016

* Estonia's coal represents oil shale.

Note: Data are provisional.

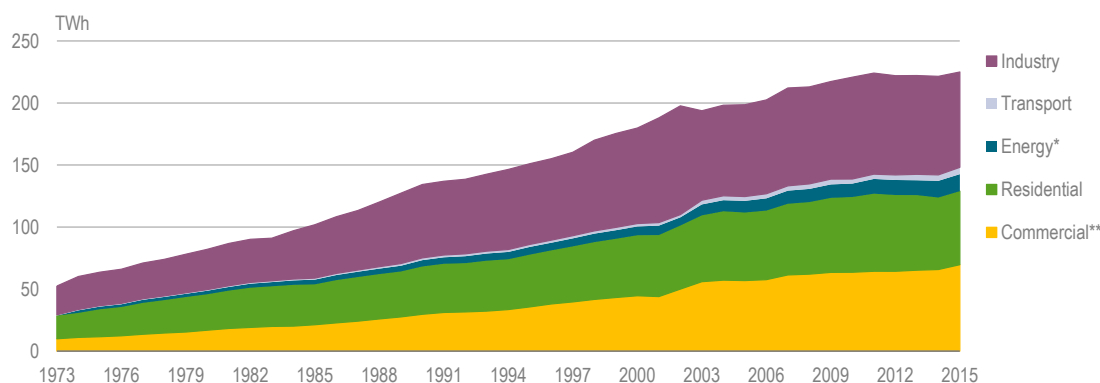
Source: IEA (2017b), *World Energy Balances 2017*, www.iea.org/statistics/.

Electricity consumption

Electricity consumption has increased steadily across all major sectors, until stabilising since 2009-10, with a recent rebound to 225 terawatt-hours (TWh) in 2015.

Australia's industry sector is the largest electricity consumer with 34% of total consumption, mainly from non-ferrous metals industry (aluminium production). Industrial electricity consumption declined by 6% in 2015 compared to a peak level in 2010, as a result of the closure or reduced production of many energy-intensive manufacturing and engineering businesses. This decline was offset by growing electricity needs in energy production (mainly coal mines, oil and gas production) which is driving a relatively small but quickly growing share of total electricity demand.

The residential and commercial sectors accounted for 26% and 31% of total electricity consumption, respectively. The lion's share comes from electricity used in commercial buildings and public services. Electricity consumption in the commercial sector has increased by 23% from 2005 to a new peak level in 2015, and residential consumption increased by 8% over ten years. Australia has experienced higher reliance on electricity use, with the rise in the use of electric appliances and increasing air-conditioning needs, which was offset by greater energy efficiency in buildings and appliances.

Figure 4.7 Electricity consumption by sector, 1973-2015

* *Energy* includes coal mines, petroleum refineries, and oil and gas extraction.

** *Commercial* includes commercial and public services, agriculture, fishing and forestry.

Source: IEA (2017a), *Electricity Information* (database), www.iea.org/statistics/.

Electricity systems and markets in Australia

Australia has two major electricity systems and wholesale markets: the National Electricity Market (NEM) with 47 GW of installed generation (in 2017) in the electricity systems of the eastern and southern parts and, on the other hand, the wholesale electricity market in Western Australia (WEM) with 5.8 GW for the South-West Interconnected System (SWIS). There is the separate North West Interconnected System (NWIS), an inland and isolated system for the mining industry, which does not have a wholesale market. The NWIS and SWIS are not physically connected to each other or to the NEM, but work is ongoing to harmonise the market rules and regulations with the NEM. The Northern Territory (NT) has a number of isolated, regulated and non-regulated power systems servicing major townships and remote settlements. It is not connected to the NEM or to Western Australia's electricity systems and, does not participate in the wholesale markets associated with those systems. NT has adopted elements of the *National Electricity Law* (NEL) relating to economic regulation of electricity networks. Figure 4.8 illustrates the three different power systems and the generation mix in the states/territories in Australia.

Western Australia

Reflecting Western Australia's geography, industry and demography, the state's electricity infrastructure consists of several distinct systems, the SWIS, the NWIS and 29 regional, non-interconnected power systems. The largest network, the SWIS, serves Perth and other major population centres in the south-west, while the NWIS serves towns and resource industry loads in the north-west and the interior of the state. There are five parties involved in the ownership of networks and generation and the operation of the NWIS: ATCO Australia, Alinta Energy, BHP Billiton, Horizon Power and TransAlta.

The Wholesale Electricity Market (WEM) is the market for the South-West Interconnected System (SWIS). It has been in operation since September 2006 when the West Australia government reformed its electricity utility (Western Power) and created a wholesale market, operated by AEMO in accordance with the WEM rules.

The WEM supplies about 18 terawatt hours (TWh) of electricity each year for one million customers, with 5 798 MW installed generating capacity. It is a concentrated market with Synergy owning around 58% of all installed power capacity. Other major participants are Alinta, NewGen, and the Collgar wind farm.

Synergy also holds a monopoly franchise covering all electricity customers with annual consumption of less than 50 megawatt hours (MWh). This is around 6 TWh per year, or around a third of energy sold in the SWIS. Customers with consumption over 50 MWh per year (the remaining two-thirds of energy sold in the SWIS) are contestable and can be supplied by either Synergy or other retailers. Western Power has a monopoly over the provision of network and metering services in the SWIS. The WEM has a reserve capacity mechanism which also includes the participation of demand-side resources. The Western Australian government is reviewing its electricity market, including the wholesale and capacity markets.

Northern Territory

The Northern Territory has three relatively small regulated electricity networks (Darwin-Katherine, Alice Springs and Tennant Creek) that are not connected to the NEM. Further, there are numerous non-regulated non-interconnected power systems in regional and remote areas.

The Northern Territory has an emerging wholesale electricity market mechanism in the Darwin-Katherine power system, known as the Northern Territory Electricity Market (NTEM). In May 2015, an interim wholesale electricity market, the I-NTEM commenced, which provides a low-risk opportunity for market participants to familiarise themselves with operating in a competitive framework and to identify and resolve technical and operational issues. Under I-NTEM, the system controller has market operator functions. The government is now undertaking work to transit the I-NTEM to NTEM. The Northern Territory's dominant generator, Territory Generation, produces about 2 000 gigawatt hours (GWh) of electricity per year using gas, diesel and solar. It owns 583 MW of installed capacity and contracts an additional 32 MW from independent power producers. There is limited retail competition with government-owned Jacana Energy as the dominant retailer for all consumer groups.

The Northern Territory's electricity retail market is split between an unregulated commercial and industrial (C&I) customer market which consumes above 750 MWh per year and a regulated market for customers below this threshold (these customers pay a government-subsidised regulated tariff set under an Electricity Pricing Order). C&I customers have been subject to competition since 2002. Until full retail contestability was introduced in 2010, the customers under the Electricity Pricing Order (or regulated tariff) were largely unable to access other suppliers, as Jacana Energy had the sole access to the subsidy arrangements associated with the regulated tariff. However, since 1 January 2016 this tariff has been made available to all electricity retailers licensed to operate in the Northern Territory.

National electricity market

The NEM commenced operation as a wholesale energy-only spot market in December 1998. Its power system stretches over 4 500 km along the Eastern seaboard and physically links transmission and distribution networks and around 47 GW of electricity generation installed in the markets of five regions – Queensland, New South Wales

(including the Australian Capital Territory), Victoria, South Australia, and Tasmania. Participation is mandatory in the gross pool. Over 300 market generators sell their electricity into the NEM, which brings together 47 GW (42 GW outside solar PV), around 70% of Australia's total installed generation (67 GW) in 2016.

The NEM is built on common rules and governance structures on the basis of the intergovernmental Australian Energy Market Agreement (AEMA) of 30 June 2004, amended in December 2013 (AEMA, 2014).

The market and system operator for the NEM, the Australian Energy Market Operator (AEMO) classifies market and non-market generators into:

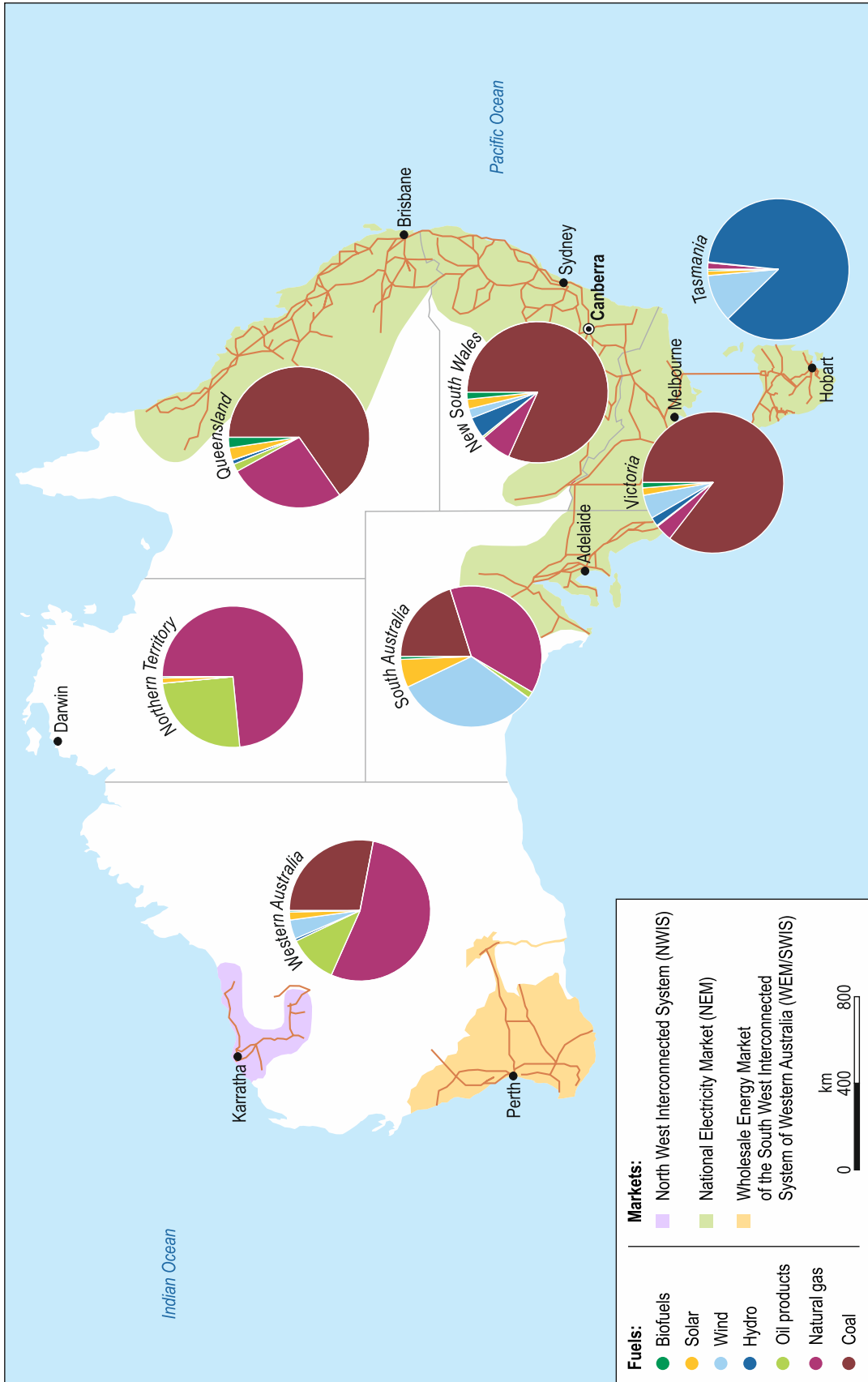
- Scheduled generators: aggregate generating capacity over 30 MW (predominantly coal, gas and hydro power plants).
- Semi-scheduled generators: aggregate generating capacity over 30 MW with variable output (predominantly wind power plants).
- Non-scheduled generators: aggregate generating capacity between 5 and 30 MW.

Power plants with nameplate capacity of less than 5 MW may be exempted from being registered with AEMO as generators. The exempted power plants are considered as part of the demand side (as a negative load). Scheduled and semi-scheduled generators must offer to supply the market with specified amounts of electricity at specified prices for set time periods. As such, AEMO has limited visibility of distributed renewable sources.

The NEM has a five-minute dispatch and five-minute financial settlement interval (down from the previous 30-minute settlement period since 28 November 2017, see AEMC, 2017b). The merit order dispatch price is determined every five minutes, and six dispatch prices are averaged every five minutes to determine the settlement or "spot price" for each NEM region. AEMO uses the spot price as its basis for settling the financial transactions for all electricity traded in the NEM. The generators hedge price volatility through participation in the financial markets. The NEM has limited day-ahead visibility of the bids, as unit commitment is not day-ahead. Generators are required to submit initial price/quantity offers to AEMO one day in advance, but they can change their bids up until the start of the five-minute dispatch. This is quite remarkable, as it creates operational constraints, compared to other markets, where the system operator works with more day-ahead visibility, like in the EU or the PJM. The NEM is also unusual compared to other markets with regard to ancillary services which are purchased through a spot market for ancillary services.

The NEM is an energy-only market but has an administered market price cap, a maximum spot price, which is set at AUD 14 200 per MWh as of 1 July 2017 (annually adjusted for inflation) and a minimum (floor) price of AUD -1 000 per MWh. The Australian Energy Market Commission's Reliability Panel reviews the price-cap and floor-price settings every four years to ensure they align with the NEM reliability standard. This standard requires there be sufficient generation and transmission interconnection so that 99.998% of annual demand for electricity is expected to be supplied. Electricity wholesale prices in the NEM are generally in the range of AUD 40 to AUD 100 per MWh, however, there are many price spikes. These are linked to the cap, the power mix in the NEM as well as market participant's behavioural strategies.

Figure 4.8 Map of Australia's electricity grid



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Institutional governance of the NEM

Governance of the NEM is overseen by the Council of Australian Governments (COAG) Energy Council, a Ministerial forum made up of representatives of the Commonwealth, state, territory and New Zealand governments.¹ The Council is responsible for monitoring and reforming national energy markets and the jurisdictions have given some power to the COAG to determine so-called national energy market rules. The role of the COAG in the energy market reform and associated governance arrangements were set out in a 2013 intergovernmental agreement known as the Australian Energy Market Agreement (AEMA). The Council is responsible for four key energy market institutions:

- **Australian Energy Market Commission (AEMC)** – the market development body sets the rules governing the electricity market;
- **Australian Energy Market Operator (AEMO)** – the market and systems operator supervises Australia’s largest gas and electricity markets and power systems (10 gas hubs and the NEM, and the Wholesale Electricity Market (WEM) and power system in Western Australia). AEMO is 60% government-owned, 40% private, but funded through fees.
- **Australian Energy Regulator (AER)** – the national energy regulator is a constituent part of the Australian Competition and Consumer Commission (ACCC). AER translates AEMC rules into guidelines for market participants, monitors the wholesale market and enforces compliance with the rules. The AER monitors, investigates and enforces compliance with national energy legislation and rules. As of 1 January 2017, AER is tasked to provide advice to COAG on the effectiveness and competition in the wholesale market.
- **Energy Consumers Australia (ECA)** – the not-for profit consumer advocacy body.

The Council also has oversight of the three sets of energy market laws and rules:

- National Electricity Law (NEL)
- National Gas Law (NGL)
- National Energy Retail Law (NERL).

The NEL is a schedule to the National Electricity (South Australia) Act 1996, which was enacted by the South Australian Parliament and has been applied in the other participating jurisdictions by way of “application of laws” legislation. Participating jurisdictions include South Australia, Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and the Commonwealth. The *NEL* includes provisions that define the NEM and set out a single National Electricity Objective (NEO). The *NEL* enshrines the policy-making role of the Ministerial Council on Energy (now called COAG Energy Council) in the context of the NEM and the roles and

¹ Although a full member of the Council, New Zealand is ineligible to vote on matters solely relating to the NEM in Australia.

responsibilities of the market bodies. It also provides for information sharing between AEMC, AER and the Australian Competition and Consumer Commission (ACCC). The NEL describes certain processes related to the safety and security of the national electricity system. The National Electricity Rules (NER) underpin the operation of the NEM and are given the force of law under the NEL. The Electricity Rules cover the operation of the central dispatch process and spot market, security arrangements for the power system, economic regulation of networks and network connection access arrangements.

Outside the NEM, several agencies were created under the Clean Energy Future Package, including the Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation (CEFC) which fund research, development and commercialisation of clean energy technologies, the Clean Energy Regulator (in charge of the carbon mitigation mechanisms, renewable energy target and GHG reporting) and the Climate Change Authority (regulatory advisory agency for climate change laws and regulations). They are not part of the NEM, but their decision-making and regulatory tasks are relevant for the NEM.

Figure 4.9 illustrates the highly complex governance structure of the NEM with the legal foundations (in orange) and the NEM market bodies (in blue) as well as the related agencies of the Australian government (CEFC, CER, ECA – in green). ECA was established under the COAG but has an independent status.

Wholesale electricity market

Market power and competition in the NEM

Australia's NEM has persistently experienced market concentration in several regions. In 2017, total installed electricity generating capacity in the NEM was 47 GW (including small-scale renewable energy, notably solar PV).

Looking at bulk generating capacity, NSW had the highest installed capacity (16.2 GW) followed by Queensland (12.6 GW), Victoria (10.9 GW), South Australia (4.4 GW) and Tasmania (3 GW) (AER, 2017a).

Private businesses own most generating capacity in Victoria, New South Wales and South Australia, while government-owned corporations own or control the majority of capacity in Queensland and Tasmania.

In the NEM, three main private business players, the “big three” – AGL Energy, Origin Energy and EnergyAustralia – supplied around 73% of retail electricity consumers in 2016 besides large government-owned generators-retailers (19%), Snowy and Stanwell, which hold large installed capacity in Queensland (Stanwell) and NSW and Victoria (Snowy).

The NEM has experienced a drop in energy demand and significant retirements of ageing capacity in recent years, which led to an increase in the market shares of other market participants, notably AGL Energy. The big three expanded their share in generating capacity in the NEM from 15% in 2009 to 48% in 2017 (AER, 2017a).

4. ELECTRICITY

Figure 4.9 Governance in the NEM

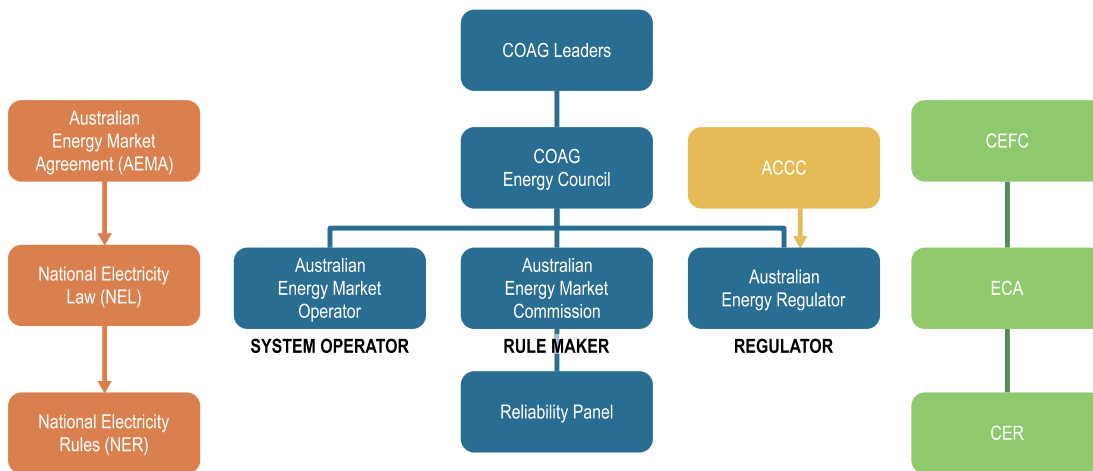
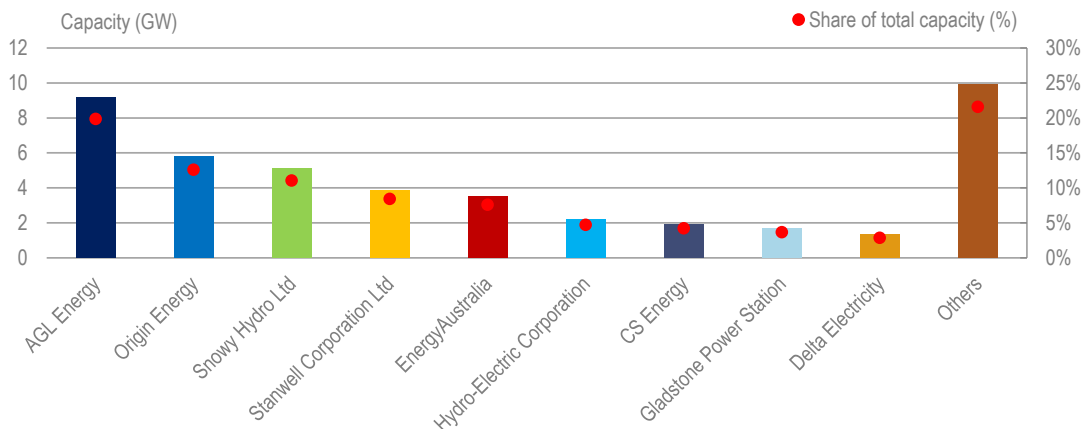


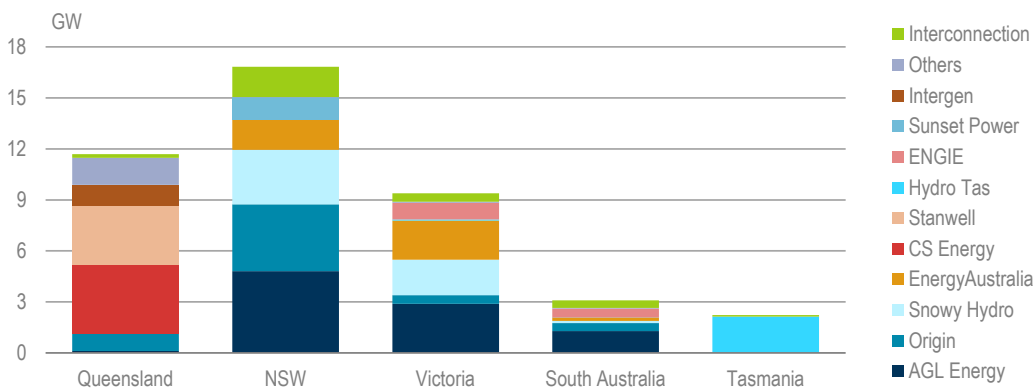
Figure 4.10 Installed electricity capacity by generator, 2017



Note: Power capacity installed in NSW, QLD, VIC, SA, and TAS (excluding WA and NT).

Source: IEA analysis based on AEMO, Regional generation information pages, www.aemo.com.au.

Figure 4.11 NEM installed electricity generating capacity by states/company, 2017

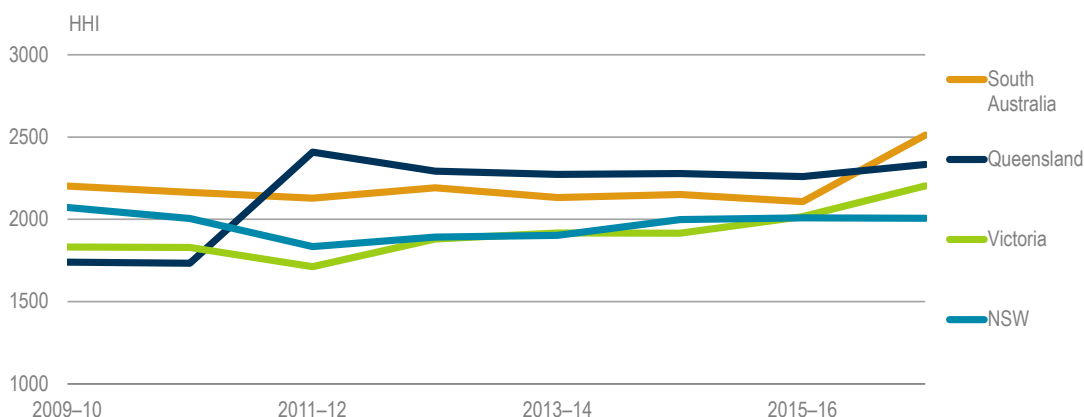


Source: AER (2017a), "State of the Energy Market".

Among the private players, AGL Energy is the major generator and retailer, holding around 20% of total generating capacity in South Australia, Victoria and New South Wales, followed by Origin Energy (13%) in four states and EnergyAustralia (7%) in three states. State-owned generators dominate generating capacity ownership in Queensland (CS Energy and Stanwell), and Tasmania (Hydro Tasmania, 96%). Snowy Hydro is the third-largest generator, jointly owned by the Commonwealth (13%), New South Wales (58%) and Victoria (29%) governments under the *Snowy Mountains Hydro-electric Power Act 1949*. It holds around 20% of capacity in Victoria and in New South Wales. South Australia and Victoria have little competition outside the three private gentailers (Figure 4.11).

A measure for market concentration is the share of market participants in the generation market and the Herfindahl-Hirschman Index (HHI).² The NEM regions have experienced constantly high concentration levels with recent upward trends reaching HHI levels of 2 000 to 2 500. The consolidation of the generators in Queensland under the government-owned companies Stanwell and CS Energy has led to a recent rise in market concentration in this state (see Figure 4.12).

Figure 4.12 Market concentration in the NEM (Herfindahl–Hirschman index HHI)



Source: AER (2017a), “State of the Energy Market”.

Australia’s private and public players (AGL Energy, Origin Energy, EnergyAustralia, Hydro Tasmania³, and Snowy Hydro) maintain the integration of generation and retail, as so-called gentailers. Experience in other IEA jurisdictions, notably in the United Kingdom and Germany, shows the possible negative impact that vertical integration of several large gentailers can have on competition, transparency and innovation, including:

² HHI = The Herfindahl-Hirschman Index or HHI is a measure for industry concentration taking into account the size of firms in relation to the industry. It is calculated by adding the sum of the squares of the percentage market shares of each market participant. For example, a market consisting of five competing firms, each with a 20% share of the market, would have an HHI score of 2 000 (i.e. 400×5). HHI is typically used to help assess the degree of market dominance and potential for market power abuse. Views vary on the interpretation of HHI scores. This study uses the scale developed by the European Union, with scores of 750-1 800 considered indicative of moderate concentration; scores of 1 800 to 5000 indicative of high levels of concentration and scores above 5 000 indicative of very high concentration consistent with the presence of substantial potential market power.

³ The retail subsidiary of Hydro Tasmania, Momentum, only retails in other jurisdictions, as retail activities are very limited in Tasmania (with the exception of the Bass Strait Islands).

4. ELECTRICITY

- undermining development of a more competitive physical market
- limiting the scope for new entrants
- undermining timely and efficient financial market development
- limiting the degree of innovation, especially in products and services
- reducing the degree of competitive pass-through of efficiency gains
- reducing the effectiveness of consumer choice and market participant behaviour.

Under the *Competition and Consumer Act 2010* (CCA), the Australian Competition and Consumer Commission (ACCC) is in charge of monitoring and enforcing competition rules. While competitive energy supplies and affordable prices are a stated goal of the COAG Energy Council reforms, analysing and addressing structural market barriers or oligopoly-monopoly structures remains a challenge. In 2014, the ACCC opposed the acquisition of the assets of Macquarie Generation by AGL Energy flagging harmful impact on competition. The ACCC took the matter to the Australian Competition Tribunal that reviewed it and gave the authorisation to proceed.

Since 2017, the regulator AER has had a new role in monitoring wholesale market performance on a regular basis. In March 2017, the ACCC was asked by the Treasury to investigate retail electricity prices in Australia, which includes the examination of the degree of vertical integration. Matters to be considered by the inquiry shall include, but not be restricted to:

- the key cost components of electricity retail pricing and how they have changed over time
- the existence and extent of any barriers to entry, expansion and/or exit in retail electricity markets
- the extent and impact of vertical integration
- the existence of, or potential for, anti-competitive behaviour by market participants and the impact of such behaviour on electricity consumers
- any impediments to consumer choice, including transaction costs or lack of information
- the impact of diverse customer segments and of different levels of consumer behaviour on electricity retailer behaviour and practices
- identification of any regulatory issues, or market participant behaviour or practices that may not be supporting the development of competitive retail markets
- the profitability of electricity retailers through time and the extent to which profits are, or are expected to be commensurate with risk
- all wholesale market price, cost, and conduct issues relevant to the inquiry.

The Commonwealth government decided to amend competition rules by presenting the *Competition and Consumer Amendment (Competition Policy Review) Bill 2017* (CCA Bill)

on 30 March 2017, and the *Misuse of Market Power Bill* at the end of 2016, following the 2014 Harper Review. The *Competition Policy Reform Bill 2017* will amend the *National Access Regime* (which provides for third-party access to nationally significant infrastructure). However, this will not affect vertical integration of generators or access to energy infrastructure, which is covered by separate national regulations.

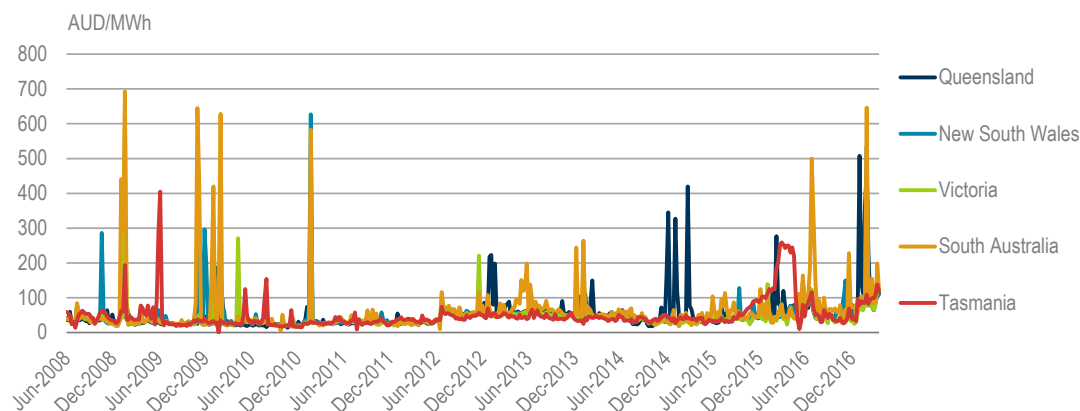
Wholesale electricity prices

Wholesale electricity costs have been on the rise, notably since 2016 when they rose to a higher level of average spot prices, mainly as a result of higher retail margins, lack of new investment in conventional power capacity, increasing gas prices and generator retirements, all of which tightened the supply-demand balance, putting upward pressure on wholesale electricity costs in several price zones of the NEM (see also findings of the AEMC, 2017a).

Wholesale prices in the NEM traditionally show strong volatility, depending on the availability of interconnectors, which can be down or highly congested between the regions and exacerbate market concentration.

Prices in South Australia experienced huge price spikes during the summer period (December), but also saw a significant price spike after the retirement of thermal capacity, the temporary loss of interconnection with eastern states, and the reliance on costly gas generators. Equally, prices in Tasmania rose following the loss of the interconnection with the Australian continent in 2015.

Figure 4.13 Weekly volume-weighted average spot prices in the NEM, 2008-17



Source: AER (2016), "Wholesale Statistics", www.aer.gov.au/wholesale-markets/wholesale-statistics/annual-volume-weighted-average-spot-prices.

Financial markets

Risk management of the generators and retailers occurs through vertically integrated structures, over-the-counter trade (OTC) or electricity futures at the Australian Securities Exchange (ASX). Around 200% of the underlying NEM demand (or around 400 TWh) was traded on the ASX in 2015/16 (AER, 2017a). There is limited scrutiny of the OTC market by the market authorities, the AER or the Australian Securities and Investment Commission (ASIC), most data are reported by the industry association, the Australian Financial Markets Association (AFMA). In fact, ASIC has discontinued a survey of OTC markets. The transparency of the financial markets is

limited and the liquidity and traded volume have both decreased over the past five years, despite constant NEM turnover (AER, 2017a).

For South Australia in particular, there is little liquidity in the financial markets of NEM ASX energy derivatives. In fact, as large-scale thermal capacity exited South Australia and as renewable energy capacity does not participate in the financial markets, the market has become very tight.

From 2016 to 2017, the demand and prices for baseload quarterly futures at the ASX for 2017/18 have more than doubled from around AUD 60 to AUD 130 per MWh for Queensland, South Australia (even AUD 150 per MWh) and Victoria. Following the exit of baseload capacity and the loss of related hedging volumes, concerns about limited gas supplies and high price spikes, the market for future baseload and peak capacity in the NEM for the 12 to 24 months ahead has become tight (CCA/AEMC, 2017; AER wholesale statistics), but is declining thereafter with a few spikes for each summer period in Australia.

Generation and fuel adequacy

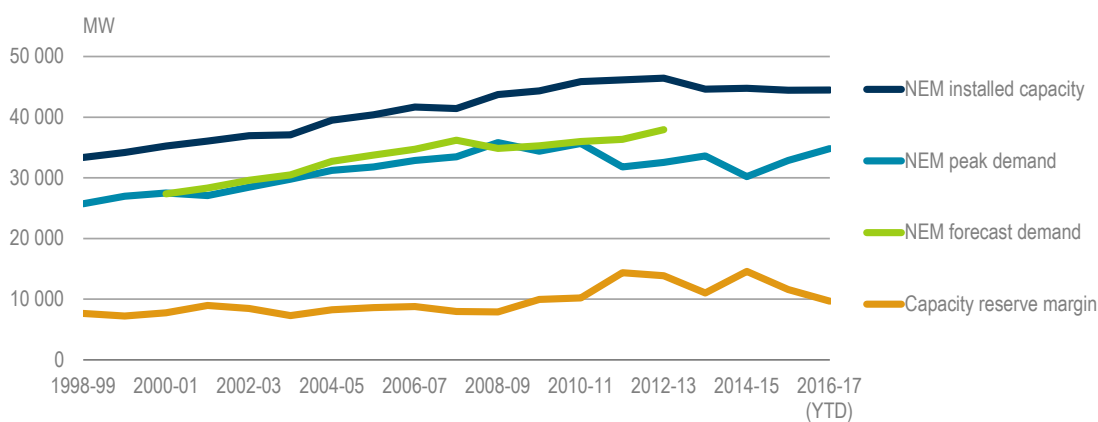
The NEM market was designed for the pool of centralised thermal and hydro generators, insignificant levels of variable renewable energy or distributed generation, and low levels of demand response in the retail and wholesale markets. However, the electricity market in Australia is experiencing the transformation of the electricity mix towards decreasing thermal generation and higher shares of variable wind and solar generation.

South Australia and neighbouring Victoria and New South Wales are at the forefront of the transformation. In the case of South Australia, the share of variable renewable energy rose to 42% in 2016 in the electricity mix, while the share of thermal capacity decreased by 50% during 2015/16. Besides renewable energy, South Australia was the main state with large investment in natural gas-fired power generation. Recent retirements included the withdrawal of two Alinta Energy stations, the Playford B coal-fired power station (240 MW) and the Northern coal-fired power station (520 MW). Despite the large gas investment, the second Pelican Point unit (a 239 MW of gas-fired power plant) was mothballed in 2016, operating only on half capacity, amid a very tight gas market in the southern states. South Australia also relies on the expanded capacity of the Heywood interconnector to Victoria (upgrade was completed in 2016 from 460 MW to 650 MW). However, ENGIE's Hazelwood power station (1 600 MW) closed in Victoria on 29 March 2017, reducing the amount of synchronous generation available in the two regions.

The pace and scope of retirement of coal-fired capacity have been faster than anticipated – ten coal-fired generators have closed since 2012, for a total of 5.1 GW (see Chapter 6 on Energy and Climate Policies). The NEM encouraged a boom in investment in gas-fired power plants in 2008-12. There has been no investment in thermal capacity in recent years. Several gas-fired power plants have been mothballed. This is the result of the flat electricity demand, much below earlier forecasts, uncertainty around future emissions reduction policies following the cancellation of the carbon tax, high gas prices and lower power price margins with renewable energy entering the market. In New South Wales, Smithfield (170.09 MW) announced the intention to close in July 2017 and Stanwell in Queensland is planned to withdraw Mackay GT power station (34 MW) in July 2021. The overall reserve capacity margin in the NEM has fallen from 48% in 2014 to 28% (Figure 4.14). Thermal power plant retirements were mostly offset by newly committed generation, so that the installed capacity remained flat. However, the

generation type differs in terms of its location, availability and characteristics for the network and system operation. By 2035, the majority of Australia's coal-fired power plants would be expected to close if the power sector has to contribute to Australia's 2030 GHG emissions reduction pledge under the Paris Agreement (AEMO, 2016a). To date, only AGL has announced that the Liddell (coal-fired) power station (2 000 MW) in New South Wales will be withdrawn in March 2022. Planned additions are all renewable energy facilities with 1 591 MW of large-scale solar and 2 130 GW of wind power across Australia, according to data by the Clean Energy Regulator.

Figure 4.14 Generation adequacy in the NEM



Source: IEA analysis based on data from AER, "Wholesale Statistics", www.aer.gov.au/wholesale-markets/wholesale-statistics/generation-capacity-and-peak-demand, 2017.

Table 4.2 Australia's generation adequacy outlook to 2035/36

Region	Announced generating capacity withdrawals and additional modelled withdrawals based on COP21 commitment assumptions						Announced generating capacity withdrawals only	
	Weak economic growth with COP21		Neutral economic growth with COP21		Strong economic growth with COP21		Neutral economic growth	
	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall	Timing	Shortfall
NSW	Beyond 2025/26	N/A	2025/26	0.0024%	2022/23	0.0070%	2025/26	0.0022%
QLD	Beyond 2025/26	N/A	Beyond 2025/26	N/A	Beyond 2025/26	N/A	Beyond 2025/26	N/A
SA	Beyond 2025/26	N/A	2019/20	0.0022%	2019/20	0.0043%	Beyond 2025/26	N/A
TAS	Beyond 2025/26	N/A	Beyond 2025/26	N/A	Beyond 2025/26	N/A	Beyond 2025/26	N/A
VIC	Beyond 2025/26	N/A	2025/26	0.0020%	2024/25	0.0041%	Beyond 2025/26	N/A

Source: (AEMO) (2016b), "Electricity Statement of Opportunities".

The market operator AEMO's 10-year supply adequacy outlook – which is part of the Electricity Statement of Opportunities (ESOO) for each NEM region – regularly looks at the impact of plant retirement, demand-and supply-side changes with regard to any potential breach of the reliability standard. Consumption of grid-supplied electricity is forecast to remain flat for the next 20 years, despite projected growth in population and the economy. In 2016, AEMO modelled additional retirements of brown/black coal generation and additions of renewables in line with Australia's pledge at the Paris COP21, and found that significant medium-term adequacy shortfalls are projected to occur in New South Wales, South Australia and Victoria (AEMO 2016b), notably if strong economic growth continues.

The NEM is expected to experience tight demand-supply situations in both gas and electricity markets already much earlier during 2017-18, notably in South Australia and Victoria (Hazelwood retirement also reduces exports from Victoria to South Australia).

In its most recent inaugural *Energy Supply Outlook 2017*, AEMO found that reliability standards are likely to be met in all NEM regions, but that risks of electricity supply shortfalls can occur in South Australia, Victoria and New South Wales after 2022 (Liddell retirement expected), in the event of heatwaves and peak demand coinciding with low levels of PV or wind generation, constrained interconnector flows, gas supply or generator outages (AEMO, 2017a).

While the market is likely to respond to some of these shortfalls as a result of higher wholesale prices, AEMO is indicating that constraints (New South Wales, Victoria, South Australia) reduce the already limited flexibility of the networks to deliver the required generation. AEMO announced that the South Australian Government's Energy Plan, by developing additional diesel generation and battery storage, will help to some extent, but that it will be procuring a supply and demand response through the Reliability and Emergency Reserve Trader (RERT) (AEMO, 2017a).

Other IEA jurisdictions have responded to the transformation of the energy system and capacity shortfalls through different approaches. Energy-only markets are being used in a number of cases outside Australia, including New-Zealand and ERCOT in Texas. Most jurisdictions are enhancing the robust short-term markets, but many have also implemented some sort of capacity remuneration mechanism (see Box 4.1). The question of whether a capacity mechanism is needed should be studied with great care. Avoiding market reforms by introducing a capacity mechanism may be more expensive and may not deal with the structural issues.

Retail markets and consumer engagement

Retail market structure

Australian retail electricity markets remain concentrated. The retail arms of the three large gentailers (Origin Energy, AGL Energy and EnergyAustralia) dominate supply to final customers. In 2017, the “big three” served 70% of national retail electricity customers, 96% of gas retail consumers and together owned almost 50% of generation in the NEM (AER, 2017a).

Box 4.1 Market-based approaches and capacity safety nets in IEA countries

In 2012-14, the **Public Utility Commission of Texas** carried out a review of whether or not to introduce a capacity market. A majority of commissioners decided to keep an energy-only market and to improve scarcity price formation by introducing an Administrative Operating Reserve Demand Curve, which is a form of regulatory intervention on the price formation in case of capacity shortage.

Germany is promoting a Power Market 2.0 that fosters free price formation on wholesale markets and competition for flexibility. Germany has introduced four different types of reserves (grid reserve, capacity reserve, grid stability reserve and climate reserve) to provide a safety net and reduce CO₂ emissions.

New Zealand's government has implemented a suite of reforms to strengthen competition and security of supply in the electricity market following the Ministerial Review of 2010. The government sold its strategic reserve plant in favour of improved incentives on market participants to better manage security. These included penalty payment for all retailers in the form of a consumer compensation charge for an electricity shortage; the requirement for market participants to submit their risk positions for aggregated publication, and enhancements to the product mix available for financial risk management. The transmission system operator publishes an assessment of the risk of future shortages, which helped to stimulate the conclusion of bilateral contracts among market participants to continue the operations of the backup coal power plant (Huntly).

Sweden's power reserve includes the following capacities for the time horizon to 2020:

2011-13: 1 750 MW with a 25% demand reduction

2013-15: 1 500 MW with a 50% demand reduction

2015-17: 1 000 MW with a 75% demand reduction

2017-19: 750 MW with a 100% demand reduction.

Svenska Kraftnät, the Swedish transmission system operator, can procure up to 2 000 MW via auctions for the winter periods between 16 November to 15 March on the basis of commercial bids on the Nord Pool Elspot, the day-ahead market. Owners of reduction bids are required to offer their bids to the market. If not traded, they have to place the bids on the intraday market. The reserve price can range between the highest commercial bid plus EUR 0.10 per MWh (the smallest price step on Nord Pool) and the minimum of the average variable cost plus start-up cost. The price is communicated to the market through Urgent Market Messages (UMM) on Nord Pool. Svenska Kraftnät recently changed the management of the demand reduction of the power reserve as a result of the new legislation. The procurement of consumption reductions will only cover bidding on the balancing market and the management of the consumption reduction resources shall also permit plant owners to make their own bids for the resource to the Elspot market. If the resource is not activated on the spot market, it will remain at the disposal of the balancing power market.

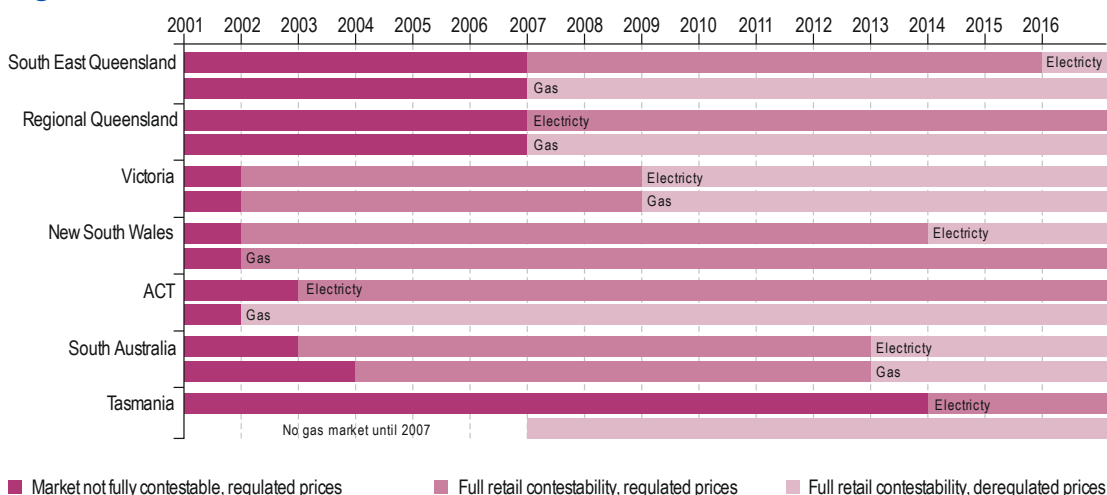
In **Europe**, the Nordic countries and the Netherlands expressed their wish to rely on an energy-only market in the long run, by removing price caps in the energy market. There is some discussion about abandoning the strategic reserve mechanism of Sweden.

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There are around 20 authorised retailers offering smaller contracts (Momentum, Powershop, GDF Suez' Simply Energy, Mojo Power, Alinta Energy, Click Energy, Dodo, Sumo Power, among others). State-owned retailers compete along these private retailers (Tasmanian government-owned Momentum, the retail arm of Hydro Tasmania, and Aurora Energy, Queensland-owned Ergon and the Capital Territory co-owned ActewAGL). Small retailers have been able to enter Victoria, New South Wales, South Australia and south-east Queensland and offer so-called market contracts.

Retail electricity market rules fall within the competence of each state/territory jurisdiction. However, most states/territories have adopted the *National Energy Retail Law* (NERL) of 2012. The NERL complements the *Australian Consumer Law* with specific regulation of the relationships for small retail customers in both gas and electricity markets. Most states and territories have adopted the NER Law, Tasmania (electricity only) and the ACT from 1 July 2012, South Australia from 1 February 2013, New South Wales from 1 July 2014 and Queensland from 1 July 2015, and Victoria partly harmonised its retail code with the NERL in 2014.

Figure 4.15 Retail market reform in Australia



Source: AER (2016), "Annual Report on the Performance of the Retail Energy Market 2015–16".

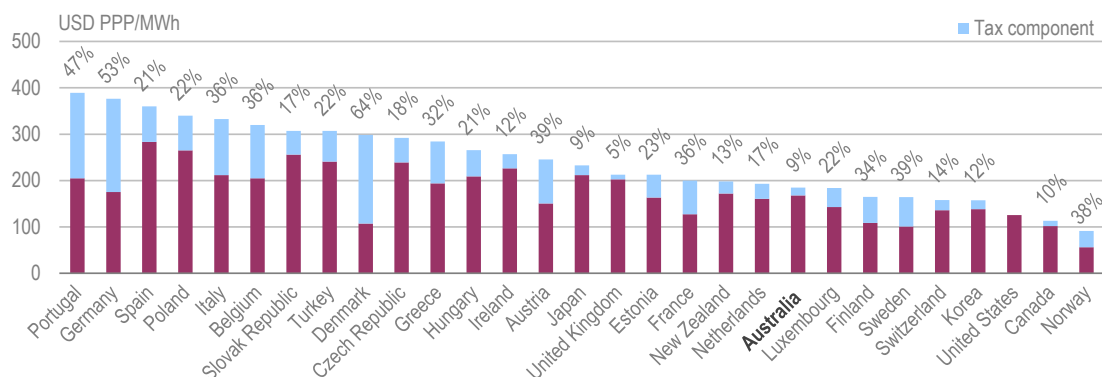
Since 2009, NEM regions have been phasing out retail price regulation for electricity, where effective retail competition was demonstrated, in line with the Australian Energy Market Agreement (AEMA). Now, most electricity and gas customers can choose their supplier in all NEM regions (full retail contestability). The concept of standing (regulated) retail offers has become less relevant as customers move to a variety of market-based offers. However, retail electricity price regulation still exists in the Capital Territory, Tasmania (for residential and small business consumers on standing-offer contracts) and in Queensland (for rural customers), as illustrated in Figure 4.15. Outside the NEM, Western Australia and the Northern Territory retain price regulation.

Electricity prices and taxes

Electricity prices for households have increased significantly in Australia over the past decade, almost threefold, rising from USD 98 (AUD 134) per MWh in 2004 to USD 283 (AUD 314) per MWh in 2014. Reaching a peak in that year, the trend has changed since, with prices declining by 14% to USD 202 (AUD 272) per MWh in 2016, except for

Queensland where prices remained at high levels. By international comparison in US dollars adjusted for purchasing power parity (PPP), Australian households paid electricity prices of USD 185 PPP/MWh in 2016, which was among the ten lowest in the IEA (see Figure 4.16).

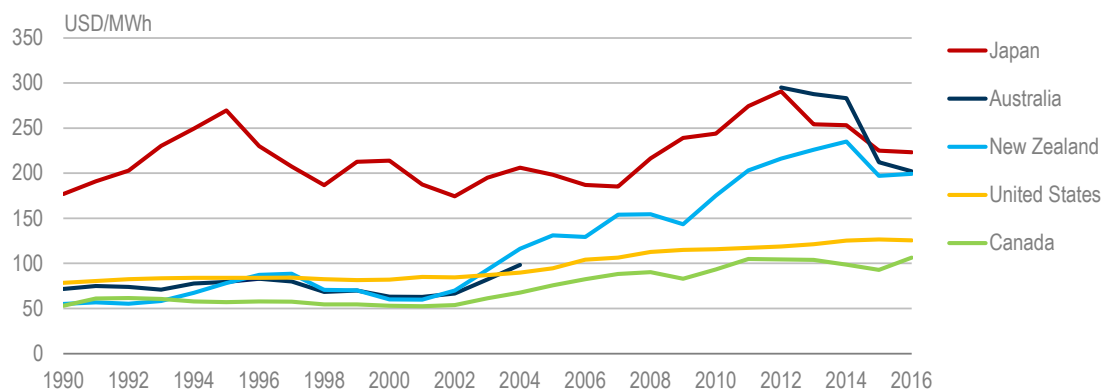
Figure 4.16 Household electricity prices (in PPP) in IEA member countries, 2016



Note: Tax information not available for United States.

Source: IEA (2017c), *Energy Prices and Taxes Q7 2017*, www.iea.org/statistics/.

Figure 4.17 Household electricity prices in IEA countries, 1990-2016



Note: Price data in Australia are not available from 2005 to 2011. The Australian government DoEE sources prices for households from the Australian Energy Market Commission's (AEMC) Residential Electricity Price Trends, which refer to the average expenditures per MWh received via a survey that samples households Australia-wide. These averages are weighted by the reporting institution by the number of residential connections in each jurisdiction and are therefore most closely representative of the most populous jurisdictions of Australia.

Source: IEA (2017c), *Energy Prices and Taxes Q3 2017*, www.iea.org/statistics/.

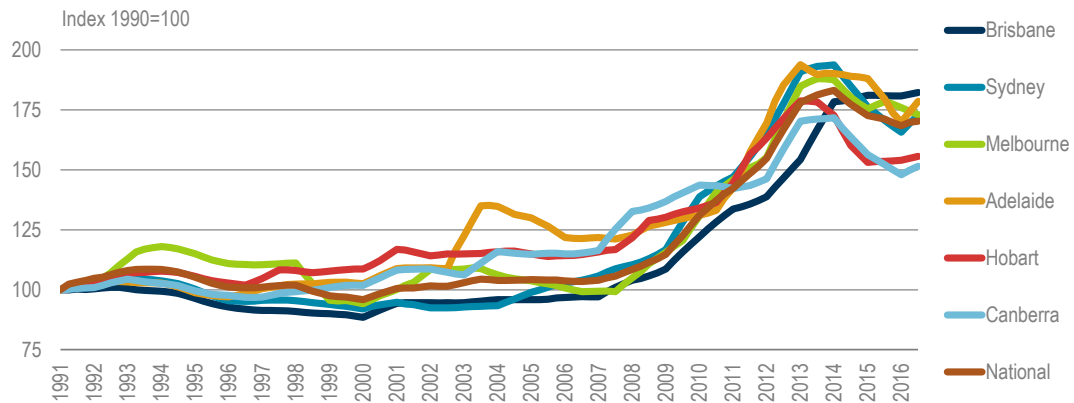
Australian retail electricity prices are on the rise because of a combination of several factors, mainly the high gross retail margins, which are a result of the closure of ageing plants (and thus higher margins for remaining generators) and of their gentailing market structure. Other factors relate to higher network costs following a period of strong transmission and distribution investment, rising gas prices, pushing up wholesale costs, and to a lesser extent the costs of environmental policies (e.g. renewable support schemes).

Japan and New Zealand have seen a similarly dramatic rise in retail electricity prices during 2009-14, which coincided with the creation of gentailing regional monopolies leading to a lack of competition.

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Since 2014, household electricity prices have been on a downward trend, which is coinciding with a decrease in market concentration of the gentailers from 98% to 70%. However, since 2017, electricity prices have gone up again, mainly because of higher gas prices.

Figure 4.18 Household electricity prices in Australia's NEM regions, 1990-2015/16



Note: Retail electricity price index CPI.

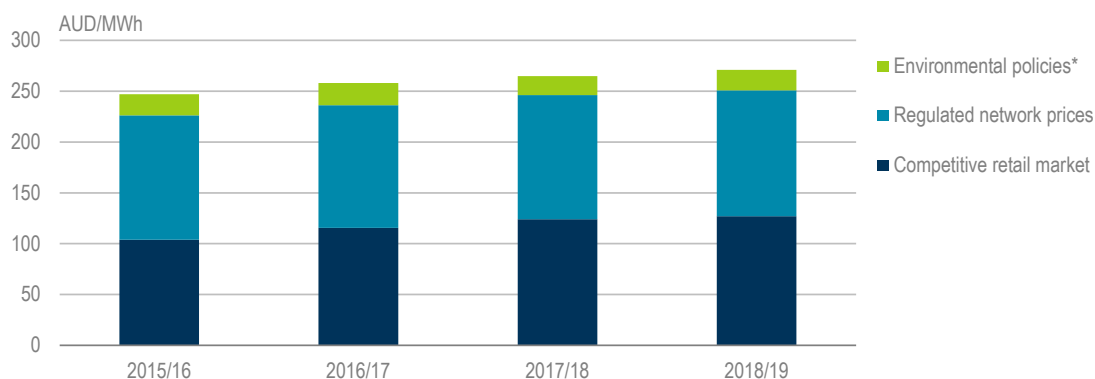
Source: AER (2017a), "State of the Energy Market".

The cost of the electricity network accounted for around 40% of the electricity retail bill (AER, 2017a; AEMC, 2016; Figure 4.19). These levels are high by international comparison, although there is only limited comparability between networks. The share of network cost in the final electricity retail bill is 25% in the United Kingdom; in New Zealand it amounts to 36% (26% distribution and 10% transmission charges), which have much smaller and denser topographies.

As illustrated in Figure 4.19, the recent price spike is due to an increase in the competitive component and not the environmental costs (subsidies for renewables, the renewable energy target, the Emissions Reduction Fund, etc). The ACCC inquiry of 2017 confirms that drivers of the electricity price increases were mainly network prices (41%), higher retail costs and margins (24%), generation costs (19%) and green scheme costs (16%).

The section below on electricity networks will provide further analysis. New cost-reflective pricing of distribution network services will apply to the next regulatory determination period for each distribution network service provider (DNSP). This should help avoid under/overcoverage of network cost and incentivise retailers to offer time-of-use pricing.

There are concerns that the gentailing structure gave rise to high retailer margins in markets that have become competitive after the end of regulated prices (Grattan Institute, 2017) and that market price offers are not transparent for consumers. There are also concerns that, because of low levels of consumer engagement, intransparent pricing practices, lack of smart metering and other barriers to consumer choice, many consumers are paying more than they need to for their electricity and gas.

Figure 4.19 Trend projection in Australian residential electricity prices

*Environmental policies include the cost of the renewable support schemes.

Source: AEMC (2016), "2016 Residential Electricity Price Trends", EPR0049.

Retail prices and monitoring

The sharp rise in electricity and gas retail prices and concerns about rising profit margins across the sectors have prompted several price reviews in Australia in recent years.

Several NEM market bodies and federal and jurisdictional authorities carry out price monitoring and retail market enforcement, based on a variety of methodologies and data sets. Every year, the energy regulator and the market commission assess retail market competition and performance. AER is looking at a subset of jurisdictions and examines a range of performance indicators, including retailers' market shares, the number of customers on standard and market contracts, switching, complaints, energy bills, support schemes (payment plans, concessions, the proportions of disconnections and customer debt levels) and the performance of electricity distribution companies. Where states do not apply the *National Energy Retail Law* (NERL), state-based bodies monitor and report on market performance (Victoria, Western Australia and the Northern Territory).

The AEMC is also required under the AEMA to annually assess competition in retail energy markets and to prepare reports on residential retail electricity prices, providing information on the electricity supply chain cost components expected to affect the trends in residential electricity prices for each state and territory of Australia.

The AER (and the ACCC) have also enforcement functions and can issue infringements against misleading advertising, discounts and other business practices. In March 2017, the Commonwealth government (Treasury) directed the ACCC to carry out an inquiry into retail electricity pricing with an interim report by 27 September 2017 and a final report due for 30 June 2018. In December 2016, the *National Electricity Law* was amended and tasked AER to monitor the performance of the wholesale electricity market including state of competition, price spikes and market concentration, and a role in imposing fines for non-compliance. The first AER report is expected for March 2018 and biennially thereafter.

In November 2016, the Victorian government announced an independent review of Victoria's electricity and gas retail markets and their operation and provided options to improve outcomes for consumers. The final report was released on 13 August 2017 and the Victorian government is currently considering the panel's final report.

Supplier switching and billing

As retail markets vary strongly across Australia, also supplier switching rates differ across states and territories. Small customer-switching rates have been declining or remained flat in most jurisdictions for the past years (AER, 2017a). Within the NEM, switching rates are the highest in Victoria (with an average rate of 7%) and New South Wales (with an average rate of 5%⁴). The AEMC 2017 retail competition review found that around 50% of consumers have not switched in five years and awareness of independent government price comparison sites is low (AEMC, 2017a).

In line with the *NERL*, AER developed and operates a price comparison website, “Energy Made Easy” (www.energymadeeasy.gov.au/) to help residential and small business energy consumers to navigate the often complex electricity and gas retail markets to find a suitable energy offer.

Electricity users are concerned by intransparent billing and contract information, and by cumbersome switching due to lack of ownership of consumer data and limited data portability. Electricity users on accumulation meters receive their bills for three-month periods. These factors and the lack of advanced meters and dynamic pricing offers hamper the capacity of consumers to switch supplier and/or become more energy-efficient. In markets where regulated retail tariffs (standard offers) co-exist with market offers or during the transition phase towards the end of regulated tariffs, consumers find it difficult to understand on which tariffs they are (AEMC, 2017a).

Smart meters and smart grids

Australia has still a low penetration of smart meters. Victoria was the first jurisdiction to roll out smart meters with remote communication during 2009-14. Jurisdictions other than Victoria will start the competitive roll-out of smart meters. Upon a request from the Council of Australian Governments, the AEMC introduced a rule change to open metering services to competition as from 1 December 2017 (in Victoria it will not commence before 2021).

The new rule will remove the current role of electricity distribution businesses in providing basic meters for residential and small business customers; it will make electricity retailers responsible for arranging metering services for customers; and will introduce a new participant in the market, the Metering Co-ordinator, who is responsible for operational metering functions. The new rules require that all new meters must be capable of delivering a set of minimum services, which include remote reading and remote connection and disconnection. Rather than specifying the hardware required in meters through minimum functionality specifications, metering providers will be able to innovate in how they choose to deliver services.

Moreover, regulated distribution network businesses must ring-fence their assets when they invest in competitive unregulated services (battery, solar PV, metering), in line with the regulator’s 2016 guidelines, at the latest by 1 January 2018.

⁴ www.aer.gov.au/retail-markets/retail-statistics/electricity-customer-switching.

Demand response

Demand-side participation⁵ in the NEM is at low levels; demand response in the wholesale market does not exist and it is underdeveloped in the retail markets. The market operator AEMO evaluated the levels in 2017 and found that around 512 MW of demand response is available for reliability purposes (from industrial consumers, including LNG industry) and around 109 MW of load is responsive to wholesale market prices above AUD 1 000 per MWh in the NEM (AEMO, 2017b).

Building on the *Power of Choice* review of 2012, the AEMC initiated a number of rule changes and rule change proposals in recent years, intended to improve opportunities for demand-side participation, including reforms to distribution network pricing, network demand-side management, and metering. Distribution-sector regulation is being amended in the future to stimulate demand-side management by network businesses through demand reduction, load shifting or embedded generation (small-scale local generation). This rule change was introduced in August 2015.

AEMC decided not to proceed with plans to introduce a centrally defined demand-response mechanism in the wholesale market but has introduced changes to improve the access of demand-side resources to other reserve markets, notably the ancillary services markets (FCAS), including for aggregators. The Finkel Review presented a recommendation to develop a demand-response mechanism, which was retained by the COAG for implementation. The AEMC is considering if new wholesale mechanisms are needed to support greater demand response through its Reliability Frameworks Review.

In 2017, AEMO and ARENA, the renewable energy agency, started a three-year innovative demand response initiative in south-east Australia, and in parallel, a specific New South Wales programme to pay consumers for temporarily reducing their demand to help manage peak demand. ARENA and the New South Wales government are providing AUD 37.5 million to support approximately 160 MW of demand-response capacity, including 60 to 70 MW in New South Wales. Successful proposals will be dispatched during extreme peaks and grid emergencies under AEMO's Reliability and Emergency Reserve Trader (RERT) mechanism. Outcomes of this trial will inform development of a demand-response mechanism for the wholesale market, recommended in the Finkel Review.

Vulnerable consumers

Across Australia, around 20% of customers are considered highly vulnerable, notably the middle-income class (8%) and low-income customers (12%) (AEMC, 2016).

Some support is targeted on pensioners and consumers which receive other public support (i.e. medical support), but many jurisdictions offer wider support. As an example,

⁵ Demand-side management (DSM) programmes have been developed and co-ordinated by utilities, often supervised by regulators, seeking to minimise the operating cost base used to determine regulated tariffs for end-users. Demand response differs from DSM in that it is the product of voluntary and independent decentralised decision making by suppliers and customers. The UK DECC defines demand response as "all actions that reduce demand from the transmission system at a particular moment in time." It includes dispatchable distributed resources and storage. For further information see IEA (2011), *Empowering Customer Choice in Electricity Markets*, OECD/IEA, Paris.

in 2015-16, Victoria paid AUD 557.5 million to around 910 866 households for electricity concessions and to 643 957 households for gas concessions (with a total population of around 6 million and 3 million dwellings). Western Australia maintains regulated electricity prices and provides subsidies and concessions for electricity services for small-use customers, including a direct retail business subsidy (AUD 277 million per year or 15% of total cost) and concession payments (AUD 80 million per year or 4.5% of total cost to 20% of household customers). New South Wales provides bill assistance in the range of AUD 250 million per year to around 900 000 customers a year out of 3.3 million electricity and 1.5 million gas consumers. Queensland provides concessions in the range of AUD 163 million per year to around 530 000 electricity consumers (out of a total of 2.1 million) and AUD 2.4 million to around 32 000 gas customers (out of a total of 197 000).

Under the National Energy Productivity Plan (NEPP), the Commonwealth is working with Energy Consumers Australia and stakeholders on measures improving consumer choice and on a best-practice voluntary guideline for service providers to reduce the barriers for vulnerable consumers to make effective use of energy productivity actions.

Consumer engagement and participation

The COAG Energy Council created in 2015 the Energy Consumers Australia as a not-for-profit organisation which is one of Australia's policy achievements to increase consumer engagement, information and participation.

Building upon the 2012 *Power of Choice* review by the AEMC, rule changes are being made to promote efficient use of energy networks and to empower customers to take efficient decisions: through competitive metering, ring-fencing of system operators' investment in storage or other competitive products, cost-reflective network pricing and embedded generation. The Commission also introduced new rules making it easier for customers in embedded networks to participate in retail markets. As of 1 December 2017, an embedded network manager has to link customers to the market operator AEMO's electricity market systems so that customers can have access to multiple retail market offers other than from the network manager.

The regulator AER manages a retailer of last resort scheme for the case of failure of a retailer, for instance following bankruptcy proceedings.

Electricity networks

Transmission networks

Each state or territory in the NEM has transmission network service providers (TNSPs) and a system control operator for the high-voltage electricity (transmission) network in their jurisdiction. The role of TNSPs is to plan, develop and operate their respective electricity network. TNSPs in the NEM are AusNet Services (Victoria), ElectraNet (South Australia), Powerlink (Queensland), TransGrid (New South Wales) and TasNetworks (Tasmania). The TNSPs of the NEM are interconnected through six cross-border interconnectors. Australia has private and public ownership of electricity networks. Jemena, AusNet Services, APA Group and Cheung Kong Infrastructure have stakes in both electricity and gas networks. With the exception of Queensland and Tasmania, where governments own the transmission networks, the TNSPs are privately owned

companies with majority shareholdings from investment funds (Hastings) and foreign grid companies (China State Grid Co-operation owns 46.5% of ElectraNet and 19.9% of AusNet Services; Singapore Power owns 31% of AusNet Services).

Interconnectors

There are six interconnectors in the NEM, three direct current interconnectors: Directlink (NSW-QLD Terranora), Murraylink (VIC-SA), and Basslink (TAS-VIC); and three alternate current interconnectors, Heywood (VIC-SA), VIC-NSW and Queensland NSW Interconnector (QNI), which all form part of the state-based networks. While five of these interconnectors are regulated (originally merchant lines Murraylink and Directlink have subsequently received regulated status), Basslink is a merchant and non-regulated interconnector, operating on the basis of the price differentials between the Tasmanian and Victorian regions of the NEM. Regulated interconnectors receive revenues based on the value of the asset and operational expenditure, not on usage.

Distribution networks

Australia has 16 major electricity distribution networks (distribution network service providers – DNSPs) of which 13 are located in the NEM. New South Wales, Victoria and Western Australia have multiple network companies which each have a geographically limited monopoly on their network. Queensland, the Capital Territory, South Australia and Tasmania have one DNSP each. Distribution networks are state-owned but leased (50.4%) in South Australia and New South Wales (Ausgrid, Endeavour Energy), except for rural NSW Essential Energy which remained state-owned. Queensland government merged its state owned distribution network businesses (Energex and Ergon Energy, including retail business) under a new parent company Energy Queensland. In Tasmania, TasNetworks is the single network business that is both the TNSP and the DNSP. Northern Territory and Western Australia have also government ownership of electricity distribution networks.

Network adequacy

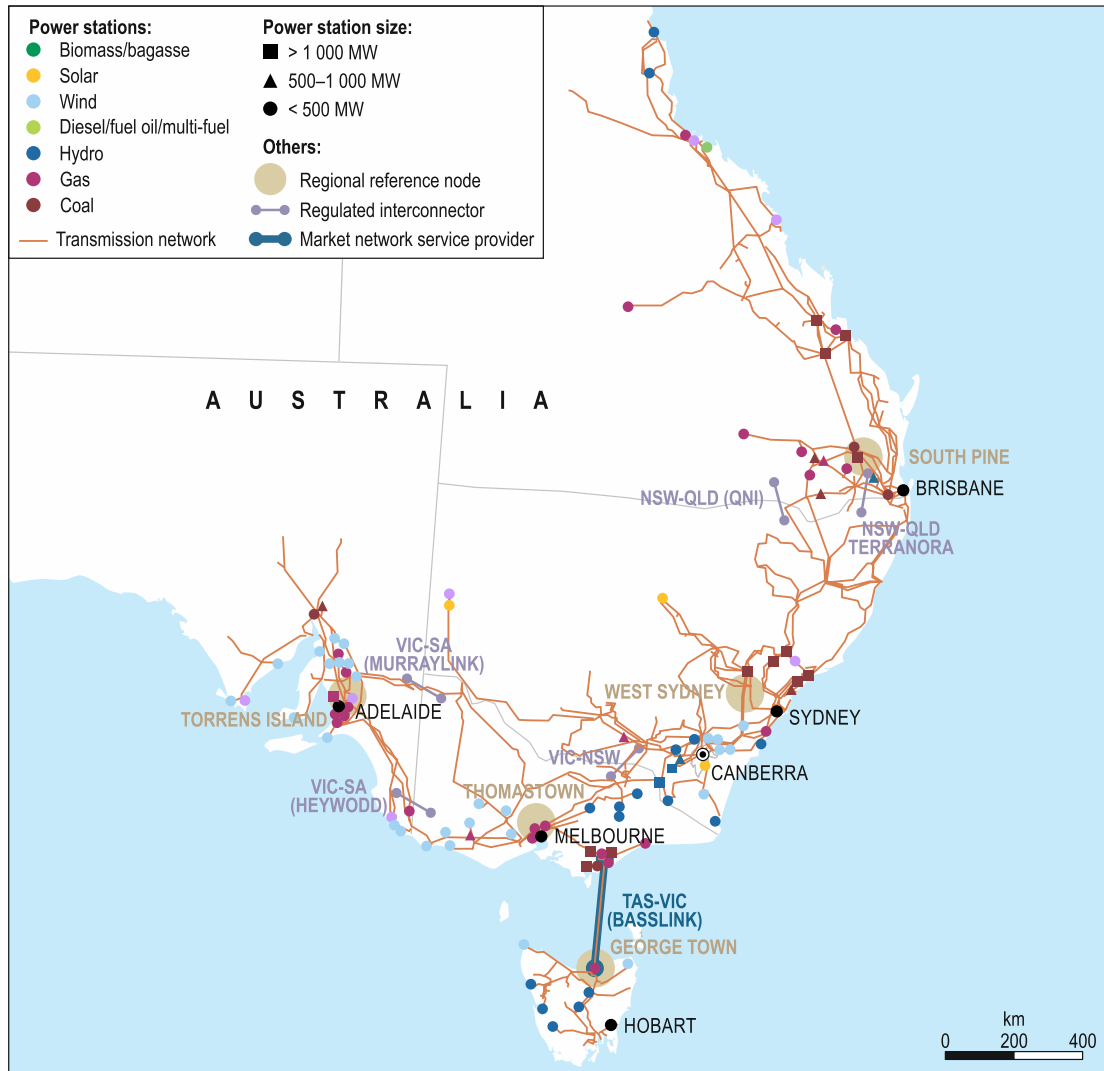
Following liberalisation and deregulation, network planning has become complex, with a large number of network companies, generators, and the four market authorities as well as a wide range of stakeholders.

AEMO prepares an annual network development plan (National Transmission Network Development Plan, NTNDP). However, investment decisions are taken by the market and the regulated TNSPs which are in charge of both network operation and investment, with the exception of Victoria, where network operation and investment planning are separated. In this region, AEMO is in charge of the investment, while AusNet Services owns and operates the network.

Network adequacy remains a concern in Australia, given the unique characteristics of the NEM transmission grid in terms of its low density and long, thin and radial structure, bridging long distances between demand centres and fuel sources for generation. The radial nature of the NEM grid carries the risk that any transmission line failure, notably a fault on an interconnector, quickly isolates the region and magnifies the events in this region. The interconnectors are critical for market functioning but can also be the cause of disruptions, for instance during an electricity security incident, when the overload of the interconnector can quickly breach the

capacity limits for a short period. The 290-kilometre link between Victoria and Tasmania is one of the longest submarine power cables in the world and a failure in the cable can lead to long-term outages, until the fault is detected, as evidenced by the prolonged outage period from December 2015 to June 2016.

Figure 4.20 Transmission network and interconnectors in the NEM



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Planned interconnectors and benefits from new ones are included in the AEMO NTNDP 2016. AEMO illustrates benefits of a new interconnector linking South Australia with either New South Wales or Victoria from 2021, augmenting existing interconnection between New South Wales and both Queensland and Victoria in the mid to late 2020s, and a second Bass Strait interconnector from 2025 (AEMO, 2016a). The NTNDP provides information about potential projects, but undertaking these projects depends on investment decisions by TNSPs or private investors. To recover regulated revenues from customers, interconnector proposals must pass an economic efficiency test known as the Regulatory Investment Test for Transmission (RIT-T, see also below). Private investments proceed on a merchant basis, earning revenues from the wholesale market price differential between regions.

The AEMC assessed a transmission model known as optional firm access (similar to financial transmission rights in other jurisdictions) to improve co-ordination of generators and connection investments (AEMC, 2013). In July 2015 the AEMC recommended that, in the current environment, the implementation of optional firm access would not contribute to the National Electricity Objective. Given the uncertain patterns of investment, the COAG Energy Council tasked the AEMC to undertake regular reporting and assessment of drivers of transmission and generation investment.

The Finkel Review recommended a new energy-system wide planning and a prioritisation of projects, similar to the EU wide network planning with priority projects.

Network regulation

The AER regulates all electricity transmission and distribution network businesses in the NEM and determines the maximum revenue that a network business can recover from customers accessing and using the network. Regulated entities apply to the regulator AER to assess their revenue requirements and the AER determines revenue collection typically for a five-year period (although there are exceptions where a revenue period may be under five years). AER follows the regulatory building blocks model which remunerates capital expenditure (CAPEX) and operational expenditure (OPEX) through a price cap approach.

During the period 2009-13, Australia has seen a general increase in network tariffs, reaching up to between 40% and 50% (see Figure 4.19). While the privatisation of network businesses has contributed to a more efficient management of the networks, many network businesses experienced a period of high cost of capital and related weighted average cost of capital (WACC) of 8.5-10.5%. A number of states set mandatory stricter reliability standards, including bushfire safety standards, which all meant that investments requirements had increased, besides refurbishment needs and an overall need to meet forecast rising peak demand. These factors led to an increase in network cost for final consumers. The return on capital accounted for around 50% of transmission and distribution companies' revenues in Australia (AER, 2017a), which is by international comparison a very high share.

Rising network costs prompted several reforms of network regulation: the introduction of greater scrutiny of new investment through the Regulatory Investment Test both for transmission and later on for distribution (RIT-T and RIT-D), the benchmarking of network proposals, a service target performance-incentive schemes applied to each transmission and distribution business to ensure that companies do not cut operating expenditure (OPEX) to the detriment of quality of service, as well as financial incentives (bonuses or penalties) for (non)-compliance with guaranteed service level, benefit sharing with consumers and stronger consultation on proposed network investments with the public. However, results are mixed to date.

Since 2010, transmission network businesses seeking new augmentations (subject to exceptions) must satisfy the RIT-T where the estimated cost is over AUD 6 million, and where the business intends to receive regulated revenue from the completed asset. The RIT-T process seeks to promote efficient transmission investment in the NEM while protecting consumers from paying for inefficient investment in transmission infrastructure. The RIT-T framework is set out in the National Electricity Rules (NER) and is administered by the regulator. A cost-benefit analysis is used to

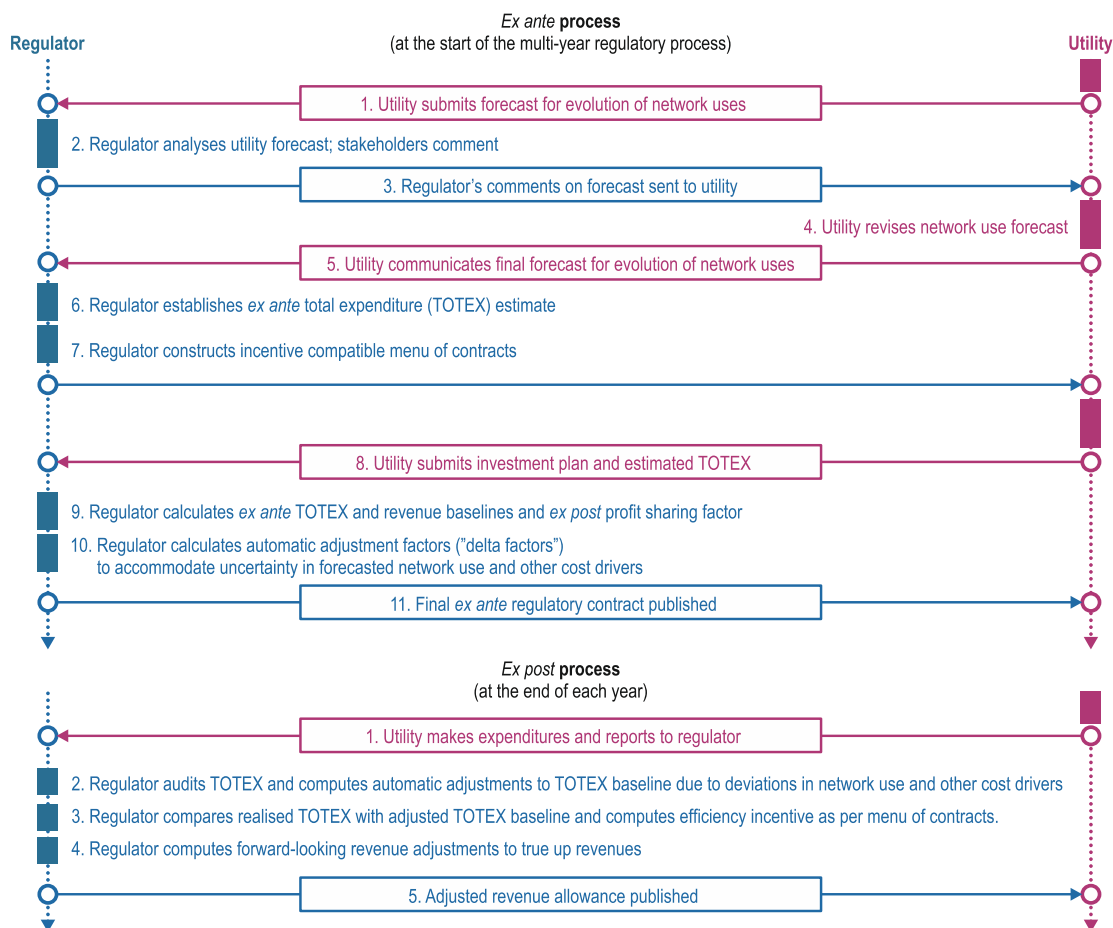
support investment decisions in regulated transmission assets. For distribution businesses the process (RIT-D) applies to investments greater than AUD 5 million. To date, the RIT-T and RIT-D only apply to the augmentation investments, not to replacement. In 2016 AER proposed a rule change to require the inclusion of both replacement and augmentation.

In 2016, the COAG Energy Council asked to review the RIT-T to ensure it remains effective in the current market environment, to foster energy system security, notably reliability investments for low-probability/high-impact events, and ensure investment in interconnectors. AER is reviewing its service performance incentive scheme in 2017. Until recently, AER decisions were subject to a limited review by the Australian Competition Tribunal and a judicial review by the Federal Court. Since 2008, almost half AER regulatory determinations were challenged through limited reviews leading to an upward correction of most AER determinations and cost of debt/capital values. On 24 May 2017 the Federal Court upheld the findings of the Australian Competition Tribunal in the limited merits review lodged by network businesses with regard to the AER revenue determination for New South Wales and the Capital Territory network companies, concluding that networks' operating expenses and the cost of debt should be revised upwards by AER. Network costs are driven also by companies' needs to meet network reliability standards set by the jurisdictional governments which are outside the scope of the AER. In June 2017, the Australian government proposed legislation to remove access to the limited merits review for economic regulatory decisions under national energy laws.

Internationally, energy regulators have been able to address high network cost. In the interest of consumers and efficiency, regulators have to pursue a conservative approach when it comes to the assessment of the regulated assets by adjusting the WACC in line with a comparable bond (pension fund or government bond), extending the lifetime of the (mostly already depreciated) assets, reducing the gearing (actual debt to equity ratio), extending the depreciation and regulatory periods, and accounting for differences between new equity investment and old depreciated assets. Network tariffs should support three key criteria: the system stability, economic efficiency, and consumer protection. Tariffs need to ensure the full recovery of the efficient network cost and reduce OPEX at the lowest consumer cost, while providing for a reasonable return on capital, which should reflect the relative risk of investment and actual financing conditions and, at the same time, encourage investment in peak reduction, flexibility and innovation. An essential part of network regulation is to minimise the total system cost by co-ordinating distribution investment and operation with investment carried out by other operators in the market.

At an international level, more and more regulators are reforming network regulation towards an output-based approach with longer regulatory periods and total expenditure (TOTEX) as basis. Such an approach removes the bias of investing in assets and makes companies "indifferent" as to whether it requires a CAPEX or OPEX solution and rely on the network businesses to co-ordinate efficient outcomes (see also Jenkins/Pérez-Arriaga, 2015, and Figure 4.21). Network companies can choose the most cost-effective solution over the lifetime of the asset, in particular if they are legally authorised as neutral facilitators of demand-side services and have a full overview of flexible sources on their network (demand-response, solar PV, electric vehicles, battery storage, etc.).

Figure 4.21 Regulatory TOTEX remuneration of distribution network companies



Source: Jenkins/ Pérez-Arriaga, 2015

The United Kingdom has pioneered a new output-based model with UK's Revenue = Incentives + Innovation + Outputs (RIIO) model in 2010 (see Box 4.2). RIIO focuses on the delivery of a specified range of outcomes for customers to be achieved by distributors through a regime of incentives (rewards and penalties) to encourage efficient and cost-effective delivery and profit from innovation and incorporating third parties in the delivery of energy services. RIIO is being used to facilitate public policy outcomes in relation to reliability, affordability and sustainability. Performance-based regulation can promote timely and efficient investment and innovation that benefits consumers, while providing distributors with the ability to effectively act in a complex business environment. However, it can be difficult to set effective output targets, particularly in the context of driving innovation and smart-grid investment. The Council of European Energy Regulators (CEER) suggests that a range of factors should be considered, i.e. the conditions for effective application of a performance-based methodology; the selection and calibration of the performance metric; the period needed between undertaking investment and delivering the target outcome; and the need to avoid overlap with other regulatory incentives.⁶

⁶ See CEER (2015) for further discussion of these issues.

Box 4.2 An overview of the UK's RIIO performance-based regulatory framework

RIIO (revenue = incentives + innovation + outputs) is the United Kingdom's Office of Gas and Electricity Markets' (Ofgem, 2010) new performance-based framework for setting price controls for regulated energy businesses. The new regulatory period for distributors commenced in 2015. RIIO encourages distributors to: *i*) put stakeholders at the heart of their decision-making process; *ii*) invest efficiently to ensure continued safe and reliable services; *iii*) innovate to reduce network costs for current and future consumers; and *iv*) play a full role in delivering a low-carbon economy and wider environmental objectives. Key elements of the regime include:

- Eight-year regulatory period: extended regulatory period provides more regulatory stability and encourages longer-term focus.
- Upfront (*ex ante*) assessment: sets base revenues and basis for changes in revenues over the subsequent eight-year period with limited possible reopeners providing a high level of certainty for regulated distributors.
- Cost-sharing mechanism: if the distributor spends less than the target set, the savings are shared between the distributor and customers. This produces strong incentives to outperform. Conversely, if the distributor overspends, the extra costs are shared between the distributor and its customers the same way. This mitigates the impact of cost overruns.
- Weighted average cost of capital approach: reimburses debt and equity investors at an appropriate level. The cost of debt is updated annually, which reduces financing risk to distributors and risk of overcompensation to consumers.
- Comprehensive quality outputs: distributors' business plans need to be informed by and tailored to their customers' needs, e.g. level of network reliability, availability and environmental impacts.
- Regulatory asset value (RAV) approach: revenues for long-term investments are recovered over their lifetime as a return on the RAV so the costs are shared between all the customers who benefit from the investment.
- Totex approach: assesses total expenditure (totex), taking operational expenditure (opex) and capital expenditure (capex) together. This provides the company with incentives to choose the most economic option when deciding between opex and capex solutions.
- Uncertainty mechanisms: limited provisions to manage specific cases of uncertainty risk through possible revenue changes during the period, e.g. extra revenues for providing greater network capacity.
- Promoting innovation: encourages distributors to consider different ways to achieve greater cost savings or increase the scope of future delivery.

Under RIIO, Ofgem asks distributors to submit business plans on how they intend to meet the RIIO, established by Ofgem. RIIO places a strong emphasis on stakeholder engagement and distributors must obtain stakeholders' input and use in the plans. Ofgem reviews the plans to determine the scrutiny. Where a distributor's business plan is considered high-quality, its new price control settlement may be fast-tracked.

Ensuring that regulated distribution network business ring-fence their assets when they invest in competitive unregulated services (battery, solar PV, metering) is being implemented in Australia, in line with AER 2016 guidelines which should be implemented at the latest by 1 January 2018. In 2017, AER is finalising a new demand management incentive scheme and innovation allowance mechanism (to fund research, development and demonstration projects).

Electricity security

IEA in-depth reviews generally focus on the adequacy dimension of electricity security, which has been discussed above within generation and network adequacy. Reliability in the Australian context refers to the physical capability of the power system to generate and transport electricity to meet consumers' demand. Security refers to the operation of the system within the defined limits and the capacity to return to a safe state if there is an incident.

A short overview of emergency preparedness and response for electricity in Australia is provided in this section. System security and operation will be discussed in more detail in Chapter 5 on System Integration which follows. It will present an in-depth review of challenges and opportunities for the system integration of variable renewable energy in Australia and will reflect on related power system security aspects.

Legal framework for security of electricity supply

Security of electricity supply is ensured by the actions of the market participants within the electricity market rules set by the COAG Energy Council, the three market authorities and the states'/territories' governments. Relying on a market-based approach, security of electricity supply requires careful planning and co-ordination, and responses across all NEM regions between the market operator, the local transmission and distribution companies, and generators. Having one system operator that is also in charge of the market operation, AEMO, across the entire NEM, has its advantages and disadvantages.

The National Energy Security Assessment (NESA) of December 2011 had highlighted the significant challenges the electricity sector will face from reliability and price pressure associated with refurbishment of ageing infrastructure, rising peak demand and stronger additions of renewable energy resources. It highlighted that capacity constraints to gas transmission infrastructure or the exit/failure of Victoria baseload capacity would have short-term impacts on electricity reliability. South Australia's network operator, ElectraNet, has continuously raised the need for interconnections in the NEM. In 2011, the Australian government proposed the creation of an Energy Security Council as part of the Clean Energy Future Package, composed of the managing director of the operator AEMO, heads of the market commission AEMC, the regulator AER and the Australian Securities and Investment Commission (ASIC), as well as industry and energy market participants and experts.

The centrepiece of electricity security in the NEM is AEMO that is required to operate the NEM power system efficiently and within the agreed standards of security and reliability, in line with the *National Electricity Law* (NEL) and National Electricity Rules (NER). The rules underpin the operation of the NEM and are given the force of law under the NEL, which includes provisions on safety and security of the national electricity system.

4. ELECTRICITY

The NER cover the operation of the central dispatch process and spot market, network connection access arrangements and, in chapter 4 of the Rules, security arrangements for achieving and maintaining a secure power system. The framework determines:

- Conditions under which AEMO can intervene in the processes of the spot market and issue directions to registered participants so as to maintain or re-establish a secure and reliable power system, including:
 - to detail the principles and guidelines for achieving and maintaining power system security
 - to assess the adequacy of power system reserves
 - to plan and conduct operations within the power system to achieve and maintain power system security
 - to dispatch scheduled generating units, semi-scheduled generating units, scheduled loads, scheduled network services and ancillary services.
- Responsibility to maintain and improve power system security;
- Jurisdictional System Security Co-ordinator for each participating jurisdiction.

Within the NEM, the reliability standard for generation and bulk supply is set per region of the NEM at a level that can ensure that unserved energy per year for each region does not exceed 0.002% of the total energy consumed in the region that year. The Reliability Panel, which reports to the AEMC, oversees and regularly updates the reliability standard (which includes the market price cap, the cumulative price threshold and the market floor price) and the connection standards for generators and large consumers. The Panel also reports on the performance of the NEM in terms of reliability, security and safety. Within the NEM reliability concept, only constraints to bulk generation or the bulk transmission network that affect interconnection capability are considered, but not power system failures or interruptions in the local transmission and distribution networks.

In line with chapter 3 provisions of the Rules AEMO applies the reliability standard in its short-term and medium-term Projected Assessments of System Adequacy (PASA) through the so-called minimum reserve levels (MRLs in megawatts) for each jurisdiction.⁷ In the short-term operational timeframe, AEMO looks at the lack of reserve (LOR 1 to 3) values. AEMO can alert the market on supply shortages via lack of reserve alert notices. AEMO can also contract for medium- and short-term additional electricity generation reserves (as of November 2017 maximum ten weeks ahead of a shortfall), through the Reliability and Emergency Reserve Trader (RERT) mechanism. To date, the RERT does enable demand-side participation but AEMO and the ARENA are developing a trial to be in place by early 2018.

With the goal to monitor security of supply, AEMO produces several demand and supply adequacy assessments and transmission plans, notably the Projected Assessment of System Adequacy (PASA), the National Electricity Forecast Report (NEFR), both of

⁷ The standard is met if sufficient generating capacity is available in the region, including from interstate generation via an interconnector.

which provide electricity consumption forecasts for each NEM region over a 20-year forecast period (2016–17 to 2035–36). On the supply side, AEMO evaluates the adequacy of electricity supply through the NEM Electricity Statement of Opportunities (ESO), the Gas Statement of Opportunities (GSOO) and, with regard to the transmission system, AEMO provides for a long-term outlook in the National Transmission Network Development Plan (NTNDP). In 2017, a new Energy Outlook was released by AEMO with the objective to bring together some of these planning processes towards a more energy system-wide planning.

In the NEM, local transmission providers (TNSPs) perform a number of functions on AEMO's behalf to assist with the management of power system security. The role of the TNSPs is to plan, develop and operate their local electricity network in accordance with the mandated reliability and security standards set out in the Rules and the state Transmission Code. They are also required to comply with applicable power system performance and quality of supply standards set by the regulator. Specified power system security responsibilities are delegated to each TNSP in accordance with National Electricity Rules clause 4.3.3 via Instruments of Delegation, the details of which are incorporated in each of the relevant Regional Power System Operating Procedures. Each of the TNSPs in the NEM – AusNet, TasNetworks, ElectraNet, TransGrid and Powerlink – is acting in accordance with its Instrument of Delegation.

States and territories determine the transmission and distribution reliability standards in their respective jurisdictions. After a period of high network investments and rising retail prices, the COAG Energy Council in 2014 decided to reform the distribution/transmission reliability standards. The Council required them to be based on common principles agreed by the COAG and independently from the network businesses, taking into account the value that consumers place on reliability and the likelihood of interruptions.

Reliability of electricity supply

The NEM bulk generation and transmission area has seen relatively high reliability levels. There was no unserved energy in the NEM at regional level until 2015, except in Victoria and South Australia on 29 and 30 January 2009 following heatwaves (AEMC, 2017b). However, the blackout and load-shedding events in 2016 negatively impact this record (see Box 4.3). Within the NEM reliability concept, only constraints to wholesale generation or to the transmission network that affect interconnection capability are considered.

However, more often, reliability issues, such as power system failures or interruptions, occur in the local transmission and distribution networks. To measure the reliability of electricity supply, and thus the capacity of generators and transmission/distribution operators to meet final customer demand, the levels of unserved energy and the number and length of interruptions (by means of the System Average Interruption Duration Index, or the Frequency Index) are useful indicators.

At the local level, an average consumer in the NEM experiences 1.5 outages with an average duration of 200 minutes per year (AER, 2017a). Across the NEM, there are large regional variations of distribution network performance and reliability (most of them weather-induced and depending on the size of the grids).

Box 4.3 Recent electricity security events

The issue of electricity system reliability and security has received considerable attention in Australia since 2015, following the Basslink interconnector failure, a state-wide blackout in South Australia on 28 September 2016 and severe heatwaves provoking load shedding events in February 2017 in several states.

Outage of Basslink to Tasmania

A subsea cable fault of unknown origin disconnected the Basslink interconnector between Tasmania and Victoria for the period from December 2015 to June 2016. During this time, which coincided with historically low-rainfall and low-water levels, Hydro Tasmania implemented an Energy Supply Plan that included increased gas-fired generation and the mobilisation of short-term diesel generators to ensure supply. The disconnection of Tasmania from the mainland (NEM wholesale market and Victoria grid) impacted the electricity supply situation of Tasmania with higher wholesale prices and voluntary demand reduction, especially among the small number of power-intensive industries.

Black System South Australia – 28 September 2016

During a severe storm, the system experienced a sequence of six voltage disturbances within two minutes, triggering disconnection of approximately 450 MW of wind generation (which was supplying around half the generation at the time). During this event (which began just after 4pm on 28 September), the electricity supply to South Australia was lost across the entire state, disrupting supply to around 850 000 electricity customers. The “Black System event” formally concluded at 6:25 pm on 29 September, although some customers remained without power because of remaining network problems in some areas. The South Australian market remained suspended from the NEM until 11 October while AEMO implemented special procedures to manage power system security.

Load-shedding events in South Australia and New South Wales 2017

A strong heatwave occurred in South Australia and New South Wales on 8 February 2017 and 10 February 2017, respectively, leading to a so-called insecure operating state. In the late afternoon, an unexpected downward wind ramp and expected solar PV decline exceeded forecasted levels and coincided with higher than expected demand and the unavailability of several thermal generators (related to high temperatures).

In South Australia, the insecure state triggered load shedding of intended 100 MW by transmission network service provider ElectraNet at the direction of AEMO, although the load actually shedded amounted to 300 MW because of software failures. The Heywood Interconnector was operating at full capacity and Murraylink also was at its operating limits.

On 10 February 2017, in New South Wales, a similar situation occurred in the late afternoon at peak electricity demand of 13 986 MW. However, three interconnectors into NSW were overloaded, as one gas-fired generator was off and another one unable to start because they lacked pressure in the gas pipelines. In NSW, AEMO had to direct TransGrid to shed 290 MW interruptible load from the Tomago aluminium smelter.

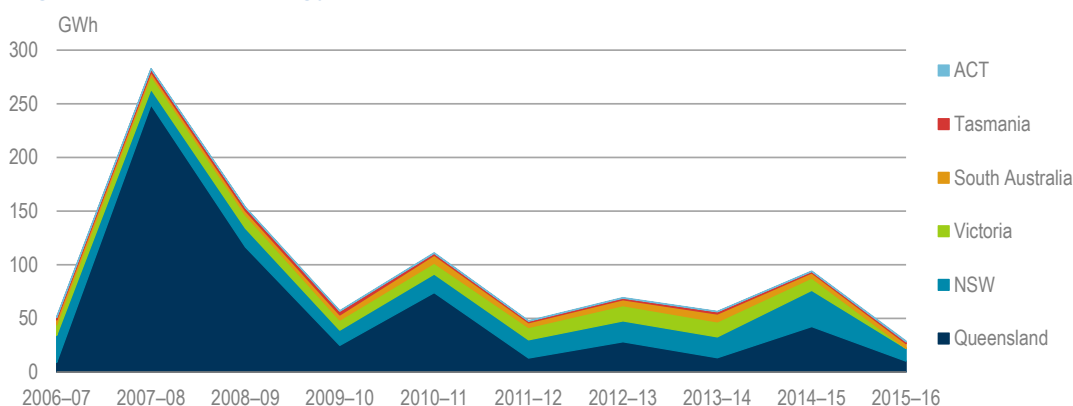
Urban and rural areas differ strongly in terms of reliability. Reliability levels in rural areas of Australia are considerably lower in some cases because of a combination of factors, including low customer density, extreme weather events and natural disasters (including wildfires) and challenging terrain and system topology.

Overall levels of unsupplied energy were the highest in Queensland (average of 58 GWh and reached a peak of 250 GWh in 2007-08) due to its rural dispersed network topography and exposure to cyclones along the coast of Queensland in 2010/11 and 2012/13. The Australian Capital Territory has a constant high reliability with the lowest number of interruptions and the lowest outage duration. Since 2014/15, the average duration of outages has decreased but their number went up in South Australia, Tasmania, while Queensland and South Australia have seen an improvement (AER, 2017a). In 2015/16 there was no unserved energy recorded. Data are not yet available for the year 2016/17 which had a number of incidents.

Flexibility and reliability have become strongly interlinked with the growth of generation from variable renewable energy (VRE). This requires adjustments to AEMO's demand forecast, to the connection standards, to VRE generator settings and to system operation in the NEM by the market authorities and the system and market operator AEMO, which is described in more detail in Chapter 5 on System Integration. Several evaluations made after the heatwave events raised questions about the appropriateness of weather and related demand forecasting by AEMO (AEMO, 2017a; AER, 2017a) and of reserve holding against downward wind ramps, which play out over periods of several hours. Downward wind ramps are well known in other countries, including Ireland, Spain and the United States Electricity Reliability Council of Texas (ERCOT).

Various reforms are ongoing to address the lessons learnt from the 2016 power incident events. The AEMC completed the System Security Market Frameworks Review, and rule changes on ancillary services and has commenced a review of the market rules for managing system frequency. The Reliability Panel is conducting the Reliability Standard Settings Review (by April 2018) and completed the Review of the Frequency Operating Standard (FOS). The FOS requirements relating to multiple contingency events and the incorporation of a new contingency event (protected events) are being implemented.

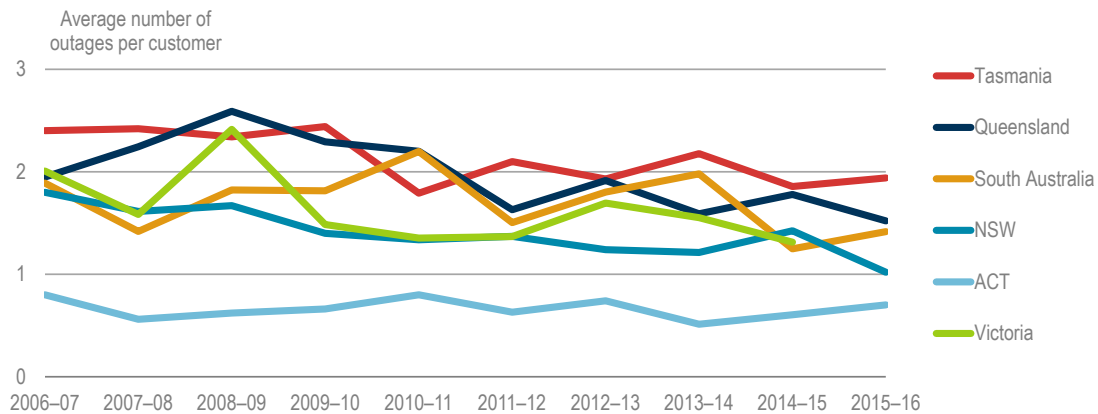
Figure 4.22 Total energy unsupplied in the NEM



Source: AER (2017a), "State of the Energy Market".

4. ELECTRICITY

Figure 4.23 System reliability in Australia (SAIFI*)

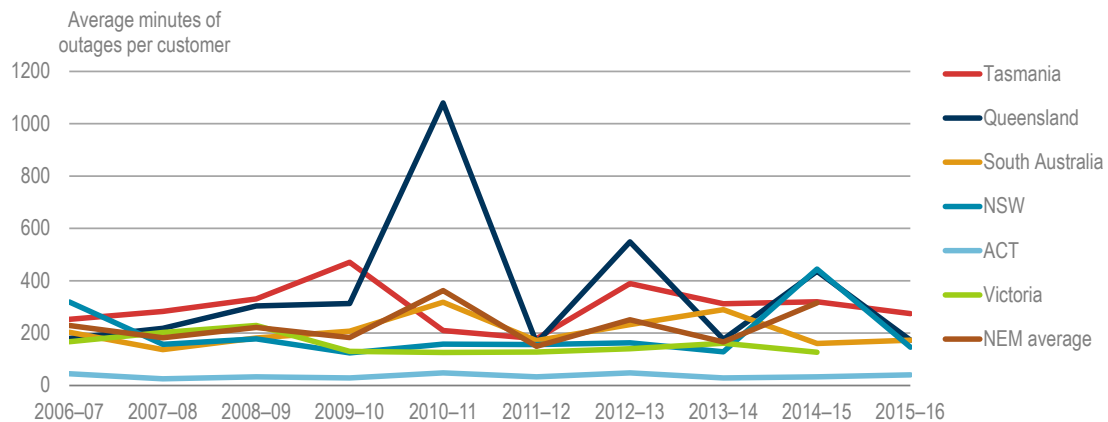


* The System Average Interruption **F**requency Index (SAIFI) represents the average number of all planned and unplanned outages per year per customer.

Notes: The figure shows the annual average number of outages per customer between 2006/07 and 2015/16.

Source: AER (2017a), "State of the Energy Market".

Figure 4.24 System reliability in Australia (SAIDI*)



* The System Average Interruption **D**uration Index (SAIDI) represents the average minutes lost per year per customer from all planned and unplanned outages.

Notes: The figure shows the annual average number of minutes of outages per customer during 2006/07 and 2015/16.

Source: AER (2017a), "State of the Energy Market".

Emergency preparedness and response

As system and market operator of the NEM, the AEMO is the key body to co-ordinate emergency responses across the NEM through the Power System Emergency Management Plan (PSEMP, and the Victoria PSEMP), in line with the NEM Emergency Powers Memorandum of Understanding and the NEM Emergency Protocols. The PSEMP was developed by AEMO and the jurisdictions and sets out principles and processes to co-ordinate actions taken by transmission and distribution companies as well as governments under individual state legislation to manage power system security emergencies. The AEMO, in conjunction with NEM participants and other stakeholders, develops contingency plans to cover planned and unplanned outages on the power system to an N-1 standard.

AEMO contingency plans are designed to ensure that the power system is prepared for the next worst credible contingency, i.e. the loss of a generator, of a major load source, or transmission line or interconnector. The contingency plans may involve a number of network operator actions including:

- transferring load pre-contingency
- additional switching on the power system post-contingency
- calling upon additional generation.

AEMO operates the NEM with generation “reserves” that can be called upon at very short notice to balance the system or contribute to a power system recovery following credible and non-credible incidents. Looking at the example of recent incidents, including the Black System event in South Australia, it seems that the contingency of calling upon additional generation is not always reliable.

NEM generation reserves usually consist of fast-acting hydro or natural gas plants. The reserves are procured and activated through the use of ancillary services, i.e. a market-based mechanism that assists AEMO in managing both short-term supply and demand imbalances (4-second regulation services), and longer-term services (6-second to 5 minute contingency services). This system is supported by the National Electricity Rules (NER), which require generators to provide information on generating capacities and energy limits reflecting available fuel supplies. AEMO takes this information into account when developing electricity reserve forecasts ranging from (near) real time to two years ahead. AEMO covers N-1 contingencies for generation and transmission events by maintaining reserve margins in each region or state, equivalent in broad terms to the size of the two largest generating units. There are defined intervention triggers where these are required to be dispatched.

In addition to NEM generation reserves, “local” emergency control systems can be called upon to return the power system to a secure and satisfactory operating state post-contingency. These include both automatic and manual under-frequency load-shedding schemes.

AEMO’s response to changing conditions in the power system occurs through:

- Control schemes to safeguard and manage loading of equipment and switch to reactive power plant.
- Procedures specifying action when conditions change beyond acceptable thresholds.
- Generation dispatch procedures designed to ensure that any single credible contingency can be managed without violating ratings of equipment or affecting power system stability. Procedures are in place to make changes to power transfers used in market dispatch when abnormal conditions such as lightning are experienced (in such abnormal conditions, loss of double-circuit lines can be declared as a single contingency and change the relevant power transfers so that loss of both lines can be managed).
- Availability of manual and automatic under-frequency load shedding evenly spread across the power system of up to 60% of the load supplied (an requirement under the National Electricity Rules to assist managing multiple or non-credible contingencies).

- Availability of under-voltage load shedding at various locations.
- Reliability and Emergency Reserve Trader (RERT) arrangements allow AEMO to increase supply during periods of predicted supply deficits up to nine months in advance, including through short-term demand response.
- Directing NEM participants or instructing any other relevant party to take relevant action to maintain power system security and reliability of supply.

The resources allocated by AEMO (and available) are considered sufficient to meet all credible contingencies. They are also reviewed periodically to ensure they continue to meet power system requirements. AEMO has the authority to direct any market participant to take action to maintain system security, including disconnecting equipment, generators or load. AEMO develops and publishes *Power System Security Guidelines*, which detail the policies governing power system stability in order to facilitate the operation of the power system within stable limits. The *Guidelines* include: defining what AEMO must do to maintain the system's security, in a suggested priority order; detailed responsibilities of registered participants if load shedding is required; and responsibilities for maintaining a secure power system during contingent events, planned transmission outages, and secondary equipment outages.

It also defines responsibilities for fault level and voltage control. Network Service Providers (NSPs) responsibilities include co-operating and assisting AEMO in the execution of AEMO's responsibilities pertaining to power system security and ensuring that interruptible load is available in the execution of these duties. NSPs must also operate their transmission or distribution system in accordance with the *Power System Security Guidelines*. Market customers' responsibilities, as defined in the Rules, include ensuring load-shedding facilities for automatic under-frequency load shedding.

AEMO has developed a suite of system-restart procedures in the event of a region or a number of regions being subjected to a "black system" event. The system restart procedures describe how system-restart services should meet a "system restart standard" as set by the Reliability Panel. The system restart standard establishes the timeframes and number of megawatts that restart services have to provide when required to resupply the power system.

Recent electricity security incidents illustrated how natural gas and power security and markets are increasingly interlinked (see Chapter 3 on Natural Gas).

Ongoing market reforms in the NEM

Over the past five years, the COAG Energy Council (the Council) has initiated a number of reviews and reforms in five key areas. In line with its governance, the Council has promoted regulatory reviews which brought about various rule changes by the NEM regulators.

- **Security, sustainability and stability of the NEM:** In 2015, the Council created the Energy Market Transformation Project Team with a work programme to promote power system security, electricity infrastructure investment, competition and consumer empowerment, while the NEM transits to new technologies and renewables. This power system transformation has been anticipated by the market authorities through initiatives

including AEMO's Future Power System Security Programme and the System Security Market Frameworks Review by AEMC. After the South Australia blackout event, the states/territories, the Council and the Australian government have taken actions, including public investment decisions. The Council requested Dr. Alan Finkel to review how to ensure reliability and security of the NEM power system during the energy system transformation (Finkel, 2017; see Box 4.3). The final Blueprint for NEM reform was presented in June 2017 and its proposals have been accepted by COAG in July 2017 (see Box 4.4).

- **Integration of energy and climate policies in the NEM:** The NEM rules (*National Electricity Law* and the National Electricity Objective) focus on effective energy markets; emissions reduction policies are outside their scope. The Finkel Review recommended mechanisms for an orderly transition to low-emission technologies, rather than amending the National Electricity Objective (NEO), and a Statement of Policy Principles by the Council. The Australian government has been reviewing its climate policies in 2017. The Part II of this report will review climate policies and their interplay with the electricity market rules.
- **Competition and consumer engagement:** Several NEM jurisdictions have phased out regulated prices over the past decade and have introduced competitive offers, while maintaining a large scope of consumer protection (through general concessions). The Council adopted the National Energy Customer Framework (NECF) in 2012 as a NEM-wide regime (except Victoria) for the sale and supply of electricity and gas to customers, which also promotes harmonising energy consumer protection. The NECF includes the *National Energy Retail Law*, National Energy Retail Regulations and National Energy Retail Rules. The Council supports the reform of network tariffs and the transition to more cost-reflective pricing as part of the energy collaboration with NEM states/territories. The Council created the Energy Consumers Australia (ECA) as a dedicated consumer advocacy body in 2015. The Australian Energy Regulator and the ECA plan to work together to strengthen consumer engagement in the network tariff regulation. The AEMC reports regularly on competition in retail markets to the Council. Under the umbrella of the 2012 *Power of Choice Review*, rule changes were made by AEMC to ensure competitive roll-out of meters, consumer access to data, faster retailer-switching and reform of distribution pricing, and demand response, and embedded networks. The rule change facilitates competition in the emerging contestable energy services market through the introduction of restrictions on distribution network service providers' ability to earn regulated returns on assets located "behind the meter".
- **Australian gas markets:** With the start of LNG exports from Queensland, the east coast gas market is now interconnected to global gas markets, a factor that has contributed to the rise in gas prices. This was not unexpected. In 2014, the Council's Australian Gas Market Vision set in motion a number of initiatives to address supply and competition concerns, and build a competitive Australian gas market. The Council's Gas Market Reform Group is working on the implementation of Gas Market Reform Package of 2016 along four priority areas and 15 reform measures. The four priority areas are gas supply, market operation, gas transportation and market transparency. Amid concerns about gas supply shortages in 2017/18, these reforms have been accelerated. On 1 July 2017, the Australian government introduced the Australian Domestic Gas Supply Security Mechanism, which allows the government to apply restrictions on LNG exports if an export-driven shortfall of gas supply is determined in a particular calendar year.

Box 4.4 Independent Review into the Future Security of the NEM (the Finkel Review)

The Blueprint for the Future of the National Electricity Market of June 2017 proposed a range of actions to increase security, ensure future reliability, consumer participation and lower emissions.

System security: Transmission companies should be required to maintain a minimum level of system security per region (minimum level of inertia). Fossil fuel generators may be required to change their settings to control the frequency in the system, and all new generators, including renewables, should be required to provide fast frequency-response. Generator connection standards should be reviewed regularly. New standards required in South Australia should become NEM-wide rules. **A stronger risk management framework** is suggested against natural disasters and cybersecurity attacks. **An emergency management plan for the 2017/18 summer** is proposed along with measures to support demand response and encourage consumers to reduce their demand at peak times. **Regular security-reliability assessments** by the system operator AEMO should be conducted to strengthen the risk management. Large electricity generators should give three years notice of closure and system operator AEMO should publish a non-binding register of intended generator closures. A **system-wide grid plan** is needed with priority projects and the development of **regional renewable energy zones** from a system-wide perspective. **Reliability obligation on new generators** should provide for regional diversity of investment in backup capacity.

NEM market design: The Finkel review considers that the **NEM energy-only market** can ensure reliability also in the future and calls for fine-tuning of the design, through a **review of the electricity rules code by end 2020**. Acknowledging that there may be disadvantages of a short-term market (five-minute dispatch) versus day-ahead market and capacity mechanisms (as implemented in Europe with greater forward transparency of supply), the review supports a study to determine if an out-of-market strategic reserve is needed in addition to AEMO's Reliability and Emergency Reserve Trader (RERT) mechanism.

The Finkel Review called for an **orderly transition** based on the Paris Agreement and Australia's COP21 pledge to reduce GHG emissions by 26% to 28% by 2030 below 2005 levels, through a **strategic energy plan** agreed **among COAG Energy Ministers**, and through a **new Australian Energy Market Agreement** and a **Clean Energy Target**.

Affordability and empowering consumers through greater transparency of electricity pricing (building on the competition review by the Australian Competition and Consumer Commission (ACCC) and market monitoring by the Australian Energy Regulator (AER), encouraging **demand response, solar PV generation and using battery storage**. Finkel Review calls for a comprehensive **energy data strategy**.

An **independent Energy Security Board** under the COAG Energy Council was set up to ensure the implementation of the Blueprint and co-ordination between COAG and the market authorities. An **annual health check of the NEM** should review market, reform progress and provide strategic advice to market bodies.

- **Improving institutional performance:** The NEM governance is defined by a complex division of labour between four main regulatory/market bodies (Figure 4.9). However, the rule making and revisions are numerous but lengthy as they aim to match rapidly changing markets, which creates uncertainty for investors. The regulators have overlapping responsibilities, notably in retail, competition, security and reliability. The 2013 review of the Productivity Commission found the NEM governance is caught in “paralysis of analysis” (Productivity Commission, 2013). While confirming the analytical strength of the regulators, the Vertigan Review of 2015 called for several reforms, including faster rule making, strategic policy leadership, comprehensive rule review, the separation of the regulator AER from ACCC and a new Statement of Role for AEMO (Vertigan, 2015). To ensure a clear strategic focus and direction for market bodies, the Finkel Review of 2017 suggests the creation of a strategic energy plan of the COAG Energy Council and a new regulatory body, the Energy Security Board (ESB), with an independent chair and vice-chair. The ESB has been created by the COAG Energy Council on 8 August 2017 with Dr Kerry Schott as Chair and Clare Savage as Vice-Chair to co-ordinate the implementation of the Reform Blueprint produced by Dr. Alan Finkel, Australia's Chief Scientist.

Assessment

The Australian electricity system is undergoing significant changes. Coal capacity is ageing and old plants are closing faster than expected; renewable energy – including distributed solar PV systems – is increasing rapidly, but is concentrated in a few regions. There are growing concerns about the availability of affordable natural gas for the power sector both over the coming years and out to 2030, amid increasing moratoriums. Following the South Australia Black System event on 28 September 2016, electricity security and energy system transformation in the NEM have received considerable attention and made evaluation and work progress towards identifying actions to foster the NEM's capacity to safeguard security, sustainability and reliability. A Blueprint for the NEM was presented by Dr. Finkel in June 2017 and is being implemented by the COAG.

The discussion in this section focuses on five main points that have emerged during the IEA in-depth review. It will analyse how the NEM can *i)* ensure sufficient investment certainty for new generation, *ii)* manage the retirement of ageing generation, *iii)* address the rapidly changing role of distribution grids with battery storage, demand response, electric vehicles and solar PV installations, *iv)* reduce consumer bills and enhance competition and *v)* ensure short- and long-term electricity security and reliability.

The questions of reliable and cost-effective system integration of wind and solar power and the market reforms in natural gas are each discussed in detail as part of the two special focus chapters.

Providing certainty for new investment in the NEM

The NEM suffers from high levels of generation concentration in some regions and rising electricity and gas prices. Gentailers can manage market risk through vertical integration, but other retailers are reliant on competitively priced hedge products, either through a futures exchange or through over-the-counter deals with large generators. The 2017 AEMC Retail Competition Review reported a decline in market concentration of the three big gentailers, but highlighted the limited access to competitively priced risk management contracts as a significant barrier to entry, particularly in South Australia (AEMC, 2017a). This finding illustrates the difficulty that new entrants and small retailers who are

increasingly interested in entering the market may be having in finding competitively-priced risk products. The gas shortage expected over the coming years, and the closure of baseload coal plants further exacerbates this lack of liquidity in the financial markets.

All actions should be pursued to boost competition and restrict anticompetitive behaviour through the ACCC inquiries and higher penalties by the regulator to follow generator market power during high price events, increase the liquidity of the financial market products, and foster access of new retailers to the wholesale market, including through demand response and large-scale storage, and other new technologies. In this context, the alignment of the 5-minute dispatch and 30-min settlement periods to shorter timeframes can help, thus encouraging renewable generators and retailers to provide bids in this short-term market. At the same time, the completion of the gas market reform is critical to secure more and affordable gas supply for the power market.

The investment outlook in the NEM is challenging. Gas generation is currently squeezed out by exceptionally high gas prices and several plants were mothballed in 2014-16. The Renewable Energy Target (RET) expires in 2020 while the investors can still earn certificates through 2030. After 2020, there is no RET scheme that would encourage new investment in new renewable energy. It is expected that more coal power plants will retire by 2030. Investment in new coal capacity is largely ruled out by market participants on the basis of commercial risks and uncertainty about environmental policies, in light of the past stop-and-go policy around the carbon tax. The Australian government is reviewing climate policies in 2017. It is critical that the government swiftly adopt the policies needed to implement the Paris Agreement, including a long-term emissions reduction goal and climate policies for 2030. To ensure that new investments are consistent with climate objectives, greater visibility is needed with regard to the role and contribution from energy efficiency and renewable energy to emissions reductions and an emissions reduction mechanism needs to be in place for 2030. As set out in Chapter 6 on Energy and Climate Policies, several mechanisms are under discussion in Australia and there are various designs implemented in IEA member countries.

Energy-only markets signal the need for new investment through wholesale scarcity prices during demand peaks and supply shortages. Investments are underwritten by futures contracts, such as baseload swap and cap contracts which are based on future expectations of wholesale prices. Australian Securities Exchange (ASX) prices of futures for baseload and peak load have doubled for 2017/18 and remain at high levels for the summer (Q4/Q1) periods up to 2022. In the past, this would have provided a strong signal for new investment.

The NEM has been able to provide signals for a range of investments in new combined cycle gas plants (CCGTs) and renewables, also encouraged by the carbon price which was in place during 2012-14. However, the market is facing considerable uncertainty about future policy, particularly around emissions reductions from the sector after 2020. This has increased risk premiums for new electricity generator investments, particularly for generators that would have a relatively high emissions intensity. Higher risk premiums can make capital-intensive projects less attractive. For markets to attract investments, sufficient long-term visibility on expected energy and climate policies and future emission policies is critical.

Australia has seen a range of state-based feed-in tariffs and reverse auctions which overlap with the federal Renewable Energy Target. For market signals to work efficiently

in the NEM, it is welcome that the COAG Energy Council is working to harmonise the schemes, in line with the experience gained in other IEA jurisdictions which are now phasing out feed-in tariffs and are implementing competitive tenders, system friendliness (locational signals) and improved energy system-wide transmission planning in line with decreasing technology costs, as explained in Chapter 8 on Renewable Energy and Chapter 5 on System Integration. Support for low-emission technologies should therefore be market-based.

Plant retirements

Across Australia, the role of coal in power generation has declined from 80% of the total several decades ago to 63% in 2016. Australia's coal plants are ageing, many reaching their expected end of life of around 50 years by 2035. There is little likelihood of refurbishment (with a few exceptions). A prominent example is the retirement of Hazelwood plant which gave less than 6 months notice and removed 1 600 MW from the system on 30 March 2017. While market participants were aware that retirement was likely, the announcement in late 2016 was perceived as a wake-up call. Some gas plants have been mothballed in recent years, mainly as a result of skyrocketing gas prices and the removal of the carbon price in 2014. The operator of the Liddell coal-fired power plant announced the plant will retire in 2022.

Retirement of older coal plants is consistent with the need to move to a low-carbon economy under the Paris Agreement. The question is more on how this process can be paced in a way that does not undermine security of supply. The Finkel Review recommended that plants should give at least a three-year notice ahead of their retirement. While this is a feasible option, it invites generators to exit the market even faster without governments, regulators or the system operator being able to guide the process.

Some countries have adopted low-emission development roadmaps to 2050 or a legislated emission standard in the power sector, which organises the exit of old capacity. Other countries have included old power plants in a safety net (strategic grid reserves and ancillary services) used for maintaining energy security and flexibility. Adopting an emissions reduction mechanism of this sort is critical as it will provide greater certainty, but may also bring problems. Careful attention to the design of any scheme is needed to avoid encouraging unneeded generation or over-rewarding assets. In this context, one option can be to build on the existing structure of operator AEMO's Reliability and Emergency Reserve Trader scheme. In September 2017, AEMO called for the creation of a permanent strategic reserve to deal with summer reliability issues. AEMO also flagged the need to secure new capacity to avoid dropping capacity margins in the NEM, when coal-fired power plants retire in the coming decades.

Distribution network reform - Changing role of power grids

Australia's distribution grids are rapidly shifting away from passively distributing electricity to consumers to a situation where active "pro-sumers" invest in their own distributed resources to reduce costs. Australia has the highest market penetration of small-scale PV systems internationally and this trend is bound to continue to grow significantly (AEMO's forecast is 20 GW of solar PV by 2037 producing an equivalent of 12% of demand for grid-supplied electricity). Reform of distribution grid tariffs, roll-out of smart meters and reforms of institutional arrangements to better align system operations between the transmission and distribution levels are key priorities during this process.

New rules are in place and progress towards their implementation is under way. They will move networks to cost-reflective distribution network tariffs, competitive smart meter roll-outs and the phasing-out of regulated retail prices in many jurisdictions.

Australia has high-cost network assets and the network component in the retail tariff amounts to between 30% and 40%. Increases in electricity retail prices and falling technology costs are making it increasingly economic to avoid some of the cost of grid-supplied energy by investing in solar PV and battery storage. If such a trend continues, it can lead to serious under-recovery of distribution grid costs and to higher shares of network costs for the customers who are not able to invest in distributed resources and consider going off grid (referred to as “death spiral”).

Regulators and governments focus on investment into energy networks, notably at a time of increasing network costs and rising electricity prices. Nonetheless, the increase in renewable energy and more flexible consumer demand will also require investment in the network. The “building block” approach to network revenue determination and the Regulatory Investment Test (RIT) used in Australia tend to focus on reducing the incentives for network companies to invest in capital expenditure. Many network companies have been able to challenge the AER determinations through the limited merits review and get higher revenue allowances adopted. In 2017, the Australian government proposed legislation to abolish access to the limited merits review. The competences of the AER could be strengthened through an output-based regime, similar to the one implemented by Ofgem in the United Kingdom.

In several jurisdictions around the world, regulatory authorities have moved towards reducing rates of return and more stringent asset evaluations, with the aim to introduce a TOTEX approach with output-based performance regulation, as for instance the United Kingdom, which provides greater optionality between operational and capital expenditure, choice of non-network solutions and longer-term investment horizons for grid companies. The government should review the economic efficiency of the network companies and consider the introduction of a TOTEX approach, based on an in-depth review and evaluation of network operators’ productivity, for instance by the Productivity Commission. The move to an output-based regulation can encourage distribution companies to fulfil their public and social mandates and become a neutral facilitator of a competitive retail market by offering technology-neutral solutions for embedded technologies, smarter systems, battery storages and solar PV for the interest of the consumer. Such a new regulatory regime is being implemented for the next regulatory period by the AER, which is welcome.

Retail market reform – Consumer bills and enhancing competition

Household electricity prices have more than doubled since 2004. While much of this rise may be attributed to transmission and distribution costs, energy prices make up the other 50% of the final price, driven by the threefold increase in the wholesale gas price in Australia. There are several drivers of these increases.

The degree of generation and retail market concentration remains too high and has been increasing with the closure of thermal capacity. The 2017 AEMC Review of Retail Market Competition report noted that electricity markets in Tasmania, regional Queensland and the Capital Territory were not effectively competitive (AEMC, 2017a). While the report

found higher levels of competition in New South Wales, Victoria and South Australia, it also found that retail competition continued to be dominated by the large (incumbent) gentailers (AGL Energy, Origin Energy and EnergyAustralia). The three gentailers supplied around 73% of retail electricity consumers in 2016, besides government-owned generators-retailers (19%) and expanded their share in generating capacity in the NEM from 15% in 2009 to 48% in 2017 (AER, 2017a). The investments in solar rooftop PV and significant retirements of ageing capacity in the NEM led to a further increase in the market shares of existing market participants, notably AGL Energy. In 2016/17, South Australia and Victoria had little competition outside the three gentailers. And industry has not been investing in new baseload power plants amid uncertainty around federal climate policies.

Since the last IEA in-depth review in 2012, most states/territories have phased out regulated retail electricity prices, which is a welcome development. The rates of customers switching supplier in states with competitive markets are rather high. However, it is unclear how widespread switching is across customer segments. As in other (overseas) jurisdictions, switching behaviour may be concentrated among more affluent and tech-savvy consumers. The AER in 2015 reported that most consumers in South Australia, NSW, Victoria and south-east Queensland are now on competitive contracts, as opposed to standing offers. In some regions of the NEM, consumers still remain on the standing offers. Benefits of competition thus may not have reached all consumer groups equally, and retailers may be earning significant margins off those consumers on standing offers. There are many concessions for vulnerable consumers. Around a quarter of consumers in most states receive some form of assistance with paying their energy bills and many consumers remain on standard offers. These consumption price subsidies are to a large extent not well targeted and undermine energy efficiency efforts. These customers are generally not looking at market offers with other retailers after the end of regulated tariffs. This phenomenon of consumer inertia has been seen in other countries.

Many jurisdictions are deploying smart meters but the penetration levels remain low in Australia. Consumers' ability to actively manage their consumption is expected to be improved by the planned competitive roll-out of smart meters. However, this would need to be accompanied by better data portability, timely billing, price transparency, time-of-use and dynamic pricing to allow demand response, actions that should be reinforced through the work of Energy Consumers Australia.

Robust statistics and metrics on the wholesale and retail markets are crucial for policy making, including information on hedging liquidity, customer tariffs and switching behaviour, which to date have been lacking. A joint market monitoring and reporting by ACCC/AER and AEMC should be agreed, including on retailer margins, competition within the retail electricity sector, the extent to which hedge liquidity is a barrier to new retailers is important. The requested electricity price inquiry by the ACCC is very welcome in this context. Despite the fact that AER functions have been enhanced, penalties by AER for market manipulation are currently low and limited to civil liability. Competition rules need to be adapted so as to improve the ability of the competition authority to pursue retail practices that are abusive and to more effectively control anti-competitive behaviour in the market.

Much of the recent energy market reforms have focused on wholesale market design. Retail market rules have been adopted since 2012 through the Council of Australian

Governments (COAG), but are not yet fully operational. International experience suggests that empowering consumers and increasing their participation are critical to building transparent and competitive retail markets. Within the legal framework of the *National Retail Law*, COAG should review the retail market reform and decide on a few key actions to increase its transparency and consumers' engagement, building on the *Power of Choice* review of the AEMC of 2012, on the work of the COAG Energy Market Transformation Project team, with a view to ensure that common principles are adopted in favour of competitive retail markets in those states/territories that have phased out price regulation.

The key areas for retail market reform towards consumer engagement should include:

- Increasing customer exposure to real-time and cost-reflective pricing, with protection of vulnerable consumers addressed through targeted transfers that do not unduly distort efficient price formation.
- A competitive, dynamic retail market to encourage the development of innovative products and services that can harness demand response effectively and at least cost.
- Ready access to detailed, real-time customer information, while ensuring privacy, to help stimulate competition, facilitate competitive entry, support the emergence of innovative business responses, and improve customer choice.
- A knowledgeable and well-informed customer base that has the capability and opportunity to take full advantage of available choices.
- Market processes for contracting, switching and billing that are as simple and seamless as possible to keep transaction costs to a minimum.
- Legal and regulatory governance frameworks that reduce uncertainty, establish clearly specified rights, responsibilities and obligations on contracting parties, promote greater harmonisation of standards and functionality specifications, and maximise scope for participation among potential service providers and customers.
- Enabling technologies that provide cost-effective, real-time metering information, verification and control capability to support the introduction of real-time pricing, the development of a wider range of innovative demand response products, and more effective customer choice.

Electricity security and reliability

The National Energy Market (NEM) has served Australia for well over 20 years; helping to ensure that a secure, affordable and reliable power supply is maintained. Its reliability levels have been generally high. Electricity security and reliability have received considerable public and political attention following a state-wide blackout in South Australia on 28 September 2016 and the load disconnections during a country-wide heat wave in February 2017. After the South Australian blackout a number of immediate remedial actions were taken to avoid a similar event recurring. As part of the Energy Supply Plan, South Australia announced a range of public security investments, including 200 MW emergency generation and a large battery storage (Tesla and Neoen's wind farm deployed the world's largest lithium battery of 129 MWh in South Australia in late

2017), next to legislation to allow its Energy Minister to direct the market under the Emergency Management (Electricity Supply Emergencies) Amendment Bill 2017.

There is a clear challenge for the NEM governance to ensure reliability through market-driven responses in the consumer's interest. The energy system transformation offers challenges and opportunities in this respect. The integrity of the NEM relies on common rules and responses. To date, the roles and responsibilities of the NEM market bodies are overlapping; AEMO is also involved in market procedures but has few system operation functions in comparison to an Independent System Operator. The new Commonwealth government agencies (CER, CEFC, ARENA) are not part of the NEM governance, while they impact the market functioning. Retail monitoring functions are present in all market bodies. This complexity invites high regulatory activities, analysis and constant rules reviews. It is paramount to promote the NEM towards the new world with higher shares of renewable energy in the system and to integrate energy and climate policies in the NEM participating jurisdictions. Many parts of the puzzle have been identified, but there is no overall NEM market design projected. The Finkel Review brought together a blueprint for such a design with many new rules and regulations.

The electricity security events in 2016 and 2017 highlighted the vulnerability of Australia's electricity infrastructure in the NEM regions to simultaneous peak demand and extreme weather events or generator outages, and loss of interconnection capacity combined with gas supply shortages, leading to power system disruptions. Network investment and flexible system operation remain critical to ensuring electricity reliability and integration of renewable energy. Transmission planning, including new interconnectors across the NEM, regional security collaboration between New South Wales, South Australia and Victoria within AEMO, and new renewables deployment must therefore go hand in hand, but equally policies supporting consistent and common NEM-wide rules, notably on energy and climate change and electricity security. In this context, the recommendations of the Finkel Review should be implemented without delay. Building on the above, from the IEA perspective, the government should prioritise measures to *i)* foster the emergency preparedness and response in the NEM, the resilience of the energy infrastructure and energy security collaboration among all levels of government and system operators; *ii)* ensure that electricity codes, rules and standards are in place for new generators, notably variable renewable energy generators so as to integrate them seamlessly into the grid and markets, and encourage energy-system-wide planning of the transmission networks and interconnectors; and *iii)* consider to implement a market-based safety net as a grid stability reserve, for instance a modernised AEMO Reliability and Emergency Trader scheme.

Recommendations

The government of Australia should:

- Prioritise measures to enhance the functioning of the National Electricity Market, building on scarcity pricing and actions to increase competition and new entry, while reducing anticompetitive behaviour and market power, through shorter settlement periods aligned with dispatch, demand response and more liquidity in the financial markets.

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- Guide the energy transition with an emissions reduction goal and related mechanisms for the power sector to provide a market signal to retire older and less efficient generation, while ensuring that plants provide sufficient advance notice of their intention to close.
- Ensure that federal and jurisdictional energy and climate policies are aligned by enhanced collaboration under the COAG Energy Council towards well-functioning wholesale and retail electricity markets fit for the energy transition, more specifically by:
 - > Stepping up efforts to increase energy efficiency across the Electricity Market, including by implementing energy efficiency schemes and demand response in the wholesale and retail markets;
 - > Ensuring that low-emission technology support is market-based and guided by locational signals and supported by energy system-wide network planning;
 - > Considering adopting a safety net to ensure that sufficient system reserves are available during the transition, for instance by enhancing the market operator's Reliability and Emergency Reserve Trader mechanism.
- Foster national retail market transparency and consumer engagement under the Energy Council, expanding the National Energy Retail Law and regularly evaluate progress, based on joint reporting and monitoring by ACCC, AER and AEMC on the basis of a consolidated metrics of retail indicators (evaluation of electricity retailer margins, electricity cost and consumer prices by sector, to identify non-competitive outcomes).
- Work with the COAG Energy Council, energy market bodies and industry stakeholders to proactively support the transformation of distribution systems, including by ensuring harmonised technical standards, interoperability of resources in different states and consistent economic regulatory arrangements.

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5. Focus area 2: System integration of variable renewables

Key data

(2015/16 provisional)

VRE installed capacity (2015): wind 4.2 GW (6.3% of total installed capacity) solar PV 4.4 GW (6.5% of total installed capacity)

VRE generation (2016 estimated): wind 12.1 TWh (4.7% of electricity generation), solar PV 6.8 TWh (2.7% of electricity generation).

Focus region: South Australia

VRE installed capacity: wind 1.5 GW (30% of total installed capacity) solar PV 679 MW (13% of total installed capacity)

VRE generation: 5.2 GWh (42% of electricity generation)

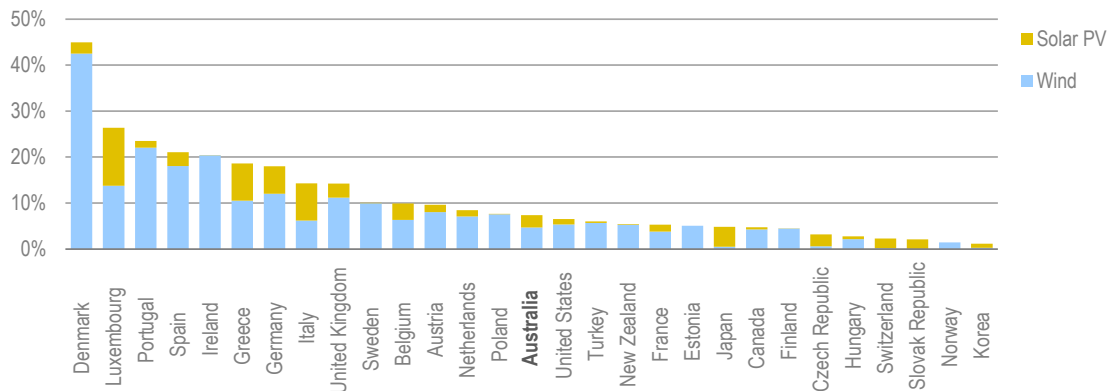
Maximum instantaneous VRE penetration: over 119% (wind) and 38% (solar PV)

Overview

Australia is currently experiencing a rapid rise in the deployment of wind and solar photovoltaics (PV), driven by a combination of policy support and increasing competitiveness of the technologies. By late 2015, the installed capacity of large-scale wind plants totalled 4 GW, large-scale solar PV amounted to 800 MW and rooftop solar PV to 4.1 GW. At the end of 2016, total PV capacity stood at 5.4 GW in Australia. However, deployment has occurred very unevenly across the country. In 2016, South Australia had a share of 38% of wind power and a penetration of 17.8% of rooftop solar, which is much larger than their share in national electricity generation (2.7% for solar and 4.7% for wind, respectively).

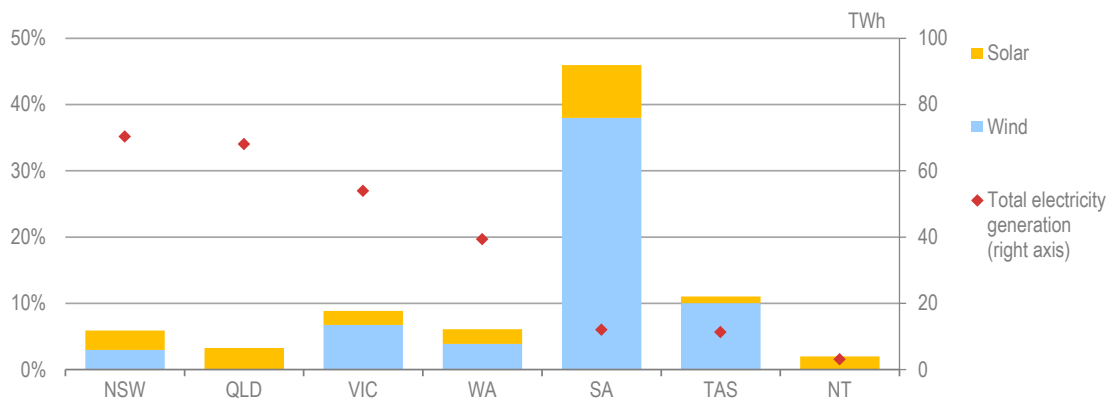
This special focus chapter on system integration is dedicated to the National Electricity Market (NEM), the largest interconnected power system in Australia, accounting for 85% of the country's demand, covering the states of Queensland, New South Wales, Victoria, South Australia and Tasmania. The challenges around system integration are examined in this chapter, while echoing some of the broader issues around power market design and electricity of supply in the NEM which are the subject of Chapter 4 on Electricity.

Figure 5.1 Electricity generation from variable renewable sources as a percentage of total generation in IEA member countries, 2016



Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 5.2 Electricity generation from variable renewable sources as a percentage of total generation in Australian states, 2016



Source: DoEE (2017), "Australian energy statistics, Table O", www.environment.gov.au/energy/publications/australian-energy-update-2016.

Among IEA member countries, Denmark and Ireland are the countries which have reached the highest level of VRE penetration. The state of South Australia also has very high shares of VRE generation in its electricity mix, leading to a situation in which short-term stability issues become relevant and system integration measures become critical. In this sense, the experience from Denmark and Ireland can be of particular interest to South Australia. Like Denmark and Ireland, South Australia is also part of a common electricity market that crosses jurisdictional borders.

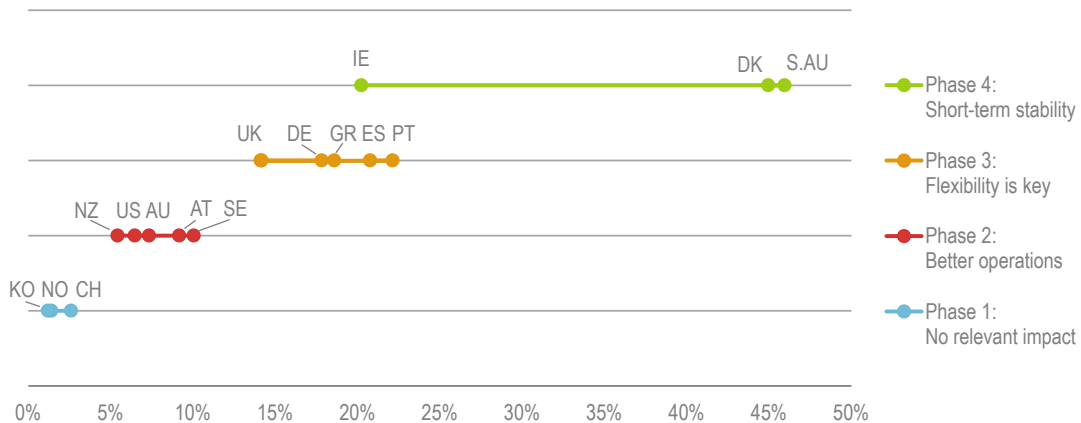
General considerations for system integration

System integration of renewable energy encompasses all the technical, institutional, policy and market design changes that are needed to enable the secure and cost-effective uptake of large amounts of renewable energy in the energy system. The adaptations required are most profound for integration of variable renewable energy (VRE) technologies, namely wind and solar power.

The physical nature of electricity requires that generation and consumption must be in balance at all times. System planning and operation need to ensure this, respecting the technical limitations of all system equipment under all credible operating conditions, including unexpected events, equipment failure and normal fluctuations in demand and supply. This task is complicated by the fact that electricity cannot currently be stored in large quantities economically.¹

The difficulty (or ease) of increasing the share of VRE in a power system depends on the interaction of two main factors: the properties of VRE generators and the flexibility of the power system into which they are deployed (a more detailed discussion can be found in IEA, 2014 and IEA, 2016).

Figure 5.3 VRE share in annual electricity generation and system integration phase in selected IEA member countries, 2016



Note: AT = Austria; AU = Australia; CH = Switzerland; DE = Germany; DK = Denmark; ES = Spain; GR = Greece; IE = Ireland; KO = Korea; NO = Norway; NZ = New Zealand; PT = Portugal; S.AU = South Australia; SE = Sweden; UK = the United Kingdom.

Sources: Adapted from IEA (2017a), *World Energy Balances 2017*; www.iea.org/statistics; IEA (2017b), *Getting Wind and Sun onto the Grid*.

Re-cap of the South Australia Black System event of 28 September 2016

South Australia (SA) experienced a state-wide blackout, which occurred on 28 September 2016, a so-called Black System. Following the events, concerns about grid code design and power system stability at high shares of non-synchronous generation have featured prominently in the policy debate. The Australian Energy Market Operator (AEMO) carried out an analysis into the “Black System” event of 28 September 2016 in South Australia, which included an analysis of the factors that led to the blackout and a set of lessons learned (AEMO, 2017a). AEMO’s conclusions from its investigation were:

- Access to correct technical information about grid-connected equipment is critical for system security.

¹ Relevant storage technologies first convert electricity before storing energy. Capacitors are an exception, but these cannot store large energy volumes.

- The wind turbines themselves performed according to specifications. It was the action of a control setting responding to multiple disturbances that led to the Black System. Changes made to turbine control settings shortly after the event have removed the risk of recurrence given the same number of disturbances.
- Had the generation deficit not occurred, AEMO's modelling indicates that South Australia would have remained connected to Victoria, and the Black System would have been avoided.
- The following factors must be addressed to increase the prospects of forming a stable South Australia island and avoiding a black system:
 - **Sufficient inertia** to slow down the rate of change of frequency (RoCoF) and enable automatic load shedding to stabilise the island system in the first few seconds. This will require increases in SA inertia under some conditions, improvements to load-shedding systems and the management of interconnector flows under certain conditions, through special protection schemes (SPS).
 - **Sufficient frequency control** services to stabilise frequency of the SA island system over the longer term. This will require increases in local frequency control services under some conditions.
 - **Sufficient system strength** to control over voltages, ensure correct operation of grid protection systems and correct operation of inverter-connected facilities such as wind farms. This will require increases in local system strength under some conditions.

Looking at the longer-term challenges, in order to address the lack of firm capacity following the closure of large coal-fired plants and the mothballing of gas-fired generators, AEMO invited bids for a long-notice reserve for Victoria and South Australia (combined requirement) for the summer 2017/18.

On 30 March 2017, the Australian Energy Market Commission (AEMC) carried out a rule change to enhance emergency frequency-control schemes and introduce a new category of contingency events, the so-called protected events, which are high-impact but low-likelihood events. This will allow AEMO to take pre-emptive action when frequency changes occur ahead of possible disturbances. Instead of controlled load shedding, AEMO could purchase frequency control services or apply constraints on the dispatch process.

Rather than focusing on the 28 September 2016 event in isolation, this chapter first develops a number of general considerations for system integration of renewables and then discusses how these apply in the Australian context.

Different time-scales of system transformation

Challenges and solutions for system integration of variable renewable energy (VRE) are usually categorised according to three distinct time dimensions.

The first is **resource adequacy**, which relates to the availability of sufficient power system resources (generation, demand response, storage, imports from other areas of the grid) to reliably meet demand.

The second is **flexibility** (or balancing), which relates to the ability of the power system to maintain the balance of supply and demand in the face of high variability and uncertainty. In order to achieve this, the power system needs sufficient flexible resources that can change their output quickly, at short notice and within a wide range, from a few minutes to several hours.

The third issue is **system stability**, which relates to the ability of the power system to withstand disturbances within the first milliseconds to several seconds following a load or generation change event.

Achieving high shares of wind and solar power cost-effectively and reliably

Given the broad impacts that high VRE shares can have, a comprehensive and systemic approach is the appropriate answer to system integration challenges. As identified by comprehensive IEA analyses, a co-ordinated approach can significantly reduce integration costs and ensure electricity security (IEA, 2014 and IEA, 2016, see Figure 5.4). Achieving such a transformation requires strategic action in three main areas:

System-friendly deployment to maximise the net benefit of wind and solar power for the entire power system. Such an approach leads to different deployment priorities as compared to a focus on generation costs alone.

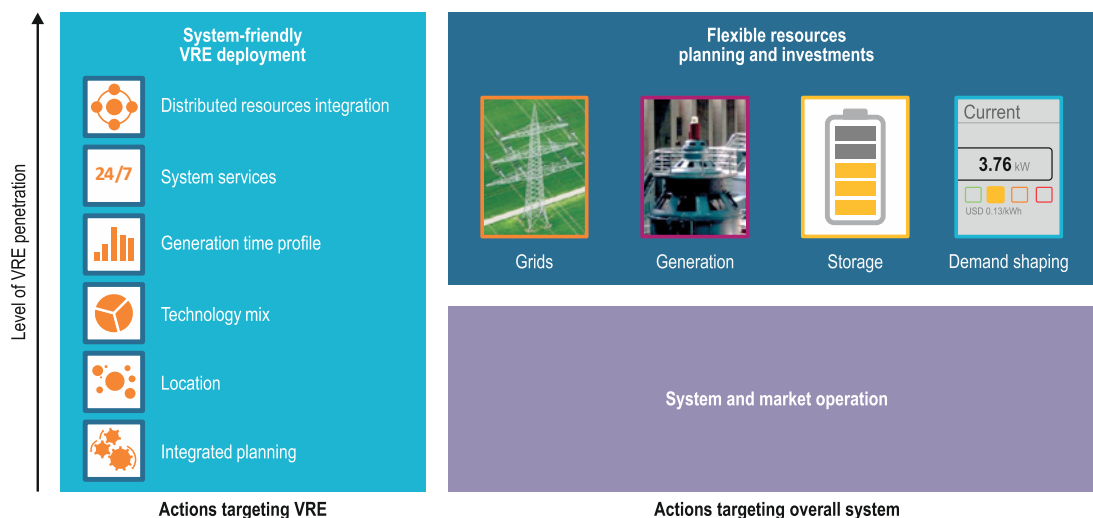
Improved operating strategies as a powerful tool to maximise the contribution of existing assets and ensure security of supply. These include advanced renewable energy forecasting and enhanced scheduling of power plants. Where liberalised wholesale markets are in place, this may require an upgrade of market rules and products. In heavily regulated systems, action will need to target operational protocols and key performance indicators (KPIs) for system and power plant operators.

Investment in additional flexible resources. Even in concert, improved operations and system-friendly VRE deployment practices will be insufficient to manage high shares of VRE in the long term. The point at which investment in additional flexible resources becomes necessary depends on the system context. In all systems, however, an increase in flexible resources will become a cost-effective integration strategy at some point, requiring additional investment. Broadly speaking, resource adequacy and multi-hour flexibility issues have the largest economic impact. These can be addressed by systematic expansion of the grid, ensuring an appropriate power plant fleet, unlocking demand response potential and storage.

Mobilising the contribution of each of the three areas requires appropriate market, policy and regulatory frameworks, besides changing the roles of institutions in the power system, which can require time and resources. Actions to adapt the overall power system to VRE generation need to be complemented by measures that make VRE suitable for the power system. The following discussion reviews these three aspects in the Australian context. The discussion of system-friendly deployment focuses on distributed energy resources. South Australia is a particular hotspot of the analysis. In this state of the NEM, the share of VRE in total generation has reached 40% and the state has the highest solar PV generation in the world, while at the same time, significant system inertia has been lost because of the mothballing of gas-fired

plants and closure of coal-fired plants, including in neighbouring Victoria (Hazelwood), to which South Australia is interconnected.

Figure 5.4 Integrating large shares of VRE requires system transformation



Source: Adapted from IEA (2014), *The Power of Transformation*.

System and market operation in the NEM

Generation dispatch

The NEM has a sophisticated generation dispatch process. Generators are dispatched in quasi-real time (five minutes ahead) five-minute intervals. On the basis of the generator offers submitted and transmission network parameters, AEMO performs central dispatch optimisation using software called the NEM Dispatch Engine (NEMDE). Quasi-real time dispatch process maximises the value of trade, subject to a number of constraints, including transmission grid limitations, allowing last-minute fluctuations in weather conditions to be taken into account, in order to allow effective dispatch of VRE generators, even if some of them are not directly visible to AEMO. About 52% of wind farms in the NEM system are currently semi-scheduled generators, with the remainder non-scheduled generators. The short dispatch intervals (five minutes) and the classification of generators into three categories allow for more accurate representation of variations in VRE output and, subsequently, net load.

Forecasting of wind and solar output

Wind and solar forecasting plays an increasingly important role in the NEM in facilitating the integration. Forecasting systems have been established in response to the rise of VRE generation and they have been incorporated as part of the dispatch process (see Box 5.1).

Frequency control ancillary services

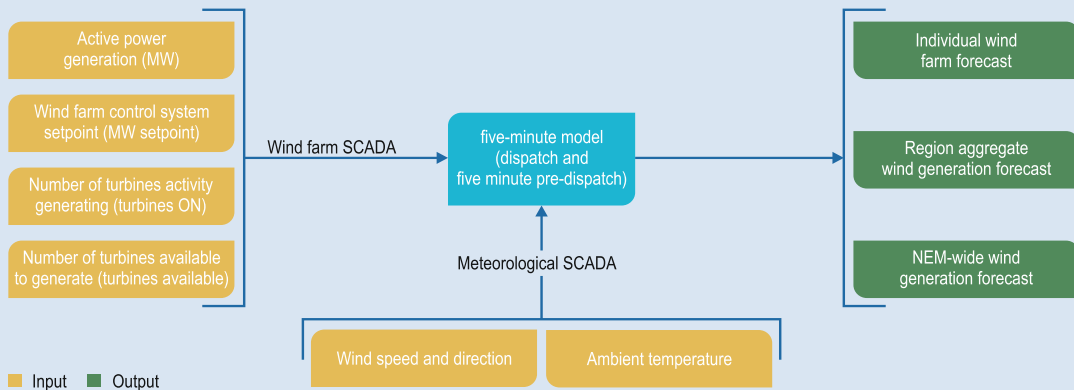
Besides the wholesale trading process, the NEM also has competitive spot markets for frequency control ancillary services (FCAS). There are eight real-time FCAS markets:

two regulation markets (regulation raise and regulation lower), and six contingency markets (6-second raise and lower, 60-second raise and lower, and 5-minute raise and lower).

Box 5.1 The Wind and Solar Energy Forecasting System

The Australian Wind Energy Forecasting System (AWEFS) and the Australian Solar Energy Forecasting System (ASEFS) are used to provide weather and VRE production forecasting, for time frames from five minutes to two years. They take into account plant-level static data (plant details, historical meteorological measurements) and dynamic data provided by real-time supervisory control and data acquisition (SCADA) measurements of VRE plants. AEMO hosts the systems and maintains their interface with the existing market system, to feed information for the five-minute ahead dispatch orders (Figure 5.7). The AWEFS feeds valuable quasi-real-time information to the dispatch centres, which alter the five-minute dispatch orders accordingly.

Figure 5.5 Wind forecasting system as part of the dispatch processes in the NEM



Source: Adapted from AEMO (2016), Australian Wind Energy Forecasting System (AWEFS).

During each dispatch interval of the market, AEMO enables a sufficient amount of each of the eight products, from the bids submitted, to meet the system requirement via a co-optimisation. Regulation services are continuously used to correct for minor changes in the demand/supply balance. Contingency services are only occasionally used to cover contingency events, although the services are always enabled.

AEMO procures FCAS for “credible contingency events” (e.g. loss of a generator, loss of a line, etc.), while for “non-credible contingency events” (more severe and rare system disturbances, like loss of multiple generators, multiple lines, etc.), the rules in the past did not allow AEMO to procure FCAS. Instead, controlled load shedding would be utilised through under-frequency load-shedding schemes and special protection schemes to limit the consequences of a non-credible contingency event. In response to the black-out events in 2016 and the South Australian government’s request for a rule change, AEMC issued new rules for emergency FCAS schemes. AEMC introduced a new category of non-credible contingency events, the so-called “protected events”. The new category is a way of limiting the consequences of certain non-credible contingency events. In the case of a protected

event, AEMO is allowed to use a mixture of *ex-ante* solutions, such as the purchase of FCAS and constraining generation dispatch to maintain the frequency operating standards and to limit the amount of controlled load shedding.

The growth of wind generation in South Australia and the retirement of old coal-fired capacity, displacing synchronous generation has led to periods of low synchronous inertia, when high wind output meets low demand. This translates into a high rate of change of frequency (RoCoF) following a system disturbance, which was one of the factors that featured in the Black System event in September 2016.

Synchronous inertia is an instantaneous and automated response provided by synchronous machines such as large thermal and hydro generators that are connected to the grid. Synchronous inertia acts to decrease RoCoF of a power system after a contingency event, such as the loss of a large generator. Wind and solar PV, on the other hand, are non-synchronous generation and do not directly contribute to system inertia. It is worth noting that low inertia is a property of a power system in a given moment rather than long-term, i.e. the system has low inertia when wind and solar cover much of the demand and will have higher inertia when thermal power plants meet most of the demand.

Synchronous inertia allows time for other frequency control mechanisms to respond, including fast frequency response (FFR), primary frequency response (PFR) and secondary frequency response (SFR) (GE, 2017).² In the NEM, PFR and SFR are formally provided through FCAS products but there are no provisions of FFR. The FFR service would act to arrest the frequency change more quickly than the current FCAS. Although FFR cannot directly replace synchronous inertia, it can be an effective means to arrest frequency decline by injecting active power within 1 to 2 seconds of a contingency event. FFR service can be provided by different technologies, including wind turbines, solar PV (if applicable), batteries, flywheel and supercapacity storage systems, high-voltage direct current transmission and demand response, although their response times do vary.

With the growth of non-synchronous generation, many jurisdictions such as ERCOT and Eirgrid/SONI (Ireland and Northern Ireland transmission system operators) have put in place or are in the process of establishing mechanisms to handle low system inertia and high RoCoF.

Eirgrid/SONI has been developing a new framework for ancillary services to include inertia response, FFR and PFR. Eirgrid/SONI has established the limit of non-synchronous penetration (SNSP), as part of their multi-year work programme, to ensure the reliable operation of the power system with a high amount of wind penetration.

The Australian Energy Market Commission (AEMC) has completed a review and rule changes to improve the management of systems strength and rate of change of frequency as more non-synchronous generation enters the system and FCAS costs have increased significantly:

² Synchronous inertia is a physical characteristic, rather than a control action that is not sufficient by itself to arrest frequency decline.

- Network service providers will be required to maintain system strength at generator connection points above agreed minimum levels, with new connecting generators required to “do no harm” to system strength.
- Transmission network service providers (TNSPs) will be required to provide minimum required levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.
- A market-based mechanism will also be proposed to support the provision of inertia above the minimum obligation on TNSPs.

The AEMC has also started a broader review of frequency control in the NEM, which will consider whether the current market frameworks will remain fit for purpose, and how to incorporate fast-frequency response services.

There is also a debate on how much inertia is required and the amount of non-synchronous generation that can be accommodated while the system can still operate within the security boundary. The work programme used by EIRGRID/SONI to determine limits on SNSP based on in-depth studies could also be an option for AEMO. This is in addition to the review of the existing FCAS markets to increase inertia and FFR.

While currently not widely discussed, a heatwave event raises questions about the appropriateness of holding reserves against downward wind ramps, which play out over periods of several hours. As an example: on 8 February 2017, at 6.30 pm, the temperature hit about 46°C in South Australia. As many people returned home and turned on the air conditioner, SA Power Networks announced it would start load shedding to cope with demand, plunging some areas into blackouts for about 30 minutes. In addition to impacts at very short notice, wind power can have impacts especially on the need for slower acting reserves. This is a well-known issue for other IEA member countries, including Ireland, Spain and the Electricity Reliability Council of Texas (ERCOT) in the United States, but appears to have received no systematic consideration in Australia so far.

Flexible resources

Grid infrastructure

The main electricity grid planning process in the NEM occurs under the National Transmission Network Development Plan (NTNDP), which is an annual process for which scenarios are prepared using PLEXOS software.³ The 2016 NTNDP made steps to better co-ordinate and integrate transmission network planning with other elements. It took into account Australia’s COP21 commitment, the federal Large-Scale Renewable Energy Target and states’ policies. However, the NTNDP is largely based on the aggregation of plans from the transmission service providers.

³ PLEXOS is a commercial energy market simulation package with capabilities for modelling power system operation and planning. It contains over 150 technical and economic characteristics, which can be defined for each individual generation asset. Simulations can be produced over different time frames, ranging from long-term generating capacity expansion to short-term dispatch and unit commitment.

Planning of the transmission network in Australia remains a challenge, since transmission services and investment decisions are carried out by independent transmission service providers in each state, which have to comply with state-level reliability targets and renewable support schemes. It emphasises the need for the states to adopt a co-ordinated approach to grid planning, because of the interdependencies between state transmission systems. Energy system-wide transmission planning becomes even more important as individual jurisdictions have developed their own energy plans, including targets for renewable energy and energy efficiency.

The Finkel Review (Finkel, 2017) calls for a better system planning, with a central agency (like the market operator AEMO) having a stronger role in planning the transmission network. The Review highlights the importance of a NEM-wide integrated grid planning: significant investment decisions on interconnection between states should be made from a NEM-wide perspective, with a more distributed and complex energy system. In June 2017, AEMO released its new *Energy Supply Outlook*, which integrates the gas and electricity statements of opportunities and demand forecasts (AEMO, 2017b).

Network operators around the globe co-ordinate power system planning across interconnected systems to optimise the use of resources and benefit from increased flexibility. Inter-regional co-ordination is used in the European Union, South Asia, the Association of Southeast Asian Nations (ASEAN) and the United States (IEA, 2017c). The European Union is a prominent example of regional co-ordination in transmission planning, as it has a large number of jurisdictional transmission network companies. The European Network of Transmission System Operators for Electricity (ENTSO-E) was created to co-ordinate transmission network planning and operation across different jurisdictions. ENTSO-E publishes the *Ten-Year Network Development Plan* (TYNDP) every two years to give an overview of the transmission expansion plans in the next 10 to 15 years that have been identified as necessary to facilitate EU energy policy goals. The TYNDP is a co-ordinated planning initiative to deliver a pan-European transmission plan within the ENTSO-E region. The TYNDP 2016 pinpoints about 100 spots on the European grid where bottlenecks may persist if reinforcement solutions are not implemented. On the basis of the TYNDP, projects of common interest (PCIs) are selected and will benefit from accelerated licensing procedures, improved regulatory conditions, and some access to financial support.

Providing incentives for system-friendly deployment of VRE

The Victorian annual feed-in tariff set by the Energy Authority (Essential Services Commission, ESC) considers the value of produced energy from residential PV plants for the entire system.

Table 5.1 Forecast value of feed-in electricity, Victoria, 2015 to July 2017 (in AUD)

FiT component	2015	2017	July 2017
Forecast solar-weighted average wholesale electricity pool price	5.7	4.6	8.1
Value of avoided T&D losses	0.4	0.3	0.6
Avoided market feed and ancillary service charges	0.05	0.1	0.1
Value of avoided social cost of carbon	-	-	2.5
FiT	6.2	5.0	11.3

Source: ESC (2017), Minimum Electricity Feed-In Tariff To Apply From 1 July 2017 Decision (Final).

Box 5.2 Location signals for VRE deployment

With the cost of solar PV falling rapidly and technological improvement, deployment is becoming economical even in lower resource conditions. Locational flexibility can increase the system value of the power plants by producing electricity closer to demand or in regions where alternative generation options are very expensive. To deploy wind and solar power in a system-friendly manner, there are several policy options to optimise the locational mix of VRE deployment: integrated planning, location-dependent pricing on the wholesale market or advanced auction mechanisms.

Since the deployment of VRE often outpaces network development, it is necessary to anticipate where renewables are likely to be built, while explicitly linking incentives for new transmission lines to support investment in renewables. The Competitive Renewable Energy Zones (CREZs) in Texas are an example of such a policy. One way to represent the locational value of electricity is the adoption of “nodal pricing”, where market clearing prices are calculated for a number of physical locations on the transmission grid (the “nodes”). The price at each node includes the cost of energy and the cost of delivering it, including losses and congestion. Chile is an example with the nodal pricing structure. As part of the power sector reform, Mexico has also moved from a zonal pricing system to a full nodal pricing regime.

Mexico’s energy reform has introduced a number of products that are traded on a long-term basis: electricity, clean energy certificates and capacity. Market participants can also trade financial transmission rights (FTRs). The Mexican auction scheme is one of the most sophisticated procurement mechanisms for renewable energy. Through these actions, long-term resource adequacy can be maintained. Mexican auctions incite independent power producers (IPPs) to develop projects that provide power at locations that optimise the overall system value. This is achieved by clearly indicating the spatial value of electricity production through location-dependent correctional factors during the selection process (these correctional factors have no influence on the final price). In addition, VRE projects are subject to time-dependent price adders that determine their revenues during operation, which means that developers are given the incentive to prioritise measures to produce power at a time when it is most valuable to the system.

CENACE (the Mexican independent system and market operator) developed a model to estimate expected electricity prices. These calculated prices are then used for setting hourly price adders for the entire length of a project, as determined by a power purchase agreement (PPA), and on a region-specific basis. The adders are defined as the difference between the price of electricity in a specific hour and the average price of electricity across the length of the PPA. In hours where the calculated price is above average, the VRE producer receives the value of the bid plus the price adder. Similarly, if the project feeds power into the grid at a moment when the adder is negative, this amount will be deducted from the contract price. The revenues of the generator give an indication of the system value of electricity produced during each specific hour. Price adders are updated for each auction to account for the evolution of supply and demand, considering the (future) commissioning of awarded projects. This price calculation pushes bidders to design their plants in a way that optimises the system value.

Source: IEA (2017c), Status of Power System Transformation 2017; IEA (2016), Next Generation Wind and Solar Power.

Common price-setting mechanisms focus on the levelised cost of electricity (LCOE) of the power plants. ESC forecasts the average solar wholesale electricity price, the value of avoided T&D losses, the avoided market fees and ancillary services charges and, since 2017, the value of avoided social cost of carbon.

Storage

Following the 28 September blackout in South Australia and capacity shortages during a countrywide heatwave in early 2017, it has been increasingly viewed that storage options could ease the integration challenges by providing additional flexibility. A number of storage projects and plans have been announced by state and federal governments, which include pumped storage hydropower (PSH) and large-scale batteries. South Australia's government is building the largest grid-connected battery in the country with up to 100 MW/129 MWh of battery storage.

In addition, the potential of battery storage in providing system services, particularly fast-frequency response (FFR), has also been considered for South Australia. The AEMC made a rule change to align operational dispatch and financial settlement from thirty to five minutes. This will have a major implication on the adoption of battery storage. The Finkel Review (Finkel, 2017) has also outlined the importance of storage requirements for wind and solar projects by recommending that these projects should be paired with storage capacity (or dispatchable generation) to manage variability.

For pumped storage hydro (PSH), the federal government announced a plan to expand the Snowy Hydro Scheme to improve its pumped storage capabilities. The existing scheme consists of seven power stations and two pumping stations with a total capacity of two gigawatts (GW). The new scheme would double its capacity to four GW and is estimated to cost around AUD 2 billion. The feasibility study of the expansion project is currently under way and is expected to be completed by 2018.

Battery and PSH options can provide additional flexibility to help to integrate higher penetration of VRE. They will play a key role in the future of Australia's power sector. The costs of battery storage technologies, however, are still relatively high, as there are no major policies to promote the deployment of battery storage.

In December 2017, the world's largest lithium-ion battery went officially on stream in South Australia when Tesla's battery completed its challenge to ensure construction in 100 days. The battery can support power to 30 000 homes.

Demand response and electrification

Demand-side participation⁴ in the NEM is at low levels, with no wholesale mechanism and limited demand response at retail levels, as described in Chapter 4 on Electricity. Building on the *Power of Choice* review, the market commission AEMC initiated a number of rule changes and rule change proposals in recent years, intended to improve opportunities for demand-side participation, including reforms to distribution network

⁴ Demand-side management (DSM) programmes have been developed and co-ordinated by utilities, often supervised by regulators, seeking to minimise the operating cost base used to determine regulated tariffs for end-users. Demand response differs from DSM in that it is the product of voluntary and independent decentralised decision making by suppliers and customers. For further information, see IEA (2011), *Empowering Customer Choice in Electricity Markets*, OECD/IEA, Paris.

pricing, network demand-side management, and metering. The distribution sector regulation has been amended by the regulator AER to promote demand-side management by network businesses through demand reduction or embedded generation (small-scale local generation). This rule change was introduced in August 2015.

In 2017, AEMO and the Australian Renewable Energy Agency (ARENA) have started a three-year innovative demand-response initiative in the NEM, to pay consumers to temporarily reduce their demand to help manage peak demand. ARENA and the New South Wales government are providing AUD 37.5 million to support approximately 160 MW of demand-response capacity, including 60 to 70 MW in the state. Successful proposals will be dispatched during extreme peaks and grid emergencies under AEMO's Reliability and Emergency Reserve Trader mechanism. Outcomes of this trial will inform development of a demand-response mechanism for the wholesale market, as recommended in the Finkel Review.

The Clean Energy Finance Corporation is providing funding, in excess of AUD 450 million, for projects that decrease the emissions intensity of transport, including electric vehicles. However, no direct or indirect incentives are provided for the deployment of electric vehicles (EVs). The federal luxury car tax (paid by businesses that sell or import luxury cars) is applied to vehicles valued over a certain threshold (USD 49 352 or AUD 64 132 in 2016/17). This threshold is higher for energy-efficient vehicles such as EVs (up to USD 58 120 or AUD 75 526 in 2016/17), but this is not a strong incentive to purchase an electric vehicle.

The electrification of the residential heating and cooling sector is supported by the Small-scale Renewable Energy Scheme (see Chapter 8 on Renewable Energy). During 2015, the scheme encouraged the installation of 39 806 solar water heaters and 15 025 air-sourced heat-pump water heaters (Clean Energy Regulator). The deployment of heat pumps, together with the expected deployment of residential smart meters, is an effective way to trigger demand shaping in the residential sector.

Electrification of transport or industrial processes, such as ammonia manufacturing, could offer new opportunities for a larger deployment of renewable power generation substituting emission-intensive technologies (e.g. steam methane reforming), based on the exceptional combination of world-class wind and solar resources in Australia (and more specifically in Western Australia).

Power plants

Coal is the dominant fuel source for electricity generation. There are currently 18 coal-fired power plants in the NEM with a total generating capacity of 23.1 GW. The median and mean ages of coal plants in the NEM are around 31 and 29 years, respectively (data from Energy Supply Association of Australia [2015]). Most of the existing coal plants have been in operation for almost 30 years and many are now approaching their expected lifespan of around 40 to 50 years. The oldest operating coal plant in the NEM is Liddell in New South Wales (2 000 MW), which was first built in 1971, while the youngest are Bluewaters in Western Australia, built in 2009/10, and the Kogan Creek in Queensland (750 MW), which was commissioned in 2007.

Because of their low efficiency, high emission intensity and oversupply of generating capacity, ageing coal plants are likely to be retired rather than refurbished. The most recent retirement was the Hazelwood plant, which was built during the 1960s and was

one of the least efficient power stations in the country. Although large coal-fired power plants are generally inflexible, they can contribute in providing synchronous inertia response. Retirements of thermal generating capacity can present challenges for power system operation because of an increasing share of non-synchronous generation.

With further coal-plant retirements expected in the coming years and most of the existing plants reaching the end of their technical lives in the next two decades, it is important to ensure that the system remains secure. Since new generating capacity is likely to come from wind and gas-fired power plants, it is important they are installed and operated in a system-friendly manner to provide the flexibility to accommodate the needs of the power system. In addition, a continuous monitoring of resource adequacy will help to avoid any shortfalls in firm generating capacity. The three-year closure notice period for large generators, as recommended by the Finkel Review, can prevent unexpected closures of large thermal power plants and allow system operators to find alternatives to ensure security of supply.

System-friendly deployment of distributed resources

Solar PV systems are the main form of distributed generation currently installed in Australia. Feed-in tariffs (FiTs) combined with rising electricity prices encouraged almost 1.5 million Australian households to install solar PV systems between 2009 and 2015. Installed solar PV capacity reached 3 700 MW in the NEM in 2014/15, equivalent to 8% of total installed generating capacity, and supplied 2.7% of the total electricity consumed that year. AEMO expects the strong uptake of solar PV to continue, estimating 20 GW of solar PV by 2037, producing electricity equivalent to 12% of demand for grid-supplied electricity (AEMO, 2017b).

The low- and medium-voltage (up to 66 kV) grids are managed by the distribution network system providers (DNSPs). Several DNSPs operate in each transmission region in Australia and can be state or privately owned, as described in the Chapter 4, “Electricity”.

The exchange of data between AEMO and the DNSPs is relatively limited, based on energy flows at the connection points between DNSPs and transmission network service providers (TNSPs). AEMO aims to increase its interaction and data exchange with the DNSPs in the future, as the presence of distributed energy sources increases.

In fact, AEMO treats solar PV as a negative load which has led to distorted demand forecasts. AEMO forecasts residential and business consumption by using information from previous five-minute dispatch periods, extrapolated from historical behaviour, considering weather conditions, the hour and the day of the week. To improve its forecasting and its ability to manage extreme weather events, AEMO is building closer relationships with Australia’s Bureau of Meteorology.

Given the shift towards greater residential solar PV in the grid and the emergence of new business models, the role of the DNSPs is likely to change. Currently, the market commission AEMC is conducting a distribution market model project to explore how the operation and regulation of distribution networks may need to change to accommodate increased uptake of distributed energy resources (DER). On the basis of experience in other IEA member countries, adapting to this new paradigm requires innovative approaches to the planning and operation of low- and medium-voltage grids, with technical, economic and institutional implications.

On the technical side, more dynamic and bidirectional flows of electricity (from lower- to higher-voltage levels and vice versa) require reinforced monitoring and control as well as upgrades to infrastructure. Moreover, planning standards need to be upgraded in order to manage the uptake of large shares of distributed resources. In this context, next-generation VRE technology – such as advanced inverters – can offer technical capabilities to support and sustain safe and reliable operations in local power grids, while also reducing energy losses in the overall power system. For example, under a business-as-usual approach, a high local penetration of distributed solar PV can create challenges related to maintaining voltage at appropriate levels. These challenges can be mitigated by using solar PV inverters themselves to control voltage – a next-generation approach to deployment. To unlock this contribution, however, the technical requirements for VRE (grid codes) need to ensure that inverters are technically capable and correctly programmed, and that their combined performance is monitored by a technically robust information technology and data management systems.

Based on the 2012 *Power of Choice* review by the AEMC, rule changes are being made to promote the efficient use of energy networks and to empower customers to make efficient decisions: through competitive metering, ring-fencing of system operators' investment in storage or other competitive products, cost-reflective network pricing and embedded generation.

On the economic side, there is a need to reform electricity pricing, beyond cost-reflectiveness. Where citizens install their own solar PV systems behind the electricity meter, the design of retail tariffs becomes a critical lever to guide investment in and operation of distributed resources.

In the past, consumers did not have a strong incentive to substitute grid-based electricity by generating their own power. The rise of distributed solar PV, combined with cost reductions in smart-home and battery technology, has begun to change this. However, the design of electricity tariffs is often based on the assumption that consumers have no alternative to the grid for their electricity. For example, the cost of the electricity network itself is frequently recovered via per-unit charges on electricity. In a situation where customers use their own solar PV generation rather than electricity from the grid, such pricing arrangements may be rendered dysfunctional for the grid cost coverage.

Tariff design will need to evolve, reflecting the fact that consumers can now also become electricity producers, and consequently are required to bear a fair allocation of grid costs across grid users. This may entail a departure from the current model of recovering the cost of the distribution grid infrastructure. For example, the state of New York is reviewing the design of electricity tariffs (State of New York, 2016). As part of the reform, it is proposed to introduce a new pricing element, a so-called demand charge. Customers who use electricity when the grid is most strained will need to pay more, while those customers who avoid consumption during peak times will pay less. In Australia, bills are delivered to consumers for three months and data portability is limited; there is no harmonised distribution tariff system across the NEM.

Reform will need to take electricity tariffs beyond simply pricing consumption. Distributed solar PV systems, combined with smart-home systems and electric batteries, are valuable resources for the entire power system. However, electricity

tariffs need to allow these resources to offer their services and receive appropriate compensation. For example, distributed resources can contribute to the provision of system services. But unlocking this contribution requires commercial arrangements to appropriately remunerate resources.

Current status of retail and network tariffs

As explained in the Chapter 4 on Electricity, electricity retail prices for residential and small business customers have been deregulated in Victoria, South Australia, New South Wales and South East Queensland, while they remain regulated in the Australian Capital Territory, and for residential and small business customers in Tasmania and for rural customers in Queensland. (Outside the NEM, Western Australia and Northern Territory also retain price regulation). Most retailers in the deregulated markets of the NEM are privately owned.

Retail tariff structures and prices vary by contract, distribution network service providers (DNSP) and by supplier; each tariff, however, includes fixed and variable charges. Fixed charges apply to all connected customers in a distribution zone, irrespective of their energy consumption. They amount to between 10% and 20% of the average retail tariff, varying by retailer. In Queensland, customers can opt for a demand charge during peak periods in summer, to obtain lower fixed and variable charges.

There are few retailers that offer dynamic tariffs, beyond time-of-use (TOU) options (with day/night tariffs, up to four time periods per day and/or seasonal differentiation). Network charges account for around 30% to 40% of the average residential bill. Since 2014, the AEMC has required DNSPs to set more cost-reflective distribution network tariff structures to reflect better individual consumers' grid usage and encourage retailers to offer TOU tariffs. As explained above, TOU tariffs and advanced network tariffs are limited by the large presence of manually-read accumulation or interval meters. These meters are provided by the DNSPs as a regulated service. Only in Victoria, nearly all customers have a smart meter: the Victorian government committed to the Advanced Metering Infrastructure Programme in 2006, and the roll-out was largely completed by December 2013.

A newly implemented rule introduces competition in metering services and removes the current role of DNSPs in providing meters for residential and small business customers. Retailers, instead, become responsible for arranging metering services. The new rule requires that all new meters are capable of delivering a set of minimum services, such as remote reading, connection and disconnection. The new metering rules will increase visibility and control, and are expected to result in improved system operation as well as, possibly, more conscious demand management in the residential sector.

Assessment

System integration of variable renewables is a topic of growing importance which encompasses various aspects of the power system. While at low shares of VRE there are low power system concerns, at higher shares, like in Australia, system inflexibility can become a barrier for further VRE expansion.

Blackout events and the role of grid codes

In Australia, system integration of variable renewable energy has received considerable public and political attention, following the blackout in September 2016. The main cause of the blackout was clearly the heavy storm on 28 September, but some blame the renewable generators, too. The loss of the entire system could have been avoided by having in place more stringent operating rules.

As for the role of wind power, plants performed exactly as prescribed in technical standards, but the sequence of events had not been anticipated when the standards were established (rapid sequence of voltage dips). Technical standards and requirements for generators in the NEM are established under the National Electricity Rules (NER) by the Reliability Panel. However, it appears that the current provisions have not been updated since 2010 to account for the rise in the share of generation provided by variable renewable energy (VRE). The NEM market rules are not made explicitly for VRE; rather they apply to all generators (although additional requirements are applied in South Australia through licensing conditions). There are concerns that existing grid code requirements may not be appropriate to facilitate the rising shares of VRE. More precise technical requirements for generators, particularly from VRE, are likely to be necessary to maintain system security. The IEA therefore calls for a systematic and comprehensive review and upgrade of technical standards towards state-of-the-art techniques. Such a review should include the role of decentralised, rooftop solar PV and the possible implications of higher amounts of distributed battery systems from the onset – recognising that Australia may soon find itself as a global leader in this matter.

The implementation of measures to address system stability should *not* be delayed and a pragmatic approach should be taken, given their critical role for system integration and their moderate impact on total system costs. The remedial actions taken by the market operator (mandating two synchronous units to remain online and limiting Heywood interconnector to contain rate of change of frequency (RoCoF)) come at a cost to consumers in the form of higher electricity prices because of higher costs of frequency control ancillary services (FCAS), a result of increased technical constraints and exercise of market power. Having fast-tracking wind plants in Australia to provide FCAS is a priority.

The ongoing process of reforming system service products (including inertia, fast frequency response) is commendable, including the staged approach on FCAS, and should be pursued as quickly as practically possible. Any new market rule should duly consider the difficulties in establishing a market for highly specific system services, which inherently suffer from low liquidity and possibly high transaction costs, which may outweigh the theoretical benefit of establishing a market mechanism.

Improving market design and system operations

While the immediate dominance of stability-related considerations (e.g. system inertia) in the current debate on renewables integration is understandable, this may divert attention from economically more impactful measures. Indeed, a longer-term and structural approach towards the cost-effective integration of large shares of VRE, including improving resource adequacy and flexibility of the NEM, is critical in order to manage the integration of renewable energy in a manner that also improves the benefits for consumers and avoids the negative impact on consumer bills.

Centralised resources

Australia has an ageing black and brown coal power-plant fleet (see Chapter 4 on Electricity). Not all plants will be able to cope with a more flexible operating pattern and it is likely that a significant number of plants will exit the market in the coming two decades. Reliable integration of VRE will require that a sufficient level of dispatchable and flexible capacity remains available. Instruments to manage the exit of a legacy plant from the market or to maintain required generation online should be considered to facilitate the transition.

The design of wholesale power markets has a critical role to play in ensuring reliable system operation along the three time frames of resource adequacy, flexibility and stability. Market operations also have a critical impact on making technical flexibility potential available in practice.

In the NEM, generators are dispatched in quasi-real time (five minutes before actual generation) via a reoptimisation that takes into consideration an array of economic and technical factors. Quasi-real-time dispatch enables adjustment to short-term fluctuations in weather conditions, and allows effective dispatch of VRE generators. The increase in temporal resolution for commercial settlement (from 30 minutes to 5 minutes) appears to be an appropriate instrument to level the playing field for flexible resources to join the market, including aggregators of battery storage systems.

Large shares of wind and solar generation increase the variability and uncertainty in the supply/demand balance a few hours ahead. This may challenge market paradigms that only provide price signals very close to real time, such as the NEM. More specifically, it may be prudent to investigate the effectiveness of the current pre-dispatch and market notice mechanisms in the face of larger shares of wind and solar generation. In other IEA member countries, measures have been implemented to protect the system from wind ramping events, such as the one that occurred in South Australia on 8 February 2017.

The system operator needs to be given the powers to intervene in the market in a timely and proportionate manner in order to avoid possible security of supply challenges. It is prudent that AEMO's rights are being further strengthened in this regard; the introduction of "protected events" is a first step in the right direction. As explained in Chapter 4 on Electricity, the reserve trader function of AEMO and its market notices could be improved towards a safety-net function.

The locational value of energy can also be reflected in the renewable energy support scheme design. The Council of Australian Governments (COAG) already has experience in harmonising renewable energy support policies. A harmonisation effort to introduce locational value in the support policies would benefit the Australian power system by stimulating the deployment of VRE power plants in a system-friendly manner.

Distributed resources

Future uptake of distributed resources in Australia, in particular solar PV, can be expected to cement the country's position as a global leader in the field. Indeed, AEMO projections for South Australia expect distributed solar PV alone to exceed demand from residential and commercial segments in less than ten years; according to the Commercial; Scientific and Industrial Research Organisation (CSIRO) and Energy Networks Australia estimates, up to 30% to 50% of annual electricity consumption could be supplied from residential PV systems by 2050 (ENA/CSIRO, 2017). ENA/CSIRO

consider that such a transformed energy system would also reduce the cumulative total expenditure of AUD 101 billion by 2050 and avoid AUD 16 billion of network infrastructure investment.

As has been experienced in other countries, this may happen considerably earlier if solar PV and battery economics continue on their current favourable trajectory. Given the shift towards greater residential solar PV in the grid and the emergence of new business models, the role of the distribution network service provider is bound to change.

If well managed, this increase can bring reliability benefits for the Australian power system. Decentralised resources also allow citizens and small and medium-sized enterprises to participate directly in power-sector investment thereby opening up new sources of capital that do not need to be paid from customers' bills. However, achieving this positive outcome requires a coherent, structural reform of distribution grids and tariffs in a timely manner. This should be treated as a clear priority by all stakeholders in order not to compromise the reliability of the grid.

The reform of network charges and the smart meter roll-out that is due to occur will allow more conscious demand-side management (DSM) in the residential sector. Smart meters will enable more residential consumers to choose time-of-use tariffs, which can help to bring down demand during peak hours.

Tariffs for grid use will also need to evolve. Payments should not only be based on how many kilowatt-hours are drawn from the grid. Rather, these should reflect the costs that consumers cause to the grid. For example, consuming electricity during times of peak demand in distribution grids should be more costly than during times when there is much spare capacity. Such an approach will also help limiting financial transfers between customers with and without residential PV systems. Under current arrangements, there is a risk that the cost of the grid has to be allocated to less and less energy, in turn increasing grid charges and further encouraging customers to displace grid consumption.

Much closer collaboration between transmission and distribution network service providers and the national market operator will be required to achieve benefit from the opportunity of distributed energy resources in a reliable fashion. AEMO will need to have sufficient real-time visibility and control of generation assets, including distributed rooftop systems, if their penetration continues to grow on the system. Current arrangements should be reconsidered in light of the rapidly changing situation. An array of emerging innovative technologies on the supply and demand sides, including smart technologies, flexible resources and resource-efficient technologies, can facilitate a more flexible, reliable and affordable power system.

Wind and solar power plants can also actively participate to their own integration into the system. The basic principle behind such 'system-friendly' deployment is to put in place market signals or regulation that optimises the location and technology mix of wind and solar. Current support policies have led to a very strong geographic concentration of renewable energy capacity, in particular in South Australia. Many technical problems surrounding grid integration could have been avoided if deployment had been done in a more geographically diversified way; Australia's resource endowment and low population density likely provide alternative sites at only marginally higher generation costs. The evolution of market, policy and regulatory frameworks should take this aspect into account for future capacities.

Some price-setting mechanisms for residential photovoltaic feed-in tariffs consider the system value of the energy. These considerations may be applied on a broader level for the procurement of renewable energy; also on a large scale. Storage and demand response can both improve the temporal match between VRE supply and demand. In the current discussion, electricity storage – including large-scale batteries and pumped hydro – feature quite prominently. Strikingly, demand-side response options had received little attention in Australia until the South Australia Black System event. Demand response is still at low levels in Australia, the NEM does not have any at the wholesale level. Experience from other countries shows that demand-response potential can be mobilised cost-effectively, going beyond traditional interruptible supply contracts.

Demand response enabled by thermal energy storage can be a cost-effective flexibility option, in particular in the face of growing shares of solar PV on the system. The reliable availability of solar PV on hot days allows charging the thermal storage (including for water heating) and provides continued cooling during and after sunset. Relevant funding entities in Australia (ARENA, Clean Energy Finance Corporation) may foster the uptake of these options as a priority.

Planning

Grid planning is a central pillar of grid integration in all countries that are successfully managing high shares of VRE. The reason for this is that sequential, marginal improvements to the grid may fail to minimise long-run system costs. The AEMO National Transmission Network Development Plan is a long-term forward-looking document. It highlights investment opportunities in support of future system management, taking into consideration local transmission service providers' plans and key stakeholders' considerations. However, there is no nationally integrated planning of the transmission network in Australia outside the economic regulation of individual transmission investments by the market regulator AER under the Regulatory Investment Test for Transmission (RIT-T) and the Regulatory Investment Test for Distribution (RIT-D). The current practice of the RITs takes a conservative approach, aimed at avoiding and reducing capital expansion investments in new networks in favour of other options. AER's decisions have been challenged by the network companies through the limited merit reviews, which illustrates the limits of the current network planning. The current regulatory system (that does encourage CAPEX) is bound to lead to system-wide suboptimal outcomes and increase overall cost to consumers. As explained in Chapter 4 on Electricity, a reform of network regulation is fundamental to the the integration and affordability of renewable energy sources. Australia should consider the introduction of output-based regulation to reflect the growing requirements imposed on grid companies and move to an energy-system wide planning across the NEM.

For example, Chile has recently changed its planning regime by passing a new transmission law, recognising the importance of co-ordinated planning for least-cost system development. Similar measures have been put in place as part of the Mexican electricity sector reform. ERCOT in Texas designated Competitive Renewable Energy Zones, and decided to socialise the cost to develop the transmission, and to connect these zones ahead of construction of wind plants. It is worth noting that all three jurisdictions either have a very strong commitment to competitive electricity markets (Chile, Texas) or have implemented very ambitious reforms for their introduction (Mexico). The European Ten-Year Network

Development Plan (TYNDP) is an example of functional medium-term grid planning across 28 and more EU jurisdictions with a European cost-benefit assessment against a range of political priorities and energy and climate goals.

Recommendations

Through the COAG and the NEM market bodies, the government of Australia should:

- Ensure the review and effective implementation of all technical connection standards needed to reflect power system needs at high shares of wind and solar PV generation. Ensure the appropriate inclusion of rooftop solar PV systems and electric batteries in such standards.
- Develop the scope of ancillary services, whether procured through markets or regulated, so as to ensure system reliability, especially during periods of high wind and solar PV generation.
- Provide the operator AEMO with appropriate powers to intervene in the market in a more timely manner to ensure system security.
- Ensure appropriate co-ordination between the transmission and distribution systems as well as provide sufficient visibility of distributed resources to the system operator AEMO.
- Ensure AEMO can further integrate the planning process of the transmission systems at the NEM level in co-operation with the distribution and transmission network service providers, with consistent scenarios of generation expansion as well as uptake of innovative flexibility options such as demand-side response and energy storage.

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Summary of Part II

Australia is a leading producer and exporter of coal, uranium and liquefied natural gas (LNG), supporting economic growth in Asian markets. While Australia's fossil fuel exports are well committed into the mid-2020s, its domestic markets are in the midst of the energy system transformation. Australia has become a global leader in the deployment of solar rooftop photovoltaic (PV) and is beginning to rapidly deploy large-scale solar and wind power. Power generation from coal has seen a decline. Over five gigawatts of coal-fired generating capacity has closed since 2010 and the ageing fleet, mostly built in the 1970s and 80s is facing more plant closures in the coming decade up to 2030. Amid flat domestic gas production but ramped up exports of LNG, natural gas supply has become tight in the eastern gas market area. As production is more and more unconventional (coal-bed seam gas), natural gas supply has also become more expensive, potentially limiting its capacity to be a transition fuel in the power sector, as already illustrated by the number of mothballed gas-fired power plants. High variable renewable energy (VRE) penetration in some regions where there are lower contributions from conventional power sources has brought about challenges for system integration. More frequent extreme weather events (heatwaves, storms, floods and droughts) impact the system resilience.

Australia's energy system and energy markets are faced with a range of unexpected challenges to manage the energy system transformation. Reliability and affordability concerns have increased across the National Electricity Market (NEM). There is a lack of visibility for business, consumers and policy makers alike as regards the pace and magnitude of the transformation of the energy system unfolding in the coming decade. Existing federal energy and climate policies will need to deliver on these challenges. In June 2017, the COAG Energy Council, endorsing the recommendations of the Finkel Review, acknowledged that the energy market design in the NEM needs to evolve to meet these challenges. However, controversy remains over the design of the future support to low-carbon technologies. The government set out an ambitious target of reducing GHG emissions by 26-28% by 2030 (below 2005 levels), which would translate into a cut of per capita CO₂ emissions by 50% by 2030 and by 65% per GDP across the economy. In 2017, the Commonwealth government is reviewing its climate policies to 2030-50 and measures to implement its pledge under the Paris Agreement.

Given the role of the power sector in emissions, Australia has an opportunity to prepare its electricity system for the energy system transformation. Climate change is an area where government leadership is critical to guide the transition from coal use in power generation to the integration of renewable energy, as well as the future of natural gas supply in the transition. As the energy system transformation is under way, government action to ensure an orderly energy transition becomes vital. A 2050 strategy and an integrated energy and climate policy framework at federal level are essential to boost renewable energy, energy efficiency and other low-carbon technologies.

6. Energy and climate policies

Key data

(2015)

GHG emissions without LULUCF*: 533.3 MtCO₂-eq, +27% since 1990

GHG emissions with LULUCF*: 525.6 MtCO₂-eq, -9.3% since 1990

CO₂ emissions from fuel combustion**: 380.9 MtCO₂, 46.7% since 1990

CO₂ emissions by sector**: heat and power generation 50%, transport 24.9%, industry (manufacturing and construction) 11%, other energy industries 8.6%, commercial and other services 3.1%, residential 2.4%

CO₂ (energy related) intensity per GDP**: 0.36 kgCO₂/USD GDP PPP (IEA average 0.25)

Energy intensity (2016 estimated): 0.120 toe/USD million PPP (IEA average: 0.109) - 13.9% since 2006

TFC: 81.3 Mtoe (oil 52.4%, electricity 22.4%, natural gas 16.6%, biofuels and waste 5.4%, coal 2.9%, solar 0.4%), +13% since 2005.

Consumption by sector: transport 40.0%, industry 34.5%, residential 12.9%, commercial and public services including agriculture, forestry and fishing 12.6%.

TPES (2016 estimated): 132.32 Mtoe (coal 34.4%, oil 32%, natural gas 27%, biofuels and waste 4.1%, hydro 1%, wind 0.8%, solar 0.7%), +12% since 2006

2020 emission reduction target (second commitment period of the Kyoto Protocol): -5% from 2000 levels

2030 emission reduction target (Paris): -26% to -28% below 2005 levels

*Australian Government (2017a), "National Inventory Report 2015", Department of the Environment and Energy, Canberra.

** IEA (2016), CO₂ Emissions from Fuel Combustion 2016, www.iea.org/statistics/.

Overview

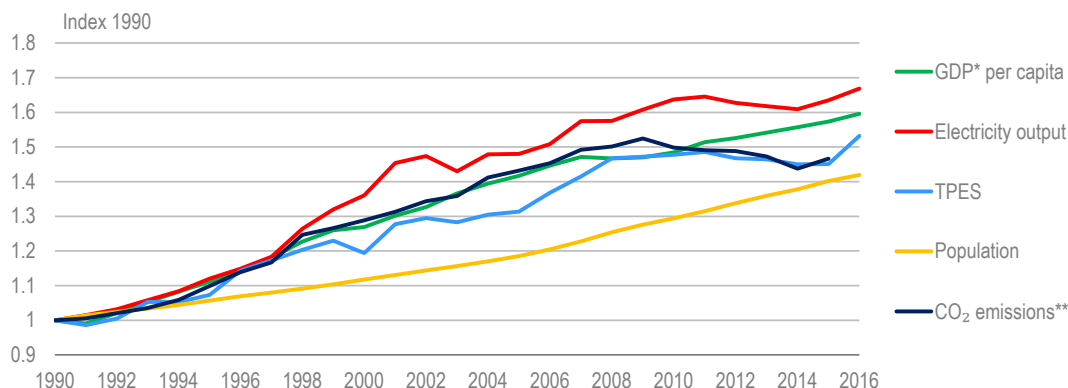
Australia's energy system is undergoing a significant transformation, changing the way energy is produced and used in the economy, impacting on the role of the different fuels and their importance in various sectors. This chapter analyses the drivers of the energy system transformation from domestic and international commitments, including the Paris Agreement, trends in emissions in the country and technology opportunities. This chapter aims to provide guidance on making energy and climate policies fit for the energy system transformation and insights into how energy/climate policy interactions can be managed.

Energy system transformation trends

Australia's economy and population have seen an uninterrupted growth over the past 25 years. Gross domestic product adjusted for purchasing power parity (GDP PPP) per capita grew by 60% between 1990 and 2016 (total GDP grew by 126%) and the population by 40% over the same period (see Figure 6.1).

Total primary energy supply (TPES) increased at a rate between GDP growth and population growth, driving up CO₂ emissions and energy demand. Since the global financial crisis 2008/09, growth rates of GDP energy demand and CO₂ emissions have been slowly decoupling. Total final consumption (TFC) has stabilised since 2012, which illustrates the energy sector transformation, leading to a growth in decentralised renewable energy deployment that decreased demand from the grid. Since a peak in 2009, CO₂ emissions have levelled off, faster than declines in energy intensity (TPES per GDP). Electricity generation has increased more than TPES. The growing share of renewable energy, declining shares of coal and natural gas, contributed to the reduction in carbon intensity of the economy and the decoupling of CO₂ emissions from economic growth.¹ However, recent rebounds suggest the decoupling might not remain a structural change. Higher energy supply and energy production (LNG, mining) in a growing economy, including the higher use of high-carbon electricity is leading to a slight rebound in emissions since 2014.

Figure 6.1 Trends in energy system transformation in Australia, 1990-2016



*Real GDP in USD 2010 prices and PPP.

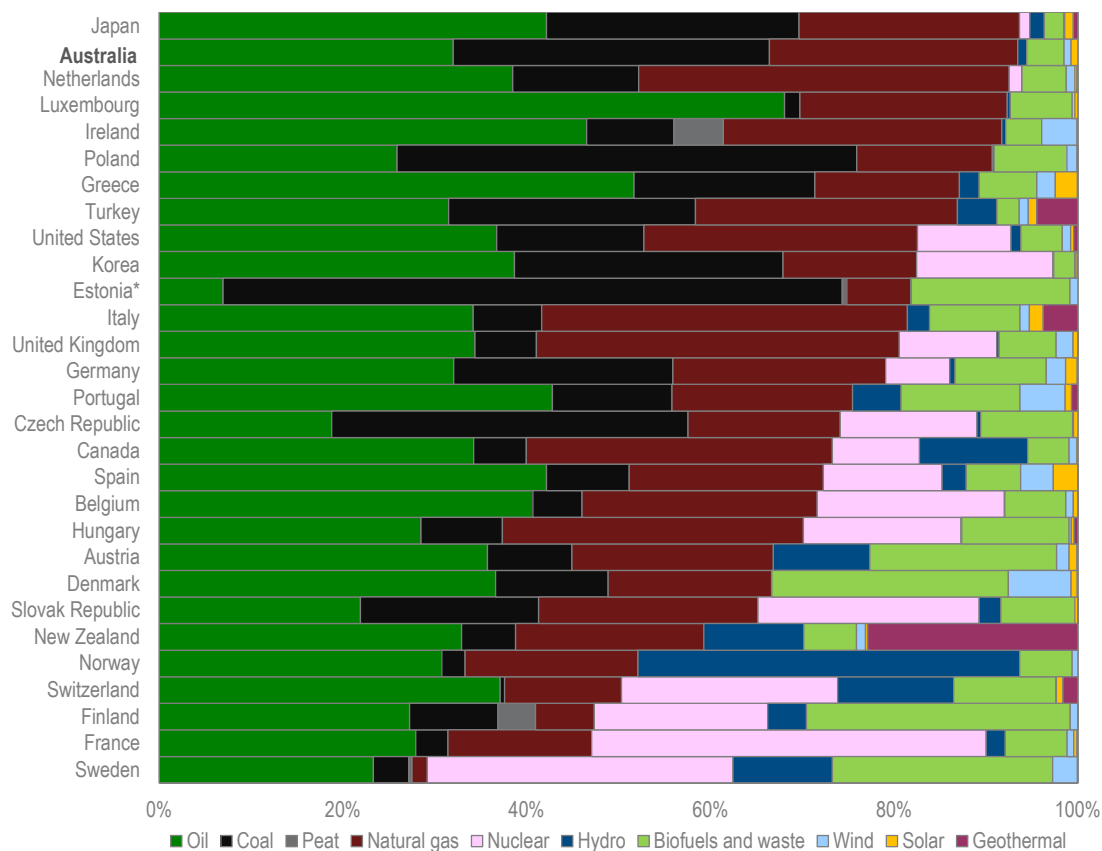
** CO₂ emissions include only energy-related emissions. Data are not available for 2016.

Note: Data are provisional.

Source: IEA (2016), *CO₂ Emissions from Fuel Combustion 2016*, www.iea.org/statistics/.

Australia's share of fossil fuels in TPES was 93.5%, the second-highest after Japan at 93.74%, among IEA member countries in 2016 (see Figure 6.2). The largest renewable energy source was biofuels and waste, accounting for 4% of TPES in 2015, which was the fifth-lowest share, among IEA countries. Wind and solar energy have increased in recent years, but still represent less than 1% of TPES each. Hydropower has continuously accounted for around 1% of TPES for the past decade.

¹ The difference between TPES and TFC can be explained by lower energy use in the transformation sector, mainly as more efficient natural gas power and renewable energy sources have replaced coal in electricity generation.

Figure 6.2 Breakdown of TPES in IEA member countries, 2016

*Estonia's coal is represented by oil shale.

Note: Data are provisional.

Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

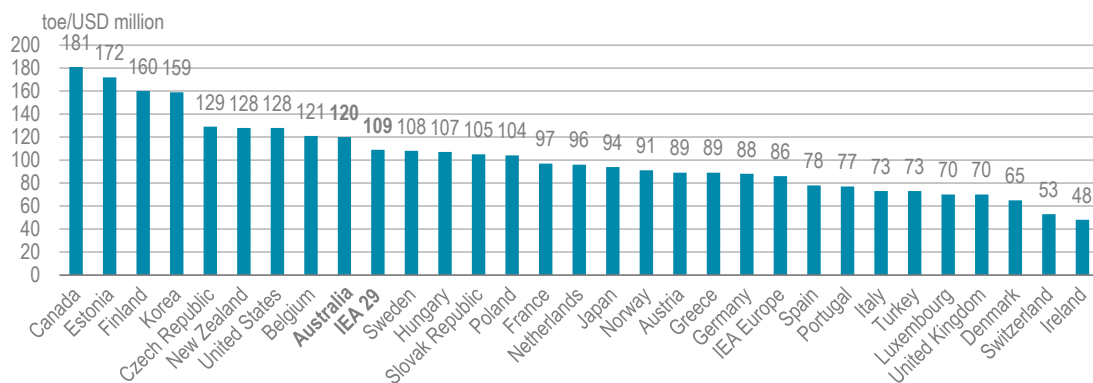
Energy intensity

Australia's energy intensity (TPES per GDP) has been reduced by 14% over the decade 2006-16, slightly less than the 17% decrease in the IEA average, or 17% in the United States and 22% in Japan, as shown in Figure 6.4. The country has the seventh-highest TPES per capita among IEA countries in 2016. With a total supply of 543 tonnes of oil equivalent (toe) per person per year, Australia's population used 22% more primary energy per person than the IEA average in 2016. In terms of energy intensity of the economy, Australia ranks the ninth-highest in the IEA at 120 toe per USD million (in purchasing power parity, PPP), or 10% higher than the IEA (Figure 6.3).

Renewable energy in TPES

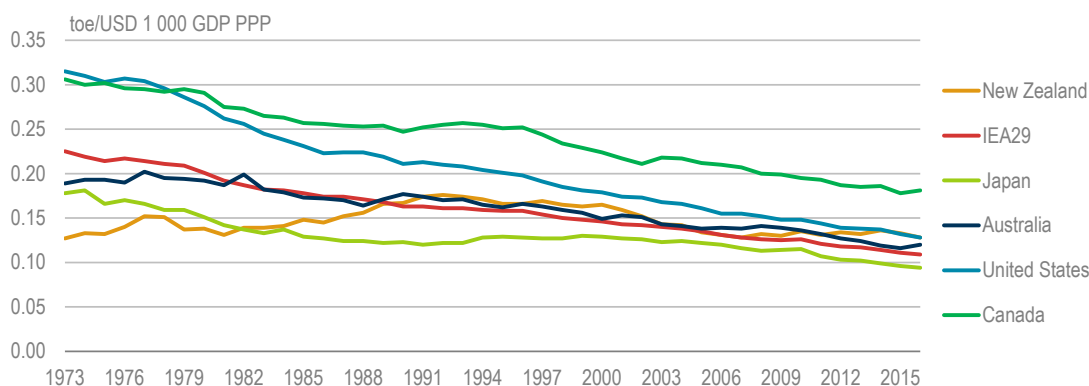
Since 2006, renewable energy in TPES has increased by 28%, as both solar and wind grew more than tenfold. In 2016, solar energy comprised electricity from photovoltaic (59%) and solar thermal generation (41%). Renewables accounted for 6.5% of TPES in 2016, up from 5.7% in 2006. Among IEA countries, only three have lower shares of renewable energy in TPES (Figure 6.4). However, the share of variable renewable energy (VRE) in electricity generation has been growing fast to reach a nationwide share of 7% in 2016 and 40% in South Australia in 2015 (see Chapter 8, "Renewables", and Chapter 5, "System Integration").

Figure 6.3 Energy intensity in IEA countries, 2016



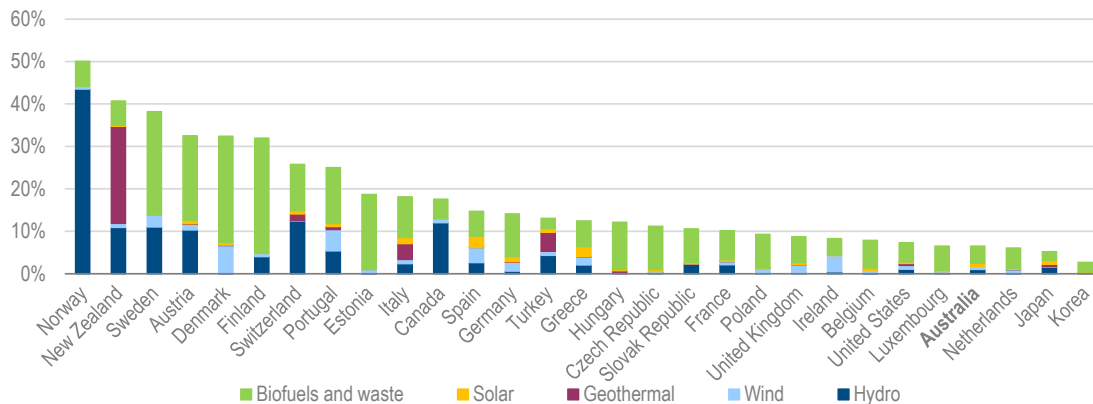
Note: GDP in real USD 2010 PPP prices. Data are provisional for 2016.
 Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 6.4 Energy intensity trends in IEA countries, 1990-2016



Note: GDP in real USD 2010 PPP prices. Data are provisional for 2016.
 Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 6.5 Renewable energy as a percentage of TPES in Australia and in IEA member countries, 2016



Note: Data are provisional for 2016.
 Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

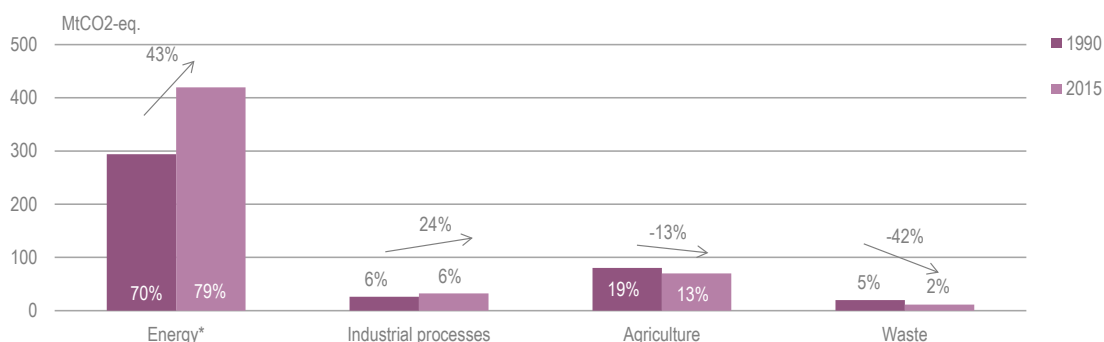
Greenhouse gas emissions in Australia

Greenhouse gas (GHG) emissions were 9% lower in 2015 than in 1990 if including effects of land use, land-use change and forestry (LULUCF). Emissions excluding LULUCF have, on the other hand, increased by 27% over the same period.

Most of this increase stems from the energy sector, including transport and combustion in industry, which accounted for 79% of total emissions (excluding LULUCF) in 2015 (Figure 6.6). Of energy-related emissions, stationary energy installations in electricity generation and industry accounted for two-thirds, transport emissions for 23% and fugitive emissions for the remaining 11%.

Agriculture accounts for the largest share of non-energy-related GHG emissions followed by industrial processes and waste. Non-energy emissions have declined by 10% between 1990 and 2015.

Figure 6.6 GHG emissions by emission source (sector) excluding LULUCF, 1990 and 2015



*Energy includes emissions from transport and manufacturing industries and construction.

Source: Australian Government (2017a), "National Inventory Report 2015", Department of the Environment and Energy, Canberra.

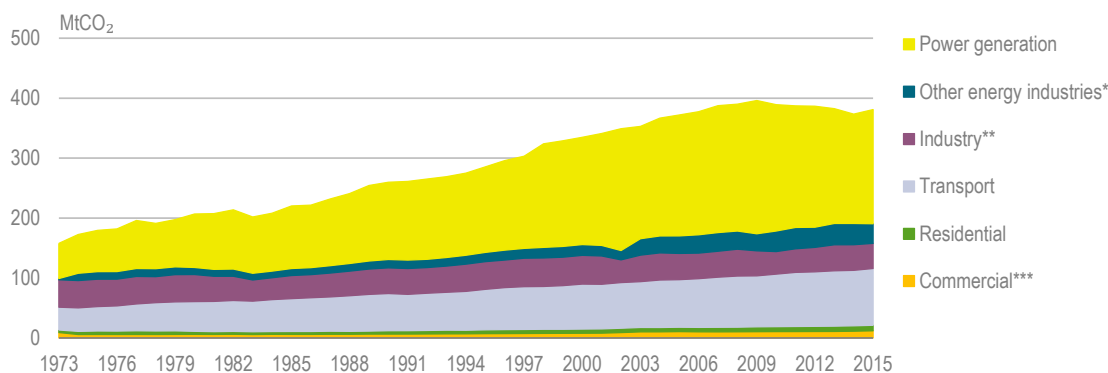
Drivers of GHG emissions in Australia are economic growth and resource development, notably coal mining, oil and gas consumption in industry, but also the fuel needs of a growing population, reflected in increases in passenger and freight transport. Maritime, domestic aviation and road freight transport are critical for Australia's economy. Rail accounts for the largest share in Australia's freight, as most commodities are railed to ports. While fuel combustion in the power sector and industrial processes remains an important GHG source today, coal mining and coal seam gas (CSG) production for LNG production are driving future increases.

In Australia, according to the latest figures available in 2015, methane emissions from natural gas accounted for 356 thousand tonnes of methane, while solid fuels accounted for 1 077 thousand tonnes (kt) of methane and oil production for 4 kt of methane (Australian Government, 2017a). Once the growth in GHG emissions from LNG production and CSG are accounted for in GHG statistics, they are likely to outpace the CO₂ emissions decline due to lower use of coal in power generation, where renewable energy shares are growing and old coal-fired power plants are being shut down.

Energy-related CO₂ emissions

Energy-related CO₂ emissions² increased steadily in Australia until peaking in 2009, at 396 million tonnes of carbon dioxide-equivalent (MtCO₂-eq.) (Figure 6.7) and have decreased by 4% since then to reach 380.9 MtCO₂-eq. in 2015. The most significant emitting sector was power generation, accounting for 50% in 2015, followed by the transport (25%) and industry (11.5%) sectors. In recent years, energy-related CO₂ emissions have stabilised and even declined in per capita terms. However, the total of Australia's energy-related CO₂ emissions remains one of the highest in the IEA.

Figure 6.7 Energy-related CO₂ emissions by sector, 1973-2015³



*Other energy industries includes other transformations and energy own-use.

**Industry includes CO₂ emissions from combustion at construction and manufacturing industries.

*** Commercial includes commercial and public services, agriculture/forestry and fishing.

Source: IEA (2016), *CO₂ Emissions from Fuel Combustion 2016*, www.iea.org/statistics/.

Australia's electricity generation remains heavily reliant on coal combustion and accounted for half the country's energy-related CO₂ emissions in 2015. However, electricity generation has become less carbon intensive, as natural gas and renewable energy sources have increased. Emissions declined by 6% during the decade 2005-15, leading to an overall declining trend of CO₂ emissions in the country. However, coal is still two thirds of the power mix. There is large potential for further emissions reductions in the sector, as the fleet of older coal-fired power plants is expected to retire over the next ten years.

The transport sector is the second-largest CO₂ emitter, accounting for one quarter of energy-related CO₂ emissions in 2015. Transport emissions have increased by 19% in the ten years from 2005. There is little sign of slowing down, as the sector is almost entirely dependent on oil products. Improvements to the efficiency of the vehicle fleet (or in energy intensity of transport more generally) are not keeping pace with rising demand.

² The assessment focuses on energy-related CO₂ emissions, not including other GHG emissions such as nitrous oxide emissions from the agriculture sector or methane leakage from waste landfills or from industrial process. Energy-related emissions include all CO₂ emissions from combustion processes in power generation, transport, industry and other sectors.

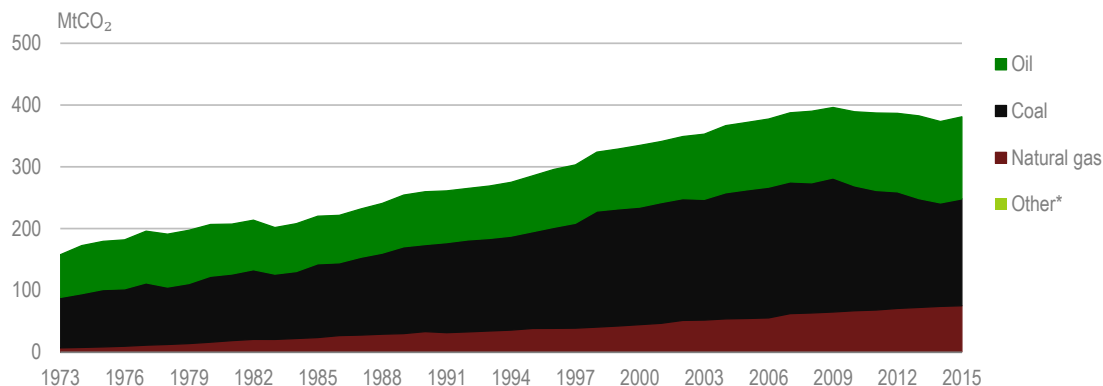
³ Based on the IEA globally collected energy data, the IEA estimates of CO₂ emissions from fuel combustion are a global database obtained from harmonised definitions and comparable methodologies across countries. They do not represent an official source for national submissions, as national administrations should use the best available country-specific information to complete their emissions reporting.

Road transport accounted for 84% of CO₂ emissions in 2015. Domestic aviation has more than doubled in the past decade and accounted for 10% of total transport emissions in 2015. Emissions from international aviation are not included.

Manufacturing and construction industries accounted for 11.5% of total energy-related CO₂ emissions in 2015 and have emitted around 40 million tonnes of CO₂ (MtCO₂) per year for several decades. The largest share of emissions comes from the non-ferrous metals industry and from mining and quarrying. Other energy industries⁴ accounted for 9% of CO₂ emissions, and emissions from the sector have increased with the growth in Australia's energy production. Most emissions from the sector come from oil and gas extraction, but coal mining, LNG plants and blast furnaces are also large emitters.

In terms of emissions by fuel type, coal is the largest source of energy-related CO₂ emissions, accounting for 45% of the total, followed by oil (35%) and natural gas (20%). Coal and natural gas emissions are related to electricity generation. Oil-related CO₂ emissions originate mainly from the transport sector where the growth of activity is the main reason for an increasing share of oil in total emissions. This is linked to diesel use in mining and the absence of fuel efficiency standards in the sector.

Figure 6.8 Energy-related CO₂ emissions by fuel type, 1975-2015



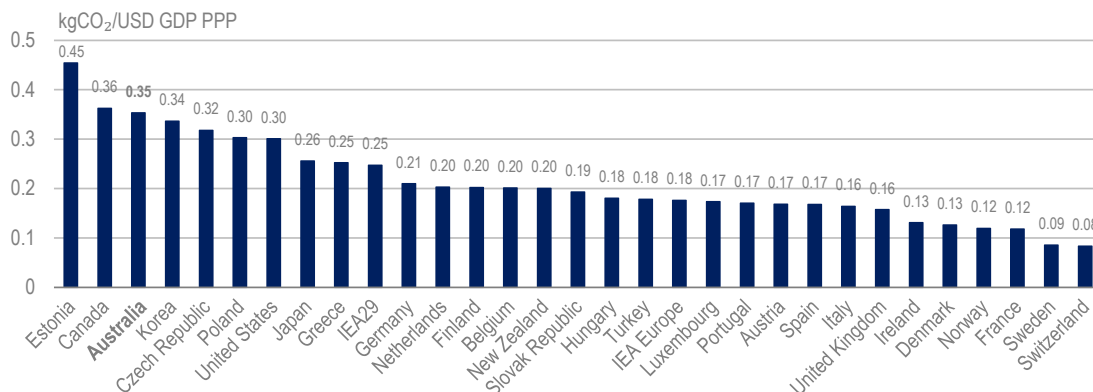
Note: Data for 2015 are provisional.

Source: IEA (2016), *CO₂ Emissions from Fuel Combustion 2016*, www.iea.org/statistics/.

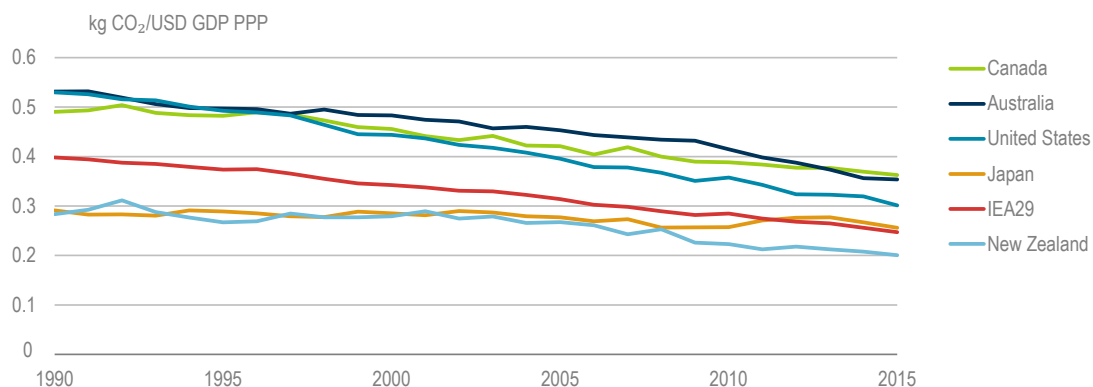
Carbon intensity

Despite the recent decoupling between economic growth and CO₂ emissions, Australia's carbon intensity is the third-highest among all IEA member countries, behind Estonia and Canada (Figure 6.9). In 2015, Australia emitted 0.36 kgCO₂ per USD/GDP PPP, which was a reduction by 22% from 2005. Australia still stands out in terms of CO₂ intensity in electricity generation (Figure 6.10), with the highest among all IEA member countries and almost twice as high as the IEA average (see Figure 4.4. in Chapter 4 on Electricity). As the share of natural gas and renewable energy sources increased, the CO₂ intensity of electricity generation has been reduced by 15% since 2005, despite a recent rebound. This trend is consistent with other IEA member countries, where a declining trend can also be seen. The IEA average carbon intensity was 0.25 kgCO₂ per USD/GDP PPP.

⁴ Other energy industry own -use includes emissions from fuel combusted in oil refineries, for the manufacture of solid fuels, coal mining, oil and gas extraction and other energy-producing industries.

Figure 6.9 Energy-related CO₂ emissions per unit of GDP in IEA member countries, 2015

Source: IEA (2016), *CO₂ Emissions from Fuel Combustion 2016*, www.iea.org/statistics/.

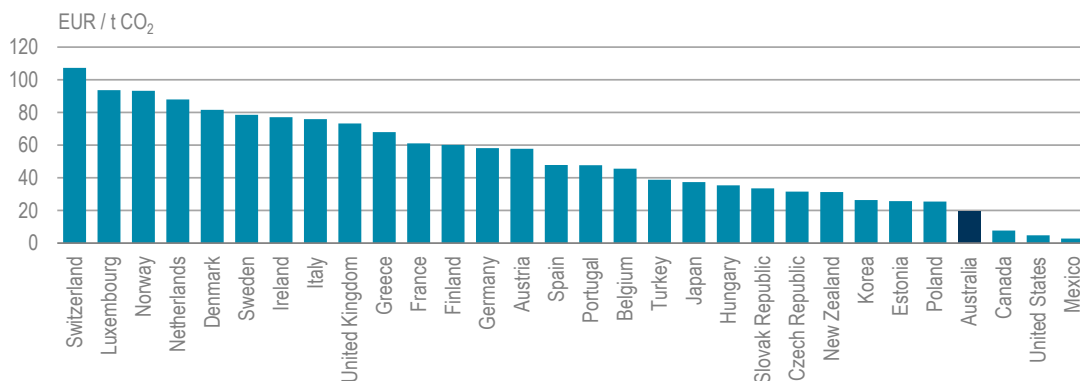
Figure 6.10 Energy-related CO₂ emissions per unit of GDP in Australia and in other selected IEA member countries, 1990-2015

Source: IEA (2016), *CO₂ Emissions from Fuel Combustion 2016*, www.iea.org/statistics/.

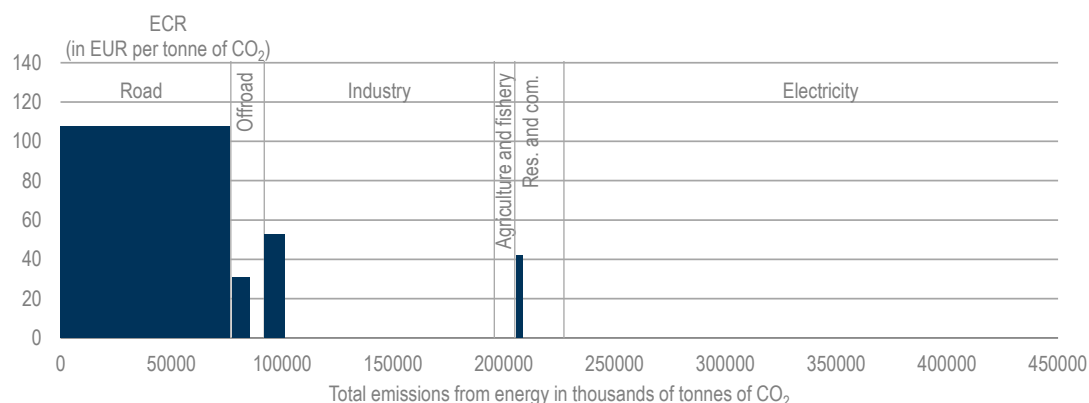
Effective carbon rates

In 2012, Australia had the third-lowest tax rate on energy use on an economy-wide basis among IEA countries, at EUR 19.6 per tonne of CO₂ (tCO₂) from energy, compared to EUR 52.9 per tCO₂ on a simple-average basis across the 29 IEA countries. In 2012, Australia had higher average tax rates on transport fuels (EUR 6.58/GJ) than on fuels used for heating and process purposes (EUR 0.35/GJ) or electricity generation (EUR 0/GJ)⁵. While the bulk of energy-related CO₂ emissions stem from the power sector and direct combustion in industry, those sectors are not subject to any effective carbon rate through energy or carbon taxes, or emissions trading systems (ETS), as shown in Figure 6.12 (OECD, 2016).

⁵ The effective carbon rate is the sum of specific taxes on energy use, carbon taxes, and prices of tradable emission permits, where these apply. It is the total price on carbon emissions from energy use resulting from market-based policy instruments (including specific energy taxes that are not explicitly intended as taxes on carbon emissions but that are economically equivalent.). They do not include fiscal effects from the Renewable Energy Target schemes.

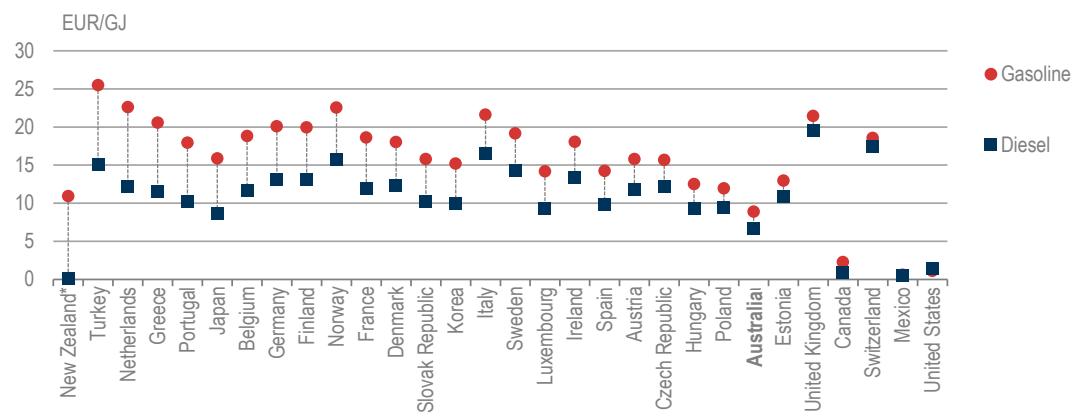
Figure 6.11 Effective tax rates on CO₂ from energy in IEA countries, 2012

Source: OECD (2015), *Taxing Energy Use 2015: OECD and Selected Partner Economies*, OECD Publishing, Paris.

Figure 6.12 Effective carbon rates by sector in Australia

Source: OECD (2016), *Effective Carbon Rates: Pricing CO₂ through Taxes and Emissions Trading Systems*, <http://dx.doi.org/10.1787/9789264260115-en>.

The tax rate on diesel for transport use was EUR 6.7 per GJ and EUR 8.9 per GJ for gasoline which is only 33% higher than diesel, less than in other countries. The difference of tax rates by fuel type was the eighth-smallest among OECD countries.

Figure 6.13 Difference tax rates on gasoline and diesel for road use

*New Zealand is the only OECD country to apply an excise duty to gasoline but not to diesel.

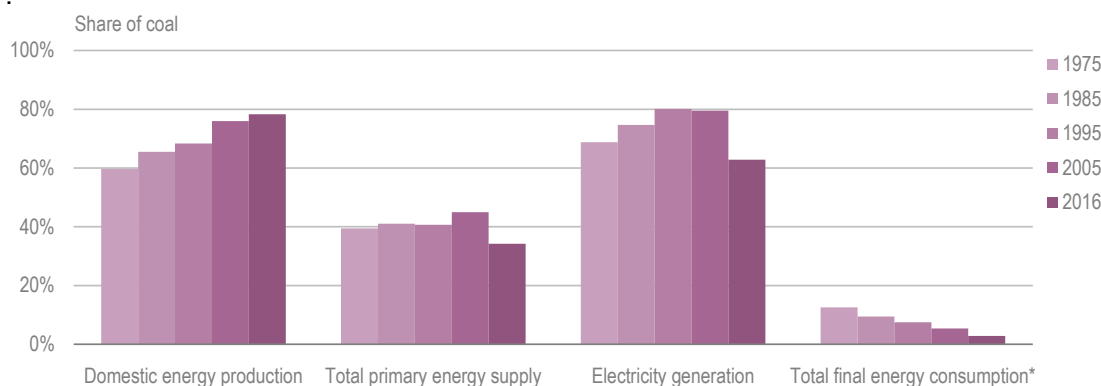
Source: OECD (2015), *Taxing Energy Use 2015: OECD and Selected Partner Economies*, OECD Publishing, Paris.

Australia's coal sector

Australia is the fourth-largest coal producer in the world after the People's Republic of China (hereafter "China"), the United States and India (WCA, 2016). Coal is also the largest energy source, accounting for 34% of TPES and 63% of electricity generation. While the share of coal in electricity generation has declined in the past decade, coal production as a share of total energy production is increasing, as Australia is a major and growing coal producer and world-leading exporter.

Coal production has increased steadily, with the exception of declines in 2011 and 2016. The production reached record levels in 2015. Hard coal accounted for 95% of total production and brown coal for 5%. Domestic coal consumption has been declining since 2009, leading to a drop in overall brown coal production. Hard coal production has increased in step with economic booms in different Asian regions. Japan accounted for the largest share, with 32% of Australia's coal exports in 2015, followed by China (17%), Korea (15%) and India (13%). India is mainly importing coking coal, rather than steam coal.

Figure 6.14 Share of coal in Australia's energy system, 1975-2016

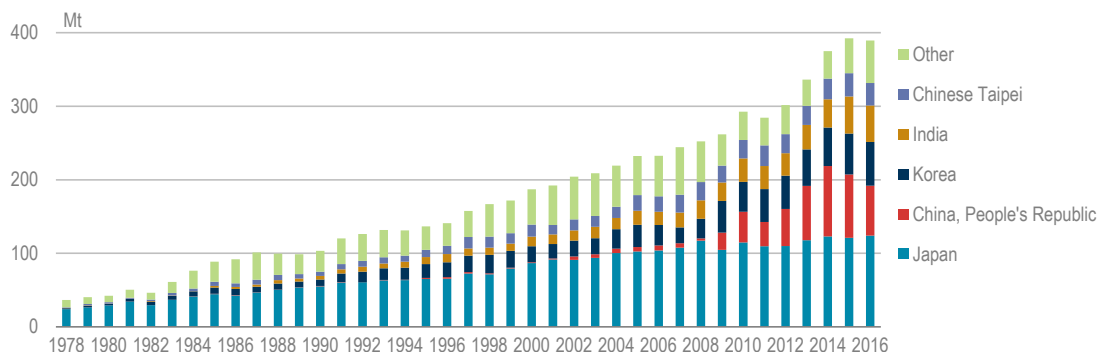


* The latest consumption data are from 2015.

Note: Data are provisional for 2016.

Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 6.15 Coal exports by country, 1973-2016



Note: Data are provisional for 2016 and includes both thermal and metallurgical coal.

Source: IEA (2017b), *Coal Information* (database), www.iea.org/statistics/.

Coal use in the power sector is slowly changing. In 2016, 63% of Australia's electricity was generated in coal power plants, down from 80% ten years earlier. The use of brown coal in power plants peaked in 2009 (see Chapter 4 on Electricity). Since 2010, around 5.1 GW of coal power stations has been retired across the NEM, including Morwell, Anglesea, Hazelwood in Victoria, Playford B and Northern in South Australia, Collinsville and Swanbank B in Queensland, and Redbank, Wallerawang and Munmorah in New South Wales. Australia's coal power plant fleet varies in age (see Table 6.1). There are a few new plants (Bluewaters 1 and 2, Kogan Creek) while most have been operating for around 30 years. Commercial closure decisions entirely depend on the cost of maintenance, safety compliance, and refurbishments, so the economic lifetime will be different from the expected technical lifetime.

In the coming decade, by 2025, old coal-fired power plants are going to shut down (see Chapter 4 on Electricity and Australian Energy Council [2016] see Table 6.1). AGL announced the withdrawal of coal-fired Liddell Power Station (2 000 MW) in New South Wales in March 2022.

Table 6.1 Australia's operating and closed coal power plants

State	Station	Fuel type	Year of commissioning	Announced decommissioning	Age (years)	Capacity (MW)
NSW	Eraring	Black coal	1982-84		32-34	2 880
NSW	Bayswater	Black coal	1982-84	2035	32-34	2 640
NSW	Liddell	Black coal	1971-73	2022	43-45	2 000
NSW	Mt Piper	Black coal	1993		23	1 400
NSW	Vales Point B	Black coal	1978		38	1 320
VIC	Loy Yang A	Brown coal	1984-87	2048	29-32	2 210
VIC	Yallourn W	Brown coal	1975, 1982		34-41	1 480
VIC	Loy Yang B	Brown coal	1993-96		20-23	1 026
QLD	Gladstone	Black coal	1976-82		34-40	1 680
QLD	Tarong	Black coal	1984-86		30-32	1 400
QLD	Stanwell	Black coal	1993-96		20-23	1 460
QLD	Callide C	Black coal	2001		15	810
QLD	Millmerran	Black coal	2002		14	851
QLD	Kogan Creek	Black coal	2007		9	750
QLD	Callide B	Black coal	1989		27	700
QLD	Tarong North	Black coal	2002		14	443
QLD	Yabulu (Coal)	Black coal	1974		42	37.5
QLD	Gladstone QAL	Black coal	1973		43	25
WA	Muja	Black coal	1981, 1986		30-35	1070
WA	Collie	Black coal	1999		17	340
WA	Bluewaters 1	Black coal	2009		7	208
WA	Bluewaters 2	Black coal	2010		6	208
WA	Worsley (Alumina)	Black coal	1982-00		16-34	135

Total operating plants						25 073.5
NSW	Munmorah	Black coal	1969	July 2012	43	600
NSW	Redbank	Black coal	2001	August 2014	13	143.8
NSW	Wallerawang C	Black coal	1976-80	November 2014	38	1 000
VIC	Morwell	Brown coal	1958-62	August 2014	52-56	189
VIC	Anglesea	Brown coal	1969	August 2015	46	160
VIC	Hazelwood	Brown coal	1964-71	March 2017	45-52	1 600
QLD	Collinsville	Black coal	1968-98	December 2012	14-44	180
QLD	Swanbank B	Black coal	1970-73	May 2012	42	500
SA	Northern	Brown coal	1985	May 2016	31	546
SA	Playford	Brown coal	1960	May 2016	56	240
Total closed plants						5 158.8

Climate change mitigation

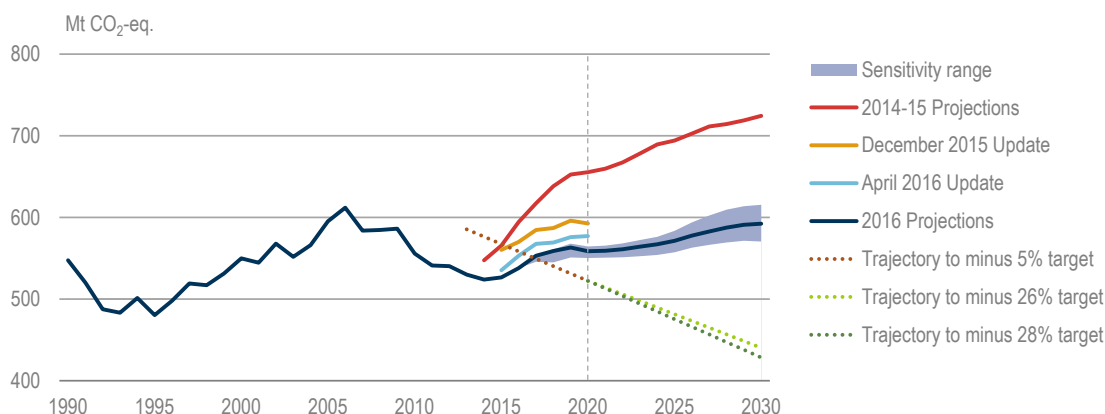
Australia is a party to the United Nations Framework Convention on Climate Change (UNFCCC), the Kyoto Protocol, the Doha Amendment (establishing a second commitment period of the Kyoto Protocol) and the Paris Agreement which Australia ratified on 10 November 2016.

With regard to climate targets up to 2020, the government estimates that the country can meet the Kyoto target by a margin of 224 million tonnes of carbon dioxide-equivalent (MtCO₂-eq.) or 5%. The carbon budget for the period 2013 to 2020 is 4 432 MtCO₂-eq., while projected emissions for the period are 4 353 MtCO₂-eq. As energy-related CO₂ emissions have increased by almost 47% since 1990, emissions reductions were mainly achieved by reductions in other sectors, notably in deforestation, that have offset the growth in energy emissions. After 2020, under projected economic growth, emissions are likely to rise to 592 MtCO₂-eq. in 2030 from 559 MtCO₂-eq. in 2020.

Up to 2030, Australia's Nationally Determined Contribution (NDC) envisages an ambitious reduction in GHG emissions by 26% to 28% below 2005 levels. This translates into a total cut from 597 MtCO₂-eq. in 2005 to 430 or 442 MtCO₂-eq in 2030. This is equivalent to a reduction of 50% of per-capita CO₂ emissions and to a reduction of emissions intensity of the economy of 64%-65% during the period 2005-30 (Australian Government, 2015b). Australia adopted a target range of cumulative emissions given the uncertainty about future demand:

- 990 to 1 055 Mt of emissions reductions needed between 2021 and 2030
- 842 to 1 202 Mt of emissions reductions needed with the sensitivity range.

Emission projections have been substantially revised downwards over the past, because of factors such as lower-than-expected demand for electricity, the global financial crisis and faster than expected technology changes.

Figure 6.16 Historic and projected CO₂ emissions in Australia

Source: Australian Government (2017a), "National Inventory Report 2015, the Australian Government Submission to the United Nations Framework Convention on Climate Change", Department of the Environment and Energy, Canberra.

Climate-change and carbon-pricing policies remain controversial, short-term and subject to frequent political change in Australia. Historically, carbon mitigation instruments have lacked bipartisan support. With a view to meeting the Kyoto target, the Australian government proposed its Carbon Pollution Reduction Scheme in 2009, which however was rejected by the Senate. The government then chose not to re-introduce the bill in 2010, but to adopt a carbon price linked to an emissions trading scheme under the *Clean Energy Act* in November 2011. This fixed carbon-pricing mechanism applied to Australia's biggest emitters from 2012 to 2014, but the Abbott government repealed the carbon pricing in 2014 and enacted the *Clean Energy Legislation (Carbon Tax Repeal) Act 2014*. As part of the Clean Energy Future Legislative Package, four new institutions were created: the Australian Renewable Energy Agency (ARENA), the Clean Energy Finance Corporation, the Clean Energy Regulator and the Climate Change Authority.

This stop-start nature of emissions reduction policy in the electricity sector over the past decade has limited the ability of the energy industry to take investment decisions in new generation assets, resulting in higher electricity prices. This has led to a marked shift in the public discourse around energy and emissions policy. Where previously the discourse was focused on a trade-off between energy affordability and security versus introducing the emissions reduction policy, the need for a stable and credible emissions reduction policy is now seen as a necessary pre-condition to achieving energy affordability and security. The Finkel Review into energy security (see Box 4.4 in Chapter 4) recommended that, to improve energy security and make it affordable, Commonwealth, state and territory governments agree to a national emissions reduction trajectory and implement a Clean Energy Target.

With the objective of designing climate change policies for meeting the Paris Agreement, the Australian government is conducting a review of its climate change policies during 2017. Public consultation on a discussion paper was carried out during March and May 2017 as part of the review. The government is considering opportunities and challenges in reducing emissions sector by sector; the impact of policies on jobs, investment, trade competitiveness, households and regional Australia; how to integrate climate change and energy policy, including the impact of

state-based policies for achieving an effective national approach; the role and operation of the Emissions Reduction Fund and its Safeguard Mechanism; complementary policies, including the National Energy Productivity Plan; and the role of research, development and innovation as well as the possibility to use credible international units in meeting Australia's emissions targets; and to adopt a potential long-term emissions reduction goal post-2030. The current government indicated that it does not intend to include carbon pricing into the future options of the climate policy mix nor does the government review of climate change policies include a discussion of the Renewable Energy Target (RET), whereas the LRET stops increasing in 2020 (but projects can still earn certificates up to 2030).

Several options for a new mechanism to reduce emissions in the power sector have been discussed. In 2016, the special review by the Climate Change Authority (CCA, 2016) recommended tailor-made policy packages by sector, departing from an economy-wide approach, with a continuation of the RET, and the emissions intensity scheme for the power sector and emission standards for light vehicles in transport, and the use of the Emissions Reduction Fund (ERF) to mitigate emissions from industrial processes, agriculture, fugitive sources and direct combustion. The Australian Energy Market Commission and the Climate Change Authority presented a joint report with focus on the power sector, as input into the government climate change review in June 2017. However, the government ruled out the emission intensity scheme (EIS), which was recommended by the Climate Change Authority and the Australian Energy Market Commission (AEMC, 2016).

In its 2017 report, the CCA and AEMC proposed a Low Emission Target (LET) combined with a National Energy Saving Scheme and Demand Management Measures (CCA/AEMC, 2017). The Finkel Review proposed the Clean Energy Target (CET) (Finkel et al., 2017), modelled as a technology-neutral target with an emission benchmark of 600 gCO₂/kWh to drive investment in renewable energy and natural gas at lower electricity prices than the emission intensity scheme or a 50-year lifetime limit for coal plants. A number of submissions to the 2017 Review of climate change policies came out in favour of carbon pricing or a market mechanism.

In October 2017, the Energy Security Board proposed the national energy guarantee scheme (NEG) to be considered by COAG Energy Council in April 2018 and introduced by 2019 (Australian Government, 2017c). With a view to ensure electricity security, affordability and emissions reductions through one joint scheme, the NEG intends to propose an obligation on energy retailers to contract capacity to meet two objectives:

- i)* A reliability guarantee which will set the level of dispatchable energy (based on technology neutrality) in each state.
- ii)* An emissions guarantee which will be set to contribute to the international climate commitment of Australia and its 2030 NDC.

The details are still to be worked out, notably the level of the reliability standards in each NEM region (to be developed by AEMC and AEMO) and the level of acceptable emissions reductions from the power sector (to be determined by the government and enforced by the regulator AER).

Box 6.1 The Paris Agreement

Under French Presidency of the 21st Conference of the Parties (COP21) negotiations of the United Nations Framework Convention on Climate Change (UNFCCC), the Paris Agreement on Climate Change was reached in December 2015 by 197 Parties, thus marking a milestone in global climate change efforts.

The Paris Agreement is the first-ever global climate deal with obligations for all Parties. It is based on several key elements:

- overall objective to limit the global average temperature rise to well below 2°C and pursuit of efforts to limit the temperature increase to 1.5°C
- aim to reach global peaking of GHG emissions as soon as possible and to undertake rapid reductions thereafter, so as to achieve a balance between emissions and removals in the second half of this century
- self-determined actions by Parties to reduce emissions outlined in their nationally determined contributions (NDCs), to review 2030 NDCs by 2020 and a commitment to present new NDCs every five years thereafter
- a common framework (with flexibility for countries that need it) to track progress towards and achievement of NDCs for all countries on the basis of a robust transparency and accountability system
- periodic collective stock-taking of progress toward the long-term aims of the Agreement (the “global stocktake”)
- other outcomes of COP21 besides the adoption of the Paris Agreement were:
 - launch of Mission Innovation and the Breakthrough Energy Coalition and support for accelerating technology innovation
 - highlighting the role of cities, regions and local authorities, but also of non-governmental stakeholders in supporting climate change mitigation and adaptation
 - encouraging countries to develop long-term low-emissions development strategies.

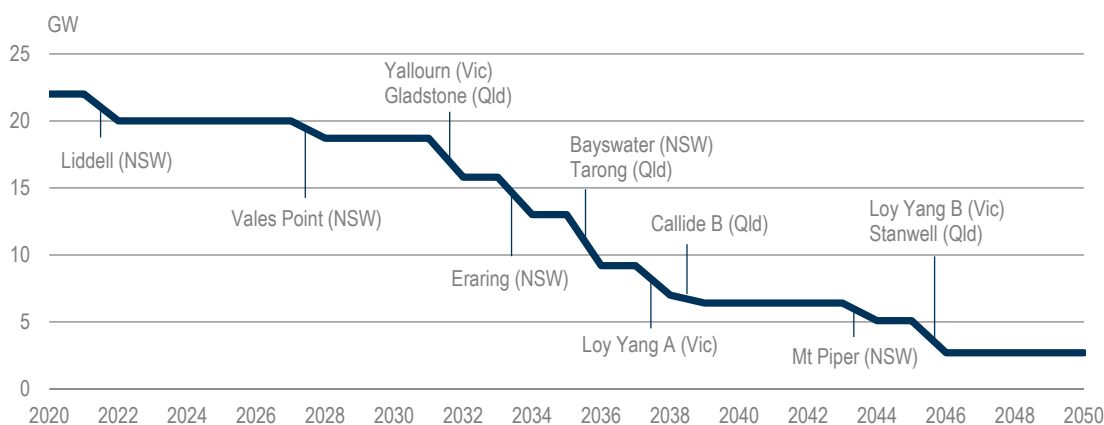
Since the signature of the Agreement in New York in April 2016, parties joined the Agreement according to their own legal systems (through ratification, acceptance, approval, or accession). Australia ratified the Paris Agreement on 10 November 2016. On 4 November 2016, the Agreement entered into force, after the threshold was reached of at least 55 Parties joining which together represent at least 55% of global GHG emissions. By the time of writing, 174 out of a total of 197 Parties have ratified.

Long-term energy and climate scenarios

Given its high carbon intensity, Australia’s power sector is playing a key role in the energy system transformation. A low carbon power system will also open the door to low-carbon electrification of energy use in the building and transport sectors. The Australian Government and the Australian Energy Market Operator (AEMO) assume a

steady decline in the use of coal in power generation up to 2035 (Figure 6.17) under a business-as-usual scenario. The power industry has already retired large capacity, as discussed in detail above, and some energy suppliers have announced plans to phase out coal by 2050 (AGL, 2017).

Figure 6.17 NEM coal capacity and closures



Source: IEA analysis based on an expected 50 year technical lifetime.

The CSIRO released in 2017 the *Low Emissions Technology Roadmap* (CSIRO, 2017) which examines four alternative technology pathways that could help achieve Australia's emissions reduction target to 2030, and further emissions reductions in later years. Four technology pathways are explored (energy productivity plus, variable renewable energy, dispatchable power and an unconstrained pathway). They analyse technology, markets and social acceptability risks. CSIRO concluded that ambitious improvements in energy productivity allow more time for a smooth transition and that progress in multiple pathways provides more flexibility for Australia to reduce the risks in having suboptimal outcomes with regard to affordability, security/reliability or sustainability.

Energy data (notably end-use and GHG emission data) are the basis for sound energy sector planning and long-term scenarios. The Clean Energy Regulator is in charge of the National Greenhouse Gas and Energy Reporting Scheme (NGERS), as outlined in Chapter 1 on General Energy Policy. Companies report energy use, emissions and production data down to the facility level (i.e. with geospatial co-ordinates). However, the data are not fully made available in a publicly accessible way. Under the previous Energy Efficiency Opportunities (EEO) programme, companies had to report publicly on their energy use, savings identified and implemented at facility or division level. Efforts are ongoing to ensure better demand data for energy planning purposes. The government, through CSIRO has been developing an Energy Use Data Model to improve data linking, analysis and modelling, and to foster energy market forecasting that will improve energy management, demand profiles and infrastructure planning.

Australia will have to develop a mid-century low carbon strategy, as foreseen under the Paris Agreement on Climate Change. A government strategy for 2050 will be able to build upon the Low Emissions Technology Roadmap and has to go beyond to identify emission reduction goals by sector. Many IEA countries have already implemented such low carbon development strategies and Australia can take the lessons learnt from these experiences, as shown in Box 6.2.

Box 6.2 Emissions reduction policies for power sector decarbonisation

IEA member countries' experience shows that government and regulatory actions are warranted to assist the transition to a low-carbon economy by providing a guiding framework for an orderly energy transition.

Most governments have adopted GHG emission reduction targets for 2030, and a number of major economies have released long-term, low GHG emissions development strategies. Many countries have integrated energy and climate strategies or adopted legally binding energy transition frameworks (France, Germany), carbon budgets (United Kingdom, France) and carbon price trajectories in energy taxation (France). Legal frameworks are useful as they provide long-term legal certainty across electoral cycles and address litigation and legal issues around decommissioning and compensations of old infrastructure, like power plants (either it coal or nuclear).

At the global level, carbon pricing based on emissions trading schemes (ETS) applied to both the power and energy-intensive industries are spreading (European Union, China, Canada, California, South Korea; in New Zealand where the transport sector is also included). In terms of technology choice and support, China, India, and Japan promote cleaner high efficiency low emission (HELE) power plants as key components in their energy mix to ensure energy security and reliability; others support new nuclear energy for their energy transition (China, United Kingdom, Hungary), while others implement nuclear phase-out policies (Germany, Switzerland).

With regard to the transition of the coal use in power generation, among IEA members, several countries have opted for regulatory certainty and adopted non-market solutions, including phase-out policies and/or emission performance standards that de facto ban new coal-fired power plants if not equipped with carbon capture and storage. In 2017, France announced the closure of all remaining coal-fired power plants or their replacement with less polluting options by 2022. Canada has in place an elaborated emission performance standard at federal level, which is legislated on the basis of equivalency agreements with provinces. By 2014, the province of Ontario had phased out coal use in power generation. Other countries have converted coal plants to biomass (Netherlands, Sweden, United Kingdom) or have retired older facilities. At COP23 in Bonn, Canada and the UK have created the "Powering Past Coal" Alliance of countries that aim to phase-out coal use.

Action can focus on reducing air pollution (nitrogen oxides, sulphur oxides) from combustion plants (EU Large Combustion Plant Directive and the Industrial Emission Directive). Besides the regulatory uncertainty around future emission reduction policies, making the case for coal-fired power plant investments risky, such legislation can therefore lead to the closing of coal power plants, even if the legislation does not specifically address CO₂ emissions but addresses air pollutants and other GHG emissions. Some countries have placed coal power plants in reserves (Germany) to ensure their contribution to electricity security if needed. Amid the shale gas revolution in the United States, coal use in power generation has been largely replaced by natural gas use and large-scale renewables, notably wind generation.

As a consequence of the policies and developments mentioned, the share of coal in the power mix is declining in US and Europe in contrast with the global trends. In the United Kingdom, the combination of the high carbon price, the European environmental legislation and the presence of an old fleet has led to the sharp decline of coal in power generation.

Climate change adaptation

Extreme weather conditions have been a historic concern for Australia. As 85% of the Australian population live in coastal areas, the country's infrastructure is vulnerable to impacts from tropical cyclones, sea-level rise, flooding and inundations. At the same time, there are large areas towards the interior with vast exposure to droughts and bush fires. Several states have developed specific programmes to combat natural disasters. For example, in response to recommendations by the 2009 Victorian Bushfire Royal Commission, following the Black Saturday bushfires, the Victorian government announced a 10-year programme aimed at reducing the risk of bushfires associated with electrical assets without affecting electricity reliability, focusing on both safer assets and safer network operations on days of high fire risk.

Energy Networks Australia (ENA) developed a *Climate Risk and Resilience Manual* with industry-specific methodology and tools to support network operators in managing climate risk and resilience across core network business activities and ensure consistency in factoring climate change risk in future network investment decisions. The National Climate Change Adaptation Research Facility (NCCARF), hosted by Griffith University, Queensland, has been supporting climate change analysis and resilience. In the 2017/18 Budget, the Australian government announced a new partnership bringing together the expertise of NCCARF and the CSIRO, to support the provision of authoritative information and guidance to help governments, businesses and the broader community manage their climate risks.

Building upon the National Climate Change Adaptation Framework, agreed by the COAG in 2007, the Australian government adopted a National Climate Resilience and Adaptation Strategy in 2015. It covers a range of adaptation and resilience initiatives across several sectors, including coasts, cities and the built environment, agriculture, forestry and fisheries, water resources, natural ecosystems, health and well-being, disaster risk management and a resilient and secure region. The action plan for the identification of risks and their management has not yet been presented. The Queensland government in 2017 released a Climate Adaptation Strategy to ensure land use development and planning policy to promote energy efficiency, integration of transport, land-use planning and policies that support renewable energy technologies.

The responsibility for protecting critical infrastructure is shared between owners of vulnerable infrastructure and operators, the Commonwealth government and state and territory governments. Australia's Critical Infrastructure Resilience Strategy of 2015 considers the National Electricity Market (NEM) as a critical infrastructure and builds on the existing and cross-sectoral Trusted Information Sharing Network (TISN), established in 2003. The Energy Sector Group (ESG) and related Oil and Gas Security Forum is one of the sector groups that report to the Critical Infrastructure Advisory Council, which advises Australia's Attorney-General on the national approach to critical infrastructure resilience. However, the National Energy Security Assessment (NESA) has not been updated since 2011 and its conclusions and recommendations on power system resilience have not been reviewed.

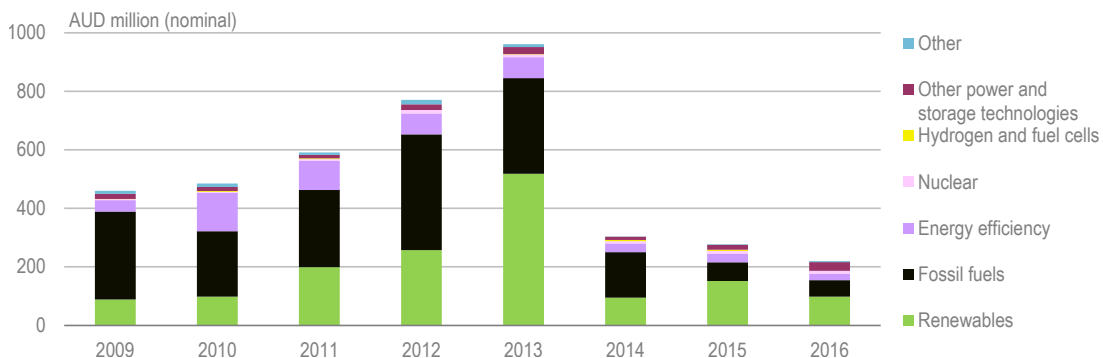
The 2016 electricity blackout in South Australia prompted a range of reviews to identify measures that can promote power sector resilience. In light of the increased severity of extreme weather events, the Finkel Review of June 2017 recommended to the COAG to develop by end of 2018 a strategy to improve the integrity of the energy infrastructure

and the accuracy of supply and demand forecasting. The Finkel review also calls upon the Australian government to regularly assess the NEM's resilience to human and environmental threats by mid-2019 (Finkel et al., 2017).

Low-carbon technologies and energy R&D policy

The GDP of Australia increased by 66% between 2005 and 2015. Government spending on energy-related research, development and demonstration (RD&D) increased fourfold from 2000 to 2013 to a peak level of AUD 961 million. However, in 2014, the energy RD&D budget fell sharply, by two-thirds, and in 2016 the spending had come down to AUD 229 million. Renewables received 43% of the total energy RD&D spendings and fossil fuels research accounted for another 25%. The remaining share was divided between energy efficiency, power storage, nuclear, hydrogen and other energy-related technologies. Australia's public spending on energy-related RD&D is at the lower end of the IEA member countries (Figure 6.19). In 2015, Australia spent 0.024% of GDP on energy RD&D, compared with Finland which is at the top with 0.114%.

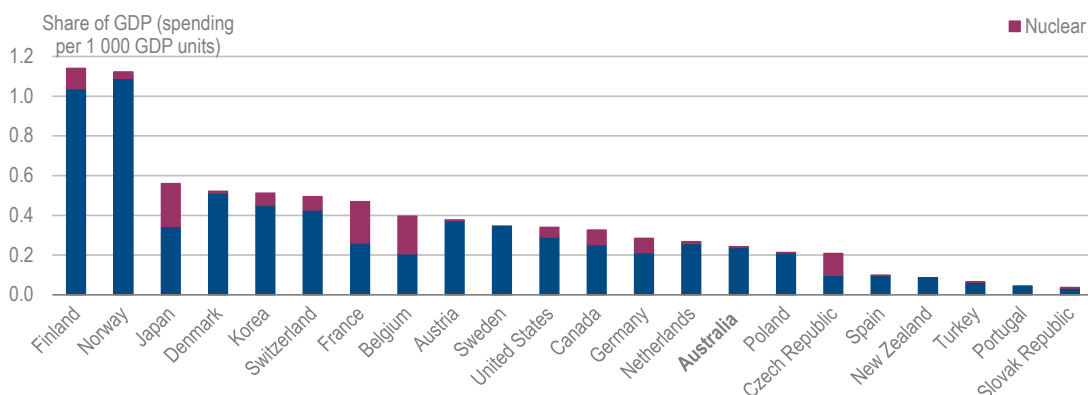
Figure 6.18 Government energy RD&D spending by category, 2009-16



Note: Data are provisional for 2016.

Source: IEA (2017c, forthcoming), "RD&D budget", *IEA Energy Technology RD&D* (database), www.iea.org/statistics/.

Figure 6.19 Total public energy RD&D spending as a ratio of GDP in IEA member countries, 2015



Note: No data available for Estonia, Greece, Hungary, Ireland, Italy, Luxembourg and United Kingdom.

Source: IEA (2017c, forthcoming), "RD&D budget", *IEA Energy Technology RD&D* (database), www.iea.org/statistics/.

Commonwealth energy R&D

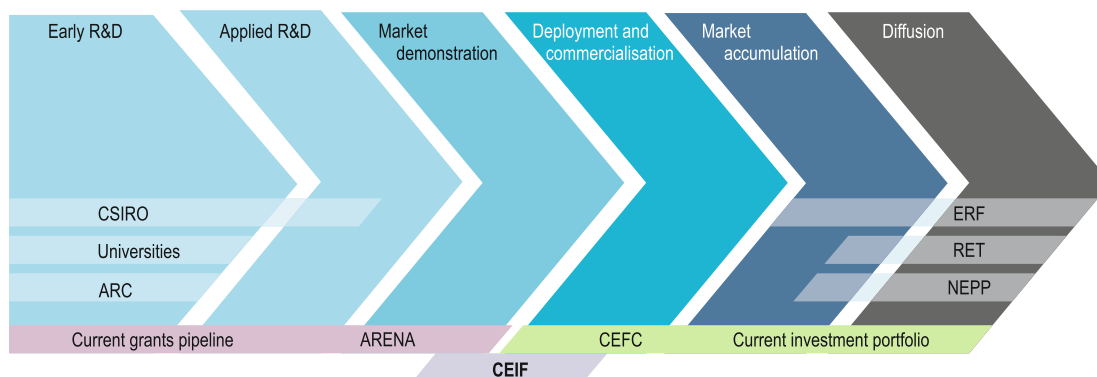
Australia joined the Global Mission Innovation (MI) initiative in 2015 and pledged to double government clean energy R&D spending (early R&D without demonstration and outside fossil fuels) to reach AUD 216 million by 2020, which represents a rather small increase on average historic levels of public RD&D support to clean energy.

Australia's energy technology governance is well established, and covers the whole innovation chain along research and development to demonstration and near-commercial deployment through the Australian Research Council (ARC), the Australian Renewable Energy Agency (ARENA), the Commonwealth Scientific and Industrial Research Organisation (CSIRO), the Clean Energy Finance Corporation (CEFC) (see Figure 6.20).

Since its creation in 2012, ARENA has co-financed activities of universities with the ARC and CSIRO. As of 30 June 2017, ARENA had committed approximately AUD 1 billion to over 317 renewable energy projects all along the innovation chain. This has been matched by approximately AUD 2.5 billion in co-funding from project proponents. It has a further AUD 1 billion to spend over the five years to 2022.

In March 2016, the government announced that it would refocus the funding of CEFC and ARENA and established a Clean Energy Innovation Fund (CEIF) with AUD 200 million to support emerging clean energy technologies to make the leap from demonstration to commercial deployment. The Fund provides both debt and equity for clean energy projects and is jointly managed by the CEFC and ARENA. At the more advanced end of the innovation chain, CEFC partners with private-sector investors to increase investment in clean energy technologies.

Figure 6.20 Energy RD&D landscape in Australia



Since its creation in 2015, the Department of the Environment and Energy (DoEE) has overseen energy innovation and the activities of ARENA, CEFC and the Climate Change Authority (CCA) as well as the Clean Energy Regulator (CER). The CCA is an advisory agency for climate change mitigation initiatives, but also a support to the National Climate Science Advisory Committee or the activities of the Bureau in climate science. The Department of Industry, Innovation and Science (DIIS) has policy responsibility for the resources sector and low-emission technologies, including carbon capture and storage (CCS). Australia participates in 18 IEA Technology Collaboration Programmes (TCPs), notably on renewable energy, end-use technologies and fossil fuels, including on CCS (see Table 6.2).

Table 6.2 Australia and the IEA Technology Collaboration Programmes

Technology collaborative programme	Signatory entity	Since
<i>Cross-cutting</i>		
Energy Technology Systems Analysis (ETSAP TCP)	CSIRO	2016
<i>End-use: buildings</i>		
Buildings and Communities (EBC TCP)	Standards Australia	2005
Energy Efficient End-use Equipment (4E TCP)	Department of the Environment and Energy	2008
<i>End-use: electricity</i>		
Smart Grids (ISGAN TCP)	Government of Australia	2011
<i>End-use: Transport</i>		
Advanced Materials for Transportation (AMT TCP)	Curtin University	2015
Clean and Efficient Combustion (Combustion TCP)	National Research Council (CNR)	1985
<i>Fossil fuels</i>		
Clean Coal Centre (CCC TCP)	DIIS	1999
Enhanced Oil Recovery (EOR TCP)	DIIS	1985
Gas and Oil Technology (GOT CP)	CSIRO	2015
Greenhouse Gas R&D (GHG TCP)	CSIRO	2001
<i>Fusion power</i>		
Stellarator-Heliotron Concept (SH TCP)	Australian National University (ANU)	1993
Plasma Wall Interaction (PWI TCP)	Australian Nuclear Science and Technology Organisation (ANSTO)	2017
<i>Renewable energy and hydrogen</i>		
Bioenergy (Bioenergy TCP)	Bioenergy Australia	2012
Concentrated Solar Power (Solar PACES TCP)	ARENA	2010
Geothermal Energy (Geothermal TCP)	Primary Industries and Regions, South Australia (PIRSA)	2005
Hydrogen (Hydrogen TCP)	Curtin University	2013
Hydropower (Hydropower TCP)	Hydro Tasmania	2013
Ocean Energy Systems (OES TCP)	Oceanlinx	2009
Photovoltaic Power Systems (PVPS TCP)	Energy Research and Development Corporation (ERDC)	1996
Solar Heating and Cooling (SHC TCP)	Standards Australia	2005

The outlook for low-carbon technologies in Australia

The CSIRO Low Emissions Technology Roadmap highlights opportunities to grow Australia's clean technology sector, to fast track emissions reductions and inform how Australia can foster its Mission Innovation goals. Australia was an early technology leader in solar, notably solar photovoltaics, and CCS and has potential opportunities to

lead at solar fuels, smart grids, concentrated solar power and low emission heating and cooling. Australia will be a technology taker in many other areas.

Carbon capture and storage

Australia has a clear and acknowledged interest in the development and global deployment of carbon capture and storage (CCS) technologies. As the world's largest exporter of coal and a major and growing exporter of LNG, the availability of CCS will be important for Australia's long-term economic prosperity. In the domestic energy context, CCS has the potential to support continued reliance on Australia's abundant coal and gas resources for power generation in a way that is consistent with long-term climate goals. It can also provide the foundation for deep emissions reductions in the industrial sector while potentially opening up new export opportunities associated with Australia's extensive brown coal resources (Australian Government, 2015a).

The 2015 *Energy White Paper* recognised the importance of CCS to underpin future coal and gas export revenue and to underpin Australia's energy security. It emphasised the need to develop CO₂ storage capacity domestically while positioning Australia as an "early adopter" of carbon capture technologies. In 2017, the government supported the development of an industry-led *Roadmap for CCS* (Greig et al., 2017).

The CCS Roadmap, commissioned by the Australian government, industry and research organisations (completed in May 2017) confirmed the viability of CCS technology in Australia and presented a comprehensive plan for its deployment. The Roadmap concludes that CCS provides an opportunity to decarbonise a number of existing and prospective emission-intensive industries in Australia, including natural gas and LNG production, iron- and steel-making, cement production, fertilisers, chemicals and textiles. The technology also facilitates the development of new industries, such as the hydrogen production from brown coal gasification.

Government programmes are targeting four priority areas for CCS technology development: *i)* improving the knowledge base of Australia's CCS resource; *ii)* demonstrating domestic low emission technology capacities and capabilities; *iii)* strategic partnering; and *iv)* building Australian skills and capacity. Financial support for CCS has been delivered through the CCS Flagships Programme, the National Low Emissions Coal Initiative, and the Low Emissions Technology Demonstration Fund (LETDF). In total, actual Australian government CCS expenditure amounted to AUD 586 million since 2009 (Mission Innovation, 2017). Support for CCS technologies in Australia is at a crossroads with Australian government funding largely committed and progressively winding down over the next few years.

Australia requires a clear and coherent policy framework to support investment in CCS if it is to remain a key player in the development of these technologies. Notably, CCS was excluded from receiving finance under the Clean Energy Finance Corporation (CEFC) when it was established in 2012, having been deemed a "prohibited technology" alongside nuclear. However, the Australian government announced in May 2017 that it would seek to remove this barrier to promote a technology-neutral approach, and legislation has been introduced into Parliament in 2017.

Australia has established one of the world's most comprehensive legal and regulatory frameworks for offshore CO₂ storage, although the lack of project developments means that this framework has yet to be fully tested. Onshore CO₂ storage regulation falls within

the responsibility of individual states, and the Commonwealth legislation has served as a model for complementary regulatory frameworks in Queensland, Victoria and South Australia. The states of Western Australia and New South Wales are yet to implement state-wide regulation to enable CO₂ storage, with the Gorgon CO₂ injection project in Western Australia regulated by a state agreement under the *Barrow Island Act 2003*.

Large-scale CCS project deployment

Since the last in-depth review in 2012, there has been good progress in Australia's delivery of CCS projects. The **Gorgon CO₂ injection project** is expected to commence injection operations in 2018 and will be the world's largest dedicated CO₂ storage facility, capturing and storing up to 4 MtCO₂ each year. This is an internationally significant project that represents a major contribution to the global CCS effort. The Gorgon project received AUD 60 million in grant funding under the LETDF.

The AUD 1.9 billion CCS flagships programme (announced in 2009) originally aimed to support 2 to 4 large, integrated CCS projects. However, the programme has now been scaled back to less than AUD 300 million and is focused on supporting targeted CO₂ storage exploration and appraisal in Victoria, Queensland and Western Australia. This work is critically important in providing confidence and better understanding of CO₂ storage availability; however complementary policy or financial support will be required if investment in integrated CCS projects is to proceed.

The **CarbonNet Project** is one of the flagship projects and has made significant progress in investigating the potential for a commercial scale CCS network in the Gippsland region of Victoria. The network could integrate multiple CO₂ capture projects in the Latrobe Valley, transporting CO₂ via a common-use pipeline and injecting it deep beneath the Gippsland Basin to be securely stored within suitable geological formations. If proved viable, CarbonNet could enable innovative new industries in Gippsland that will secure jobs, boost skills and attract investment while strengthening Victoria's energy security in a carbon-constrained future. This includes the opportunity to use brown coal reserves for coal upgrading projects (such as coal to hydrogen) for export.

The **South West hub in Western Australia** is a CCS initiative currently undertaking the pre-competitive data-acquisition phase of storage characterisation. Operations could begin at around 2025 and have a base case volume of CO₂ capture capacity of 2.5 Mt/y, with a possibility to grow to 5 to 6 Mt/y. Carbon dioxide would be captured from industrial facilities and power plants in the local region and transported via pipeline to onshore injection sites for dedicated geological storage.

Through these (or alternative) projects, Australia could aim to increase its contribution to global CCS deployment efforts consistent with Australia's unique strategic interest in CCS. There are currently 17 large-scale CCS projects operating around the world, including two applied to coal-fired power generation. These projects have been important in demonstrating the viability of CCS technologies and in supporting learning-by-doing cost reductions. For example, the Boundary Dam project in Canada, which was the first large-scale CCS retrofit of an existing coal-fired power generation plant, provided sufficient learnings that the operators believed they could reduce the capital cost of subsequent plants by as much as 30%. A growing pipeline of projects is needed to support future cost reductions and to provide a foundation for the development of large-scale CO₂ storage facilities.

Research and development

Australia has continued to make a leading contribution to global CCS research and development (R&D) activities and pilot-scale demonstrations. The CO2CRC carbon storage research programme has successfully injected more than 80 000 tonnes of CO₂ into geological storage facilities in Victoria's Otway Basin and is investing a further AUD 41 million (including private capital) between 2016 and 2020 to reduce the cost of CO₂ storage monitoring. The Australian National Low Emission Coal R&D (ANLEC R&D) programme is funded by the Australian government and the black coal industry, and has been delivering a nationally co-ordinated CCS research effort since 2010.

In 2008, the New South Wales government created the AUD 100 million Coal Innovation NSW Fund, which invests in research, development and demonstration of low-emission coal technologies, including a major CCS drilling project in the Darling Basin in the state's far west.

The 30 MW Callide Oxyfuel project, which operated from 2012 to 2015, was a world-first demonstration of oxyfuel technology on a coal-fired power plant. Post-combustion capture (PCC) pilot projects have operated on coal-fired plants in New South Wales and Victoria. Australia is also collaborating with China on a feasibility study for a PCC pilot project in China through the Australia-China Joint Co-ordination Group on Clean Coal Technology.

In 2016, the Australian government provided a boost to CCS research by setting up an AUD 23 million CCS Research and Development Fund (as part of the CCS Flagships Programme), which is providing grants on a dollar for dollar basis with the private sector on seven CCS-related projects.

CCS and HELE technologies for power generation

The Finkel Review discussed a future role for CCS in reducing emissions from the power sector, including the option to retrofit CCS to existing coal-fired power stations and for new build, high efficiency low emission (HELE) coal plants to be equipped with CCS (Finkel, 2017). The review specifically noted that a technology-neutral Clean Energy Target (CET) would allow for investment in CCS. Whether a CET would be sufficient, in practice, to support new CCS investment without more targeted measures is unclear and would ultimately depend on the CET design. However, the 2016 *Australian Power Generation Technology Report* found that coal and gas-fired generation with CCS, including retrofit options, could be competitive with other low emission technology options on a levelised cost of electricity (LCOE) basis (CO2CRC, 2016).

According to the CSIRO, a new-build HELE plant could save between 11% and 53% emissions compared with existing Australian coal-fired generation, or by 3% to 10% compared with the average emissions intensity of the NEM (Campey et al., 2017).

Analysis in the IEA 2017 *Energy Technology Perspectives* publication highlights that unabated coal-fired power generation would be phased out globally in the 2040s in the 2°C Scenario which aims to limit future temperature increases to 2°C. The emissions of an unabated HELE plant would still be almost twice that of an efficient gas plant and these emissions would be locked-in for the operating life of the plant, which could feasibly extend beyond the middle of the century. Any new investment in a HELE coal plant should therefore consider CCS from the outset or be contingent on a credible plan for future CCS operation.

International collaboration

The Australian government has been active in international forums to support the development and deployment of CCS globally, including through the Global CCS Institute, which the Australian government established in 2010, the Carbon Sequestration Leadership Forum, the Clean Energy Ministerial and more recently Mission Innovation. These initiatives are providing an important platform to promote bilateral and multilateral co-operation on CCS, share learning and accelerate technology development. Australia will host the international Greenhouse Gas Control Technologies conference in 2018.

Assessment

Under the Paris Agreement, Australia has committed to the ambitious target of reducing its emissions by 2030 to 26%-28% below 2005 levels, a substantially higher target than its goal of cutting emissions by 5% below 2000 levels by 2020.

While Australia is on track to meet its 2020 target by offsetting reductions in other sectors, after 2020, however, emissions are likely to rise to 592 MtCO₂-eq. in 2030, with projected economic growth and in the absence of additional policies. To meet its 2030 target, efforts need to increase, as the target translates into a cut of 50% emissions per capita and a 65% cut in the emissions intensity of the economy. As part of its COP21 pledge, the Australian government committed to consider a long-term emissions reduction goal beyond 2030, which is currently being done under the climate change policy review. As part of the Paris Agreement, countries are invited to prepare mid-century low carbon development strategies. To date Australia has not yet adopted such a strategy.

Accounting for 78% of total GHG emissions, the energy sector, and especially the power sector, will have to play a key role. The power sector accounted for 50% in energy-related CO₂ emissions and exhibits a share of 86% of fossil fuels and the highest carbon intensity among IEA member countries in 2015 (740 gCO₂/kWh).

While the power sector has the largest potential to contribute to the Australian emissions reduction goals, it is not facing any effective carbon rate. Current policies are unlikely to achieve the 2030 goals. In fact, the electricity sector does not face any effective carbon rate under the voluntary Emissions Reduction Fund (ERF) and industry emissions are not impacted by the high baseline of the safeguard mechanism. Rather the combination of the federal Renewable Energy Target (RET) and other state- and territory-based feed-in tariffs (FiT) and energy efficiency obligation policies have been effective in accelerating emissions reductions through the uptake of wind and solar energy (albeit concentrated heavily in a few states, which raised concerns around the reliability and stability of the electricity grid).

Australia's energy system is undergoing rapid changes, impacting the power sector in particular. CO₂ emissions from power generation have been declining after 2009, reflecting the growth of renewables, fast retirements of coal-fired capacity and lower electricity demand due to increased energy efficiency and industry plant closures. Today, Australia's emission profile is still impacted by the dominance of coal in the power sector and the energy needs of a growing mining boom (with 8% fugitive emissions in total GHGs). While current trends point in the right direction, the development of the sector is not sustainable in terms of affordability and security.

Policy uncertainty drives the fast retirement of coal capacity and equally undermines future investment in any low carbon technology. Emissions reduction policy in Australia has been marked by fast and frequent u-turns and uncertainty in recent years, notably around carbon pricing. Many attribute the high electricity prices in Australia to this uncertainty (CCA/AEMC, 2017), and it is clear that the closure of old coal plants can lead to higher electricity prices and windfall profits for remaining plants.

About 25% of Australia's coal-fired capacity is expected to retire within the next 10 years (see also AEMO, 2016). There has not been any new coal-fired generating capacity built since 2009 (Bluewaters in Western Australia) and the market has no commercial interest to build new ones. Australia's ageing fleet of coal plants will continue to retire without significant life extension investments, due to age and safety considerations. There is no obligation on providers to supply details of closure plans to the government, regulator or operator at federal or jurisdictional level, as demonstrated by the closure of the Hazelwood plant in Victoria. The Finkel Review suggested a closure notice of three years for the plant operators, which has been accepted by the COAG Energy Council in July 2017.

Experience in IEA member countries confirms that the power sector is leading the energy system transformation. Policy action needs to be long-term to enable an orderly power sector transition, based on effective energy markets, affordable prices and cost-effectiveness. With the key objective of ensuring energy security and affordability, the Australian government will need to guide the process and build a policy investment framework for 2030, underpinning its Paris pledge, which is compatible with the NEM.

First, the government has an opportunity to reinforce its strategic planning for the update of its NDC commitments through five-yearly reviews and to create visibility for the energy sector to ensure that adequate investment is forthcoming into new renewable energy, energy efficiency and clean energy technologies.

Second, a 2050 goal and related mid-century low-carbon development strategy can be helpful to identify a few no-regret options, calibrate emissions reductions over time and by sectors, notably the power sector, while ensuring that carbon budgets are aligned to long-term goals, driving innovation and technology development.

Third, as current policies (Emissions Reduction Fund and its Safeguard Mechanism) are not delivering energy-sector decarbonisation, an emissions reduction goal for the power sector and a related mechanism are critical. The IEA believes that such a mechanism should provide clarity for the exit of capacity but that it could be combined with low-carbon capacity auctions and demand-response to encourage the entry of new capacity, on the basis of locational signals in the NEM (see Chapter 8 on Renewable Energy).

During 2017, the Australian government conducted a climate policy review, supported by advice from the Finkel Review, AEMC, the CCA and many others. After assessing several policy options for the cost-effective power sector decarbonisation (emission intensity scheme, low-emission target or the Clean Energy Target of the Finkel Review), the Energy Security Board presented advice to the Australian government in the form of a National Energy Guarantee (NEG) in October 2017 for discussion at the COAG Energy Council in November 2017 and for consideration in April 2018 by the COAG.

The NEG can be an effective market-based mechanism if the government can ensure more competition, better interconnection among the NEM regions and stringent rules for the integration of renewable energy capacity into the system. The NEG cannot solve all issues, and it could create new barriers and windfall profits, if those elements are not considered.

While natural gas is a transition fuel in many countries, the Australian production is expensive and serves high-priced export markets. Gas has been squeezed out of the current electricity mix. Gas market reforms and new gas development should enable Australia to bring down the costs of domestic gas and benefit from contributions of natural gas in the transition period.

For technology change to become real, an integrated suite of policy packages can be beneficial, including low-carbon capacity auctions across the NEM, combined with a legislated emission mechanism and notice rules for the retirement of coal-fired power plants, supported by effective energy technology RD&D funding from federal and state/territorial governments.

Energy technologies are the key drivers of the energy system transformation. The reduction of public support in energy technology RD&D in 2014, notably in areas where Australia had been a leader, such as in CCS and renewables, puts energy technology priorities and RD&D support policies at risk. The government should use the opportunity to re-establish its leadership in clean energy R&D by further engaging with public and private sector under Mission Innovation and by expanding participation in IEA TCPs. Such action would position Australia well to achieve the UN Sustainable Development Goals for 2030. This would also entail higher public RD&D funding levels. It is commendable that both ARENA and CEFC now invest in energy efficiency. Upgrades of existing power generation and industrial processes which reduce pollutants could be supported under industrial projects, if the Clean Energy Regulator (CER), responsible for the collection of emission data by facility, makes these data available.

In order to meet the ambitions set out in the Energy White Paper for technology leadership, Australia has to step up its efforts and build a consistent low-carbon energy technology programme, based on the CSIRO roadmaps, evaluation of research priorities and budgets.

Concentrating solar power (CSP) has not yet developed in Australia, despite exceptional resources and long-term investment in R&D. Thanks to built-in thermal storage, CSP is considered dispatchable and more flexible than fossil-fuelled thermal plants. CSP plants are a very valuable asset for the Australian power system as they could extend the use of solar power beyond sunset during peak hours and help accommodate increasing shares of variable energy resources, notably wind power. It could also be a chance for technology leadership. Flagship projects are being developed thanks to federal equity loans provided by ARENA/CEFC. The government of South Australia and US-based company Solar Reserve are investing in the world's largest CSP solar thermal power plant of 150 MW in Port Augusta which is expected to enter operation in 2020.

Australia has a strategic interest in the development and global deployment of CCS. It has been a leader in CCS R&D, particularly for CO₂ storage, and will soon host the world's largest CO₂ storage project at the Gorgon LNG facility. However, there is no policy framework to facilitate new investment in CCS, and government programmes designed to support large-scale projects have been considerably scaled back in funding

and ambition. The proposed change to include CCS as an eligible technology under the CEFC mandate (currently before Parliament) is an important and welcome step which will reduce a significant barrier to CCS investment. Efforts to assess CO₂ storage opportunities with a high degree of confidence will be critical to support future investment and should be accelerated. Any new HELE coal plants would need to be equipped with CCS or designed to be retrofitted with CCS to avoid the long-term lock-in of emissions.

Future emissions growth is expected to come from unconventional gas production and associated methane and other fugitive emissions. The existing National Greenhouse and Energy Reporting Scheme (NGERS) should provide better access to data collected for energy planning, research and policy analysis and evaluation purposes - with potential links to the AEMO planning tools and Australia's National Maps and Australian Renewable Energy Mapping Initiative. In return, other reporting initiatives could be streamlined (including the National Pollution Inventory) to reduce duplication of reporting by industry. The Clean Energy Regulator who is now in charge of the NGERS, should publicly report on the energy use data and possibly as an indicator down to the facility or division level.

Climate change response is an area where federal government leadership will be required. While energy and climate policies are now integrated in the new Department of the Environment and Energy, joint COAG leadership is required to achieve the integration of energy and climate/environment policies within a federal structure and in the common National Electricity Market. The NEG scheme is a promising opportunity. In the absence of a Commonwealth political consensus on how to address climate change, policies at the level of states/territories are evolving in an unco-ordinated manner leading to fragmented markets and suboptimal outcomes. National leadership is best underpinned by a societal consensus and close collaboration with states/territories. The 2015 *Energy White Paper* (EWP) does not address these aspects and lacks the longer term perspective. The Australian government is therefore encouraged to review the EWP, and design a national stable and integrated energy and climate policy framework based on enduring agreement with states/territories through the COAG process.

Recommendations

The government of Australia should:

- Design a government-led 2050 low-carbon emission strategy to provide a stable outlook for long-term investments in energy efficiency, renewables and other clean energy technology opportunities.
- Design a national, stable and integrated energy and climate policy framework for 2030, in collaboration with states and territories through the Council of Australian Governments with integrated policy packages for energy efficiency and renewable energy.
- Guide the energy transition through an emissions reduction goal and related mechanism for the power sector, and provide a market signal to retire older and less efficient generation, while ensuring that plants provide sufficient advance notice of their intention to close.

- ❑ Ensure that low-emission technology support is market-based and guided by energy system-wide network planning and locational signals.
- ❑ Strengthen effective GHG measuring, monitoring and reporting, including of fugitive emissions, to reinforce long-term planning and technology investment.
- ❑ Ensure continued government support to R&D in the uptake of energy technologies through existing or new financial mechanisms, and by increasing international collaboration through TCPs and Mission Innovation.
- ❑ Accelerate efforts to develop and deploy CCS technologies domestically, including CO₂ storage assessments, and maintain Australia's international leadership and engagement on CCS.

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7. Energy efficiency

Key data

(2015)

Energy supply per capita (2016 estimated): 5.43 toe (IEA average 4.42 toe), -2.9% since 2006

Energy intensity (TFC/GDP): 75 toe/USD million PPP (IEA average: 77), -14.8% since 2005

TFC: 81.3 Mtoe (oil 52.4%, electricity 22.4%, natural gas 16.6%, biofuels and waste 5.4%, coal 2.9%, solar 0.4%), +13% since 2005

Consumption by sector: transport 40%, industry 34.5%, residential 12.9%, commercial and public services including agriculture, forestry and fishing 12.6%

Overview of energy consumption trends

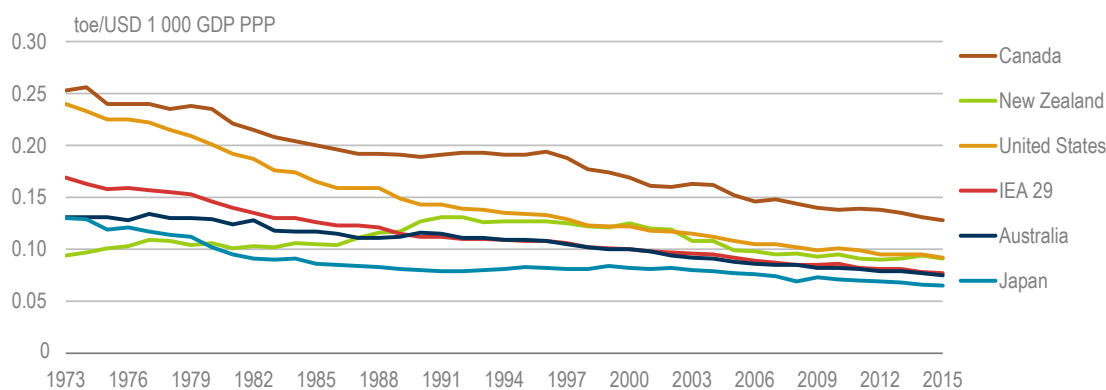
Australia's energy intensity, measured as the ratio of total final energy consumption (TFC¹) per unit of real gross domestic product adjusted for purchasing power parity (GDP PPP), was 0.75 toe/ USD million GDP PPP in 2016 (Figure 7.1). Energy intensity (measured with regard to TFC) has decreased by 15% since 2005. However, TFC has seen an overall increase by 13% since 2005.

Australia's TFC was dominated by the transport and industry sectors, which accounted for 40% and 35% of TFC, respectively in 2015. Residential and commercial sectors are relatively small energy consumers, with less than 13% of TFC each. TFC has been on the rise over the past decades until it stalled in 2013. A similar trend is visible in electricity consumption.

Looking at fuel use by sector, oil accounts for over half the fuel consumption in TFC, driven by large oil demand in the transport sector (see Figure 7.3), which is almost entirely dependent on oil products, with only minor shares of alternatives (natural gas, biofuels and electricity). The industry sector also uses large shares of oil, both as energy fuel and as feedstock in processes. Electricity is the second-largest fuel in TFC and accounted for the main part of energy consumption in the residential and commercial sectors. Natural gas is the third-largest fuel in TFC, mainly consumed in industry and the residential sector.

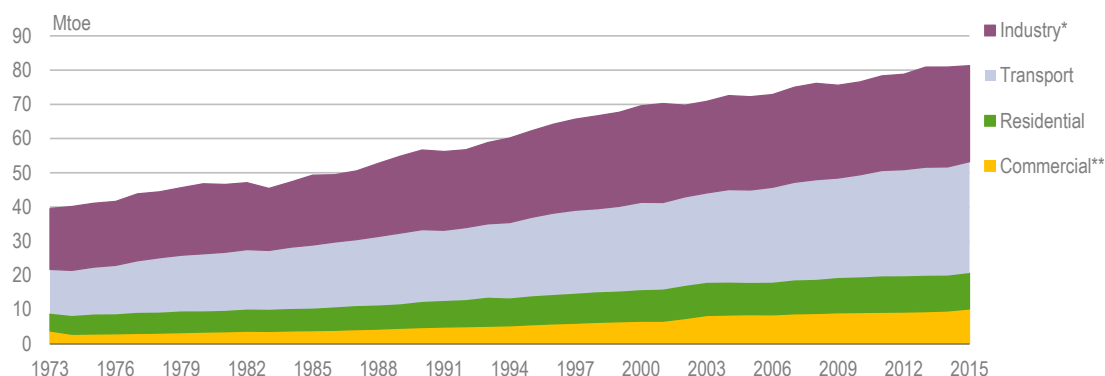
¹. TFC is the final consumption of fuels (e.g. electricity, heat, gas and oil products) by end users, excluding the transformation sector (e.g. power generation and refining).

Figure 7.1 Energy intensity (TFC/GDP PPP) in Australia and other selected IEA member countries, 1973-2015



Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 7.2 Total final consumption by sector, 1973-2015

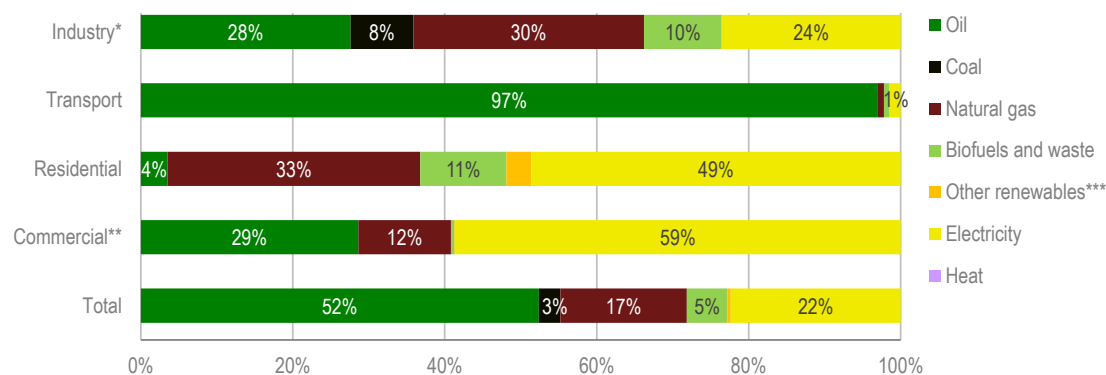


* *Industry* includes non-energy use.

** *Commercial* includes commercial and public service, agriculture, forestry and fishing.

Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 7.3 Fuel share of total final consumption by sector, 2015



* *Industry* includes non-energy use.

** *Commercial* includes commercial and public services, agriculture, forestry and fishing.

*** *Other renewables* includes hydro, solar and wind.

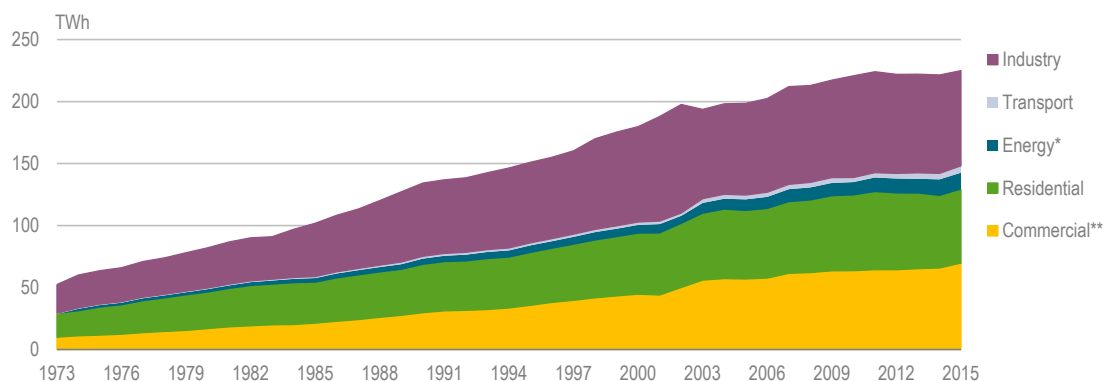
Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Electricity consumption increased steadily across all major sectors over a long period, until stabilising around 220 terawatt-hours (TWh) per year in recent years. Electricity consumption dropped in 2010 and in 2013. In 2015, electricity consumption rebound and reached a new peak of 225 TWh, a 1% increase from the previous five-year average. The industry, residential and commercial sectors together represent over 90% of total electricity consumption.

The industry sector has been the largest electricity consumer historically, accounting for 34% of TFC in 2015. Australia has considerable aluminium production; the smelting process uses large amounts of electricity generated from natural gas. In 2015, consumption in the industry sector declined by 6% below the peak level in 2010, following the closure of aluminium smelters in 2013. As non-ferrous metals industry, such as aluminium production, accounted for almost half the total industry consumption, the impact on total consumption has been substantial. The residential and commercial sectors accounted for 31% and 26% of total electricity consumption, respectively. A minor share in the commercial sector is consumption in agriculture, while the rest is electricity used in commercial buildings and public services. Electricity consumption in the commercial sector has increased by 23% in the last decade to a new peak level in 2015. Residential consumption has also increased over ten years, but since a peak in 2011, the sector has declined by 5%.

The energy and transport sectors account for small but increasing shares of total electricity demand. Electricity consumption in the energy sector is for coal, oil and gas production and saw growth of 46% from 2005 to 2015. In Australia, the mines are located in off-grid areas and generate electricity on-site to meet their needs. The transport sector has increased its electricity consumption by 55% over the same period.

Figure 7.4 Electricity consumption by sector, 1973-2015



* *Energy* includes coal mining, petroleum refining, and oil and gas extraction.

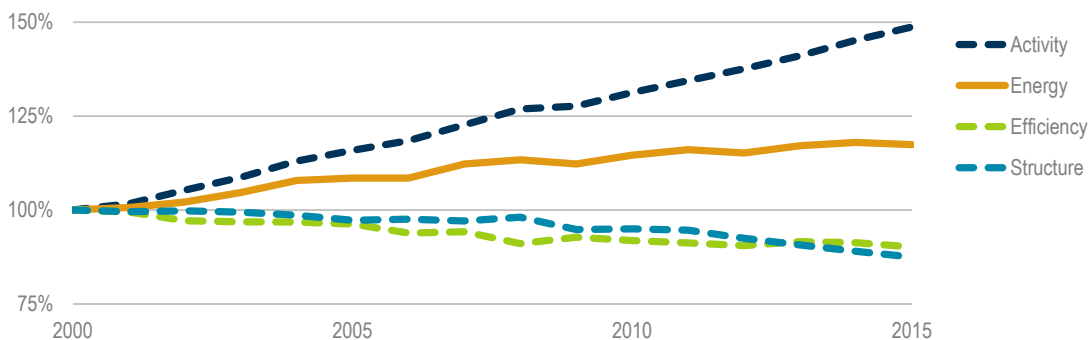
** *Commercial* includes commercial and public services, agriculture, fishing and forestry.

Source: IEA (2016), *Electricity Information*, www.iea.org/statistics/.

A decomposition analysis breaks down Australia's progress in net energy efficiency by splitting energy consumption changes into three different drivers, including activity factors, structural changes and efficiency-related factors. The activity index refers to value-added output in industry and services, to population in the residential sector, passenger-kilometre for passenger and tonne-kilometre for freight transport. The structure index refers to economic structural change in industry, floor area per person in the residential sector and modal shift in the transport sector.

In Australia, unlike in other IEA members, economic growth was robust and activity has increased significantly, resulting in rising energy consumption during 2000-12, driven by Asian demand for natural resources and Australian commodity exports. The total activity effect drives energy use. After 2012, however, the economy has seen structural changes that resulted in slightly reduced energy consumption, following the closures of aluminium smelters and impacts of the global financial and economic crisis.

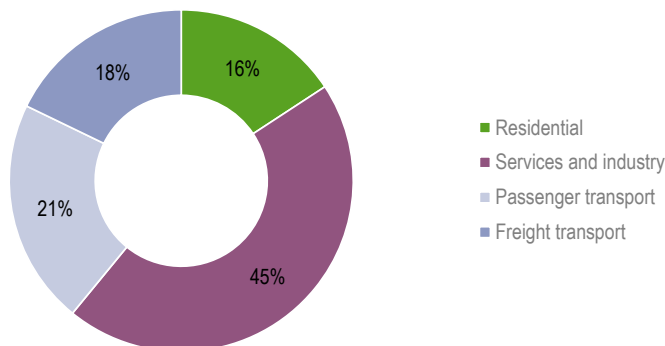
Figure 7.5 Final energy consumption decomposition in Australia, 2000-15



Note: The figure displays results from the IEA decomposition analysis and covers approximately 89% of final energy consumption. For more information on the decomposition methodology, see source report.

Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

Figure 7.6 Estimated cumulative energy savings by sector, 2000-15

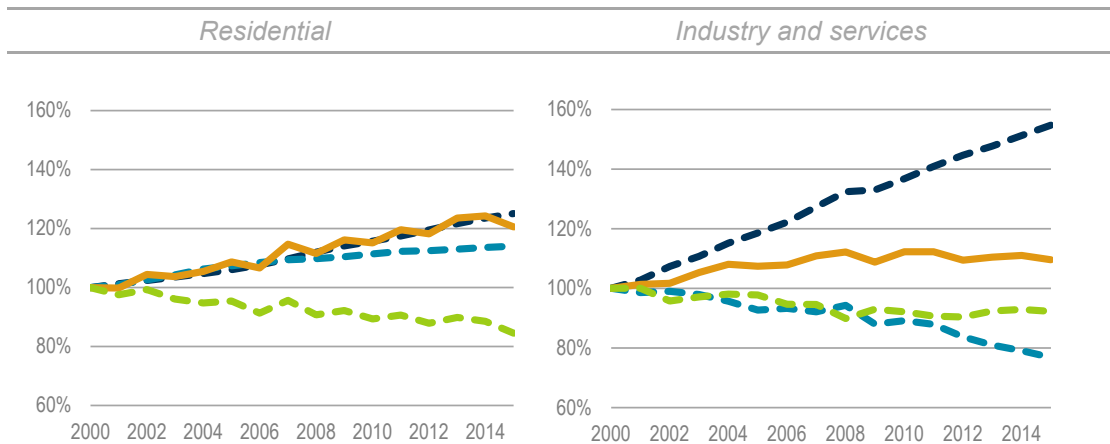


Notes: This figure displays results from IEA's decomposition analysis and covers approximately 90% of TFC. Energy savings are only related to energy efficiency improvements, not accounting for structural changes.

Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

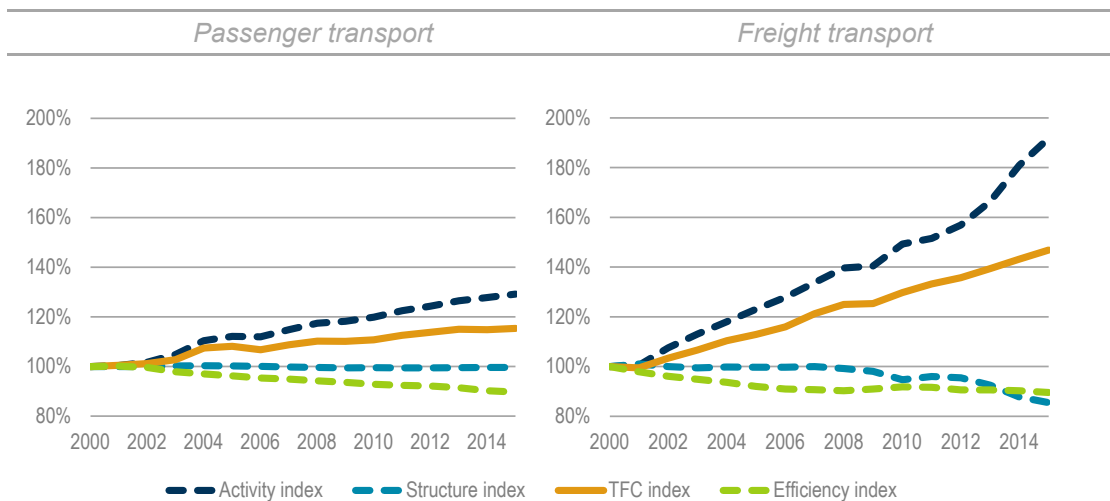
As illustrated in Figures 7.7 and 7.8, structural changes have largely contributed to reducing the effect of increased economic activity. Energy efficiency has also moderated energy demand but it was not significant enough to reduce total energy consumption. Most energy savings stem from industry and services, largely because of closures of energy-intensive industries, like aluminium smelters and refineries. The growth in activity and energy consumption, however, was decoupled in the residential sector thanks to more energy-efficient appliances and minimum standards. However, space heating and cooling needs have increased. Energy efficiency has been rather stable in transport, notably in freight transport, which explains a remaining large efficiency potential.

Figure 7.7 Decomposition into drivers of final energy consumption in the residential and industry sectors, 2000-15



Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

Figure 7.8 Decomposition into drivers of final energy consumption in the transport sector, 2000-15



Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

Energy efficiency policy and institutions

In Australia's federal system of government, the responsibility for energy efficiency policies is shared among the different levels of government, the Commonwealth, the governments of the states, territories, and local councils.

Commonwealth institutions

Over the past five years, the federal agency responsible for energy efficiency has changed several times, and moved, after a split between the resources and energy and climate change departments, to the Department of Industry, Innovation and Science and recently to the Department of the Environment and Energy (DoEE).

The **Council of Australian Governments (COAG) Energy Council** launched a new intergovernmental co-ordination framework on energy efficiency in 2015 and adopted the National Energy Productivity Plan (NEPP), which set a whole-system efficiency target of increasing energy productivity (TPES per unit of GDP) by 40% over 2014 levels by 2030.

At the Commonwealth level, the DoEE manages energy efficiency programmes and leads on the implementation of the NEPP work plan with annual progress reports.

Consistent energy end-use data collection and monitoring remains a challenge, notably with regard to the building stock, the energy performance of buildings, the commercial and residential sector consumption for non-metered data in areas that are not connected to Australia's major electricity networks. Energy consumption data for large industry are collected at facility level by the **Clean Energy Regulator (CER)** under the National Greenhouse and Energy Reporting Scheme (NGERS). The data are published as corporate aggregate.

To address ongoing issues relating to data gaps and consistency, the federal government is funding the **Commonwealth Scientific and Industrial Research Organisation (CSIRO)**, working alongside Australia's major ICT research and development organisation Data61, to develop an energy use data model (EUDM). When completed, the EUDM will increase the quantity, quality and availability of Australian energy data, and improve the accuracy of demand forecasts.

The **Energy Exchange (EEX)** website (formerly Energy Efficiency Exchange) is a joint initiative of the Commonwealth and state/territory governments and peer-reviewed by industry experts. The EEX draws on past and present energy efficiency measures to provide information on the development and implementation of energy management for large energy users. It is being revised to provide better support for small and medium businesses. Information for households to better manage energy use and costs is provided through Your Energy Savings website.

The Australian government has committed to a Business Grants Hub for all grants programmes from any department granting funds to businesses or business like organisations (local government bodies, non-profit, etc.) and there is a Citizen Grants Hub for payments to individuals. AusIndustry in the **Department of Industry Innovation and Science** runs the Business Grants Hub. Most energy efficiency grants programmes have ended in 2015. If new programmes were considered, AusIndustry would be the delivery partner for DoEE.

The **Department of Infrastructure and Regional Development** advises the government on the policy and regulatory framework for the transport sector, including vehicle emissions standards. It advises the minister on measures to reduce transport-related emissions. However, the DoEE deals with fuel quality legislation. The **Ministerial Forum on Vehicle Emissions** was created in 2015.

States and territories

Each state/territory is implementing policies in the area of energy efficiency with significant priority given to social support programmes amid rising energy prices. Some have their own targets and instruments, while others rely on Commonwealth policies.

The COAG Energy Council is supporting the harmonisation of state and territory energy efficiency policies and programmes, notably under the NEPP.

In 2016, two states had an energy productivity/efficiency target; South Australia and New South Wales (NSW). Energy efficiency obligation schemes are in place in Victoria, Australian Capital Territory, NSW and South Australia. Western Australia and Northern Territory do not have any targets or energy efficiency policies. Queensland established a cross agency Energy Productivity Working Group (QEPWG) to implement the NEPP and co-ordinate state-level programmes on energy productivity.

Australian Capital Territory

The Capital Territory has committed to achieving net-zero emissions by no later than 2050 and is on track to being 100% renewable by 2020. The Capital Territory also has an Energy Efficiency Improvement Scheme (EEIS) with an energy savings target of 8.6% (each year) from 2016 to 2020 to contribute to achieve its 40% carbon-reduction target by 2020. The EEIS has a 20% priority household target to assist low-income and vulnerable households so that the scheme's activities go to concession-card (low-income) households. The government's Actsmart programme supports efforts of businesses, schools, households and low-income households in energy efficiency.

New South Wales

In New South Wales, energy efficiency policies support the state's aspirational objective to achieve net-zero emissions by 2050. In 2011, New South Wales adopted an energy savings target to achieve 16 000 gigawatt hours (GWh) of annual energy savings by 2020. Key policies to improve energy efficiency include the Energy Savings Scheme (ESS), the Building Sustainability Index (BASIX), the 2013 Energy Efficiency Action Plan and the Government Resource Efficiency Policy.

The ESS reduces energy consumption in NSW by creating financial incentives for households and businesses to invest in energy savings by installing, improving or replacing energy-saving equipment. The state enhanced the ESS in 2015 by increasing the level of savings that would be encouraged under the scheme – 7.5% of electricity sales (2017); 8.0% (2018) and 8.5% (2019).

The BASIX requires an assessment for sustainability against BASIX targets for new buildings or changes to existing buildings with an investment over AUD 50 000. BASIX energy targets were further raised in July 2017. The 2013 Energy Efficiency Action Plan detailed 30 energy efficiency actions across five streams: build and strengthen energy efficiency markets; foster energy-efficient homes; create energy-efficient businesses; support an energy-efficient government. The 2014 Government Resource Efficiency Policy (GREP) sets targets for increasing energy (and other resources) efficiency in government operations.

In November 2016, the NSW government released for discussion the Draft Plan to Save NSW Energy and Money, which outlines options for achieving the state's 16 000 GWh energy-saving target. It also released a Climate Change Fund Draft Strategic Plan which included further proposals for energy efficiency programmes, including an upgraded Home Energy Action Program which also assists vulnerable, low-income households, including low-income renters, in reducing their energy bills.

South Australia

South Australia's Strategic Plan includes two energy efficiency targets; *i*) improve the energy efficiency of dwellings by 15% by 2020, and *ii*) enhance the energy efficiency of government buildings by 30% by 2020. The state government leads energy efficiency in public buildings on the basis of a dedicated Government Building Energy Strategy for the period 2013-2020, supported by the Government Building Energy Efficiency Investment (GBEEI) programme which requires all agencies to identify energy efficiency upgrade opportunities with simple paybacks of seven years or less at government-owned sites.

With regard to residential energy efficiency, South Australia has set an overall target for energy retailers to deliver 5.2 million gigajoules (GJ) of energy savings from 2015 to 2017, with 1.2 million GJ to be delivered in the first year (the Retailer Energy Efficiency Scheme or REES). A residential energy efficiency index is compiled to assess progress by rating the number of residential dwellings that can have their annual energy needs met by one terajoule of energy.

Victoria

Victoria's 2015 Energy Efficiency and Productivity Statement outlines the policy direction for energy efficiency policies. The main instrument is the Victorian Energy Upgrades Program which has encouraged over 1.7 million energy upgrades for residential homes and over 70 000 for businesses since its inception. In 2016 the scheme exceeded the GHG reduction target of 5.4 million tonnes (Mt). In 2017, the target increased to 5.9 Mt and will continue to increase each year to reach 6.5 Mt in 2020.

Victoria government has developed a home energy rating programme, the Residential Efficiency Scorecard to support vulnerable, low-income households in undertaking energy efficiency retrofits through the Home Energy Assist programme, and businesses in investing in energy productivity through the Boosting Business Productivity programme and the Better Commercial Buildings programme.

In 2017, Victoria decided to explore policy options to support network transformation in the state by facilitating a market for grid services and removing regulatory barriers to efficient network investment, by enabling more demand-side participation in the broader energy market through regulatory reform and by facilitating smarter electricity use by consumers and enabling new demand management services and rewards.

Tasmania

The Tasmania government has various small energy efficiency programmes targeted on vulnerable residential customers. In 2016, it announced the AUD 10 million Tasmanian Energy Efficiency Loans Scheme (TEELS) in favour of residential and small business customers. The scheme initially allowed interest-free loans of up to AUD 10 000 per application for three years for the purchase of energy-efficient appliances or upgrades. The initial allocation was fully subscribed, and an additional AUD 10 million was allocated in 2017. This scheme complements an existing No Interest Loan Scheme (NILS), which supports low-income (concession) customers to acquire energy-efficient equipment. NILS also includes a grant component, which reduces the overall cost to the customer.

Queensland

A range of sustainable building proposals focusing on improving the energy efficiency performance of buildings are intended to be included in the Queensland Building Plan. These would complement actions to reduce carbon emissions in the built environment under the Queensland Climate Transition Strategy, and cover both privately owned and government buildings.

Further to the National Construction Code for new residential dwellings in Queensland, optional credits are available when a solar energy system (houses only) or an outdoor living area (houses and units) is included in its design and construction. These credits can be used towards the energy efficiency building standard.

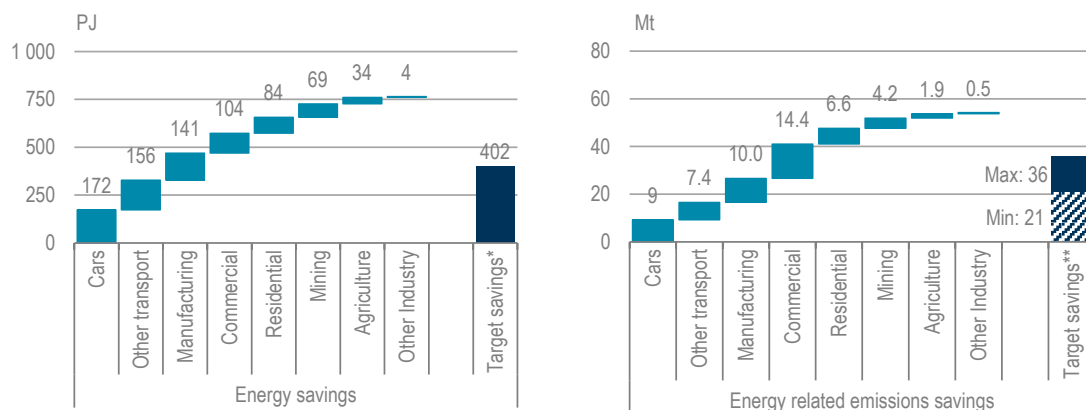
In June 2017, the Queensland Council of Social Service released its *Choice and Control? – The Experience of Renters in the Electricity Market* report. With market reforms and technological advancement creating more consumer choice over energy use, the report notes that the evolving energy market could see a widening division between those able to take advantage of opportunities to reduce their energy costs, and those who cannot. The report notes that the inequitable distribution of energy costs across households gives rise to considerable social and economic implications, with barriers identified for tenants wishing to participate effectively in the changing energy market by: *i)* making informed choices about their energy supply and use, *ii)* controlling their energy costs and *iii)* accessing energy consumer safeguards.

The Queensland Housing Strategy 2017-2027 and Queensland Housing Strategy 2017-2020 Action Plan include measures to ensure public housing design standards are up to date and include features to deliver safety, amenity and energy efficiency. The Queensland government is commencing a trial of solar installations in public housing.

The National Energy Productivity Plan

Australia is framing its energy efficiency policies within the concept of energy productivity, thus making sure that whatever energy is used gives maximum value to the economy. Energy productivity is measured as national gross domestic product (GDP, in millions of dollars) divided by petajoules (PJ) of primary energy (a measure of the total energy supplied).

On 4 December 2015, the COAG Energy Council adopted the National Energy Productivity Plan NEPP (Australian Government/COAG Energy Council, 2015) for the period 2015-30 with an initial work plan of 34 broad measures which shall deliver the Commonwealth's commitment to improve Australia's energy productivity by 40% by 2030. The NEPP follows and replaces the previous National Strategy on Energy Efficiency 2009-2020, and builds upon the 2009 memorandum of understanding under the National Partnership Agreement on Energy Efficiency (NPA-EE). As such the NEPP is a comprehensive strategy bringing together the existing measures, but without budget allocation. While the NEPP aims to cover the whole economy, it does not include dedicated energy efficiency measures for the industry sector or electricity generation.

Figure 7.9 Energy efficiency as a driver of emissions reduction

* 2030 final energy equivalent savings needed for 40% EP target.

** Range of emissions savings from reaching 40% EP target.

Source: Australian government/COAG Energy Council (2015), "National Energy Productivity Plan", December.

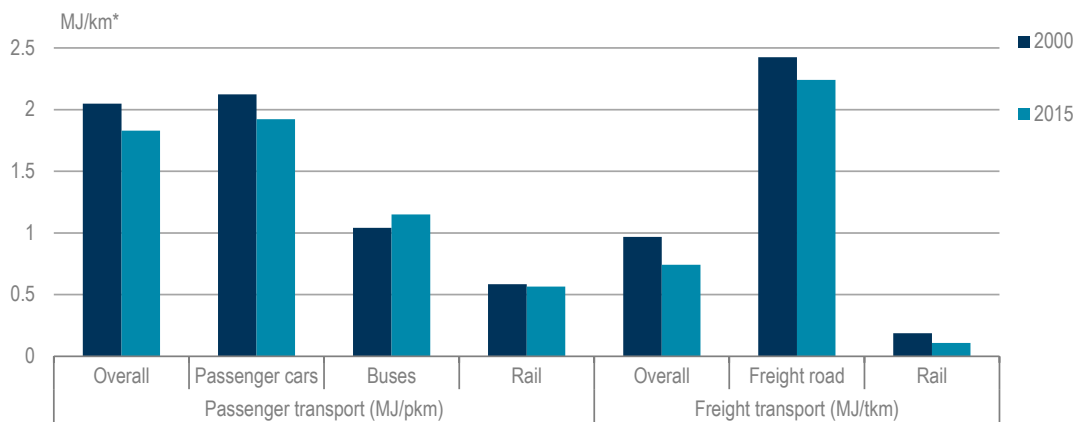
The Australian government has estimated that 23% of the 40% productivity target will be achieved through structural changes in manufacturing, i.e. the target does not focus solely on improvements driven by energy efficiency. Implementing all cost-effective energy efficiency activities would surpass the target of final energy equivalent savings needed in 2030 of 402 PJ, allowing for flexibility of choice in the activities. Part of the NEPP modelling illustrated that the highest forecast energy savings would be achieved in the transport sector, followed by commercial and residential sectors (see Figure 7.9).

The possible contribution of energy efficiency to emissions saving ambitions remains to be clarified. In 2015, the government expected that energy efficiency could make a strong contribution, which could range between 21 MtCO₂ and 54 MtCO₂, thus providing for a very broad range of 25% to 40%.

Transport

Energy consumption and intensity

Transport remains the largest energy-consuming sector in Australia. With an energy consumption of 32.5 Mtoe in 2015 it accounted for 40% of the country's TFC. At the same time, it is the sector with the fastest growth in energy consumption, experiencing a 20% rise since 2005. Oil dominated with 97% of consumed energy in the sector. Electrification has spread in rail transport, but electricity still represents only 1.4%. Biofuels and natural gas accounted for only 1.6% of total energy consumed in transport. Road transport accounted for 83% of total transport energy consumption in 2015, followed by domestic aviation with 9% and rail with 4%, and small shares of shipping, pipeline transport and other transport consumption. Passenger cars and freight trucks are the major categories of energy consumers in road transport, and both have become less energy-intensive in the recent decade (Figure 7.10). By end of 2018, the last car manufacturing facility will have closed in Australia.

Figure 7.10 Energy intensity in transport by means of transport, 2000-15

* Unit is per personal-kilometre for passenger transport and tonne-kilometre for freight transport.

Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

Policies

In the transport sector, Australia relies on labelling, tax incentives, information and awareness raising measures as well as financing through the government-owned Clean Energy Finance Corporation, to drive improvements in vehicle fuel efficiency and support the uptake of low-emission vehicles. Business can also earn Australian Carbon Credit Units by reducing emissions intensity of vehicles in land and sea transport sectors. The government has allocated funding to purchase credits through a reverse auction process. To date, Australia does not have any fuel efficiency or emission standards for motor vehicles, which is unique among the other major developed countries, which have adopted such standards.

A mandatory label showing fuel consumption and emissions applies under Australian Design Rule 81/02 to all new-model cars, four-wheel drives/sports utility vehicles and light commercial vehicles. Linked to the label, the Green Vehicle Guide (website) enables consumers to compare side-by-side the fuel consumption, emissions and environmental performance of individual vehicle models, including electric vehicles and plug-in hybrids, and calculates annual fuel costs and CO₂ emissions. The Australian government offers a luxury car tax concession for vehicles identified as fuel-efficient (combined fuel consumption of less than 7.0L/100km), through a higher value threshold for these vehicles. Some state and territory governments also offer a concession on stamp duty or vehicle registration charges for low-CO₂ and/or hybrid/electric vehicles.

Since 2009, the COAG has been considering the introduction of fuel efficiency and vehicle emission standards. In 2015, the government established the Ministerial Forum on Vehicle Emissions which is consulting on new light-vehicle fuel efficiency standards, stronger vehicle noxious emissions standards, improved fuel quality standards and other measures to encourage the uptake of more efficient and cleaner vehicles. Building on a discussion paper (Ministerial Forum on Vehicle Emissions, 2016), the government presented in December 2016 the draft regulation impact statements on improving the efficiency of new light vehicles and on vehicle emissions standards for cleaner air (equivalent to Euro 6 vehicle emission standards). It also released a discussion paper on better fuel for cleaner air with five policy options for legal instruments to improve fuel quality, based on the 2015 independent review of the *Fuel Quality Standards Act 2000*.

Industry

Energy consumption and intensity

Industry was the second-largest energy-consuming sector in Australia, accounting for just over one-third of TFC in 2015. Unlike the transport sector, energy consumption in industry has been rather stable over the last decade (see Figure 7.11). In 2015, the industry sector consumed 28.1 Mtoe, an increase by 3% since 2005 but saw a decline by 4% in the last two years. The sector included non-energy consumption, which represented 4.1 Mtoe of oil, mostly used as feedstock in industrial processes.

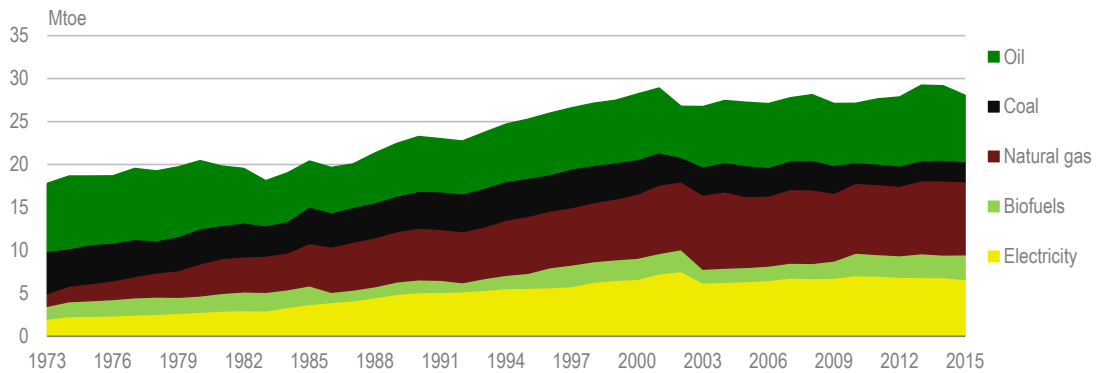
Fossil fuels accounted for nearly two-thirds of total energy consumption in industry, which is the biggest natural gas and oil user. Electricity accounted for 24% and biofuels for the remaining 10%. The fuel mix has been quite stable over the last decade, with the biggest changes being a 75% increase in biofuels and a 36% decline in coal consumption between 2005 and 2015. The three largest industry sectors, non-ferrous metals, mining and quarrying, and food and tobacco industries accounted for two-thirds of total energy consumption (see Figure 7.12). The closure of aluminium smelters has reduced energy intensity of basic metals by 25%, but the overall energy intensity in manufacturing industries has been stable because of increases in the food and chemicals industries² (see Figure 7.13).

Policies

The NEPP 2015 did not contain specific policy measures for the industry sector, although it acknowledged that energy productivity measures in industry, for instance in manufacturing, agriculture or mining, could provide cost-effective methods of emissions reduction. In 2016, industrial energy efficiency measures became eligible for funding under the Commonwealth's Emissions Reduction Fund (ERF). State-based white certificate schemes, particularly in New South Wales and Victoria, are also creating incentives for industrial energy efficiency.

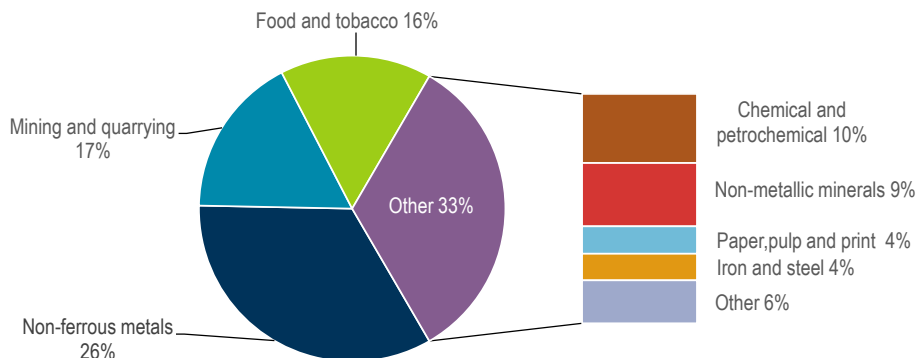
Several programmes for industry energy efficiency were carried and delivered a large amount of data to design policies and regulations for the industry sector: Energy Efficiency Opportunities (EEO) programme and the Energy Efficiency Information Grants Programme. The EEO was closed in 2014, after enhancing capacity for large energy users to act to reduce energy and thus business costs. The Energy Efficiency Information Grants Programme finished in June 2015; it had funded a number of industry associations to develop energy efficiency initiatives in their sectors. The programme had mixed success, but positive aspects for most of the industries involved. EEO was closed to reduce the regulatory burden on industry, despite the review of the first EEO cycle having recommended its continuation as it had enabled energy savings that were 40% more than business-as-usual. The EEO was extended to electricity generators in 2011, as the results from trials were better than for network companies, which were not included. The EEO programme was also extended to cover new industrial projects or major site expansions, but was not fully implemented when the programme ended.

² Some gas processing, refineries and coke ovens consumption is allocated to the chemical sector in the data submitted by Australia.

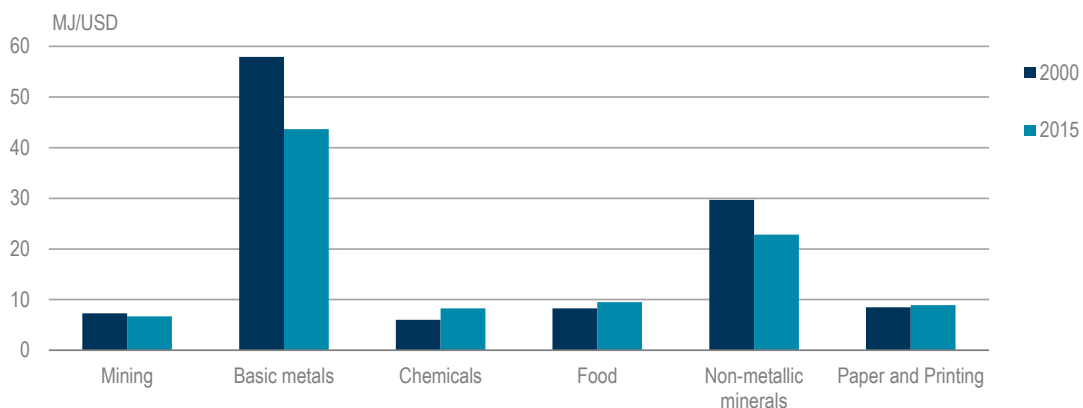
Figure 7.11 Total final consumption in industry by source, 1973-2015

Note: *Industry* includes non-energy consumption.

Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 7.12 Total final consumption in industry by sector, 2015

Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 7.13 Energy intensity in selected industry sectors, 2000-15

Note: Data on chemical industry are uncertain given that some refineries and coke ovens consumption is allocated to the chemical sector in the Australian data submission.

Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

The Australian Energy Regulator (AER) is examining initiatives to reward network companies for supporting greater demand-side management or energy savings through investing in smart grids or reducing transmission losses. After a period of increasing network tariffs, new investment programmes are being scrutinised. With larger shares of

distributed generation, notably solar PV, the network usage of the network and the distribution of cost have declined, thus creating undercoverage, while new investments are critical for the integration of renewable energy sources. The ARENA's 2017 Investment Plan includes funding for energy productivity projects. ARENA and the system and market operator AEMO started an innovation programme on demand response.

Australia aims to encourage greater energy productivity but relies on voluntary action in the industry sector. There is no benchmarking of industry's energy efficiency performance in Australia, except for a study undertaken in 2010/11. The study found that benchmarking would be too difficult and somewhat meaningless, owing to variations in energy intensity that could not be modelled with energy efficiency, e.g. the quality of ore deposits in the mining sector. Instead, the government intends to work co-operatively with business leaders on energy productivity improvements. A range of activities is carried out by industry alliances, for instance the *Doubling Australia's Energy Productivity (2xEP)* steering committee, supported by the *Alliance to Energy Productivity* (formerly the *Australian Alliance to Save Energy*), which has been working with industry to develop detailed sector roadmaps.

Industrial energy efficiency projects could benefit from the Emissions Reduction Fund (ERF), which supports industry to take direct action on emissions and improve energy productivity. However, the administrative complexity of the ERF would increase compliance cost for some business, and may make the programme less geared to industry. The Safeguard Mechanism could be a driver for large industrial facilities with direct emissions of more than 100 000 tCO₂-eq. a year (around 340 facilities) to invest in energy efficiency as a means to keep emissions at or below their baselines. This would act as a minimum performance standard for industry. As part of the 2017 climate policy review, the Australian government is considering the future role of the Safeguard Mechanism in contributing to meeting the emission targets and energy efficiency goals.

Residential and commercial

Energy consumption and intensity

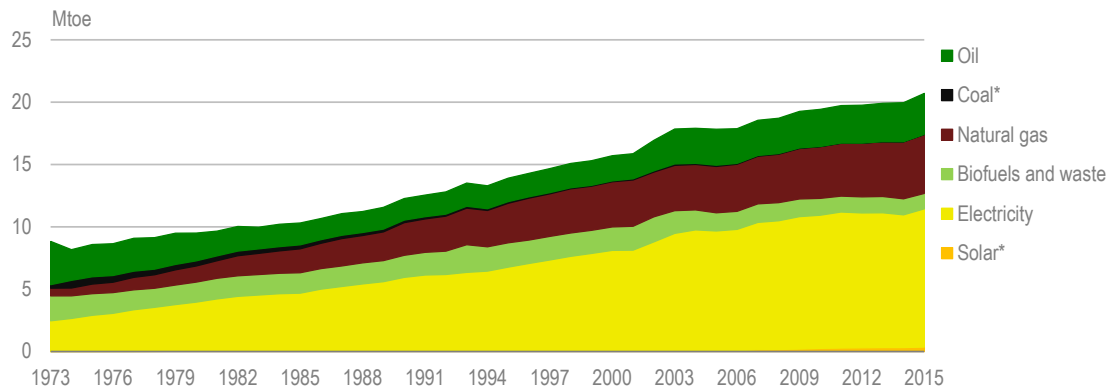
The residential and commercial sectors account together for just over one-quarter of TFC in Australia, which is the third-lowest share among IEA member countries. In 2015, residential and commercial consumption were 10.5 Mtoe and 10.2 Mtoe respectively, a total increase by 16% since 2005 (see Figure 7.14).

Electricity accounts for over half the total energy consumption in the sectors and electricity demand has increased by 15% over the decade 2005-15. Natural gas is the second-largest energy source, accounting for 23% of total consumption, followed by oil at 16% and biofuels at 6%. While natural gas and biofuels are mainly consumed in the residential sector, oil consumption is mostly in the commercial sector.

Space and water heating accounts for a majority (60%) of energy consumption in the residential sector (see Figure 7.15). Residential space heating demand has increased by 7% over the years 2000-15 (see Figure 7.17) despite an almost 30% reduction in energy intensity per floor area (see Figure 7.18). Population growth could be the main reason for the increase in space-heating demand, which has been met mainly by growing use of

natural gas. Water heating consumption has increased by 20% over the same period, with a more modest reduction in energy intensity per person. Despite its small share, space cooling is very important as it drives peak electricity demand and network cost.

Figure 7.14 Total final consumption in the residential and commercial sectors by source, 1973-2015



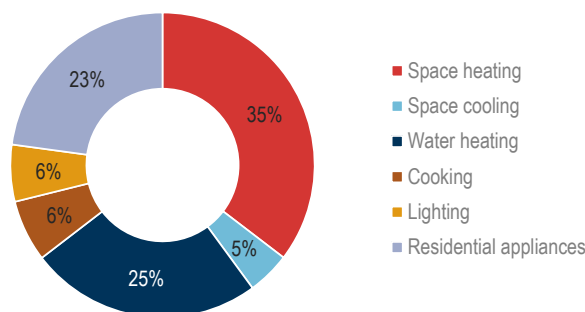
* Negligible.

Note: The commercial sector includes commercial and public services, agriculture, forestry and fishing.

Source: IEA (2017a), *World Energy Balances 2017*, www.iea.org/statistics/.

Appliances consume around one-quarter of total energy used in the residential sector. Their consumption has increased by 34% from 2000 to 2015. Residential appliances are almost entirely driven by electricity, and their growth accounted for most of the increases in electricity consumption. It is noteworthy that appliances and space cooling have both increased in energy intensity, pointing to the need to strengthen product efficiency standards over time, in step with consumption and technology development.

Figure 7.15 Energy consumption in the residential sector by energy use, 2013



Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

Policies

Appliances, equipment and lighting

The national framework for appliance, equipment and lighting energy efficiency in Australia was created with the implementation of the *Greenhouse and Energy Minimum Standards Act 2012 (GEMS Act)* on 1 October 2012. The GEMS regulator, based in the Commonwealth Department of the Environment and Energy, replaced the previous state

regulators and is the sole party responsible for administering legislation in Australia. The GEMS framework includes a robust registration and compliance process.

In 2014-15, an independent review of the GEMS Legislative Scheme was undertaken. The review found that there was a strong case for mandatory appliance standards and labelling programme; that GEMS aligns with government energy productivity policies and priorities; and that it delivers significant economic and environmental benefits cost effectively. On an annual basis, the Equipment Energy Efficiency (E3) programme contributes more than AUD 1 billion in energy costs avoided to the economy, an estimated 11.6 MtCO₂ emissions (Department of Industry and Science, 2015).

The *GEMS Act* is the underpinning legislation for the Equipment Energy Efficiency (E3) programme. For over 20 years, the E3 programme has served as a cross-jurisdictional initiative through which the Australian government, the states and territories, and the New Zealand government collaborate to deliver a single, integrated programme on energy efficiency standards and energy labelling for appliances, equipment and lighting. In June 2016 an E3 Prioritisation Plan. It was released that identifies how the E3 programme will accelerate future policy development and focus on regulating products that will deliver the most energy with emission savings. As of September 2016, there were 22 GEMS determinations that cover different products in the residential, commercial and industrial sectors.

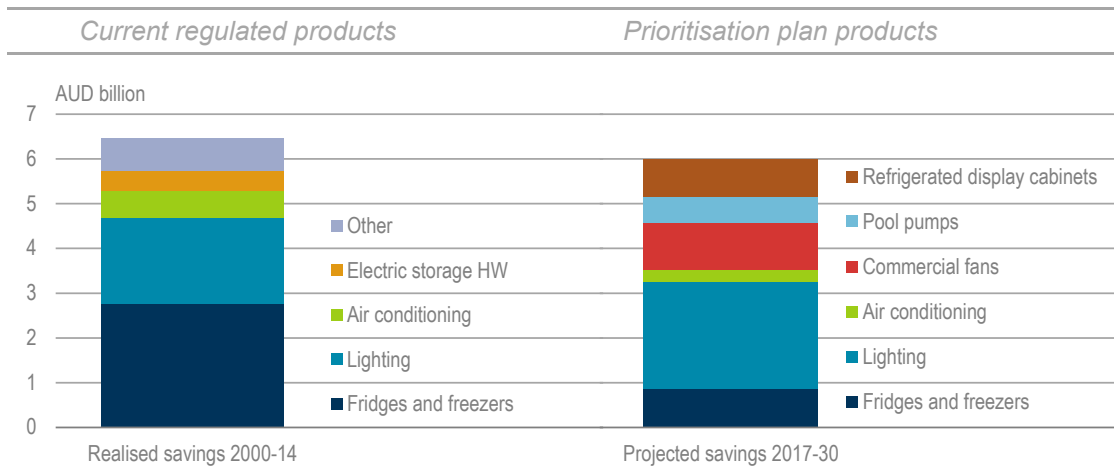
The GEMS Inter-Governmental Agreement (IGA) sets out government funding of the programme, with a total of AUD 16.9 million of operating non-staff budget over the period 2013-16, in addition to other Commonwealth funding to meet staffing costs for the implementation of the E3 programme and activities not funded under the IGA. Other jurisdictions also incur some staffing and other costs for E3-related activities. Australia is regularly reviewing the net financial benefits of the E3 programme. Such an analysis has helped guide Australia's review and development of appliance standards, i.e. it has increased the number of appliances covered, and the prioritisation plan has helped focus on those appliances that lead to large financial benefits (see Figure 7.16).

Buildings sector

Energy efficiency requirements in building codes for both residential and commercial buildings are out of date with recent technologies. As outlined in the NEPP, the COAG Energy Council is working with the Australian Building Codes Board and Building Ministers Forum to consider changes to the Code to strengthen energy efficiency within the next cycle of revision of the National Construction Code, which is to be completed by 2019. The monitoring of compliance with and enforcement of the Code has been set as an objective for the Council's activities under the NEPP, in collaboration with the National Energy Efficient Building Project.

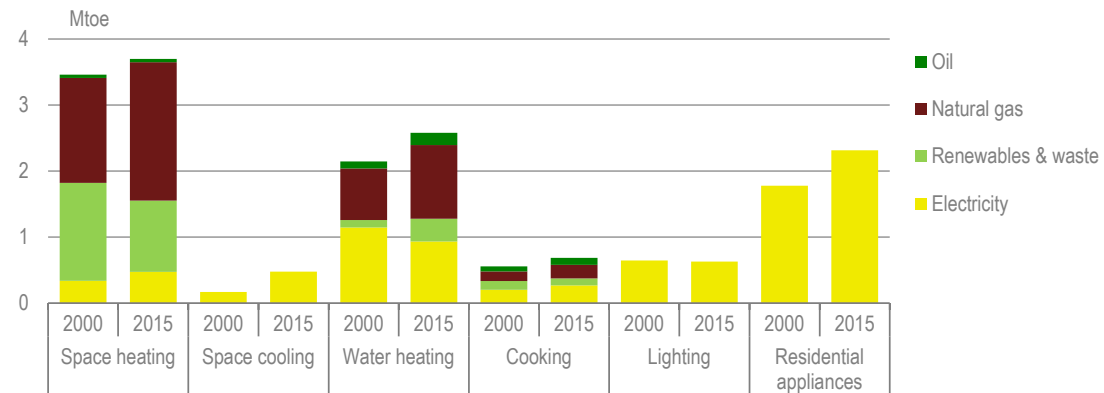
Australia has successfully implemented mandatory disclosure of the environmental performance of commercial buildings (office buildings or spaces over 2 000 square metres – and 1 000 m² since 1 July 2017) through the Commercial Building Disclosure (CBD) scheme, and the use of mandatory ratings, like the National Australian Built Environment Rating System (NABERS). This has stimulated the property market where major property companies are listed in the international sustainable building indexes. The recent expansion of the CBD scheme suggests that the scheme would provide AUD 69 million energy savings and 3.8 Mt carbon reduction from 2015 to 2019 (Acil Allen Consulting, 2015).

Figure 7.16 Benefits of the E3 programme and its future priorities



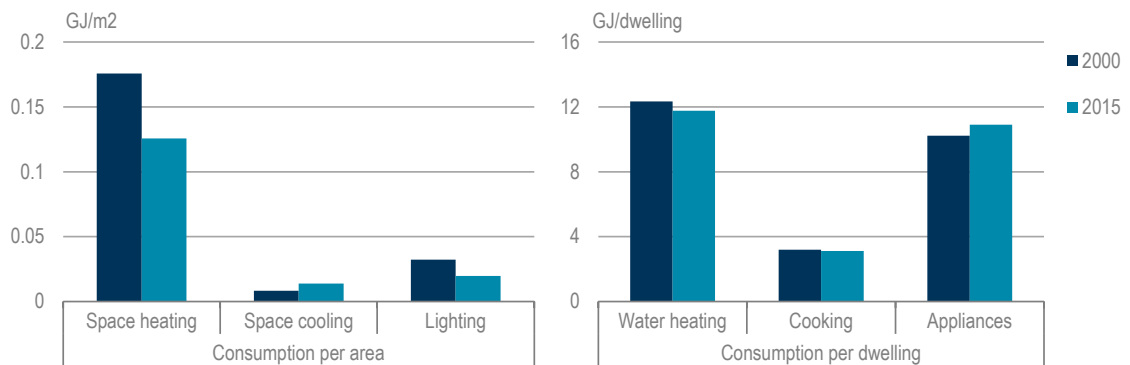
Source: Australian government, 2017.

Figure 7.17 Residential energy consumption by energy use and fuel, 2000-15



Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

Figure 7.18 Energy intensity in the residential sector by energy use, 2000-15



Source: IEA (2017b), *Energy Efficiency Indicators 2017*, www.iea.org/statistics/.

To date, residential buildings are not part of the disclosure and rating programmes, and there is no common framework in place. In December 2015, the COAG Energy Council agreed to a national collaborative approach to residential building energy ratings and disclosure and guiding principles. More work will be undertaken to consider a range of different tools to improve information for residential buildings. Greater consideration could also be given to the financing of renovation works, for instance through green depreciation (as is successfully used in France with tax rebates and zero interest loans) which would encourage certain renovations based on an improved ranking.

Unlike other major economies, Australia does not have a national target or vision for the minimum building standards required to align the performance of new buildings to a low-carbon economy. A vision towards 2050 Zero Carbon Buildings was formulated by the Australian Sustainable Built Environment Council in 2016 (ASBEC, 2016) calling for a National Plan towards 2050 Zero Carbon Buildings.

Electricity end-use

Better analysis and forecast of electricity and energy demand is critical to inform adequate energy planning. Australia has found it difficult to collect electricity consumption data behind the meter for the non-registered generators located off grid. With better demand analysis and regulatory incentives, network operators could be able to reduce costs through building less infrastructure and better matching demand with supply.

As explained in Chapter 4 on Electricity, demand response is still underdeveloped in Australia. The Australian Renewable Energy Agency (ARENA) is working with the Australian Energy Market Operator (AEMO) to pilot a demand-response initiative to drive innovation in how Australia manages the grid with high levels of variable generation from renewable energy. The initiative aims to secure 100 MW of demand-response capacity by summer 2017/18 and is over-subscribed.

At the retail level, price regulation and gentailing structures prevailed until recently. With the end of regulated prices in most states/territories, there is greater activity to consumer participation by demand response through smart meters, demand aggregators or time-of-use pricing. Almost all states/territories offer discounts on gas or electricity prices to support consumers in paying their energy bill, amid rising prices. This does not depend on whether the jurisdiction has regulated or deregulated prices. Some support is targeted on pensioners and consumers which receive other public support (i.e. medical support), but many jurisdictions offer wider support. Such policies do not yet regularly include energy efficiency objectives. The federal government's Your Energy Savings website provides targeted guidance for vulnerable energy-users and information to enable households to better manage energy use and costs.

In 2015, the COAG created the Energy Consumers Australia (ECA) as a dedicated consumer advocacy body. ECA is also developing advice to support vulnerable consumers, a growing category in Australia, amid rising electricity prices and concession programmes. ECA could also build on the Low Income Energy Efficiency Programme, which ended in June 2016, and provided funding to 20 trials looking at ways to promote energy efficiency to low-income groups of different categories. The ECA biannual Energy Consumer Sentiment Survey also provides information on household and small business consumers, satisfaction, confidence and activity.

A consumer survey prepared for the Australian *Alliance to Save Energy* by the Institute for Sustainable Futures, at the University of Technology Sydney (Ghiotto et al., 2011) found the lack of co-ordination between state and national level policies and the energy supply-bias of network operators and utilities, which have no incentive to invest in demand response, among the key barriers to electricity efficiency progress in Australia.

Assessment

Total final energy consumption in Australia saw a 13% increase over 2005, but its intensity has come down by almost 15%, following closure of large industry. The largest energy consuming sectors are transport (40%), industry (35%), residential (13%) and commercial (13%). Unlike other countries, transport is not only the largest energy-consuming sector but also the sector where energy consumption has increased the most following demographic growth and the resource boom.

Growth in energy consumption has generally remained below the rate of economic growth over the past three decades, leading to a decrease in energy intensity. In recent years, energy consumption growth stalled. Energy demand patterns have changed; industrial demand is in decline, energy prices on the rise, and electricity peak demand has been rising across Australia. One of the main challenges in Australia's electricity grid is to ensure network stability and reliability. Increased energy productivity reduces pressure on the electricity sector to transition.

Since the previous review in 2012, Australia has adopted a national target of 40% improved energy productivity by 2030 over 2014 levels. Australia does not have an energy efficiency target for 2020, so that even if the target is aspirational, and there is no burden-sharing setting, the adoption of a target is a big step forward. 40% productivity improvement between 2015 and 2030 compares to the 28% increase in energy productivity that occurred between 2000 and 2015. To implement the national target, Australia has adopted a cross-sectoral National Energy Productivity Plan (NEPP) covering a wide range of measures. The NEPP is also contributing to Australia's commitment to the Paris Agreement (reducing carbon emissions by 26% to 28% by 2030) but it remains unclear at which level energy efficiency will provide cost-effective emissions reductions.

Given the high carbon content of Australia's electricity mix, more efficient use of electricity, e.g. through more efficient appliances, will be critical to achieve carbon reductions along a general decarbonisation of the power mix. No doubt, low-carbon power generation can help reduce energy use and emissions in the transport sector if Australia endorses greater electrification.

Energy efficiency policies are implemented both at national and state levels. The level of ambition in energy efficiency varies across the states. White certificate schemes are operational in some states (Australia Capital Territory, Victoria, New South Wales, South Australia), whereas other states would prefer the establishment of a national scheme. However, frequent institutional changes of the energy efficiency policy unit within the Australian government have undermined efficient policy leadership at national level. Building on the COAG Energy Council initiatives, collaborative national frameworks for energy efficiency should be expanded to boost the implementation of the NEPP. The integration of energy efficiency policies under the Department of the Environment and

Energy (DoEE) is precondition for their integration with climate policies; this also allows DoEE to run all energy efficiency programmes (regulation and grants) to support policy implementation. However, many grants programmes ended in 2015. The DoEE's new energy data and its analysis group is continuously developing and strengthening energy end-use data, in collaboration with CSIRO, AEMO and the Australian Bureau of Statistics (ABS), notably through the AUD 13.4 million Energy Use Data Model and online platform. In 2017, the Climate Change Authority and the Australian Energy Market Commission recommended the adoption of a National Energy Savings Scheme which would also allow energy efficiency to contribute to emissions reductions (CCA/AEMC, 2017).

Transport

The transport sector represents a large share of energy use (40%) and carbon emissions. The government promotes energy efficiency in the transport sector through fuel consumption labels, green vehicle guide, fuel excise duties and a rebate on the luxury car tax for fuel-efficient vehicles. The government is promoting energy efficiency and carbon reduction in this sector including through the Clean Energy Finance Corporation (CEFC), which has a range of co-finance aggregation partnerships that can assist with finance for low-carbon vehicles (total financing support for vehicles exceeds AUD 650 million). The Emissions Reduction Fund (ERF) also covers the transport sector and provides opportunities to earn carbon credits for projects that reduce emissions through improvements to vehicle efficiency in the land and sea transport sectors.

The Commonwealth government has created a Ministerial Forum to promote its commitment to reduce Australia's vehicle emissions. To date, Australia does not have fuel efficiency or vehicle emissions standards but the Ministerial Forum is considering options. Given that the domestic vehicle manufacturing industry will close in 2018 and that the countries where Australia imports its vehicles from (Japan, Korea) all have vehicle fuel efficiency standards, the barriers to implementing these standards have been substantially reduced. An update and alignment of Australia's fuel quality standards (which cease to have effect in 2019 under the Act) with international best practice (limiting sulphur and octane content) would help to reduce harmful pollutants released by vehicles and enable Australia to use advanced vehicle technologies (including advanced emissions control systems and some fuel-efficient engine technologies) which require high quality fuel to work effectively.

Buildings

The built environment represents 49% of electricity use and 23% of emissions in Australia (ASBEC, 2016). A national construction code applies to new buildings and major renovations. Work is ongoing to strengthen the construction code by 2019 and to improve compliance under the NEPP. However, government policies in the built environment should be informed by a long-term vision for the building stock, as articulated by the Australian Sustainable Built Environment Council (ASBEC), and adopt a plan for regular and ambitious updates of the National Construction Codes.

Australia is leading a nationwide mandatory Commercial Building Disclosure (CBD) programme for disclosure of the energy performance of commercial buildings which has been introduced since the last review. It is expected to lead to AUD 69 million energy savings and 3.8 MtCO₂ reductions from 2015 to 2019 inclusive.

For existing buildings, there is a large potential for energy efficiency improvements. A general observation is that energy efficiency in existing buildings deserves more attention at both national and state levels because of the long lifetime of buildings. There is a potential for larger uptake of innovations and smart technologies in the building sector and institutions like ARENA could be invited to explore technology priorities that should be developed to stimulate this. As AEMO and ARENA have started work on the demand response, the outcomes should be evaluated and fed into the energy efficiency policy work.

Households

Consumers in Australia are facing increases in their electricity and gas bills. To some extent, high energy prices have also created incentives for households to reduce their consumption by investing in solar PV. These consumers become “prosumers” through the large uptake of rooftop solar and solar water-heating systems.

On the other hand, Australian states and territories have large subsidy schemes for households to support their energy bills, notably vulnerable consumers. However, such subsidies are often not well targeted and can fail to encourage consumers to save energy. Government aid programmes should be reformed to support consumers’ action on energy efficiency (including renovation or fuel switching as well as flexible tariffs and metering).

Consumers will play an important role in the transition to a low-carbon energy system. The importance of consumer aspects and consumer engagement has been demonstrated, for instance in the difficulties encountered in Victoria during the mandated roll-out of smart meters. The roll-out across the NEM has not been completed yet. It is voluntary and states and territories are rolling out according to their own time frames. Consumers can contribute to the transition if they are engaged in it but if consumer aspects are neglected, the transition can be severely hampered.

In this context it is welcome that COAG has taken the decision to finance Energy Consumers Australia. Innovation in energy efficiency is important for the transition and ARENA’s investment in energy productivity projects is welcome. The federal government and states’ jurisdictions are providing information to consumers and businesses on energy efficiency and related aspects. A better understanding of decision making and behavioural change in households and businesses is needed to strengthen information-based measures. There is an opportunity to assess the impact that energy efficiency policies could have on reducing power supply and grid infrastructure costs (not to mention emissions). At the same time, the government should promote distributed renewables, smart meter roll-out, contribution from demand response and time-of-use pricing as strong incentives for end-users to control their energy consumption.

Australia has an effective programme for appliance energy efficiency (GEMS legislative framework) currently covering 22 residential and commercial products. A continued strong implementation and further development of the programme is recommended, notably as the energy use of appliances and the energy efficiency of some appliances had increased in Australia in 2013 over its level in 2000.

Industry

The industry sector is a large energy user. Since the previous IEA review, the Energy Efficiency Opportunities (EEO) programme for energy-intensive industry has been

repealed with a view to ease the regulatory burden and compliance costs for energy-intensive industries. The EEO has built up capacity in industry to achieve productivity gains. The discontinuation is contrary to the recommendation in the previous IEA review to expand the scheme to grid operators, and a domestic review recommended its continuation. Given the potential for industrial energy efficiency, the scheme's effectiveness and the lack of dedicated industry measures in the NEPP, the government should consider reintroducing a programme for energy efficiency in industry, notably for small and medium-sized companies. The efficiency method of the Emissions Reduction Fund can credit emissions reductions achieved through energy efficiency improvements in industry (hardly tried to date); and it could be complemented by a sort of EEO programme.

For direct emissions, there is an important potential to reduce pollutants, which could be achieved by setting an emission threshold under the ERF safeguard mechanism, complemented by the research and development funds of the Clean Energy Finance Corporation (CEFC) for energy efficiency upgrades of power generation and industrial processes which reduce pollutants below the threshold. To structure funding of industrial projects, the Clean Energy Regulator, which collects emission data by facility, should improve the disaggregation of the published data to allow sector- or facility-level analysis and energy scenario analysis and planning.

Recommendations

The government of Australia should:

- Ensure the full implementation of the National Energy Productivity Plan, focused on improved energy end-use and emissions data collection and forecasts; understand and emphasise the role that energy efficiency will play across all relevant policy areas in the transition to a low-carbon energy system.
- Establish a long-term vision for an energy-efficient and decarbonised building sector accompanied by regular updates of the national construction code.
- Adopt ambitious fuel efficiency and emission standards for the transport sector, and start with light vehicles as a first step.
- Introduce measures for energy efficiency in business and industry, building upon the experiences from the Energy Efficiency Opportunities programme and through Clean Energy Finance Corporation funding of projects that also reduce GHG emissions in industrial facilities.

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8. Renewable energy

Key data

(2016 provisional)

Total supply: 8.7 Mtoe (6.5% of TPES) and 37.7 TWh (14.7% of electricity generation).
IEA average: 9.6% of TPES and 23.9% of electricity generation

Hydro: 1.3 Mtoe (1% of TPES) and 15.1 TWh (5.9% of electricity generation)

Biofuels and waste¹: 5.4 Mtoe (4.1% of TPES) and 3.7 TWh (1.4% of electricity generation)

Wind: 1 Mtoe (0.8% of TPES) and 12.1 TWh (4.74% of electricity generation)

Solar: 1 Mtoe (0.7% of TPES) and 6.8 TWh (2.70% of electricity generation)

Overview on demand and supply

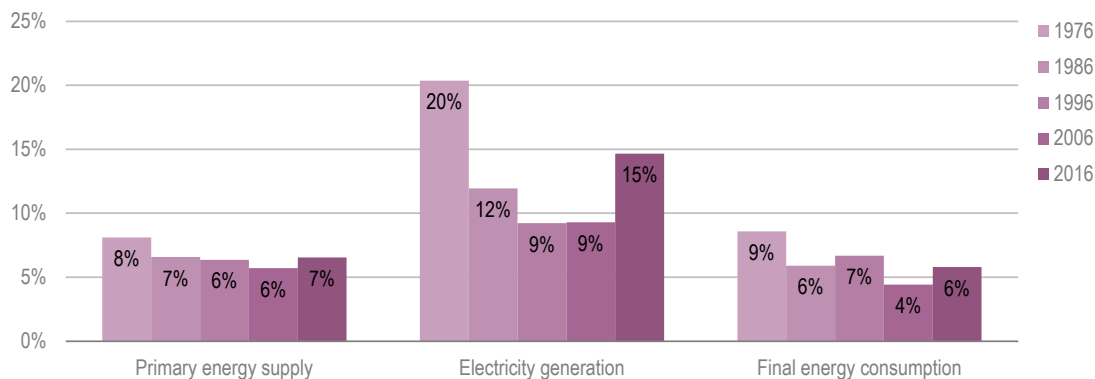
The share of renewable energy in total energy supply and in electricity generation in Australia has grown over the past decade, as Figure 8.1 illustrates. Much in line with strong growth of renewables in the IEA average, the role of renewable energy has also seen a structural shift in some regions of Australia since the last IEA review of 2012. In particular, wind and solar energy have quickly developed from a marginal electricity source to a structural driver of change in the system in South Australia.

In the power sector, Australia supports renewable energy through a quota system combined with tradable green certificates for large-scale installations and an investment support scheme for small-scale installations. Progress in the heating and transport sectors remains slow. Deployment of new wind and solar power has occurred unevenly across the country. For example, in 2016, South Australia reached a 43% share of renewable energy (AEMO, 2016), out of which 38% of wind power and 17.8% of rooftop solar, which is much larger than the state's share in national electricity consumption (2.4%) or the state's share in overall generating capacity (6.8%).

Owing to excellent resources and a favourable policy environment for small-scale solar installations, South Australia has the highest rooftop PV penetration rate per household in the world, reaching 29% of dwellings in 2016 (AEMO, 2016).

¹ Biofuels and waste = solid and liquid biofuels, biogases, industrial waste and municipal waste.

Figure 8.1 Renewables share of TPES, electricity generation and TFC, 1975-2016



Notes: Data are provisional for 2016. The latest consumption data are for 2015.

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

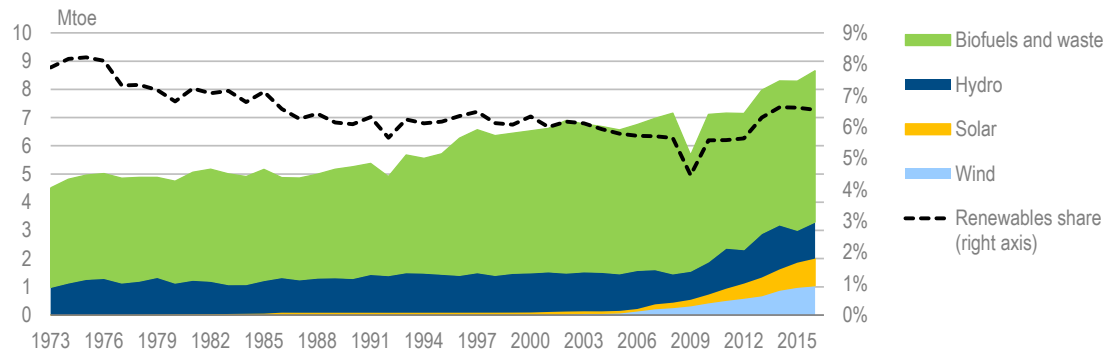
Renewable energy in TPES

After a long period of relatively stable supply, renewable energy sources have increased since 2012 as a result of a growing renewable power capacity from wind and solar. For several decades, renewable energy sources have often been unable to keep up with the total increase in total primary energy supply (TPES) and total final consumption (TFC). As a consequence, the share of renewables declined slowly.

Between 2006 and 2016, however, renewable energy has increased by 28%, thanks to solar and wind energy growing tenfold (see Figure 8.2). In 2016, of solar energy in TPES, 59% was electricity generation from PV and 41% was hot water generation from solar thermal collectors. Renewables accounted for 6.5% of TPES in 2016, up from 5.7% in 2006. This is low compared to many IEA member countries, with only three countries having lower shares of renewable energy in TPES than Australia (see Figure 8.3).

Biofuels and waste accounted for the largest share of renewable energy in TPES and have steadily supplied around 5 Mtoe per year. The industry sector, notably food production, is the largest consumer of biofuels, mostly by combustion of biomass (see Figure 8.4).

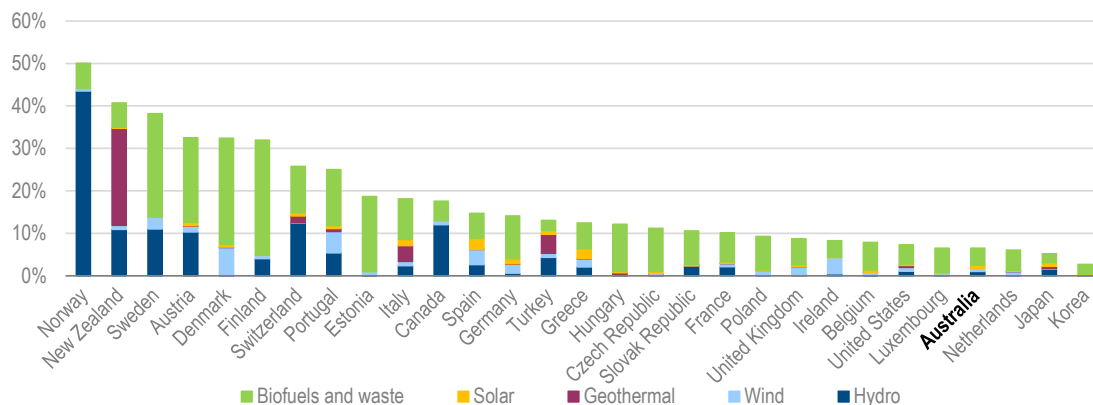
Figure 8.2 Renewable energy in TPES, 1973-2016



Note: Data are provisional for 2016.

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

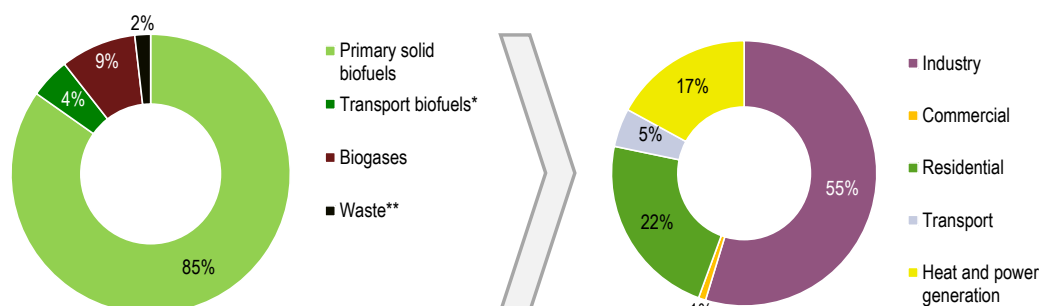
Figure 8.3 Renewable energy as a percentage of TPES in Australia and IEA member countries, 2016



Note: Data are provisional.

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 8.4 Supply and consumption of biofuels and waste, 2015



* Transport biofuels contain similar shares of biodiesel and biogasoline.

** Waste is mainly industrial waste (renewable and non-renewable).

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

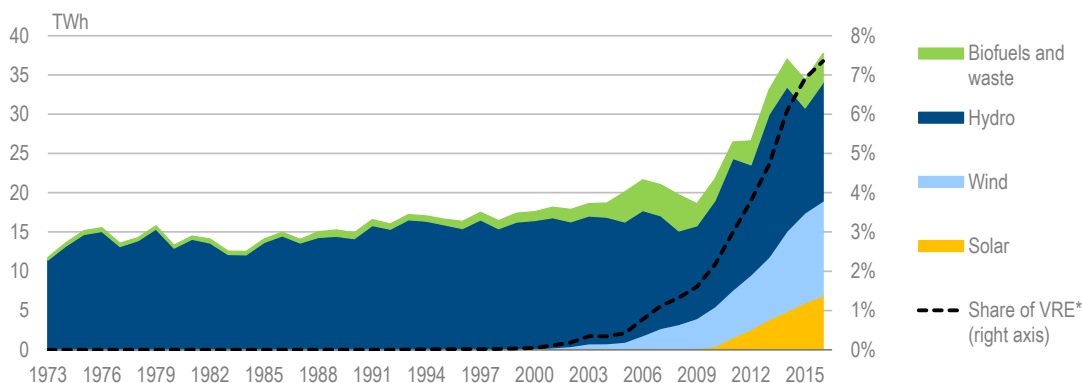
Electricity generation from renewable energy

Total electricity generation from renewable energy sources has increased by 74% in Australia as a whole between 2006 and 2016, despite annual fluctuations of hydropower availability (see Figure 8.5). The share of variable renewables (wind and solar) has seen strong growth since 2009, and it reached 7.4% in the power mix. The growth over the last ten years has been strongest in solar power, which increased from negligible levels to 6.8 TWh in 2016. Most of this growth occurred in the last five years.

Wind power has also increased significantly in the last decade, from 1.7 terawatt-hours (TWh) in 2006 to 12.1 TWh in 2016. Despite this rapid increase in recent years, in absolute terms, Australia has the seventh-lowest share of renewable energy in electricity generation among IEA member countries (see Figure 8.6).

In terms of solar energy, however, Australia has the tenth-highest share in the IEA. The average size of rooftop panel systems is increasing (Clean Energy Council, 2017), boosting solar PV penetration to high levels. Although only a small share of systems deployed in 2016 had integrated systems with battery storage, the market for batteries is expected to expand rapidly in the coming years.

Figure 8.5. Renewable electricity and the share of VRE in Australia, 1973-2016

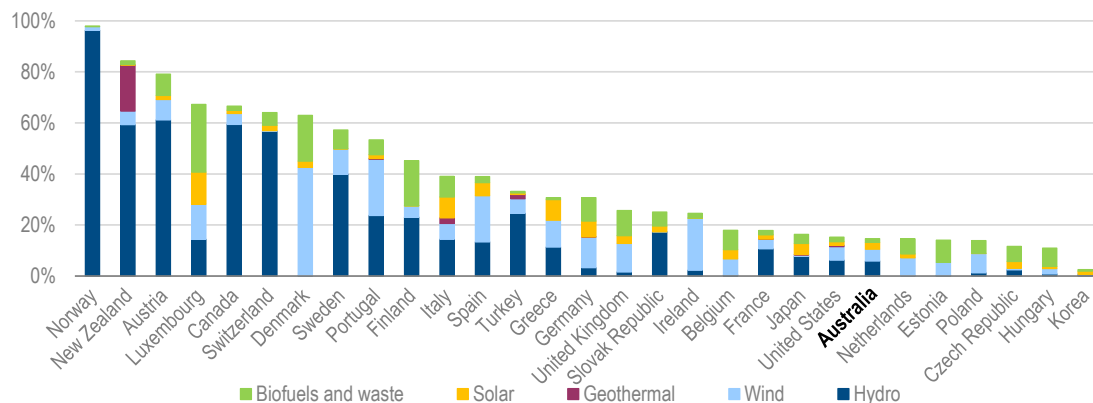


* Variable renewable energy includes solar and wind.

Note: Data are provisional for 2016.

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure 8.6 Electricity generation from renewable sources as a percentage of all generation in Australia and in IEA member countries, 2016



Note: Data are provisional.

Source: IEA (2017), *World Energy Balances 2017*, www.iea.org/statistics/.

Policies and measures

Historically, Australia was a pioneer in terms of renewable energy policies: the Renewable Energy Initiative, funded in 1994, supported the development of a renewable energy technology industry; AUD 10 million was allocated over seven years to support the establishment of a Co-operative Research Centre whose primary objective was to develop renewable energy. Many policies supporting renewable energy industry and renewable energy sources (RES) procurement have been developed.

Electricity

Renewable energy in the power sector is supported by a number of policies, at both Commonwealth and state levels. The main federal policy is the quota system, which sets a minimum medium-term target for renewable energy in Australia. State- and territory-level policies aim to reach targets which may or may not be aligned with the Commonwealth targets and policies.

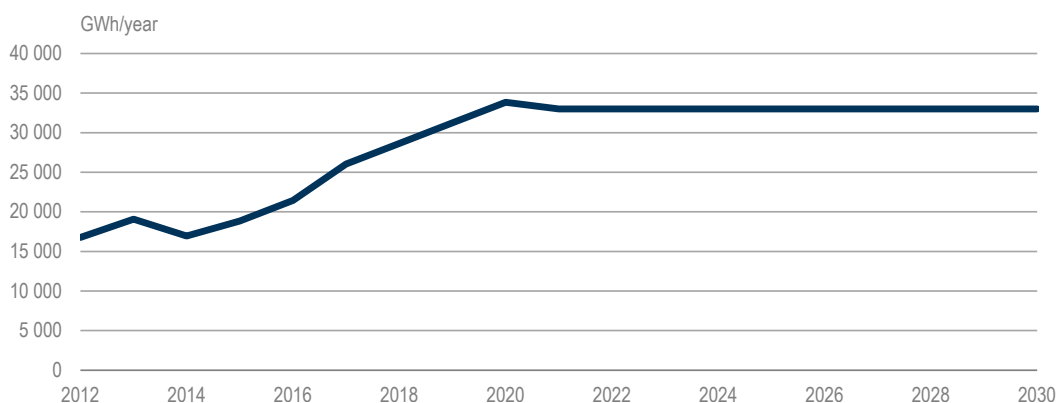
Commonwealth government policies

Quota scheme

The Renewable Energy Target (RET) is the Australian federal government quota scheme that mandates the production of 33 terawatt-hours (TWh) of renewable energy (or 23.5% of the electricity mix) by 2020. The RET is a quota obligation (put on suppliers) that is fulfilled via tradable certificates. Since January 2011, the RET scheme has been operating in two parts: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES), the latter being similar to an investment grant scheme (see below).

In 2014, the government reviewed the target during a period of several months. Meanwhile, investment in renewable energy technology stalled. Investment in the year to September 2014 was down by 70% on investments during the 12 months before June 2015, when the Australian Parliament passed the *Renewable Energy (Electricity) Amendment Bill 2015*. As part of the amendment bill, the Renewable Energy Target was reduced from 41 000 gigawatt-hours (GWh) in 2015 to 33 000 GWh in 2020 with interim and post-2020 targets adjusted accordingly.

Figure 8.7 Renewable energy target under the amended Renewable Energy (Electricity) Act 2000



Source: CER (Clean Energy Regulatory) (2017).

Large-scale Renewable Energy Target (LRET)

The LRET creates a financial incentive for the production of electricity from large-scale RES plants. A Large-scale Generation Certificate (LGC) is issued for each eligible MWh of electricity produced by an accredited renewable power plant. To participate under the LRET, power stations must generate their electricity from eligible renewable sources: solar, wind, ocean waves and tides, geothermal-aquifers, wood waste, agricultural waste, bagasse, black liquor or landfill gas. The certificates are then sold to obligated entities (mainly electricity retailers) who have to surrender their LGCs annually to the Clean Energy Regulator (CER) to demonstrate their compliance with the RET scheme's annual targets.

Small-Scale Renewable Energy Scheme (SRES)

The SRES, in a similar way, creates a financial incentive for home-owners and business to install eligible small-scale renewable systems (PV systems, solar water heaters and heat pumps). Small-scale technology certificates (STCs) are created for these installations according to the amount of energy they are expected to produce or displace

over the deemed life of the system. There is no upfront target set for the SRES and the amount of certificates is determined every year and is not capped. For simplification, the certificates for small-scale projects are issued in advance on the basis of the estimated amount of energy the system will generate or displace over its lifetime, thus providing an investment incentive instead of a production incentive.

Entities with an obligation under the RET have also a legal obligation to buy STCs and surrender them on a quarterly basis. The amount of STCs is given by the “small-scale technology percentage”, set every year by the Governor General at the recommendation of the minister. The STCs created can be sold or traded to receive an upfront cash support or a discount on the system purchased, which contributes to reducing the capital cost of the system for the home owner.

Jurisdictional policies

While the national LRET/SRES contributed to growth and coherent support methodology, state government commitments towards clean energy and local renewable conditions have been drivers of the recent energy system transformation, as illustrated in the case of South Australia. Electricity mixes differ greatly between the states and territories of Australia. Besides Tasmania, renewable energy shares are high in South Australia, with 42% of variable renewables (solar and wind).

Table 8.1 Accredited small-scale PV generation (2017) and renewable electricity share

State	Small-scale PV generation (GWh)	Share of renewable energy in electricity generation
Queensland (QLD)	2 056	6%
New South Wales (NSW)	1 461	14.0%
Victoria (VIC)	1 056	12%
Tasmania (TAS)	108.5	91%
South Australia (SA)	895	41%
Western Australia (WA)	761	7%
Northern Territory (NT)	59	2%

Sources DoEE (2017), Department of the Environment and Energy (2017), “Australian energy statistics, Table O, www.environment.gov.au/energy/publications/australian-energy-update-2016.

State and territory targets

On top of federal renewable energy targets set by the quota system, individual states and territories set their own targets for raising the share of renewable energy in their electricity mix.

- The government of Queensland is committed to sourcing 50% of its electricity from renewables by 2030.
- The government of the Australia Capital Territory has legislated a 100% renewable energy target by 2020.
- The Victoria government’s targets are to use 25% of renewable energy sources by 2020 and 40% by 2025.

- The South Australia government's commitment is to cover 50% of the state's electricity needs from renewable sources by 2025, which was achieved in 2017 (53%).
- The New South Wales Renewable Energy Action Plan supports the achievement of a national target of 20% renewable energy by 2020.
- The Northern Territory government intends to adopt a target of 50% renewable energy by 2030.

State auctions

Achievement of state-level targets is not ensured via the Renewable Energy Target because the overall volume may be too small and/or the allocation of generating capacity may not go to the state concerned. States run their own procurement mechanisms. Auction mechanisms have gained traction, following successful implementation in some states:

- In late 2015, the Queensland government, in collaboration with ARENA, held a reverse auction to support up to 150 MW of solar projects by a long-term contract for difference. The government has announced that it will undertake another reverse auction for up to 400 MW of renewable energy capacity, which will include 100 MW of energy storage.
- The Capital Territory held auctions and contracted 640 MW of wind and solar capacity. Auction bids were evaluated on their overall value for money by considering the feed-in tariff price, risk, community engagement and local investment.
- Victoria is considering a reverse auction scheme to underpin its own renewable target.
- The New South Wales government announced a tender for 137 GWh of renewable energy for its Sydney Metro Northwest rail project in January 2016.

State feed-in tariffs

Most Australian jurisdictions have feed-in tariff (FiT) schemes, providing owners of small renewable energy systems with guaranteed fixed rates for the sale of electricity fed into the grid. There is no nationally mandated FiT design.

However, the Australian government has worked through the Council of Australian Governments (COAG) to develop a set of national principles. The tariff amounts are paid usually as credits on the electricity bills, for the net energy exported into the grid.

The FiT schemes differ by rate, capacity limit, eligibility criteria and other design elements. In some jurisdictions, energy retailers set their FiT rate independently. Tariff rates are determined annually.

The government of Queensland has announced a time-dependent feed-in tariff (T-FiT) for solar energy customers, as a voluntary alternative to the current flat FiT. The T-FiT will pay a higher price during a peak period when energy demand is high and lower prices during the rest of the day.

Table 8.2 Current feed-in tariff schemes for selected states and territories

	Rate of FiT	Capacity limit	Eligibility	Eligible forms of RE generation
VIC	11.3c/kWh	100 kW	Households, community organisations and small businesses	Low- emission technology
SA	Determined by retailers		Domestic, small business and community groups consuming <160 MWh per year	Solar PV
QLD	In South East QLD: determined by retailers Other regions 10.102 c/kWh	South East – no limit Regional: 5kW (though committed to increase to 30 kW)	South East – no restriction. Regional: small customers	Solar PV
WA	Determined by Public Utilities Office within the Department of Treasury	5kW (Regional retailer allows up to 10 kW per phase)	Residential, educational and not- for-profit community organisations	Solar PV, wind and micro hydro
NSW	Determined by retailers. NSW commissions annual research to provide guidance on a benchmark range: 11.9 to 15.0 c/kWh (2017/18) No obligation for retailers to offer within this range.			Solar PV
TAS	6.671c/kWh	up to 10 kW	Small customers	Renewable generation only – solar PV, wind, micro hydro
NT	25.67 c/kWh for residential customers, 29.84 c/kWh for other customers			Solar PV

Heating/cooling and transport sectors

Australia's policies in support of renewable energy sources mainly focus on the power sector but no policy encourages the use of RES in the heating and cooling (H&C) and in the transport sectors. Both heating and cooling and the transport sectors are not the subject of dedicated Commonwealth policies, despite an acknowledgement under the NEPP that both can considerably contribute to meet the country's emission reduction goals.

Solar water heating and heat pumps are among the low-cost options for reducing both CO₂ emissions and fossil fuel dependence. In many circumstances these technologies offer net savings compared to conventional heating systems in terms of life-cycle costs. At the same time, sustainable biofuels can contribute to CO₂ emissions reductions in the transport sector, while supporting agricultural markets and rural development. Advanced biofuels can also assist in achieving deeper levels of decarbonisation, while taking advantage of low-value waste and residue resources which may not currently have markets.

The Small-scale Renewable Energy Target (SRES) provides some incentives also in the H&C sector. Installers of solar water-heating systems can create Small-scale Technology Certificates (STCs) based on the deemed MWh that a system displaces over a 10-year period. During 2015, the scheme promoted the installation of 8 898 heat pumps and 42 525 solar water heaters.

ARENA made the deployment of renewable energy for industrial process heating a priority (bioenergy, solar thermal, geothermal). Funding of fuel switching projects in the industry can be credited under the Emission Reduction Fund (ERF). It is supported by the Clean Energy Finance Corporation (CEFC). The quality of solar radiation in Australia allows the generation of process heat at all-temperature levels. To date, projects working at relatively low-temperature levels (e.g. dairies and other agrofood industries, textiles, pharmaceutical, etc.) hold a competitive position vis-à-vis natural gas projects needing high-temperature processes.

There are no federal biofuels mandates and the existing grants have been abolished because of the inability of biofuels to gain a market foothold despite the assistance. Biofuels continue to benefit from excise relief. The focus of the government's reform is to achieve carbon reductions in the transport sector through fuel efficiency rather than biofuels. There are initiatives on biofuels at state level, like the introduction of the Queensland Biofuels Mandate on 1 January 2017. New South Wales has had a biofuels (ethanol and biodiesel) mandate for about 10 years, under the *Biofuels Act 2007*. Major reforms extending the NSW biofuels mandate to more retail fuel outlets were legislated in 2016 and commenced on 1 January 2017. The adoption of fuel efficiency and vehicle emission standards would encourage a range of alternative fuels and technologies and should be a priority, as explained in the Chapter 7 on Energy Efficiency.

Assessment

In 2016, renewable energy sources had a notable share of 14.7% of Australia's electricity generation, thanks to considerable growth in solar and wind power over the recent years. Deployment has grown unevenly across Australia. A remarkable feature of Australia's renewables generating capacity is the high rate of deployment in the residential sector and in South Australia: over 29% of South Australian dwellings have a solar rooftop PV system. This has been fostered by the cost reduction of the technology, decent support policies and the benefits of self-supply and environmental considerations when electricity prices are on the rise. The deployment of rooftop PV is ongoing, despite a reduction of annual new-built, which is partly compensated by the increase in average capacity, as solar PV is spilling over to the commercial sector (20% of the certificates attributed to PV in 2015). This scale of distributed generation needs to be closely monitored for the impacts it can have on the overall system (see also Chapter 5 on System Integration). Data on small-scale PV are limited, as AEMO does not register this generation source (it does not participate in the market) and states/territories have limited information on their deployment rate. A framework is needed to monitor the uptake.

Australia's federal support scheme for renewable energy is the RET, a quota system. The nature of the certificate scheme leads to the installation of capacity where resources are best, thus large-scale generation has concentrated in a few states. Growing investors' confidence induced by the firm setting of the target has improved the performance of the LRET. Combined with state actions, it is attracting investment in generating capacity. Once the 2020 Large-scale Renewable Energy Target of 33 000 GWh renewable power generation has been reached, the certificate scheme of the LRET will no longer invite new investment in large-scale renewables, even though certificates can be earned for existing projects until 2030.

As of January 2017, around 2.7 million small-scale installations, mostly rooftop PV systems and solar water heaters, have been installed, with a cumulative electric capacity of around 5.4 GW (an addition to cumulative national capacity since 2001). Large-scale installations under the LRET have mainly been wind farms so far, but large-scale solar increased fast. By late 2015, wind capacity amounted to 4 GW, large-scale solar PV to 800 MW. Both small-scale and, in some cases, large-scale deployment is driven by consumer interest in self-supply. Future growth in small-scale RES can be expected, as increases in self-supply/self-consumption are driven by the good match between the solar resource and air-conditioning loads. For large-scale RES, additional support will be needed to attract new investment, outside self-consumption in the mining industry.

Beside the Commonwealth RET, there are several schemes in the states and territories. They range from feed-in tariffs for small-scale solar that all states and territories had (or still have) to the technology-neutral auction scheme for large-scale utilities of the Capital Territory.

Biomass power generation has not experienced much growth under the RET, in part because of a perceived unfavourable treatment of biomass in renewables support. As it provides dispatchable generation which is needed to complement variable renewables, opportunities for biomass, especially for co-firing, should be explored. Bioenergy crops are related to complex issues – they are linked to sectors like environment, agriculture, forestry, water, etc. – so the focus could be on the use of residual waste, e.g. agricultural related wastes and wood waste from the forest industry. Co-firing of biomass in coal-fired power generation was to be encouraged, too. Solar water heaters are eligible under the SRES: thermal-driven solar cooling could be an interesting option for highly demanding large buildings, given the solar resources in Australia on the one hand and the high demand for cooling on the other side.

In the absence of a Commonwealth strategy for renewable energy to grow after 2020, some states and territories have set their own targets beyond 2020 and have put in place or are considering mechanisms to underpin these targets at state or territory level. Others have highlighted the need for a perspective for renewable energy after 2020 but refrain from taking action before a decision at the federal level has been taken. The COAG Energy Council has been working on the harmonisation of support schemes, however with limited impact on jurisdictional policies and targets. A harmonisation effort to introduce locational value in the support policies would benefit the Australian power system by stimulating the deployment of variable renewable power plants in a system-friendly manner, as outlined in Chapter 5 on System Integration.

Enhanced co-ordination and aligning ongoing and future jurisdictional efforts are needed to ensure that they can complement each other towards a joint federal effort under the COAG Energy Council to the maximum benefit. The main driver for the Commonwealth and most of the states and territories for supporting renewables in electricity generation is their contribution to reduce emissions (some states and territories also strongly highlight the positive effects on economic growth and investment).

As explained in Chapter 6 on Energy and Climate Policies, the present review of climate policy does not include an examination of renewables' further abatement potential. The government will have to gain a clear understanding of the role of renewable energy in the larger technology-neutral policy approach to emissions reductions in the electricity sector, since renewables are one important driver for emissions reductions in the

electricity sector, notably with the strongly declining cost of renewable energy technology cost. States and territories are likely to continue implementing support schemes, like reverse auctions and feed-in premiums to meet their own renewable energy targets, with major impact on the National Electricity Market design. Future growth of renewable energy has to be better co-ordinated, notably its location and integration within the NEM transmission/distribution networks and markets. As explained in Chapter 5 on System Integration of Renewable Energy, best practices from Texas, Chile and Mexico should be considered for the creation of renewable energy zones. Detailed explanation is provided in Chapter 5, Box 5.2.

Recommendations

The government of Australia should:

- Underpin the role of renewable energy in the low-carbon electricity mix with a competitive, market-based and long-term stable policy framework that facilitates investment in renewables from 2020 onwards.
- Improve co-ordination and alignment of support schemes within and between the states and territories and the system integration in the National Electricity Market on the basis of locational and technology aspects to maximise the effectiveness of goals and actions taken at the state and territory levels.
- Work through the COAG Energy Council to ensure that frameworks are in place to monitor the uptake of distributed solar PV systems and long-term sustainability of deployment, both technically and economically, and the maximal contribution of private power-sector investments.
- Expand opportunities for renewables in heating and cooling, industry and transport. Encourage cost-effective fuel substitution, for example by using biomass in power generation.
- Enhance ARENA's activities to support the uptake of renewable energy for industrial process heating, and follow-up on funding by the Emissions Reduction Fund and the Clean Energy Finance Corporation for fuel switch projects in the industry.

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ANNEX A: Organisation of the review

Review criteria

The Shared Goals, which were adopted by the IEA Ministers at their 4 June 1993 meeting in Paris, provide the evaluation criteria for the in-depth reviews conducted by the IEA. The Shared Goals are presented in Annex C.

Review team

The in-depth review team visited Canberra, Melbourne and Sydney from 6 to 14 March 2017 and met with government officials, regulators, stakeholders in the public and private sectors as well as other think tanks, industry associations and other interest groups. The discussions helped the team identify the key challenges facing energy policy makers in Australia. The review team and the IEA secretariat also provided inputs to the Finkel Review. The report was drafted on the basis of these meetings, the government's initial submission to the IEA energy policy questionnaire, and several updates since the review visit. The main objective of the report is to present to the Department of Environment and Energy (DoEE) an assessment of the country's energy policy and to provide recommendations based on the IEA Shared Goals, as a basis for developing energy policies that can contribute to sustainable economic development. The Shared Goals are of particular relevance for the conduct of the country reviews, as they provide a common yardstick for assessing member countries' energy policy achievements.

The IEA and the peer review team are grateful for the co-operation and assistance of the many people it met throughout the visit. The team wishes to express its sincere appreciation and gratitude to the hosts at DoEE: Mr. Rob Heferen, Ms Margaret Sewell, Ms Helen Bennett, and Ms Leonie Wilson. Special thanks to Mr. Salim Daizli for his support in the entire in-depth review process and the report; and Mr. Paul Rickard and Ms Alison Dell for their co-ordination as well as Ms Nicole Thomas, the energy advisor of DoEE at the Australian Embassy in Paris.

The members of the team were:

IEA member countries

Mr. Scott Smouse, United States (team leader)

Ms Sonja Röder, Germany

Mr. Julien Tognola, France

Mr. Mark Pickup, New Zealand

Ms Anette Persson, Sweden

Mr. Jeremy Cousins, United Kingdom

International Energy Agency

Mr. Aad van Bohemen

Mr. Simon Müller

Mr. Andrew Robertson

Ms Sylvia Beyer (desk officer)

Sylvia Beyer (IEA, desk officer) managed the review and drafted the report with several co-authors. Chapter 2 on Oil was completed by Mr. Andrew Robertson. The Special Focus 1 (Chapter 3 on Natural Gas) was completed by Mr. Oskar Kvarnström from the IEA Secretariat. Chapter 8 on Renewable Energy and the Special Focus 2 (Chapter 5 on System Integration of Variable Renewables) was completed by Mr. Emanuele Bianco with inputs from Mr. Peerapat Vithayasrichareon under the lead of Mr. Simon Müller, Head of System Integration at the IEA. Ms Samantha McCulloch wrote the CCS section in Chapter 6 on Energy and Climate Policies.

The report was prepared under the guidance of Mr. Aad van Bohemen, Head of Energy Policy and Security Division. Valuable comments were provided by the review team members and the IEA staff, including Mr Ian Cronshaw, Mr. Carlos Fernandez, Mr. Peter Fraser, Ms Christina Hood, Mr. Joe Ritchie, Mr. Andrew Robertson, Ms Louise Vickery, and Mr. Simon Müller.

Special thanks go to the IEA Secretariat with regard to the data, editing and publication. Importantly, the report has received valuable support with timely and comprehensive data from Ms. Roberta Quadrelli, Mr. Remi Gigoux, and Mr. Oskar Kvarnström as well as from Ms Lee Hwayun on the IEA energy statistics and energy balances, including the RD&D and the *Energy Efficiency Indicators* databases.

Mr. Oskar Kvarnström and Mr. Bertrand Sadin ensured the preparation of the design of figures, maps and tables. The IEA Communication and Information Office (CIO), in particular Ms. Rebecca Gaghen, Ms Astrid Dumond, Ms Isabelle Nonain-Semelin, Mr. Sadin and Mr. Jad Mouawad provided essential support towards the report's production and launch. The author thanks in particular for the time and dedication of Ms Viviane Consoli, Ms Therese Walsh and the lead of Director Ms Rebecca Gaghen who ensured the editorial finalisation of the report. Thanks to Head of Press Mr Jad Mouawad for the support to the press launch.

Organisations visited

Commonwealth Department of the Environment and Energy (DoEE)

Commonwealth Department of Industry, Innovation and Science

Environment and Planning Directorate (Australian Capital Territory)

Government Department of Industry (New South Wales)

Department of Environment, Land, Water and Planning (Victoria)

Department of Energy and Water Supply (Queensland)

Department of State Development (South Australia)

Department of State Growth (Tasmania)

Australian Energy Market Commission (AEMC)

Australian Energy Regulator (AER)

Australian Energy Market Operator (AEMO)

Australian Renewable Energy Agency (ARENA)

Australian Competition and Consumer Commission (ACCC)

Climate Change Authority (CA)

Energy Consumers Australia (ECA)

Clean Energy Finance Corporation (CEFC)

Clean Energy Regulator (CER)
Commonwealth Scientific and Industrial Research Organisation (CSIRO)
Council of Australian Governments (COAG)
Australian Sustainable Built Environment Council
Australasian Convenience and Petroleum Marketers Association
Major Energy Users
Australian Gas Networks
Mojo Power
University of New South Wales
The Climate Institute
Australian PV Institute
Australian Alliance to Save Energy
Shell Australia
Minerals Council of Australia
Clean Energy Council
Australian Industry Group
Energy Efficiency Council
Energy Networks Australia
Chemistry Australia
St Vincent de Paul
Jemena
Caltex
ExxonMobil
BP
Viva Energy
Origin Energy
Glencore
ANU Energy Change Institute
Gas Energy Australia
Cement Industry Foundation
Australian Petroleum Production and Exploration Association
Australian Pipelines and Gas Association
Australian Institute of Petroleum
AGL
APA Group

ANNEX B: Energy balances and key statistical data

Australia

Energy balances and key statistical data

	Unit: Mtoe						
SUPPLY	1973	1990	2000	2010	2014	2015	2016E
TOTAL PRODUCTION	68.0	157.5	233.6	323.7	365.7	381.3	394.1
Coal	40.3	106.1	164.6	246.6	285.4	298.6	293.6
Peat	-	-	-	-	-	-	-
Oil	19.8	29.0	33.9	25.5	19.1	18.1	17.9
Natural gas	3.4	17.1	28.5	44.5	52.9	56.4	73.9
Biofuels and waste ¹	3.5	4.0	5.0	5.2	5.1	5.3	5.4
Nuclear	-	-	-	-	-	-	-
Hydro	1.0	1.2	1.4	1.2	1.6	1.1	1.3
Wind	-	-	0.0	0.4	0.9	1.0	1.0
Geothermal	-	-	-	-	-	0.0	-
Solar/other ²	-	0.1	0.1	0.3	0.7	0.9	1.0
TOTAL NET IMPORTS³	-10.9	-66.6	-130.5	-190.0	-239.7	-254.2	-262.6
Coal Exports	17.6	67.3	121.4	190.4	242.8	254.0	252.0
Coal Imports	-	-	-	0.0	0.1	0.2	0.1
Coal Net imports	-17.6	-67.3	-121.4	-190.3	-242.7	-253.8	-251.8
Oil Exports	3.4	9.3	22.8	17.6	14.5	14.6	13.3
Oil Imports	12.6	14.4	26.4	38.0	43.4	43.0	43.1
Oil Int'l marine and aviation bunkers	-2.4	-2.1	-3.3	-4.1	-4.6	-4.6	-5.0
Oil Net imports	6.8	3.0	0.2	16.4	24.2	23.8	24.7
Natural Gas Exports	-	2.3	9.3	20.9	27.2	29.3	41.3
Natural Gas Imports	-	-	-	4.9	6.0	5.1	5.8
Natural Gas Net imports	-	-2.3	-9.3	-16.0	-21.2	-24.1	-35.5
Electricity Exports	-	-	-	-	-	-	-
Electricity Imports	-	-	-	-	-	-	-
Electricity Net imports	-	-	-	-	-	-	-
TOTAL STOCK CHANGES	-0.1	-4.5	0.0	-6.0	-0.8	-1.8	0.8
TOTAL SUPPLY (TPES)⁴	57.1	86.4	103.1	127.6	125.3	125.3	132.3
Coal	22.6	35.1	43.1	50.5	41.5	42.9	45.6
Peat	-	-	-	-	-	-	-
Oil	26.6	31.2	34.2	41.6	43.7	41.9	42.3
Natural gas	3.4	14.8	19.3	28.4	31.7	32.2	35.8
Biofuels and waste ¹	3.5	4.0	5.0	5.2	5.1	5.3	5.4
Nuclear	-	-	-	-	-	-	-
Hydro	1.0	1.2	1.4	1.2	1.6	1.1	1.3
Wind	-	-	0.0	0.4	0.9	1.0	1.0
Geothermal	-	-	-	-	-	0.0	-
Solar/other ²	-	0.1	0.1	0.3	0.7	0.9	1.0
Electricity trade ⁵	-	-	-	-	-	-	-
Shares in TPES (%)							
Coal	39.6	40.7	41.8	39.5	33.1	34.2	34.4
Peat	-	-	-	-	-	-	-
Oil	46.6	36.1	33.1	32.6	34.9	33.4	32.0
Natural gas	5.9	17.1	18.7	22.3	25.3	25.7	27.0
Biofuels and waste ¹	6.2	4.6	4.9	4.1	4.1	4.2	4.1
Nuclear	-	-	-	-	-	-	-
Hydro	1.7	1.4	1.4	0.9	1.3	0.9	1.0
Wind	-	-	-	0.3	0.7	0.8	0.8
Geothermal	-	-	-	-	-	0.0	-
Solar/other ²	-	0.1	0.1	0.2	0.6	0.7	0.7
Electricity trade ⁵	-	-	-	-	-	-	-

0 is negligible, - is nil, .. is not available, x is not applicable. Please note: rounding may cause totals to differ from the sum of the elements. All data except GDP and population refer to the fiscal year July to June.

	Unit: Mtoe						
DEMAND							
FINAL CONSUMPTION	1973	1990	2000	2010	2014	2015	2016E
TFC	39.6	56.7	69.6	76.6	80.9	81.3	..
Coal	5.2	4.6	4.2	2.5	2.4	2.3	..
Peat	-	-	-	-	-	-	..
Oil	24.3	29.0	34.7	39.0	42.6	42.6	..
Natural gas	2.1	8.7	11.4	12.6	13.5	13.5	..
Biofuels and waste ¹	3.5	3.3	4.3	4.1	4.2	4.4	..
Geothermal	-	-	-	-	-	-	..
Solar/other ²	-	0.1	0.1	0.3	0.3	0.4	..
Electricity	4.5	11.1	14.9	18.1	17.9	18.2	..
Heat	-	-	-	-	-	-	..
Shares in TFC (%)							
Coal	13.1	8.0	6.0	3.3	3.0	2.9	..
Peat	-	-	-	-	-	-	..
Oil	61.3	51.2	49.9	50.9	52.7	52.4	..
Natural gas	5.3	15.3	16.4	16.4	16.7	16.6	..
Biofuels and waste ¹	8.8	5.7	6.2	5.4	5.1	5.4	..
Geothermal	-	-	-	-	-	-	..
Solar/other ²	-	0.0	0.0	0.0	0.0	0.0	..
Electricity	11.4	19.6	21.4	23.6	22.1	22.4	..
Heat	-	-	-	-	-	-	..
TOTAL INDUSTRY⁶	17.8	23.3	28.2	27.1	29.2	28.1	..
Coal	4.9	4.3	4.0	2.4	2.4	2.3	..
Peat	-	-	-	-	-	-	..
Oil	7.9	6.4	7.6	6.9	8.7	7.8	..
Natural gas	1.5	6.0	7.5	8.1	8.6	8.5	..
Biofuels and waste ¹	1.5	1.5	2.5	2.6	2.6	2.9	..
Geothermal	-	-	-	-	-	-	..
Solar/other ²	-	-	-	-	-	-	..
Electricity	2.0	5.1	6.6	7.1	6.8	6.6	..
Heat	-	-	-	-	-	-	..
Shares in total industry (%)							
Coal	27.5	18.4	14.3	8.9	8.3	8.3	..
Peat	-	-	-	-	-	-	..
Oil	44.6	27.5	27.1	25.4	29.7	27.6	..
Natural gas	8.4	25.9	26.4	30.0	29.6	30.3	..
Biofuels and waste ¹	8.4	6.4	8.7	9.7	9.0	10.2	..
Geothermal	-	-	-	-	-	-	..
Solar/other ²	-	-	-	-	-	-	..
Electricity	11.2	21.9	23.5	26.0	23.4	23.6	..
Heat	-	-	-	-	-	-	..
TRANSPORT⁴	12.9	21.1	25.7	30.0	31.8	32.5	..
OTHER⁷	8.8	12.3	15.7	19.4	20.0	20.7	..
Coal	0.3	0.2	0.1	0.0	0.0	0.0	..
Peat	-	-	-	-	-	-	..
Oil	3.5	1.7	2.0	3.0	3.1	3.3	..
Natural gas	0.6	2.6	3.6	4.1	4.6	4.7	..
Biofuels and waste ¹	2.0	1.8	1.9	1.4	1.3	1.2	..
Geothermal	-	-	-	-	-	-	..
Solar/other ²	-	0.1	0.1	0.3	0.3	0.4	..
Electricity	2.5	5.9	8.0	10.7	10.6	11.1	..
Heat	-	-	-	-	-	-	..
Shares in other (%)							
Coal	3.2	1.7	0.4	0.1	-	-	..
Peat	-	-	-	-	-	-	..
Oil	39.3	14.1	12.9	15.3	15.7	15.9	..
Natural gas	7.0	21.3	23.1	21.3	22.9	22.8	..
Biofuels and waste ¹	22.6	14.4	12.0	7.0	6.4	6.0	..
Geothermal	-	-	-	-	-	-	..
Solar/other ²	-	0.7	0.5	1.3	1.6	1.7	..
Electricity	27.9	47.8	51.1	55.0	53.3	53.6	..
Heat	-	-	-	-	-	-	..

0 is negligible, - is nil, .. is not available, x is not applicable. Please note: rounding may cause totals to differ from the sum of the elements.

Unit: Mtoe

DEMAND	1973	1990	2000	2010	2014	2015	2016E
ENERGY TRANSFORMATION AND LOSSES							
ELECTRICITY GENERATION⁸							
Input (Mtoe)	16.0	35.3	47.9	58.4	53.4	55.5	..
Output (Mtoe)	5.5	13.3	18.0	21.7	21.4	21.7	22.1
Output (TWh)	64.4	154.3	209.9	252.7	248.3	252.3	257.5
Output Shares (%)							
Coal	74.9	78.7	83.0	71.3	61.2	62.9	63.4
Peat	-	-	-	-	-	-	-
Oil	2.6	2.3	0.9	2.4	2.0	2.7	2.3
Natural gas	4.3	9.3	7.7	17.6	21.9	20.8	19.6
Biofuels and waste ¹	0.5	0.5	0.5	1.1	1.4	1.4	1.4
Nuclear	-	-	-	-	-	-	-
Hydro	17.7	9.2	7.8	5.3	7.4	5.3	5.9
Wind	-	-	-	2.0	4.1	4.5	4.7
Geothermal	-	-	-	-	-	-	-
Solar/other ²	-	-	-	0.2	2.0	2.4	2.7
TOTAL LOSSES	17.7	29.1	36.9	49.3	44.4	45.2	..
of which:							
Electricity and heat generation ⁹	10.5	21.9	29.8	36.6	32.1	33.9	..
Other transformation	5.4	0.2	-2.4	-2.3	-3.6	-3.6	..
Own use and transmission/distribution losses ¹⁰	1.8	7.0	9.5	15.1	15.9	15.0	..
Statistical Differences	-0.2	0.6	-3.4	1.7	-0.1	-1.2	..
INDICATORS	1973	1990	2000	2010	2014	2015	2016E
GDP (billion 2010 USD)	415.37	673.55	954.72	1293.79	1445.33	1485.31	1521.60
Population (millions)	13.61	17.17	19.18	22.22	23.66	24.07	24.37
TPES/GDP (toe/1000 USD) ¹¹	0.14	0.13	0.11	0.10	0.09	0.08	0.09
Energy production/TPES	1.19	1.82	2.27	2.54	2.92	3.04	2.98
Per capita TPES (toe/capita)	4.19	5.03	5.37	5.74	5.29	5.21	5.43
Oil supply/GDP (toe/1000 USD) ¹¹	0.06	0.05	0.04	0.03	0.03	0.03	0.03
TFC/GDP (toe/1000 USD) ¹¹	0.10	0.08	0.07	0.06	0.06	0.05	..
Per capita TFC (toe/capita)	2.91	3.30	3.63	3.45	3.42	3.38	..
CO ₂ emissions from fuel combustion (MtCO ₂) ¹²	157.7	259.7	334.7	389.1	373.3	380.9	..
CO ₂ emissions from bunkers (MtCO ₂) ¹²	7.6	6.5	10.2	12.4	14.1	14.1	..
GROWTH RATES (% per year)	73-90	90-00	00-10	10-13	13-14	14-15	15-16
TPES	2.5	1.8	2.2	-0.3	-1.0	0.0	..
Coal	2.6	2.1	1.6	-4.7	-5.1	3.4	..
Peat	-	-	-	-	-	-	..
Oil	0.9	0.9	2.0	2.3	-1.8	-4.3	..
Natural gas	9.1	2.7	4.0	2.1	4.8	1.7	..
Biofuels and waste ¹	0.7	2.4	0.4	-1.0	0.4	3.6	..
Nuclear	-	-	-	-	-	-	..
Hydro	1.3	1.5	-1.9	10.4	1.2	-27.3	..
Wind	-	-	56.3	16.3	28.8	11.8	..
Geothermal	-	-	-	-	-	-	..
Solar/other ²	-	0.5	13.0	30.7	14.2	18.4	..
TFC	2.1	2.1	1.0	1.8	0.0	0.5	..
Electricity consumption	5.4	2.9	2.0	0.0	-1.0	1.6	..
Energy production	5.1	4.0	3.3	2.1	6.1	4.3	..
Net oil imports	-4.7	-23.3	54.5	14.3	-0.9	-1.9	..
GDP	2.9	3.6	3.1	2.9	2.4	2.8	..
TPES/GDP	-0.4	-1.7	-0.9	-3.1	-3.2	-2.7	..
TFC/GDP	-0.7	-1.4	-2.1	-1.1	-2.3	-2.3	..

0 is negligible, - is nil, .. is not available, x is not applicable. Please note: rounding may cause totals to differ from the sum of the elements.

Footnotes to energy balances and key statistical data

1. Biofuels and waste comprises solid biofuels, liquid biofuels, biogases, industrial waste. Data are often based on partial surveys and may not be comparable between countries.
2. Other here includes solar photovoltaics and solar thermal.
3. In addition to coal, oil, natural gas and electricity, total net imports also include peat, biofuels and waste and trade of heat, when applicable.
4. Excludes international marine bunkers and international aviation bunkers.
5. When applicable, total supply of electricity represents net trade. A negative number in the share of TPES indicates that exports are greater than imports.
6. Industry includes non-energy use.
7. Other includes residential, commercial and public services, agriculture/forestry, fishing and other non-specified.
8. Inputs to electricity generation include inputs to electricity, CHP and heat plants. Output refers only to electricity generation.
9. Losses arising in the production of electricity and heat at main activity producer utilities and autoproducers. For non-fossil-fuel electricity generation, theoretical losses are shown based on plant efficiencies of approximately 33% for solar thermal, between 15 and 20% for geothermal and 100% for hydro, wind and solar photovoltaics.
10. Data on “losses” for forecast years often include large statistical differences covering differences between expected supply and demand and mostly do not reflect real expectations on transformation gains and losses.
11. Toe per thousand US dollars at 2010 prices and exchange rates.
12. “CO₂ emissions from fuel combustion” have been estimated using the IPCC Tier I Sectoral Approach from the *2006 IPCC Guidelines*. In accordance with the IPCC methodology, emissions from international marine and aviation bunkers are not included in national totals.

ANNEX C: International Energy Agency “Shared Goals”

The member countries* of the International Energy Agency (IEA) seek to create conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and to the well-being of their people and of the environment. In formulating energy policies, the establishment of free and open markets is a fundamental point of departure, though energy security and environmental protection need to be given particular emphasis by governments. IEA countries recognise the significance of increasing global interdependence in energy. They therefore seek to promote the effective operation of international energy markets and encourage dialogue with all participants. In order to secure their objectives, member countries therefore aim to create a policy framework consistent with the following goals:

1. Diversity, efficiency and flexibility within the energy sector are basic conditions for longer-term energy security: the fuels used within and across sectors and the sources of those fuels should be as diverse as practicable. Non-fossil fuels, particularly nuclear and hydro power, make a substantial contribution to the energy supply diversity of IEA countries as a group.

2. Energy systems should have the ability to respond promptly and flexibly to energy emergencies. In some cases this requires collective mechanisms and action: IEA countries co-operate through the Agency in responding jointly to oil supply emergencies.

3. The environmentally sustainable provision and use of energy are central to the achievement of these shared goals. Decision-makers should seek to minimise the adverse environmental impacts of energy activities, just as environmental decisions should take account of the energy consequences. Government interventions should respect the Polluter Pays Principle where practicable.

4. More environmentally acceptable energy sources need to be encouraged and developed. Clean and efficient use of fossil fuels is essential. The development of economic non-fossil sources is also a priority. A number of IEA member countries wish to retain and improve the nuclear option for the future, at the highest available safety standards, because nuclear energy does not emit carbon dioxide. Renewable sources will also have an increasingly important contribution to make.

5. Improved energy efficiency can promote both environmental protection and energy security in a cost-effective manner. There are significant opportunities for greater energy efficiency at all stages of the energy cycle from production to consumption. Strong efforts by governments and all energy users are needed to realise these opportunities.

6. Continued research, development and market deployment of new and improved energy technologies make a critical contribution to achieving the objectives outlined above. Energy technology policies should complement broader energy policies. International co-operation in the development and dissemination of energy technologies, including industry participation and co-operation with non-member countries, should be encouraged.

7. Undistorted energy prices enable markets to work efficiently. Energy prices should not be held artificially below the costs of supply to promote social or industrial goals. To the extent necessary and practicable, the environmental costs of energy production and use should be reflected in prices.

8. Free and open trade and a secure framework for investment contribute to efficient energy markets and energy security. Distortions to energy trade and investment should be avoided.

9. Co-operation among all energy market participants helps to improve information and understanding, and encourages the development of efficient, environmentally acceptable and flexible energy systems and markets worldwide. These are needed to help promote the investment, trade and confidence necessary to achieve global energy security and environmental objectives.

(The Shared Goals were adopted by IEA Ministers at the meeting of 4 June 1993 Paris, France.)

* Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea, Luxembourg, the Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

ANNEX D: Glossary and list of abbreviations

In this report, abbreviations and acronyms are substituted for a number of terms used within the International Energy Agency. While these terms generally have been written out on first mention, this glossary provides a quick and central reference for the abbreviations used.

Acronyms and abbreviations

ABS	Australian Bureau of Statistics
AC	alternating current
ACAPMA	Australasian Convenience and Petroleum Marketers Association
ACCC	Australian Consumer and Competition Commission
ACT	Australian Capital Territory
ADEME	L'Agence de l'environnement et de la maîtrise de l'énergie [Agency on environment and energy]
ADGSM	Australian Domestic Gas Security Mechanism
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AERA	Australian Energy Resources Assessment
AIP	Australian Institute of Petroleum
APS	Australian Petroleum Statistics
ARC	Australian Research Council
ARENA	Australian Renewable Energy Agency
ASBEC	Australian Sustainable Built Environment Council
ASEAN	Association of Southeast Asian Nations
ASEFS	Australian Solar Energy Forecasting System
ASIC	Australian Securities and Investment Commission
ASX	Australian Stock Exchange
AUD	Australian Dollar. The average exchange rate in 2017 was 1.30 AUD = 1 USD.
AWEFS	Australian Wind Energy Forecasting System
BEV	battery-electric vehicles
BREE	Bureau for Energy Economics
C&I	commercial and industrial
CAPEX	capital expenditure
CBD	Commercial Building Disclosure
CCA	Climate Change Authority

CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CEER	Council of European Energy Regulators
CEFC	Clean Energy Finance Corporation
CEIF	Clean Energy Innovation Fund
CER	Clean Energy Regulator
CET	Clean Energy Target
COAG	Council of Australian Governments
CREZ	Competitive Renewable Energy Zones
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	concentrated solar power
DG	distributed generation
DR	demand response
DSM	demand-side management
DSO	district system operator
DC	direct current
DER	distributed energy resources
DIIS	Department of Industry, Innovation and Science
DNSP	distribution network service provider
DoEE	Department of the Environment and Energy
DWGM	Declared Wholesale Gas Market
ECA	Energy Consumers Australia
EEIS	Energy Efficiency Improvement Scheme
EEO	Energy Efficiency Opportunities
EIS	emissions intensity scheme
EMSO	exporter market security obligation
ENA	Energy Networks Australia
ERA	Economic Regulation Authority
ERCOT	Electricity Reliability Council of Texas
ERF	emission reduction fund
ESA	Energy Statistics and Analysis
ESB	Energy Security Board
ESG	Energy Sector Group
ESO	Energy Security Office
ESOO	Electricity Statement of Opportunities
ESS	Energy Savings Scheme
ETS	emission trading systems
EUDM	Energy Use Data Model

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EV	electric vehicle
EWP	Energy White Paper
FCAS	frequency control ancillary services
FFR	fast frequency response
FIT	feed-in-tariffs
FOB	free on board
FOS	Frequency Operating Standard
FTR	financial transmission rights
GAP	Gas Acceleration Programme
GBEEI	Government Building Energy Efficiency Investment
GDP	gross domestic product
GDP PPP	gross domestic product with purchasing power parity
GEMS	Greenhouse and Energy Minimum Standards
GHG	greenhouse gas
GISERA	Gas Industry Social and Environmental Research Alliance
GMRG	Gas Market Reform Group
GREP	Government Resource Efficiency Policy
GSA	gas supply agreements
GSOO	Gas Statement of Opportunities
GST	goods and service tax
H&C	heating and cooling
HELE	high efficiency low emission
HHI	Herfindahl-Hirschman Index
HVAC	heating, ventilation and air conditioning
HVDC	high-voltage direct current
IAB	Industry Advisory Board
ICP	installation control points
IGA	Inter-Governmental Agreement
INDC	intended nationally determined contribution
IPP	independent power producers
KPI	Key performance indicators
LCOE	levelised cost of electricity
LET	Low Emission Target
LETDF	Low Emissions Technology Demonstration Fund
LGC	Large-scale Generation Certificate

LNG	liquefied natural gas
LPG	liquefied petroleum gas
LRET	Large-scale Renewable Energy Target
LULUCF	land use change and forestry
MEPS	minimum energy performance standards
MI	Mission Innovation
MIBB	Market Information Bulletin Board
MRL	minimum reserve levels
NABERS	National Australian Built Environment Rating System
NCC	National Competition Council
NCCARF	National Climate Change Adaptation Research Facility
NDC	Nationally Determined Contribution
NECF	National Energy Customer Framework
NEFR	National Electricity Forecast Report
NEG	national energy guarantee
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NEPP	National Energy Productivity Plan
NER	National Electricity Rules
NERL	National Energy Retail Law
NESA	National Energy Security Assessment
NESO	National Emergency Strategy Organization
NGER	national greenhouse gas- and energy-reporting
NGERAC	National Gas Emergency Response Advisory Committee
NGERS	National Greenhouse Gas and Energy Reporting Scheme
NGL	natural gas liquids
NGR	National Gas Rules
NILS	No Interest Loan Scheme
NOPTA	National Offshore Petroleum Titles Administrator
NPS	New Policies Scenario
NSP	Network Service Providers
NSW	New South Wales
NT	Northern Territory
NTEM	Northern Territory Electricity Market
NTNDP	National Transmission Network Development Plan
NWIS	North West Interconnected System

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OCGT	open cycle gas turbine
OPEX	Operational expenditure
OTC	Over-the-counter
PASA	Projected Assessments of System Adequacy
PCC	post combustion capture
PCI	projects of common interest
PFR	primary frequency response
PIT	priority in time
PPA	power purchase agreement
PPP	purchasing power parity
PRRT	petroleum resource rent tax
PSEMP	Power System Emergency Management Plan
PSH	pumped storage hydro
PULP	premium unleaded petrol
PV	photovoltaics
QNI	Queensland NSW Interconnector
R&D	research and development
RD&D	research, development and demonstration
RAV	regulatory asset value
RE	renewable energy
RERT	Reliability and Emergency Reserve Trader
RET	renewable energy target
RIT	Regulatory Investment Test
SA	South Australia
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SFR	secondary frequency response
SPS	special protection schemes
SRES	scale renewable energy scheme
STC	Scale Technology Certificates
STTM	short-term trading market
SWIS	South-West Interconnected System
TEELS	Tasmanian Energy Efficiency Loans Scheme
TFC	total final consumption

TISN	Trusted Information Sharing Network
TMSO	total market security obligation
TNSP	transmission network service provider
TOU	Time-of-use
TPA	third-party access
TPES	total primary energy supply
TSO	transmission system operator
TYNDP	Ten-Year Network Development Plan
UMM	Urgent Market Messages
UNFCCC	United Nations Framework Convention on Climate Change
VRE	variable renewable energy
WA	Western Australia
WACC	weighted average cost of capital
WEM	Wholesale Electricity Market

Units of measurement

bcm	billion cubic metres
b/d	barrels per day
CO ₂	carbon dioxide
CO ₂ -eq	carbon dioxide-equivalent
EJ	exajoule
GJ	gigajoule
GJ/t	gigajoules over tonne
GW	gigawatt
GWh	gigawatt hour
Hz	hertz
kb/d	thousand barrels per day
km	kilometre
km ²	square kilometre
kW	kilowatt
kWh	kilowatt hour
kWh/m ²	kilowatt hours per square metre
kWh/t	kilowatt hours per tonne
m	metre
m/s	metres per second
m ³	cubic metre
mb	million barrels

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mBtu	million British thermal units
mcm	million cubic metres
Mha	million hectare
MJ	megajoule
ML	million litres
Mt	million tonnes
MtCO ₂	million tonnes of carbon dioxide
MtCO ₂ -eq	million tonnes of carbon dioxide-equivalent
Mtoe	million tonnes of oil-equivalent
MW	megawatt
MWh	megawatt hour
MWth	megawatt hour of thermal heat
PJ	petajoule
toe	tonne of oil-equivalent
TWh	terawatt hour
W	watt

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Typeset in France by IEA - February 2018
Cover design: IEA; Photo credits: © GraphicObsession

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ENERGY POLICIES OF IEA COUNTRIES

Australia

2018 Review

Australia has abundant energy resources. It is a leading exporter of coal, uranium and liquefied natural gas (LNG), much of which is destined for Asia's growing markets. At home, Australia's energy sector is undergoing a significant transformation. The power system is seeing higher shares of variable wind and solar power; South Australia leads the deployment.

Yet despite this wealth of resources, energy security concerns are on the rise. As domestic oil production is dwindling, dependency on oil product imports and the oil supply chain are growing steadily. Gas supply in the east coast market has become tight, leading to higher prices in that market. Australia's power system finds itself exposed to concerns over reliability, particularly amid extreme weather events. While its carbon intensity is in decline, it is still the highest among IEA countries. For natural gas to play a role as a transition fuel to a low-carbon economy, resource development, additional pipeline capacity and market integration are critical.

The government is implementing reforms to foster reliability and security of supply, prompted by the South Australia system wide blackout of September 2016 and the Finkel Review. However, a consistent energy and climate framework up to 2030/50 is needed at the Commonwealth level to ensure continued and adequate investment in the energy sector.

With the intention of helping to guide the country towards a more secure and sustainable energy future, this 2018 in-depth review analyses these and other energy policy challenges facing Australia, and provides recommendations for further policy improvements.