International Energy Agency
Secure Sustainable Together

World Energy Investment 2018

International Energy Agency
Secure
Sustainable
Together

World Energy Investment 2018

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 30 member countries, 7 association countries and beyond.

The four main areas of IEA focus are:

- **Energy Security**: Promoting diversity, efficiency, flexibility and reliability for all fuels and energy sources;
- **Economic Development**: Supporting free markets to foster economic growth and eliminate energy poverty;
- **Environmental Awareness**: Analysing policy options to offset the impact of energy production and use on the environment, especially for tackling climate change and air pollution; and
- **Engagement Worldwide**: Working closely with association and partner countries, especially major emerging economies, to find solutions to shared energy and environmental concerns.

IEA member countries:

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

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

International Energy Agency
Secure
Sustainable
Together

International Energy Agency
Website: ***www.iea.org***

Foreword

Now established as a benchmark for measuring investment across the energy sector, the third edition of the *World Energy Investment* report presents the IEA's continuing analysis of the wide-ranging factors shaping energy investment decisions today. This year, we have identified a common theme about the importance of governments.

Nearly three-quarters of the USD 1.8 trillion of global energy investment is driven either by direct investing by state-owned enterprises or private-led investments incentivised by policies. In terms of direct investments, we see a growing role by state actors across all sectors in the past five years. Governments are also increasingly shaping private investment decisions through policies, regulations and standards, particularly in capital intensive sectors, such as renewables and energy efficiency.

Despite this increased role of governments, the overall trend of energy investment remains insufficient for meeting energy security, climate and air quality goals, and is not spurring an acceleration in technologies needed for the clean energy transition.

The electricity sector offers an example. Recognising the much greater role that electrification will play in the future energy system, the IEA has made 2018 "the year of electricity." Indeed, electricity is again attracting the largest share of energy investment at a time when its future is very promising, but business models for investments remain uncertain.

The report also explores a number of other trends in energy investment, from the financing for energy projects in different sectors to how oil and gas companies are responding to changing oil prices, particularly in the US shale industry. It examines the policy and market factors driving spending on energy efficiency and electric vehicles and how governments are shaping investment into technologies needed for the energy system of the future.

More than ever, decision makers across the globe need reliable and authoritative data and analysis. While governments play a central role in setting appropriate polices and reducing barriers, it will be the industry and financiers – in many cases public financial institutions – that channel the necessary capital and manage risks, particularly in emerging economies.

The future global energy system – its security, sustainability, affordability and accessibility – relies on the investment decisions being taken today and in the years to come in developing countries and emerging economies alike. As I travel around the world, I can see how decisions made in Brussels, Beijing or Brasilia all have global implications.

Dr. Fatih Birol

Executive Director

International Energy Agency

Acknowledgements

The lead authors and coordinators of this report were **Simon Bennett** (energy end-use efficiency investment and financing; R&D and new technologies), **Alessandro Blasi** (oil, gas and coal investment and financing) and **Michael Waldron** (electricity and renewables investment and financing; energy financing and funding trends). Principal contributors and supporting authors were **Yoko Nobuoka** (sources of finance; oil and gas investment; electricity financing), **Alberto Toril** (electricity generation and renewables; electricity networks and storage). **Laszlo Varro**, IEA Chief Economist, contributed valuable input. Other key contributors were Marco Cometto (nuclear investment), Carlos Fernandez Alvarez (coal), Araceli Fernandez Pales (steel), Jessica Glicker (energy efficiency investment and financing), Sina Keivani (oil and gas financing), Yang Lei (China), Samantha McCulloch (CCUS), Simon Mueller (renewables and batteries), Kristine Petrosyan (refining and petrochemicals), Joe Ritchie (white certificates), Safia Saouli (venture capital), Tristan Stanley (CCUS), Emily Stromquist (Russia) and Cecilia Tam (battery supply chain and offshore wind). Trevor Morgan and Erin Crum edited the manuscript, and Janet Pape provided essential support.

The report is indebted to the high standard of investment data production across all parts of the IEA. In particular, the work of the Energy Supply Outlook Division (Tim Gould, Ali Al-Saffar, Tae-Yoon Kim, Christophe McGlade and Pawel Olejarnik); the Energy Demand Outlook Division (Laura Cozzi, Davide D'Ambrosio, Timur Gül, Paul Hugues, Brent Wanner and Kira West); the Energy Efficiency Division (Brian Motherway, Matteo Craglia, Brian Dean, Armin Mayer, Joe Ritchie and Sacha Scheffer); the Energy Demand Technology Unit (Pierpaolo Cazzola, Marine Gorner and Leonardo Paoli); and the Renewable Energy Division (Paolo Frankl, Yasmina Abdelilah, Heymi Bahar, Karolina Daskiewicz, Pharoah Le Feuvre and Tobias Rinke) were invaluable to the analysis.

The report benefited from valuable inputs, comments and feedback from other experts within the IEA and the OECD, including Liwayway Adkins, Geraldine Ang, Neil Atkinson, Mariano Berkenwald, David Benazeraf, Rubens Bibas, Toril Bosoni, Rodney Boyd, Jean Chateau, Kieran Clarke, Anthony Cox, John Dulac, Duarte Figuera, Florens Flues, Peter Fraser, Remi Gigoux, Cesar Alejandro Hernandez, Volker Kraayvanger, Vladamir Kubecek, Peter Levi, Daichi Mabashi, Mariana Mirabile, Duncan Millard, Luis Munuera, Bruce Murphy, Dirk Rottgers, Keisuke Sadamori, Siddharth Singh, Álvaro Santos Pereira, Filipe Silva, Paul Simons, Glenn Sondak, David Turk, Aad Van Bohemen, Matt Wittenstein, Aya Yoshida and Jingjie Zhang.

Thanks also go to Jon Custer, Muriel Custodio, Astrid Dumond, Rebecca Gaghen, Christopher Gully, Katie Lazaro, Jad Mouawad, Bertrand Sadin, Robert Stone and Therese Walsh of the IEA Communication and Information Office for their help in producing the report.

We appreciate the contributions of speakers and participants at the IEA Roundtable on Energy Investment held in March, 2018.

In addition, we would like to thank the following organisations that gave their time to answer questions and respond to surveys covering different parts of the energy value chain: ABB, Banco Nacional de Comercio Exterior, BHGE, BHP Biliton, BMW, BP, Caterpillar, Chevron, Cummins, Dow, EDF, Enel, Engie, Eni, Equinor, European Bank for Reconstruction and Development, European Investment Bank, Export-Import Bank of Korea, ExxonMobil, Fortum, GE, Glencore, Hess Corporation, Hitachi, Iberdrola, Japan Bank for International Cooperation, KfW, NEOEN, Nissan, Ofgem, Reliance Industries Ltd, Royal HaskoningDHV, Schlumberger, Schneider, Shell, Siemens, Toyota, Uniper, and Vattenfall.

From the Council on Energy, Environment and Water, we would like to thank Kanika Chawla, Arjun Dutt and Manu Aggarwal for their contribution to the “Focus on Financing Power Sector Investments in India”.

Many experts from outside of the IEA provided input, commented on the underlying analytical work, and reviewed the report. Their comments and suggestions were of great value. They include:

Venkatachalam Anbumozhi	Economic Research Institute for ASEAN and East Asia
Chrisnawan Anditya	Indonesia Ministry of Energy and Mineral Resources
Manuel Baritaud	European Investment Bank
Kamel Bennaceur	Abu Dhabi National Oil Company
Jules Besnainou	Cleantech Group
Stephan Berberich	California ISO
Kanika Chawla	Council on Energy, Environment and Water
Alex Cobbold	Sarasin
Joel Couse	Total
Zita Marko Daatland	Statoil
Joanna De Mongros	Everoze
Claudio Dicembrino	Enel
Zuzana Dobrotkova	World Bank
Loic Douillet	General Electric
Mike Eckhart	Citigroup
Fabian Kesicki	E.ON

Monica Filkova	Climate Bonds
Niels Franck	Energinet
Julio Friedmann	Carbon Wrangler
Nathan Frisbee	Schlumberger
Shinji Fujino	Japan Bank for International Cooperation
Kelly Sims Gallagher	Tufts University
Faith Gan	Singapore Energy Market Authority
Asger Garnak	Danish Energy Agency
Francesco Gattei	Eni
Craig Glazer	PJM Interconnection
Christopher Kaminker	SEB
Valerie Kiefer	Natural Resources Canada
Jochen Kreusel	Asea Brown Boveri Group
Holly Krutka	Peabody Energy
Xavier LaFontaine	EDF
Francisco Laveron	Iberdrola
Xianzhang Lei	State Grid Corporation of China
Jorge Leon	BP
Yun hui Liu	China Energy Investment Corp.
Yang Liu	National University of Singapore
Rui Luo	Clean Energy Ministerial Secretariat
Ajay Mathur	The Energy and Resource Institute
Sean McLoughlin	HSBC
Zdenka Myslikova	Tufts University
Steve Nadel	The American Council for an Energy-Efficient Economy
Kota Nagamori	MHPS
Susanne Nies	ENTSO-E
Padraig Oliver	CPI Climate Finance
Anita Orban	Tellurian
Gregor Pett	Uniper
Sanjoy Rajan	European Investment Bank
Martijn Rats	Morgan Stanley
Domenico Rotiroti	Gestore dei Servizi Energetici
Charlene Russell	Occidental Petroleum
Oliver Schmidt	Imperial College
Martin Schope	Ministry for Economic Affairs and Energy, Germany
Robert Schwiers	Chevron
Mark Shores	ExxonMobil

Maria Sicilia	Enagas
Jim Skea	Imperial College
Peter Stettner	Andritz
Ulrik Stridbaek	Orsted Energy
Bert Stuij	RVO
Peter Sweatman	Climate Strategy
Kazushige Tanaka	Ministry of Economy, Trade and Energy, Japan
Michael Taylor	IRENA
Matthew Taylor	BEIS
Jakob Thoma	2 Degrees Investing
Denis Thomas	Hydrogenics
Wim Thomas	Shell
Tom Tindall	Brookfield Asset Management
Julien Touati	Meridiam
Elodie Trauchessec	Ademe
Andrew Walker	Cheniere
Colin Ward	KAPSARC
Graham Weale	Ruhr University Bochum
Paul Welford	Hess
Rick Westerdale	U.S. State Department
Marek Wolek	Fluence Energy
Akira Yabumoto	J Power
Zhufeng Yu	Shenhua
Anthony Yuen	Citi Group
Jörg Zeuner	KfW

The individuals and organisations that contributed to this study are not responsible for any opinions or judgements it contains. All errors and omissions are solely the responsibility of the IEA.

Comments and questions are welcome and should be addressed to:

Economics and Investment Office, International Energy Agency

31-35 rue de la Fédération, 75739 Paris Cedex 15, France

Telephone: (33-1) 40 57 66 16; Email: eio@iea.org

More information about the report and the methodologies can be found at: www.iea.org/investment.

Table of contents

Executive summary

For the third consecutive year, global energy investment declined, to USD 1.8 trillion (United States dollars) in 2017 – a fall of 2% in real terms. The power generation sector accounted for most of this decline, due to fewer additions of coal, hydro and nuclear power capacity, which more than offset increased investment in solar photovoltaics (PV). Several sectors saw an increase in investment in 2017, including energy efficiency and upstream oil and gas. Nevertheless, capital spending on fossil fuel supply remained around two-thirds of that for 2014. The electricity sector was the largest recipient of global energy investment for the second year running, reflecting the ongoing electrification of world's economy and supported by robust investment in networks and renewable power.

Falling costs continue to affect investment trends, prices and inter-fuel competition across several parts of the energy sector. Unit costs for solar PV projects, which represent 8% of total energy investment worldwide, fell by nearly 15% on average, thanks to lower module prices and a shift in deployment to lower-cost regions. Investment nonetheless rose to a record level. Technology improvements and government tendering schemes are facilitating economies of scale of new projects in some markets: in emerging economies outside of the People's Republic of China (hereafter, "China") the average size of awarded solar PV projects rose by 4.5 times over the five years through 2017, while that of onshore wind rose by half. Project economics in the oil and gas sector are complex, but costs for conventional oil and gas developments have not followed the trend of higher oil prices since mid-2016, thanks to cost discipline by operators and excess capacity in the services industry. In the United States shale sector, however, an upswing in activity led to an almost 10% increase in costs in 2017, and a similar rise is expected in 2018. New digital technologies are increasingly keeping costs under control across the entire energy sector, including in upstream oil and gas.

China remained the largest destination of energy investment, taking over one-fifth of the global total. China's energy investment is increasingly driven by low-carbon electricity supply and networks, and energy efficiency. Investment in new coal-fired plants there dropped by 55% in 2017. The United States consolidated its position as the second-largest investing country, thanks to a sharp rebound in spending in the upstream oil and gas sector (mainly shale), on gas-fired plants and electricity grids. Europe's share of global energy investment was around 15%, with a boost in spending on energy efficiency and a modest increase in renewables investment offset by declines in thermal generation. In India, investment in renewable power topped that for fossil fuel-based power generation for the first time in 2017.

Putting energy investment in a broader context

There was a pause in the shift of investments towards cleaner sources of energy supply. The share of fossil fuels, including thermal power generation, in energy supply investment rose slightly to 59% as spending in upstream oil and gas increased modestly. The International Energy Agency (IEA) Sustainable Development Scenario (SDS) sees the share of fossil fuels in energy supply investment falling to 40% by 2030. Mature economies and China, with a fossil fuel share of supply investment at 55%, have seen faster change than emerging economies, where the share stands at 65%, but all three regions saw an uptick in 2017. Clean energy supply investment has grown fastest in the power sector. The share of clean power sources (renewables and nuclear) in generation investment was over 70% in 2017, up from less than 50% a decade ago, though this stems partly from lower coal-fired power investment. Greater spending on electricity networks and battery storage are also contributing to a more flexible power system, which is crucial to the integration of higher shares of solar PV and wind generation. Investment in all forms of clean power, as well as in networks, would need to rise substantially under the SDS.

Investment in electrification of transport and heating continued to show exponential growth in 2017, but investments in the direct use of renewables in transport and heat remain weak. The USD 43 billion that consumers spent on electric passenger vehicles (plug-in hybrids and pure battery vehicles) in 2017 pushed up the electric vehicle (EV) market share to more than one in every one hundred passenger vehicles sold and was responsible for half of the global growth in passenger vehicle sales. However, the permanent impact of these EV sales on oil demand remains small: a reduction of just 30 000 barrels per day compared with 1.6 million barrels per day of global oil demand growth in 2017. The impact of the biofuels production capacity coming online in 2017 will be lower still. Global spending on energy efficiency in heating, ventilation, and air conditioning experienced double-digit growth, with sales of heat pumps in particular rising by 30%. Like EVs, heat pumps are more efficient than their traditional alternatives and can help low-carbon electricity to penetrate higher shares of energy demand, yet they make up only around 2.5% of total sales of heating equipment. Most of the market is dedicated to fossil fuel-burning technologies. Investments in solar thermal heating installations, at USD 18 billion, declined for the fourth consecutive year. These trends are having no discernible impact on the allocation of capital to oil and gas supply projects.

Energy end-use and efficiency

Spending related to energy efficiency improvements remained relatively immune from the overall downward trend in energy investment worldwide. A total of USD 236 billion was invested in energy efficiency across buildings, transport and industry in 2017. However, while growth of investment in energy efficiency has been strong in recent years, it slowed to 3%, against a backdrop in which energy efficiency policy implementation and global energy intensity improvements are slowing. The increase in 2017 was led by spending on heating, cooling and lighting efficiency in buildings, boosted by standardisation of projects that can be used in different building types. Guaranteed energy savings from standard lighting retrofits, in particular, are becoming familiar to financial lenders, who are prepared to lend more cheaply. In total, buildings sector energy efficiency spending rose 3%, largely due to an increase in total construction sector activity. Investment in energy efficiency in the industrial sector is estimated to have declined 8% in 2017, partly due to a slowdown in new facilities being constructed in China. In the steel sector, this slowdown has been dramatic, and as investment in coal-based steel production has collapsed, the average energy intensity of new capacity has improved by 10%.

In 2017, green bonds issued primarily for energy efficiency uses exceeded the value of those issued primarily for renewables and other energy uses for the first time. The value of green bonds issued primarily for energy efficiency uses nearly tripled to USD 47 billion. In addition, green banks, established by public authorities to stimulate investment in projects for sustainability, are also lending a higher share of their funds to energy efficiency projects. These trends reflect an emerging diversification of funding sources for energy efficiency, which remain dominated by balance sheet finance. Energy service companies – with a global market size of around USD 27 billion – are playing a particularly important role in developing financing models to lower costs for replicable energy efficiency projects, including the adoption of energy savings insurance. In certain countries, policy makers have given energy companies incentives to seek the lowest-cost energy efficiency projects via markets for tradable energy savings (white certificates). In 2017, prices on those markets in France and Italy reached record levels. Overall, investment in energy efficiency is closely linked to government policies, and there is room to tighten standards and encourage higher spending.

Electricity and renewables

The relationship between electricity demand and investment continues to evolve, with the power sector becoming more capital intensive. Over the past decade, the ratio of global power sector investment to demand growth more than doubled on average with policies to encourage renewables and efforts to upgrade and expand grids, but also due to more energy efficiency dampening demand growth. The share of investment in less capital-intensive thermal generation has generally declined over time. In 2017, global power sector investment fell by 6% to near USD 750 billion in 2017, mainly the result of a 10% slump in the commissioning of new generation capacity. Half of the drop was due to coal-fired power plants, driven by China and India. Retirements of existing coal-fired power capacity – mainly inefficient subcritical plants – offset nearly half of the additions. Investment in gas-fired generation capacity rose by nearly 40%, led by the United States and the Middle East/North Africa. There are indications of lower investment in both these sources of generation in the years ahead. Final investment decisions for gas power plants fell by 23% in 2017, while those for coal dropped by 18% to a level only one-third of that in 2010.

Although it declined by 7%, investment in renewable power, at nearly USD 300 billion, accounted for two-thirds of power generation spending in 2017. Investment was supported by record spending for solar PV, of which nearly 45% was in China. Offshore wind investment also reached record levels, with the commissioning of nearly 4 gigawatts, mostly in Europe. On the other hand, onshore wind investment fell by nearly 15%, largely due to the United States, China, Europe and Brazil, though one-third of this decline was from falling investment costs. Investment in hydropower fell to its lowest level in over a decade, with a slowdown in China, Brazil and Southeast Asia. Recent policy changes seeking to promote more cost-effective solar PV development in China raise the risk of a continued slowdown in renewables investment, even as prospects remain strong in other markets.

Robust investment in renewable power is even more important for boosting low-carbon power generation in light of a sharp fall in investment in new nuclear power, which declined to its lowest level in five years. Construction starts for new nuclear plants remain muted, while in some regions, retirements of existing plants are reducing the impact of the growth in renewables. In Europe, the decline in nuclear generation since 2010 has offset over 40% of the growth in solar PV and wind output there. Nevertheless, global spending on lifetime extensions for existing nuclear plants rose in 2017, potentially providing a cost-effective transitional measure for supporting low-carbon generation.

Global spending on the electricity network grew more slowly in 2017, at 1%, to top USD 300 billion. Spending reached a new high, and the grid's share of power-sector investment rose to 40% – its highest level in a decade. China remained the largest market for grid investment, followed by the United States. Investment is rising in technologies designed to enhance the flexibility of power systems and support the integration of variable renewables and new sources of demand. Power companies are modernising electricity grids by spending more on, and acquiring businesses related to, so-called smart grid technology, including smart meters, advanced distribution equipment and EV charging, which accounted for over 10% of networks spending. Although investment in stationary battery storage fell by over 10% to under USD 2 billion, it was six times higher than in 2012.

Fossil fuel supply

Investment in fossil fuel supply stabilised around USD 790 billion in 2017 as reduced spending in coal supply and in liquefied natural gas (LNG) offset a modest rise in upstream oil and gas. Upstream investment rose by 4% to USD 450 billion in 2017 and is set to rise by 5% to USD 472 billion (in nominal terms) in 2018, driven by the US shale sector, which is expected to grow by around 20%. Investment in conventional oil and gas remains subdued, focusing on brownfield projects, and the share of greenfield projects in total upstream investment is expected to plunge to about one-third in 2018 – the lowest level for several years. Despite the more-than-doubling of thermal coal prices since early 2016, investment in coal supply declined by 13% in 2017 to just below USD 80 billion, mainly due to reduced spending in China. The threat of tougher policy action to address climate change and air pollution and enhanced competition from renewables continue to discourage investment in coal. Investment in LNG liquefaction plants continues to plunge and is expected to fall to around USD 15 billion 2018, as only three new LNG projects have been sanctioned since mid-2016.

The oil and gas industry is shifting towards short-cycle projects and rapidly declining producing assets while expanding into the downstream sector and petrochemicals. While the recovery in upstream investment is not homogeneous, most companies continue to prioritise cost control, financial discipline and returns to shareholders. They appear to be aiming to reduce exposure to long-term risks, expanding their activities in smaller projects that generate faster payback, such as shale and brownfields. Global investment in shale is expected to reach a record of almost one-quarter of total upstream spending in 2018. At the same time, oil and gas companies are increasing their investments outside the upstream sector. Global investment in oil refining increased by 10% in 2017. Investment in petrochemicals rose by 11% to USD 17 billion in 2017, set to reach almost USD 20 billion in 2018. For the first time in recent decades, the United States was the largest recipient of investment in petrochemicals.

Higher prices and operational improvements are putting the US shale sector on track to achieve positive free cash flow in 2018 for the first time ever. Risks to the financial health of the sector remain, including inflationary pressures and pipeline bottlenecks in the Permian Basin. Since 2010, the sector has constantly spent more than it has earned, generating cumulative negative free cash flow of about USD 250 billion. This has forced it to rely largely on external source of financing. Following a very turbulent 2015-16 period, the sector appears to be benefiting from huge technological and operational advances, as well as higher prices and a more cautious approach to investment. Growing investments by the majors in the sector, tripling in only two years to 18% of their 2018 planned upstream oil spending, could boost prospects for the sector, thanks to economies of scale and technical improvements, including the increased use of digital technologies. Although in decline, the leverage of US shale companies remains high, but the average interest rate paid to service their debt – at around 6% – has been broadly stable as capital markets reward the improvement in sector's financial health.

The rollercoaster journey of oil prices in recent years has not fundamentally changed the way the oil and gas industry finances its operations. The industry generally is now on more solid financial footing, thanks to higher oil prices, continuing financial discipline and cost reductions. In the first quarter of 2018, majors achieved the highest level of free cash flow since the same period in 2012 and are starting to reduce leverage, which skyrocketed over 2014-17. The largest 20 institutional equity holders in the oil and gas majors are continuing to expanding their stakes, which in aggregate rose from 24% in 2014 to 27% in 2017, encouraged by high and stable dividends.

Key trends in financing and funding

While corporations continue to provide the bulk of primary finance for energy investments, there are signs of diversification of financing options in some sectors. With higher oil prices and better cost control, the financial health of the oil and gas companies has improved markedly, enabling the majors to better self-finance projects and US shale companies to raise funds with cheaper debt. In the power sector, the perceived maturity and reliability of renewable technologies and better risk management of renewables projects has facilitated the expansion of off-balance sheet structures outside of the United States and Europe, with project finance rising in Asia, Latin America and Africa. This trend is supported in part by public financial institutions, such as development banks, which can reduce risks for commercial finance. In Europe, better debt financing terms have helped lower generation costs for new offshore wind by nearly 15% in the past five years. Improvements in standardisation, aggregation and credit assessment for small-scale projects facilitated record issuance of green bonds of USD 160 billion in 2017. This is helping developers of energy efficiency and distributed solar PV projects to gain access to finance from the capital markets and EV buyers to get loans from banks.

The share of private-led energy investment has declined in the past five years. There is a rising share of investment in renewables, where private entities own nearly three-quarters of investments, energy efficiency, which is dominated by private spending, and private-led grid spending. However, the share of energy investment from state-owned enterprises (SOEs) rose by more over the period. Fossil fuel supply and thermal power investments are increasingly dominated by SOEs. In 2017, the share of national oil companies in total oil and gas investment remained near record highs, while the share of SOEs in thermal generation investment rose to 55%. In the case of new nuclear plants, all investment is made by SOEs. Most investment decisions for the largest thermal plants in emerging economies involve a public financial institution (export credit agency or national bank), reflecting risk profiles. SOEs contribute over 60% of electricity grid spending, and this share has remained stable over the past five years. Government-backed entities also play key roles in some renewable projects, such as hydropower, and energy efficiency for public buildings.

Investment decisions in some sectors are increasingly affected by government policies. In the power sector, over 95% of global investment is made by companies whose revenues are fully regulated or affected by mechanisms to manage the risk associated with variable prices on competitive wholesale markets. Networks investment is very sensitive to regulation of retail and use-of-system tariffs, which determine the ability of utilities to recover their costs. In some emerging economies, regulated tariffs are still too low to ensure the financial viability of the power system and support investment. Utilities in mature electricity markets are finding that their thermal power generation assets exposed to wholesale market pricing are becoming less profitable or even unprofitable and are seeking profitable opportunities in other areas, such as renewables and networks. While most renewables investment depends on contracts and regulated instruments, over 35% of utility-scale investment is underpinned by competitive mechanisms, such as auctions, to set prices. Outside China, this share reached a record 50%. Most energy efficiency investments are underpinned by energy performance standards, and a growing amount involve financial incentives. Government purchase incentives for electric cars represented 24% of the global spending on electric car sales in 2017 and their combined value is growing at 55% per year.

Innovation and new technologies

Government energy research and development (R&D) spending increased by around 8% in 2017, reaching a new high of USD 27 billion. Most of the growth came from spending on low-carbon technologies, which is estimated to have risen 13%, which is welcome after several years of stagnation. Low-carbon energy technologies account for three-quarters of public energy R&D spending. On average, governments allocate around 0.1% of their total public spending to energy R&D, a level that has remained stable in recent years. IEA tracking of corporate energy R&D investment shows that this grew in 2017 by 3% to USD 88 billion, with faster growth in low-carbon sectors. A major contributor to this growth was the automotive sector, driven by intense technological competition, notably in EVs and new forms of mobility. Venture capital (VC) investment in low-carbon energy fell to USD 2.1 billion in 2017, following a spike in big deals in low-carbon transport in 2016. The longer-term trend is nonetheless positive. Recent growth has been driven almost entirely by clean transportation investments, but digital efficiency technology is attracting more funding. Renewables hardware VC investment remains lower than 2014.

New approaches to boosting investment in carbon capture, utilisation and storage (CCUS) are needed for the world to be on track to meet its climate change goals. Only around 15% of the USD 28 billion earmarked for large CCUS projects since 2007 was actually spent, because commercial conditions and regulatory certainty have not attracted private investment alongside available public funds. However, investment may pick up with the stronger incentives for carbon dioxide (CO_2) storage set out in a revised US tax credit. Building on this type of policy approach, this report estimates that a dedicated commercial incentive as low as USD 50 per tonne of CO_2 sequestered could trigger investment in the capture, utilisation and storage of over 450 million tonnes of CO_2 globally in the near term. This is equal to the global growth in CO_2 emissions in 2017 and would increase the amount of carbon captured and stored by 15 times compared with today.

Electric batteries are increasingly being deployed across the energy sector, but their impact will largely depend on cost trends, which will be strongly influenced by investments outside the energy sector. Investment in lithium mining has risen almost tenfold since 2012, and investment in battery manufacturing capacity has risen more than fivefold. Bottlenecks and supply risks will be avoided only if investments throughout the value chain, including EV factories, are aligned. To help this, governments can set clear policies for the market to follow. A record number of investment decisions were taken in 2017 to build electrolysers to make hydrogen for clean energy applications. While investment remains well below that in electric batteries for stationary storage and road vehicles, interest in hydrogen projects is growing.

Introduction

This third edition of *World Energy Investment (WEI)* again quantifies in a comprehensive manner investment in the energy sector across technologies, sectors and regions. In response to feedback from government and private-sector stakeholders, in part through an International Energy Agency (IEA) roundtable on investment,[1] this year's report focuses on the critical questions surrounding energy investment today. These include the interaction of investment flows and energy policies, the impact of changing business models on investment, associated trends in digitalization and innovation, and the implications of investment for energy security and the environment. In addition to tracking investment in physical infrastructure, *WEI 2018* describes how financing mechanisms and sources of funding for the energy sector are evolving.

The focus is on what happened in 2017 and how it compares with prior years. The report also highlights important 2018 trends where reliable data are available. *WEI* complements IEA projections and analysis in the annual *World Energy Outlook* and *Tracking Clean Energy Progress* and the series of annual market reports for the major energy supply sectors and energy efficiency. The aim is to advise policy makers and private entities on how investment is responding to policy and market factors and thereby inform decision making.

The way investment is measured across the energy spectrum varies, largely because of differences in data availability and the nature of spending.[2] The report aims to ensure that estimates are consistent and comparable across sectors. In most cases, investment is defined as overnight capital expenditures ("capex") on new assets; i.e. the capital cost of a project as if it was completed overnight. For some sectors, such as power generation, this investment is attributed to the year in which a new plant or the upgrade of an existing one becomes operational. New data sources now also allow for analysis of decisions to commit new capital to power projects. For other forms and sources of energy, where sufficient data are available, such as for upstream oil and gas and liquefied natural gas projects, investment reflects actual capital spending over time. Investment in energy efficiency is defined and measured differently. It includes incremental spending on energy efficiency by companies, governments and individuals to acquire equipment that consumes less energy

[1] The World Energy Investment Roundtable, held in March 2018, provided an opportunity for more than 80 senior officials from industry and finance to guide IEA work on energy investment. The insights and data provided at that event have helped to shape the main messages and analysis of this report.

[2] A document explaining in detail the methodology is available at www.iea.org/investment.

than that which they would otherwise have bought. Although the distinction cannot always be clearly made, we generally refer to consumer "spending" and company "investment" when discussing energy efficiency, in recognition of the difference between the motives for the expenditures.

The scope of the energy investments tracked by *WEI 2018* is slightly expanded compared to previous editions. Power generation investment now includes small-scale diesel and gas generating sets and long-term operation extensions for nuclear power plants. The scale of coal supply and electricity networks investment in the People's Republic of China have been revised upwards, as has electricity networks investment in the United States. For some technologies and prior years, capacity additions have been adjusted as better data has become available. Following these changes, global energy investment was found to be higher than previously reported, leading to an upwards revision of 9% to USD 1.82 trillion for 2016 for example.

As in previous editions, the scope of *WEI 2018* includes several relevant areas of investment and expenditure that fall outside the above definition of "energy investment" but are nonetheless relevant to the future of energy supply, demand and prices. These include energy technology research, development and demonstration (RD&D), for which the best available data for the public sector is a mix of actual spending, estimated spending and budgeted spending for a given year, and venture capital deals. They also include several selected focus topics related to energy end-use technologies. In *WEI 2018* these are electric vehicles, heat pumps, hydrogen filling stations, steelmaking capacity and water electrolysers. It is not feasible to present a comprehensive study of all expenditure on energy-using technologies each year, but the market size for these few areas is presented as a snapshot of interesting and relevant trends. Only the incremental energy efficiency components of these investments is incorporated into the energy investment total in order to provide an estimate of investment and spending that explicitly reduces energy demand alongside data on investments that explicitly contribute to energy supply.

1. Energy investment trends

Highlights

- **Global energy investment amounted to USD 1.8 trillion (United States dollars) in 2017,** making up 1.9% of global GDP. For the third consecutive year, investment in real terms fell, by 2% compared with 2016, mainly due to stagnation in fossil fuel spending and lower capacity additions of coal, hydro and nuclear power plants.
- **The share of fossil fuels, including thermal power generation, in total energy supply investment rose slightly for the first time since 2014, to 59%**. This despite sharply lower investment in coal power plants and less spending on renewable and nuclear capacity, combined with a halt to the annual declines in upstream oil and gas investment since 2014. While it is too early to judge if investment is off-track from the 40% share projected under the International Energy Agency (IEA) Sustainable Development Scenario (SDS) for 2030, current investment patterns suggest a still-significant role for fossil fuels in coming years.
- **Lower costs are an important driver of investment trends in some sectors**. Unit costs for solar photovoltaics (PV) projects fell nearly 15%, with technology improvements and deployment in lower-cost regions, even as investment rose to a record high. In addition to technology improvements, government tendering schemes are contributing to an increase in the scale of new projects in some markets: in emerging economies the average size of awarded solar PV projects rose by 4.5 times over the five years to 2017, while that of onshore wind rose by half. Global upstream oil and gas costs flattened out in 2017, but costs for both conventional and unconventional projects are expected to rise slightly in 2018, mainly in the US shale basins, as activity creeps up.
- **The People's Republic of China (hereafter, "China") remained the largest destination of energy investment**, at over one-fifth of the global total. With a decline of over 55% in investment of new coal-fired power plants, China's energy investment is increasingly driven by low-carbon electricity supply and networks, and energy efficiency. The United States consolidated its position as the second-largest investing country, thanks to a sharp rebound in spending in the upstream oil and gas sector (mainly shale), on gas-fired plants and distribution grids. Europe’s share of global energy investment remained constant at around 15%, with an increase in spending on renewables being offset by declines in both thermal generation and networks.
- **Spending on energy efficiency improvements remained relatively immune from the overall downward trend in energy investment in 2017, but the pace of**

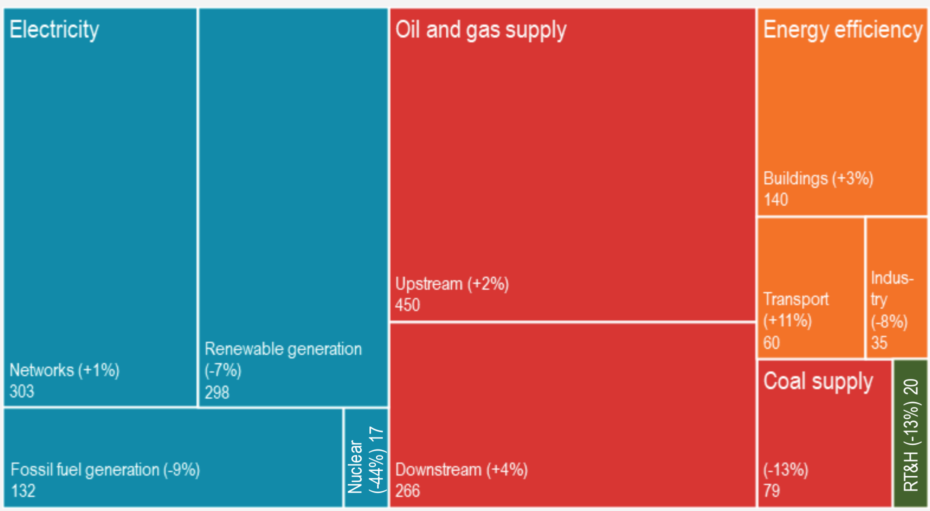
growth is slowing. USD 236 billion was invested in energy efficiency across the buildings, transport and industry sectors – an increase of USD 8 billion, or 3%. The increase was largely due to heating, cooling and lighting.

- **Global power sector investment fell by 6% in 2017 to USD 750 billion.** A 10% decrease in generation investment outweighed a 1% rise in networks and storage, due to fewer new coal plants in China and India, and less nuclear and renewable investment. Solar PV rose to record levels, but was offset by lower hydropower and onshore wind. The share of low carbon in generation investment remained at a high level over 70%, but due to less new nuclear and hydropower, expected generation is 10% lower. Global spending on electricity networks grew more slowly in 2017 than in the previous year, by 1%. Investment in stationary battery storage fell by over 10% to USD 1.8 billion.
- **Investment in fossil fuel supply stabilised around USD 790 billion in 2017 as a modest rise in oil and gas upstream spending was mainly offset by reduced investment in coal supply and in liquefied natural gas (LNG).** Upstream investment is set to rise by around 2% in real terms in 2018 driven mainly by US shale and increasing activity from national oil companies (NOCs). Investment in coal supply fell by 13% to just below USD 80 billion in 2017, mainly due to reduced spending in China. LNG investment continues to plunge as only three new LNG projects have been sanctioned since mid-2016.
- **Higher prices are not derailing the transformation of the oil and gas industry, but upstream investment is rapidly shifting towards short-cycle and high-decline production**. Companies continue to prioritise cost control, financial discipline and shareholder returns, while reducing investment per project and bringing assets into production more quickly. At a global level, investment in shale assets should reach almost one-quarter of the total in 2018, while the share of offshore keeps declining, though activity starts to recover. Investment by majors in shale projects is set to reach 18% of total oil spending in 2018, triple the 2016 level.
- **Several companies are increasingly targeting an integrated model with a notable shift towards expansion into the downstream and petrochemicals.** Global refining investment increased by 10% in 2017 and investment in petrochemicals rose by 11% to USD 17 billion in 2017, set to reach almost USD 20 billion in 2018. For the first time in recent decades, the United States became the largest recipient of investment in petrochemicals.
- **The electric vehicle (EV) market continues to grow, and USD 43 billion was spent in 2017 on electric car purchases**. Of this, batteries represent over USD 8 billion, and the expansion of electricity storage on wheels is proceeding much more rapidly than stationary batteries, in which just USD 2 billion was invested. However, uptake is largely driven by policy. Purchase incentives provided by central and local governments represent 24% of the spending on electric cars, or USD 10 billion, a value that is rising at 55% per year.

Global energy investment trends

Total energy investment worldwide, including capital spending on energy supply and improvements in end-use energy efficiency, in 2017 is estimated to have amounted to 1.8 trillion USD,[1] accounting for 1.9% of global GDP, a lower share compared with the previous two years (Figure 1.1). Investment in all sectors of the economy as a share of GDP has been stable, suggesting that availability of capital generally has not been a constraint. The power generation sector accounted for most of the decline, due to fewer additions of coal, hydro and nuclear power capacity, which more than offset increased investment in solar PV. Capital spending on fossil fuel supply also stagnated at 34% below 2014.

Figure 1.1 Global energy investment in 2017 and percent change from 2016



Global energy investment in 2017 fell for the third consecutive year, to USD 1.8 trillion, with declines in electricity and coal supply, while oil and gas grew marginally and efficiency rose 3%.

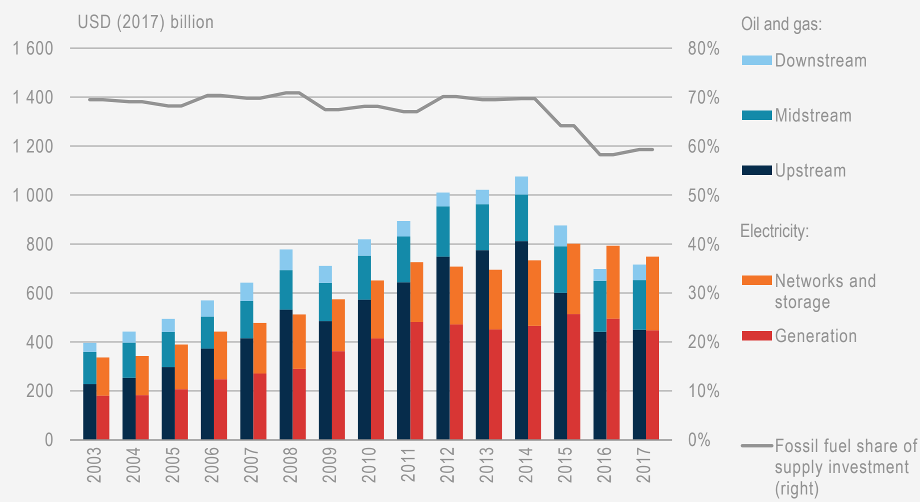
Notes: RT&H = Renewable transport and heat. All values in USD (2017) billion. "Networks" includes battery storage.

[1] Unless otherwise stated, economic and investment numbers cited in this report are presented in real USD (2017), converted at market exchange rates.

Unit costs remain an important driver of overall investment trends. For example, solar PV projects commissioned in 2017 cost nearly 15% less per megawatt (MW) of capacity than in 2016, due to technology improvements and deployment in lower-cost regions, even as capacity additions and investment rose to record levels. Oil and gas costs rebounded in response to rising oil prices, but only weakly outside the United States shale sector.

Energy efficiency, oil and gas supply, and electricity networks were the major sectors that saw an increase in investment in 2017. Energy efficiency investment rose by 3%, a slower pace than in 2016, and investment in electricity networks and battery storage rose by 1%, but also at a slower pace than the previous year. The share of investment in low-carbon power sources – including renewables and nuclear – remained elevated at over 70% of total power plant investment. This share has grown quickly from less than 50% a decade ago. Electricity networks, a backbone and key enabler of the clean energy transition, accounted for more than 40% of total investment in the electricity sector, up from one-third just five years ago.

Figure 1.2 Global investment in oil and gas and electricity supply



Electricity kept its position as the leading sector for energy supply investment in 2017, with the overall share of fossil fuels rising for the first time since 2014.

Notes: Fossil fuels include oil, gas and coal. Electricity includes electricity generation and networks. Does not include energy efficiency investment.

For the second consecutive year, investment in electricity generation and networks in 2017 was higher than investment in oil and gas supply, including upstream, midstream and downstream investments (Figure 1.2). This reversal of historical experience was maintained despite a 6% decline in investment in the electricity sector and a 3% increase in capital spending for oil and gas supply. The world’s energy will be increasingly supplied by electricity.

As a reminder that much of the world’s power generation continues to depend on fossil fuels, it is noteworthy that the share of fossil fuels, including thermal power generation, in total energy supply investment rose for the first time since 2014 to 59%. The growth was marginal, at one percentage point, but the uptick in oil and gas spending overcame the drop in coal investments to arrest the steep declines seen in 2015 and 2016. Over the past three years, mature economies and China, with a fossil fuel share of energy supply investment at 55%, have seen a faster reduction than emerging economies, where the share is at 65%, but all three regions saw an uptick in 2017. While accounting for only 8% of total energy investment, combined investment in coal-fired power and coal supply suffered an 22% drop, declining by USD 38 billion since 2016.

In the long term, the International Energy Agency (IEA) Sustainable Development Scenario (SDS) sees a strong shift away from fossil fuel supply and fossil fuel power generation towards low-carbon power supply.[2] Realising this shift suggests that the fossil fuel share of energy supply investment will need to decline to 40% by 2030.

China remained the largest destination of energy investment, at over one-fifth of the global total. With a decline of over 50% in the commissioning of new coal-fired power plants, China's energy investment is increasingly driven by low-carbon electricity supply and networks, and energy efficiency. The share of the United States was around 16% as more gas plants were commissioned and spending on electricity grids expanded, despite less capital going to new renewables capacity. Europe’s share of investment was around 14%, with renewable power and networks investment relatively steady while fossil-fuel based generation investment declined.

[2] The SDS presents an energy transition where the world meets climate objectives under the Paris Agreement, achieves universal energy access and substantially reduces the impacts of air pollution. For further information, see www.iea.org/weo/weomodel/sds/.

Table 1.1 Energy investment by fuel and region (USD [2017] billion)

	Oil and gas		Coal	Power generation			Renewable transport and heat	Electricity networks	Total energy supply	Energy efficiency
	Upstream	Downstream/ infrastructure	Mining and infrastructure	Coal, gas and oil	Nuclear	Renewables				
OECD	167	115	11	43	8	139	5	137	625	140
Americas	114	63	3	16	8	48	1	73	326	47
United States	*70*	*49*	*2*	*14*	*4*	*41*	*1*	*65*	*245*	*42*
Europe	*40*	*22*	*2*	*7*	*0*	*66*	*4*	*44*	*185*	*75*
Asia and Pacific	14	30	6	19	0	25	1	19	114	18
Japan	*1*	*3*	*0*	*2*	*0*	*18*	*0*	*8*	*33*	*9*
Non-OECD	282	128	64	89	9	159	15	166	913	96
Europe/Eurasia	84	24	7	9	0	5	0	17	147	6
Russia	*58*	*16*	*6*	*6*	*0*	*1*	*0*	*10*	*97*	*4*
Non-OECD Asia	58	54	54	55	9	125	14	120	488	81
China	*31*	*27*	*44*	*22*	*8*	*98*	*12*	*80*	*322*	*65*
India	*3*	*9*	*7*	*16*	*0*	*19*	*0*	*20*	*74*	*8*
Southeast Asia	*17*	*13*	*2*	*9*	*0*	*3*	*1*	*14*	*58*	*3*
Middle East	63	28	0	8	0	2	0	9	110	1
Africa	37	14	2	15	0	9	0	9	84	3
Latin America	41	9	1	3	0	18	1	12	84	4
Brazil	*23*	*3*	*0*	*1*	*0*	*14*	*1*	*7*	*49*	*2*
World	450	266	79	132	17	298	20	303	1 566	236
European Union	*14*	*33*	*2*	*6*	*0*	*55*	*2*	*36*	*148*	*n.a.*

Notes: Renewable transport and heat include transport biofuels and solar thermal heating. Regions do not sum to world as fossil fuel shipping is not regionally allocated. Russia = the Russian Federation. OECD = Organisation for Economic Co-operation and Development. Electricity networks include battery storage.

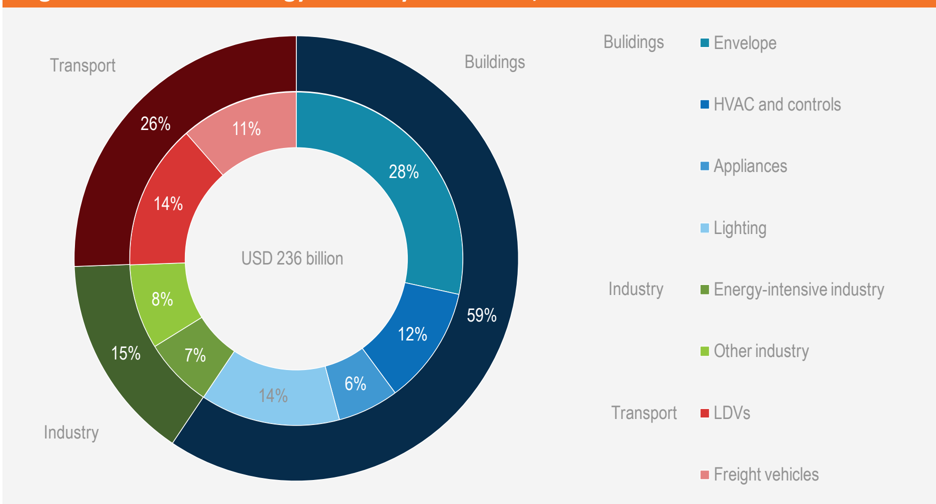
Energy end-use and efficiency investment

Trends in investment in energy end-use equipment can have profound impacts on future energy demand. This section covers trends in business and household spending on more energy efficient goods that reduce energy consumption, i.e. spending that can be directly attributed to the objective of improving energy efficiency. It covers developments in markets for certificates for energy savings and three focus sectors where investment trends and patterns are having a growing impact on energy efficiency and the electrification of energy end uses: heat pumps, electric vehicles (EVs) and steelmaking.

Global spending on energy efficiency

Spending related to energy efficiency improvements, which has grown strongly in recent years, remained relatively immune from the overall downward trend in energy investment worldwide in 2017. A total of USD 236 billion was invested in energy efficiency across the buildings, transport and industry sectors – an increase of USD 8 billion, or 3%. The increase was largely due to investments in heating, cooling and lighting, while spending on industrial energy efficiency declined somewhat. The highest share of investment was in buildings (Figure 1.3). This report's estimate of energy efficiency spending corresponds to the incremental spending on equipment that consumes less energy than would have been used had the purchaser opted for a less efficient model or, in the case of building refurbishments, not undertaken the efficiency improvements (Box 1.1).

Figure 1.3 Global energy efficiency investment, 2017



USD 236 billion was spent on improving energy efficiency in 2017, mostly in the buildings sector where growth is being driven by more installation of efficient heating, cooling and lighting.

Notes: HVAC = heating, ventilation and air conditioning; LDV = light-duty vehicles.
Sources: Includes inputs from Machinchick and Freas (2018); Marklines (2018); IHS Markit (2018).

Spending on energy efficiency in the buildings sector remains healthy. It is the largest destination of energy efficiency expenditures, with spending in the sector growing 3% to USD 140 billion in 2017, or 59% of the total, the same share as in 2016. While improvements in the energy efficiency of building envelopes – the material components of a building's structure such as insulation, walls, roofs and windows – is the largest component of spending in buildings, spending on envelopes actually dropped 3% to USD 67 billion in 2017. This fall was offset by a 17% increase in spending on energy efficiency in HVAC and a 14% increase in incremental spending on energy efficient lighting. In part, this reflects low-cost interventions using technologies that can be replicated across different building types. There is increasing standardisation of lighting retrofits and appliance upgrades that do not require bespoke or intrusive solutions for the building occupant. As this results in dependable energy savings that are becoming familiar to financial lenders, it enables the development and continued growth of financing mechanisms for efficiency projects in the buildings sector, such as dedicated credit lines, green bonds for infrastructure, and energy service companies (see Chapter 2). While investment in appliances and HVAC continues to rise, this sector has great potential for energy efficiency investment and savings, due to the rapid adoption of cooling appliances. In 2016, 135 million air-conditioning units were sold, four times that in 1990 (IEA, 2018a).

Box 1.1 Measuring investment in energy efficiency

As in *World Energy Investment 2017* (*WEI 2017*) (IEA, 2017a) and other recent IEA reports, an energy efficiency investment is defined as the incremental spending on new energy-efficient equipment or the full cost of refurbishments that reduce energy use. The intention is to capture spending that leads to reduced energy consumption. Under conventional accounting, part of this is categorised as consumption rather than investment.

In the buildings sector, the incremental investment for new or renovated buildings is the change in cost for services (design, delivery, installation) and products (lighting, appliances, equipment and materials) that achieve increased energy efficiency performance beyond the investment required for the minimum performance legally allowed. For building types and products that have legal requirements on the performance of buildings, buildings services or building products, this cost is the incremental spending beyond that needed to achieve the minimum energy performance standards, energy efficiency regulations or building energy codes. For building types and products that do not have energy requirements, this cost is the incremental spending on energy-efficient services and products beyond what would have otherwise been spent, which in some cases is no spending. For the incremental investment in buildings achieved due to the improvement in energy efficiency policies, this cost is the incremental spending required to achieve the new energy performance requirements beyond the previous level to which the market had already adapted.

In the transport sector, it is assumed that the buyer of a relatively efficient vehicle would have otherwise chosen a less efficient model of similar size and power; the incremental expenditure is calculated for each country as the additional price paid for the 25% most efficient cars sold in each size and power class, compared with the average price in that class. Spending on infrastructure to support shifts to more efficient transport modes, such as public transport or cycle paths, is not included.

For the industry sector, the incremental investment includes both an estimate of industry investments in equipment to realise energy intensity gains and investment in energy management systems to unlock system-wide efficiencies.

Spending on improved energy efficiency in the transport sector – i.e. purchases of efficient cars and trucks – also grew, by 11% to USD 60 billion in 2017. At USD 33 billion, LDVs represent just over half of this total, a 9% increase from 2016, as consumers around the world opted for larger, more expensive cars, for which the incremental cost of a model with higher fuel economy is greater. While energy efficiency spending on LDVs is considerable, it remains a very small part of total spending on new vehicles. By comparison, global sales of electric cars in 2017 represented a total purchase expenditure of USD 43 billion, but occupy only 1.3% of the car market (see section below on EVs).[3] The majority of LDV spending growth occurred in emerging economies. China saw a 2% increase and India 8%. These trends reflect increased efficiency spending in response to strengthened fuel economy standards in these countries and the policy-driven shift toward electric mobility in Chinese cities. Freight transport energy efficiency expenditures increased by USD 3 billion to USD 27 billion in 2017. The presence of fuel economy standards for trucks in China was also a contributing factor to the increase in freight efficiency spending. Fuel economy standards for freight transport are also being considered in the European Union (EU), which, if implemented, will provide a regulatory driver for increased investment.

The biggest contributor to the dip in the overall rate of growth in investment in energy efficiency in 2017 was the industry sector, where investment fell 8% to USD 35 billion. The slowdown was most noticeable in China, which remains responsible for 39% of total industry sector energy efficiency spending, but where the rate of growth fell by 20 percentage points to 15%. This was due to a slowdown in the construction of new energy-intensive industrial facilities and the continued movement away from heavy industry towards less energy-intensive services and commercial sectors. Globally, among industry sectors, the overall drop in industrial energy efficiency investment means that spending was largest in non-energy intensive sectors, such as food and beverage manufacturing, exceeding energy-intensive sectors, such as iron and steel manufacturing. This shift was especially marked in OECD economies, but was also noticeable in major emerging economies, particularly China. Falling investment levels may also reflect a preference for energy efficiency projects requiring low or no capital expenditure in order to

[3] Only the incremental cost of an EV compared with a vehicle of similar size and power is included in the energy efficiency spending estimate.

meet aggressive return expectations, particularly in economic sectors that face strong global competition. Furthermore, industrial energy efficiency projects do not always lend themselves well to standardisation and the development of scalable financial products.

Investment driven by markets for energy efficiency certificates

The past year has seen record high prices in France and Italy – the two main national markets for certificates for energy savings. These so-called “white certificate” markets, set up by the national authorities to encourage investment in the most cost-effective projects aimed at improving energy efficiency, have been in operation for just over ten years. As with renewable energy certificates, energy suppliers such as utilities are required to obtain a minimum number of white certificates equal to a pre-determined target in each trading period. These certificates are generated by investment in projects that deliver verifiable energy savings. Obligated parties can invest in efficiency in their own operations or purchase certificates generated from measures implemented by external parties, including their customers and accredited energy service companies (ESCOs). By registering themselves as an ESCO, obligated parties in some markets can work with any energy user. White certificate markets also exist in the Australian states of New South Wales and Victoria, with trading of energy savings also incorporated into systems in Poland and in India’s Perform, Achieve, Trade scheme.

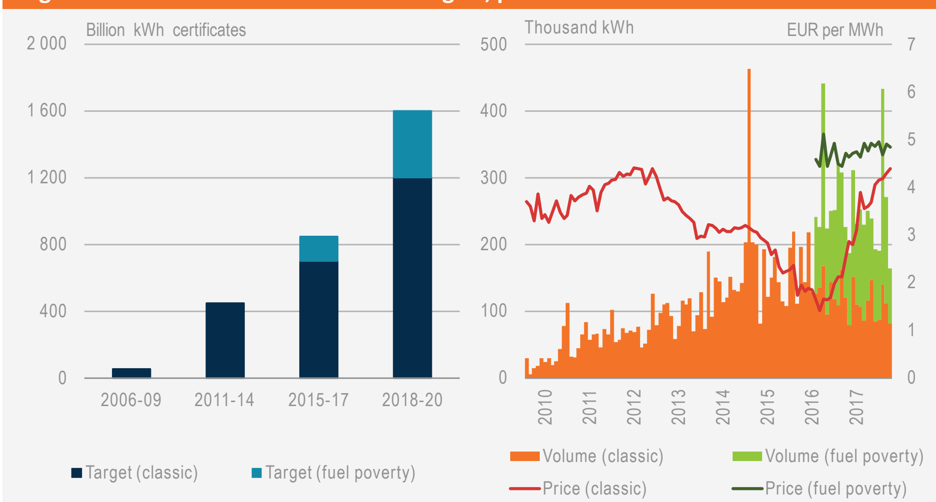
The trends in traded certificate volumes and prices in France and Italy indicate that such markets can be effective in supporting investment in energy efficiency, by providing an additional financial incentive for each unit of energy saved. Experience also shows the difficulties faced by policy makers in estimating the amount of energy savings that a white certificate market may generate. There has been a tendency to underestimate the extent of low-cost efficiency opportunities, leading to lower prices than desired and adjustment of market rules in response.

Changes in market design have caused the market to tighten in France

In France, energy savings targets were recently raised and the structure of the market modified. The French Environment and Energy Management Agency (ADEME) sets targets for all energy suppliers with annual sales of more than 400 gigawatt hours (GWh) of electricity, gas, heating, cooling or transport fuel, or 100 GWh of liquefied petroleum gas (LPG). Targets are set for multi-year compliance periods and, since the launch of the scheme in 2006, have been increased for each compliance period (Figure 1.4). In response to the apparent oversupply of certificates, the system was changed in July 2016, mid-way through the third compliance period to 2017, with the introduction of an additional obligation for energy savings in fuel-poor households, which generate separate “fuel poverty” certificates. An 88% increase was also announced for the energy savings target for 2018 to 2020, with one-quarter of the market reserved for energy savings in fuel-poor households.

While most compliance in France is achieved by bilateral or internal projects, rather than purchasing certificates on the exchange, the recent changes to the market have led to a sharp increase in certificate prices, which are a good indicator of the value and scarcity of energy efficiency projects meeting eligibility criteria. Higher targets did not lead to higher prices in the second period, 2011-14, due to the continued availability of low-cost efficiency measures and stockpiling of certificates from the first period in anticipation of higher prices in the second (Figure 1.4). However, the changes that took effect midway through the third period have driven prices sharply higher. This is particularly the case for classic certificates, for which the price almost tripled between August 2016 and January 2018. Since mid-2016, the amount of trading has risen markedly and this report estimates that the total value of trades rose 60% to a record EUR 12 million from 2016 to 2017. It appears that the higher value of fuel poverty certificates shifted investments towards these projects and away from classic certificates, returning the classic certificate market to a scarcity situation. There is now some concern about the sufficiency of classic certificate supplies in the fourth trading period, which should stimulate companies to seek and invest in more energy efficiency projects. However, the profitability of certificates has led regulators to pay closer attention to the methods for estimating project savings and implementation quality, and tighten the verification rules, to avoid potential fraud.

Figure 1.4 French white certificate targets, prices and annual market value



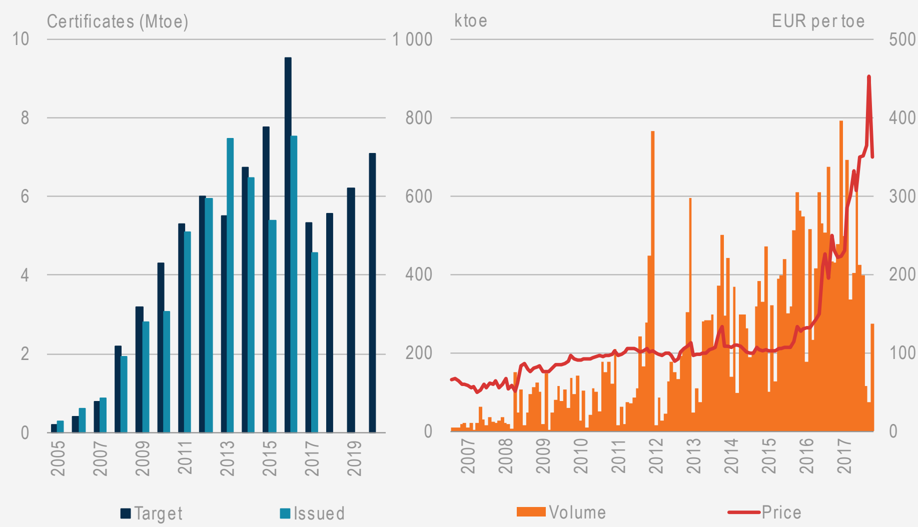
Following the introduction of fuel poverty certificates and the announcement of raised targets, the French white certificate market for energy efficiency projects has surged in traded volumes and prices.

Notes: kWh = kilowatt hours; EUR = euros; MWh = megawatt hours. Each certificate represents 1 kWh of energy savings over the lifetime of the intervention, discounted at 4% per year. The target for fuel poverty certificates was applicable from July 2016, part way through the third compliance period.
Source: Adapted from EMMY (2018).

Certificate prices in Italy have soared with tighter rules on project eligibility

Changes to market design have also helped drive up white certificate prices in Italy. All companies that supply electricity or gas to more than 50 000 customers are obliged to participate in the market. As in France, certificates traded at a relatively stable level of EUR 100 per tonne of oil equivalent (toe) – equal to around 5% of the average household electricity price – between 2005 and 2016, even as annual targets continued to rise and traded volumes spiked at the end of each annual trading period (Figure 1.5). Obligated parties in the Italian white certificate market receive annual compensation that reflects the cost incurred in obtaining white certificates in the preceding year. This compensation is funded by a charge on the electricity and gas bills of all Italian consumers.

Figure 1.5 Italian white certificate market



Rule changes in the Italian white certificate market in 2016, including a reduction of the target level, have driven prices and traded volumes upwards, incentivising energy efficiency investment.

Notes: Mtoe = million tonnes of oil equivalent; ktoe = thousand tonnes of oil equivalent. Monthly prices are expressed as a weighted average across certificate types (I, II, II-CAR, III and V).
Source: Adapted from GME (2018).

From 2011 to 2013, regulatory changes were introduced to recognise projects that generated energy savings for an extended period of time and reduce potential duplication between other incentive schemes. This increased the volume of issued certificates but did not have a substantial impact on price. In 2017, the eligibility criteria for new projects were tightened, the additional credit for long-lasting projects was reversed – though each project is now able to generate certificates for more years – and the annual targets were reduced to reflect this new regulatory framework. In anticipation of these changes, market activity surged in 2016 as obligated parties sought to lessen the impact of the new regulatory framework. Ever since, the market has experienced unprecedented tightness and traded volumes have surged. Prices reached EUR 450/toe in 2017, though still only around 15% of the household electricity price. A consequence of the spike in the white certificate price was a rise in the compensation amount paid to obligated parties and thus the amount levied on electricity consumers, from EUR 100 per certificate from 2005 to 2010, to EUR 191 in 2016 and an expected level above EUR 200 for 2017. Whether prices will remain at this level in future will depend on participants innovating to find low-cost energy efficiency opportunities as the "low-hanging fruit" becomes scarcer, as well as movements in energy prices, which strongly affect project payback times. The rise in traded volumes also reflects the ability for white certificates to be traded multiple times. In 2017, the number of white certificates traded exceeded the total amount issued by an estimated 35%.

The Italian white certificate market has been successful in stimulating the financing of ESCOs, which can standardise projects. ESCOs are generally considered to be an important means of increasing energy efficiency investments.[4] An example of this is the decision by the Hera Group – an Italian electricity and water utility – to establish a certified ESCO that provides energy savings services to customers and purchases the associated certificates, allowing the parent company to fulfil its obligations. This move was underpinned by the development of the skills and expertise in the Hera Group to undertake energy efficiency projects within its own business operations to meet its target. To maintain its flow of white certificates and capitalise on its new skill base, it started providing certified ESCO services to other companies. It has now obtained nearly 3.5 times more white certificates from external companies than from its own operations, generally at lower cost, generating primary energy savings of over 0.35 Mtoe over the lifetimes of the projects.

Focus on heat pumps

Heat pumps are among the most efficient ways to increase the share of low-carbon energy in heating in buildings, which currently accounts for around 15% of total final energy demand worldwide.[5] Heat pumps are not new. The technology has long been used in cooling and air

[4] See Chapter 2 for more information on ESCO financing.

[5] The additional costs of heat pumps and other forms of energy efficient heating technology compared with less efficient alternatives are included in the estimate of global spending on energy efficiency in buildings (above). This section highlights the heat pump market as one indicator of progress towards more energy-efficient and lower-carbon heating. Improvements to other technologies, including higher combustion efficiency, integration of biomass and solar energies, and better controls and automation are helping to lower the energy intensity of heating, often driven by standards and policy and sometimes in situations where heat pumps are not a viable alternative.

conditioning, but sales of heat pumps for space heating are now expanding beyond their traditional markets, such as Japan. Their potentially key role in the electrification of heat to reduce fossil fuel consumption has been promoted in several major economies, including Europe and China, and performance and costs have improved. Heat pumps are expected to gain market share from only around 2.5% of sales of global building heating equipment today, boosting energy efficiency spending in the buildings sector and helping to reduce emissions, especially as decarbonisation of electricity supply proceeds.

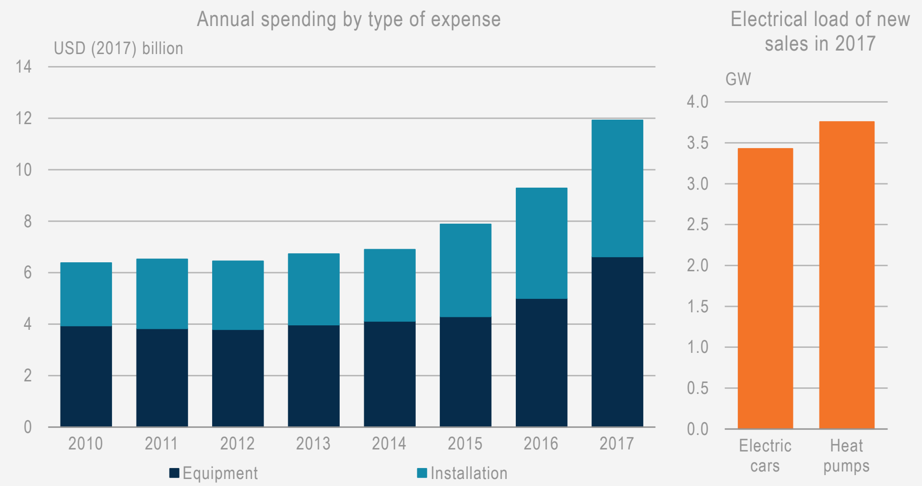
Households and businesses spent almost USD 12 billion on heat pumps dedicated to heating in 2017, with global sales continuing to grow at roughly 30% per year (Figure 1.6). In addition, there is a growing market for reversible air-to-air heat pumps that also provide air conditioning, sales of which reached approximately USD 34 billion for 42 million units in cold and temperate climate countries in 2017 (IEA, 2017b; BSRIA, 2018).[6] As in 2016, China accounted for over 90% of the growth in sales of heat pumps for heating in 2017, supported by city-level policies to replace coal-fired heating in order to reduce local pollution. Outside China, sales are concentrated in Europe and Japan. Both markets grew steadily in 2017, and after reaching parity in 2016, Europe overtook Japan in terms of units sold, with an increasing number of EU countries offering incentives for the uptake of heat pumps to displace fossil fuels and help meet EU renewable energy targets. In EU legislation, heat output that exceeds the energy needed to drive heat pumps is counted as a renewable energy source regardless of the origin of the input electricity for the compressor and pump.

In Europe, the deployment of heat pumps is proceeding at a faster rate than the turnover of the building stock in general thanks to policy action. In several countries, the requirement to include at least one source of renewable energy in the construction of a new large building or the major renovation of an existing one is a driver of the deployment of heat pumps. This is the case in France, Germany, Denmark and Finland. Other measures used across Europe include fossil fuel taxes, grants, tax credits and standards. In addition, heat pumps are taking a larger share of the renewable heat market in many countries. In the United Kingdom (UK), 38% of projects supported by the Renewable Heat Incentive in 2014 were for heat pumps; by 2017, the share had risen to 71% (UK BEIS, 2017). Policies have helped to support the replacement of fuel oil boilers with heat pumps, despite lower oil prices in recent years.

Most heat pumps are still deployed in the residential sector. Almost 90% of global sales in 2017, by units sold, were for residential buildings, around two-thirds of which were for new dwellings. Japan and Sweden, which have mature heat pump markets and high shares of sales for existing buildings and replacements, are exceptions.

[6] The rest of this section focuses on air-to-water (hydronic) heat pumps dedicated to heating only.

Figure 1.6 Global investment in heat pumps for space heating and associated electricity load



Heat pump sales are growing strongly, with the load associated with the pumps installed in 2017 exceeding that of all the electric cars sold in the same year.

Notes: GW = gigawatts. Does not include reversible air conditioners and air-to-air heat pumps. Assumes connection of EVs to slow-charging 3 kilowatt (kW) supplies.
Sources: Calculations based on BSRIA (2018) and IEA (2018b).

Further reductions in the cost of installing heat pumps would encourage their deployment, alongside higher prices for carbon dioxide (CO_2) emissions from fossil fuel use. Where natural gas is available, and especially where gas prices are low, heat pumps can still be a more expensive alternative to gas-fired boilers. Heat pump installation costs declined on average by around 8% in 2017, though there is a wide variation by country (BSRIA, 2018). As with solar PV in the residential sector, equipment costs are falling more rapidly than the other costs of installation (mainly labour). This report estimates that global investment in heat pump installations represented by costs other than the heat pump equipment itself amounted to USD 5 billion, or 45% of the total, up from 41% five years ago.

Like other electrical loads, heat pumps can support the decarbonisation of electricity generation by playing a role in demand response. Consumers can be incentivised to operate heat pumps at times when congestion on the grid is lower, which can help reduce overall carbon intensity if prices in the electricity market reflect CO_2 emissions. Such arrangements with utilities or third-party aggregators are starting to become available. This type of market co-ordination of supply and demand will become more valuable as the share of variable renewable electricity rises. Where heat pumps displace electric resistance heating, electricity demand is sharply reduced, but in general, electrification of heat and transport provision is likely to boost overall electricity demand in the years to come. While

EVs are commonly regarded as a major potential source of new electricity demand and demand response, the heat pumps installed in 2017 offer more capacity for demand response in aggregate than all the electric cars sold in the same year (Figure 1.6).

Focus on EVs

In total, global sales of EVs – including passenger vehicles, commercial vehicles, buses and two- and three-wheelers – are estimated to have reached around 27 million in 2017.[7,8] At around 26 million, the vast majority of these vehicles are two- and three-wheelers sold in China, for which detailed data are scarce. The next-largest market is electric passenger vehicles, with sales growing 54% to 1.1 million in 2017 – the first time they have exceeded the 1 million mark. The electric bus market was stable, with sales of around 100 000 worldwide in 2017, mostly in China.

The share of EVs in the total stock of passenger vehicles, commercial vehicles and buses is still low, at less than 0.4% (excluding two- and three-wheelers). Consequently, their impact on oil and electricity demand remains modest for now: electric cars, buses and commercial vehicles sold in 2017 will reduce global oil demand by around 30 thousand barrels per day (kb/d), of which almost half is due to buses in China. When two- and three-wheelers are included, the annual electricity needs of EVs sold in 2017 is around 10 terawatt hours (TWh), equal to 1.3% of global demand growth in 2017.

Public spending on electric car incentives is rising as sales climb

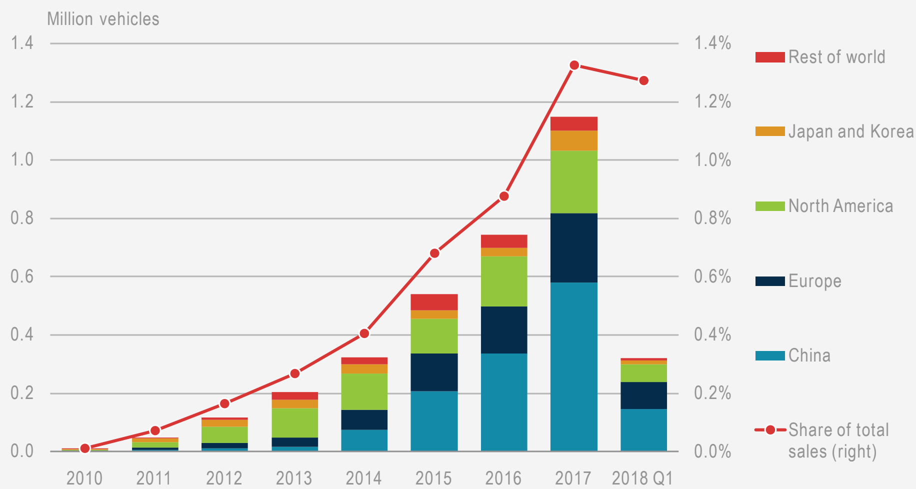
The 1.1 million electric cars sold in 2017 represent 1.3% of all passenger car and passenger truck sales worldwide, a new high, compared with just 0.2% in 2010 (Figure 1.7). Preliminary data show that their market share was maintained at the start of 2018. Annual sales growth rose in 2017, to 54%, equal to the average of the prior three years. To meet the level of EV deployment projected in the IEA SDS, the average annual electric car sales growth would need to be 33% to 2030, alongside an expansion of EV charging infrastructure to meet the needs of higher shares of car owners and a corresponding decarbonisation of electricity supply (IEA, 2018b; 2017c). In addition, continued expansion of the electric car market will depend on the ability of car prices and running costs to decline to meet customers' expectations while avoiding unsustainable increases in government budgets for purchase incentives.

---

[7] This section on EU trends draws primarily on data from *Global EV Outlook 2018* (IEA, 2018b).

[8] EVs are defined here as battery electric vehicles without an internal combustion engine, plug-in hybrids and fuel cell electric vehicles.

Figure 1.7 Electric passenger LDV sales and market share



Sales of electric passenger vehicles exceeded 1 million for the first time in 2017, accounting for 1.3% of total vehicles sales, driven mainly by China.

Notes: Q1 = 1st quarter. Includes passenger cars and passenger light trucks. The first quarter of each year typically has much lower absolute sales of electric cars and all passenger LDVs than subsequent quarters.
Sources: IEA (2018a); Marklines (2018).

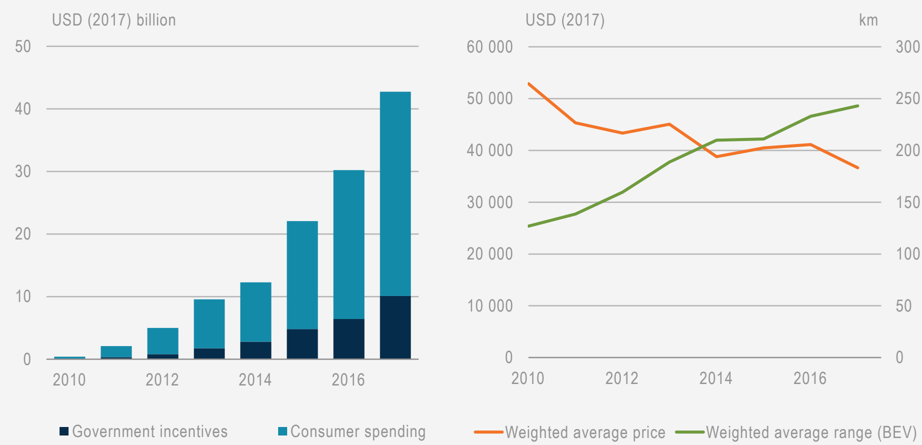
Electric cars sold globally in 2017 represented a total purchase cost of USD 43 billion (Figure 1.7).[9] Most of these purchases benefited from some kind of government incentive (national or local). As a result, consumers and governments shared that spending. In 2017, purchase incentives provided by central and local governments amounted to USD 10 billion, representing 24% of total spending on electric cars. Globally, public budgets for electric car incentives have risen at 55% per year over the last four years.

Purchase incentives today generally take the form of grants, tax exemptions and tax credits. These are sometimes variable by car weight or range, capped at a certain car price or

[9] EVs are generally more efficient than internal combustion engines cars. A BEV uses around 70% less energy and a PHEV around half less than an equivalent gasoline-powered vehicle (ICCT, 2016). When energy losses in power generation, refining and other transformations are taken into account, both BEVs and PHEVs use at least 30% less primary energy. However, our estimate of energy efficiency investment includes only the incremental cost of an EV compared to comparable internal combustion engines cars.

income, or differentiated for plug-in hybrid electric vehicles (PHEVs). Globally, the share of subsidies in total expenditure has increased slightly in recent years, largely because of the rising share in worldwide sales of China, where the government contribution is higher.

Figure 1.8 Global spending on electric cars and trends in price and driving range



Over USD 40 billion was spent on buying electric cars vehicles in 2017, one-quarter of which was covered by government incentives.

Notes: Spending is inclusive of sales taxes. Government incentives assigned per model in each year based on national policy documents and include tax incentives and transfers to consumers or manufacturers to reduce purchase prices. Where possible, local incentives are weighted by distribution of national sales. Non-purchase incentives, such as lower road taxes or parking fees, are not included. Averages weighted by sales per model. Ranges converted to Worldwide Harmonised Light Vehicles Test Procedure (WLTP).

This shift towards China is also the main driver of falling sales-weighted average electric car prices globally (Figure 1.8). Average prices before subsidies are almost one-quarter lower there than they were five years ago, and are 40% lower than US average prices and 50% lower than in Norway. In contrast, average prices in the United States were unchanged in 2017, while in Germany they increased slightly. In Europe, the price trend is a reflection of the growing share of PHEVs, up to 57% in 2017 from 33% in 2013, and the rising share of sales in higher-price countries, such as Norway, Germany and the United Kingdom. In general, there is not yet a clear decline in average electric car prices for either battery-electric vehicles (BEVs) or PHEVs in most countries as variations in market composition, especially the sales of luxury vehicles, dominate the trend. However, when looking at individual models, a price drop is clear: the global average prices of the best-selling BEV models outside China, the Renault Zoe and Nissan Leaf, are 25% and 33% lower than they were in 2012, despite improved battery range. The trend towards higher battery range is clear across all BEV models and countries. The sales-weighted average worldwide range is 100 kilometres (km) higher than in 2010 (Figure 1.8).

Unless government incentives adjust as sales prices change, further pressure will be placed on public budgets. At the current rate of growth, annual public expenditure will exceed USD 50 billion per year in 2021. Policy changes are already being made in some countries to rein in the cost of these subsidies. There is a growing use of standards, regulations and mandates to shift costs from the public sector to consumers and manufacturers. A few examples are listed here.

- **Portfolio standards and trading**. In September 2017, the Chinese government set a minimum size for the electric car market by 2020, with flexibility through a cap-and-trade mechanism (MIIT, 2017). This could lead to a market share of 3% to 6% by 2020.[10] While the central government has indicated that its subsidies in China will be phased out over the period to 2020, in the short term they have been increased for vehicles with ranges over 400 km and reduced for vehicles with ranges under 300 km, while BEVs with ranges of less than 150 km are ineligible. Fleet average fuel economy standards are being tightened in parallel.
- **Environmental performance standards**. In November 2017, the European Commission proposed a 30% reduction of the CO_2 emissions per km for new cars and vans between 2021 and 2030 (EC, 2018). The proposal includes updated emissions standards and penalties for carmakers exceeding emissions limits. For manufacturers, higher shares of zero- and low-emission vehicles, such as electric cars, in annual sales would be rewarded by relaxation of CO_2 emissions targets.
- **Public procurement**. India has adopted an approach to kick-starting the production and sales of electric cars that is similar to its successful programme used to deploy light-emitting diodes (LEDs). It is based on bulk public procurement that seeks to minimise prices. Tata Motors won the first tender and a second, for 10 000 EVs, was launched in March 2018 (EESL, 2018), though its conditions are being re-evaluated for the adequacy of the performance requirements.

[10] Currently, China also has a large market for so-called low-speed EVs that are cheap and unsuitable for highway use, estimated unofficially at close to 4 million. Policies are now designed to reduce annual sales of these cars.

- **Scheduled bans on cars with only internal combustion engines (ICEs)**. Worldwide, 8 countries[11] have announced bans on sales ICEs by 2040, while 19 cities have announced restrictions on ICEs by 2040 at the latest (6 of which take effect by 2025) (IEA, 2018a).

China continues to dominate the global market for EVs. Just over half of all electric cars sold in 2017 were in China, where Chinese manufacturers supply almost the entire market. Globally, Chinese manufacturers, including joint ventures with manufacturers from other countries, now supply half of all EVs, based on local value chains that include battery manufacturing.[12] China's policy push towards EVs covers a range of objectives beyond climate change, including lessening fuel import dependence, increasing high-tech manufacturing exports and reducing local air pollution. In an indication that innovation in China will play a major role in the development of new technologies and companies in the EV market, some of the largest venture capital transactions in the last two years involved Chinese EV start-ups (see Chapter 3). The European Union and the United States together accounted for about another quarter of global registrations.

The breakdown of the EV market by type of vehicle varies markedly across countries and regions. Whereas China's EV market is dominated by BEVs, Europe and North America have higher shares of PHEVs – due to a different interplay of consumer preference (PHEVs are attractive to those who make longer journeys), policy incentives, fuel prices and concerns about access to charging. Where purchase incentives for BEVs and PHEVs are similar in European countries, consumers currently favour PHEVs, but this may change if oil prices rise further and battery prices continue to fall (Chapter 3). In 2017, shares of PHEV sales were above 50% of the electric car market in countries such as Germany, Japan, Sweden and the United Kingdom and below 25% in China, France, the Netherlands and South Korea. In the case of the Netherlands, this is a turnaround from the situation in 2015 and is the result of policy change. Norway, which, at 39% in 2017, has by far the highest share of electric cars in total car sales, is moving in the opposite direction: the share of PHEVs has been rising as the availability of PHEV models has expanded along with some uncertainty over the policy outlook.[13] Globally, 65% of electric car registrations in 2017 were BEVs, for which production

---

[11] France, Ireland, Netherlands, Norway, Slovenia, Sri Lanka, Sweden, United Kingdom. In the cases of Sri Lanka and Sweden the targets are for car fleets without ICEs, equating to *de facto* sales bans.

[12] The impact of EV market growth on investments in the battery value chain are discussed in Chapter 3.

[13] Survey results in Norway indicate that purchase prices tend to be the most important factor for consumers in deciding what type of car to buy (IEA, 2018d).

costs are largely determined by battery prices. To reduce the upfront consumer cost, leasing arrangements for EVs and batteries that allow third parties to pool battery price and technology risk are expected to become more commonplace, building on services from Renault and Australia's Clean Energy Finance.

Sales of fuel cell electric vehicles (FCEVs) are rising, but more slowly and from a lower base. Half of the 7 200 FCEVs that have been sold worldwide to date are in California, and nearly one-third are in Japan. In California, FCEVs are eligible for rebates of USD 5 000 to USD 7 000, twice the level of BEVs.

The boom in EVs concerns not just cars

Sales of electric buses are also growing rapidly. China accounts for the bulk of global battery electric bus and minibus sales, estimated at over 100 000 units in 2017, 85% of which are BEVs. The total fleets of buses on the road has now reached 370 000 units, of which 2 350 are in Europe, Japan and the United States, including 250 FCEV buses. The rest are in China. Due to Chinese subsidy policies at national, regional and city levels, the purchase price of a BEV bus is now close to that of a conventional diesel bus. In 2017, national incentives for electric buses could be up to CNY 500 000 (Chinese Yuan renminbi — USD 80 000), though this has since been reduced by 40% as policy makers seek consolidation in the sector. By the end of 2017, the city of Shenzhen had completely replaced its urban bus fleet with EVs and is now targeting its taxi fleet. Chinese cities benefit from the fact that much of the transport infrastructure is being developed for the first time. With cost reductions, some European countries have also introduced targets; for example, the Netherlands aims to restrict bus sales to emissions-free vehicles by 2025. Sweden introduced policy support for electric buses in 2016.

While electric cars have attracted most attention, there are actually far more electric bikes on the road around the world. There are thought to be around 250 million electric two-wheelers in China, and around 50 million electric three-wheelers. This is comparable to all the LDVs in the world. Sales in China in 2017 alone reached around 30 million, a level that has been relatively flat in recent years (China News, 2017; IEA, 2018a). The vast majority of these bikes are unsophisticated cheap alternatives to scooters and motorbikes, powered by lead-acid batteries and with low maximum speeds and ranges.

Charging infrastructure is expanding in anticipation of demand

Alongside cost reductions and smart EV policies, continued growth in EV sales hinges on the development of charging infrastructure that can serve a wider range of customer needs. Globally, around 117 000 publicly accessible electric car chargers were installed in 2017, 10% fewer than in 2016, at a total cost of around USD 3 billion (see Investment in electricity networks section, below).[14] This brings the total number of publicly accessible charging stations to 430 000, of which one-quarter are fast chargers. Half of these charging points are in China.[15]

A number of companies have recently announced plans to invest in EV charging services. Electricity retailers are seeking to capitalise on a potentially significant new market by developing services that allow billing for charging away from home and allow them to make money by exploiting the value of demand flexibility for utilities and their power trading operations. They face competition, however, from oil retailers seeking to take advantage of their existing retail sites, carmakers offering competitive and convenient charging deals to their customers, and new entrants trying to build a customer base. Despite some high-profile investments in, or alongside, charging infrastructure and related service providers – such as Shell's purchase of NewMotion in Europe, BP's investment in Freewire in the United States and Engie's acquisition of EV-Box – public fast-charging stations are rarely profitable alone unless they have unusually high rates of use. Each public fast charger can cost USD 30 000 to USD 100 000 to install, depending on the charging speed and region.[16] As a result, companies have tended to seek strategic partnerships to share costs. Recent tie-ups include: Vattenfall and Volvo; Shell and Ford, Daimler and Volkswagen; E.ON and Nissan; PG&E and BMW; and GM and EVgo, with partnerships with US utilities.

To help build the market for EVs, most countries have incentives in place to encourage the establishment of charging infrastructure in anticipation of future demand. In general, these incentives are available to all interested parties. However, because retail of electricity has traditionally been a highly regulated business, there can be legal considerations. In India, fewer than 250 EV charging stations have been installed to date, due to an interpretation of power sector regulations that suggested they fell under the licensing requirements for the sale and distribution of electricity. The government issued a clarification in April 2018 stating that stations for charging a battery within an EV were providing a service and not selling electricity. Therefore they do not require such a licence. This action may open the door for third-party development of charging points, particularly to meet demand for a recent tender by government-backed Energy Efficiency Services Limited for the installation of 2 000 charging stations. In other countries, including the United States, investments in

[14] Total global investment in chargers could be as high as USD 6 billion, including those for 2/3 wheelers.

[15] Since most electricity there is generated from coal, average life-cycle emissions of greenhouse gases from EVs today can be higher than emissions from their gasoline-powered equivalents. But in almost all other countries, switching to EVs results in a reduction in emissions today and can complement the ongoing expansion of variable renewable power.

[16] Not including associated grid upgrades for EV chargers, which remain a small share of network investment.

EV charging stations by utilities can be eligible for a regulated rate of return, but still have to compete with third parties for customers, permits and policy support.

Focus on iron and steel capacity additions

Investments that are made in iron- and steelmaking capacity – the biggest industrial energy consumers – are of major importance to future energy demand and CO_2 emissions. The iron and steel sector is responsible for 9% of total global final energy demand and 7% of total global CO_2 emissions from fossil fuels.[17] Its assets are long-lived and, with refurbishment of components over time, can operate for more than 60 years. Between 2000 and 2017, global crude steel production capacity more than doubled, from 1.05 billion tonnes to 2.25 billion tonnes per year (OECD, 2018). Around three-quarters of the capacity added over that period was in China and involved blast furnace technology that uses coal as its primary energy source and coke, derived from coal, as the reducing agent. Blast furnaces represent 70% of global capacity. This section explores recent trends in investment in crude steel production routes based on coal, natural gas and electricity.[18]

The rapid expansion of crude steelmaking capacity up to 2013 was not accompanied by an equivalent rise in global crude steel demand, leading to overcapacity and a subsequent reduction in new crude steel capacity investment (OECD, 2018). Global production was around 1.69 billion tonnes in 2017. The biggest annual capacity increase since 2000 occurred in 2013, with around 185 million tonnes (Mt) of new additions, compared with just 45 Mt the following year and 30 Mt in 2016. This report estimates that investment in new capacity fell to around USD 6 billion in 2017 – the lowest level for decades (Figure 1.9).[19] Most of the decline in new capacity investment has been in coal-based processes, while investment in direct reduction of iron (DRI) – usually using natural gas – and electric arc furnaces (EAFs) has fallen much less. Alongside the dramatic reduction in the total level of investment, this has increased the share of gas and electricity-based capacity to coal-based capacity in new investment from 26% in 2013 to 43% in 2017.

Recent trends in investment in crude steel production reflect a combination of policies to tackle overcapacity and energy prices. In 2016, the Chinese government set a target to

---

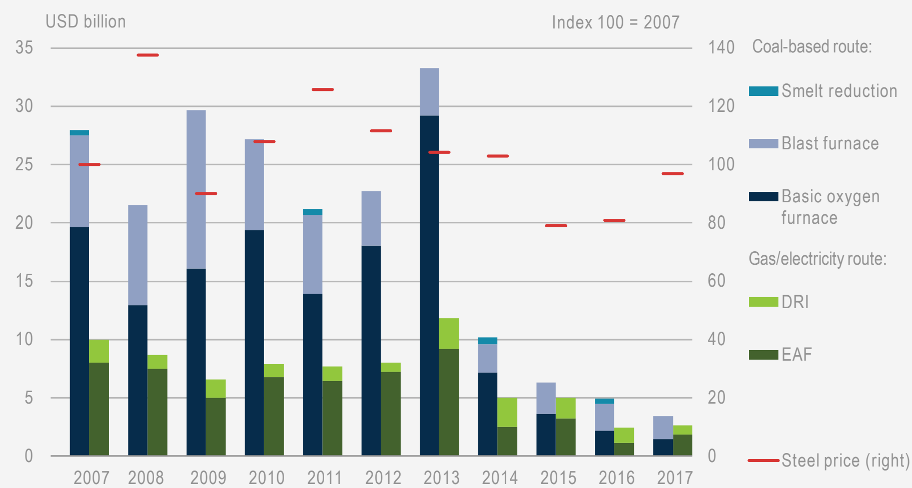
[17] Includes both combustion and process emissions.

[18] The dynamics of the global steel industry are highly complex. Not all steelmaking routes produce equivalent qualities or types of steel today, limiting substitution between them. The degree of substitutability will affect future investments but is not covered in this section due to space constraints.

[19] An estimate of the incremental component of investment in heavy industry sectors is included in the reported total for global energy efficiency spending.

close 100 Mt to 150 Mt per year of capacity for the period until 2020 to address overcapacity and raise average energy efficiency to lower costs. In 2017, there were indications that the 2016 interim target had been exceeded. In addition, 140 Mt of induction furnace capacity (not included in official statistics, or the target above) were reported to have closed in 2017 (MIIT, 2018). New investments in China have been almost completely frozen, but China – where around 90% of capacity uses blast furnaces – still accounts for around 45% of global capacity. In India, the National Steel Policy 2017 outlines that 300 Mt of crude steelmaking capacity would be needed by 2031 to satisfy the expected increase in demand. Ongoing investments into steelmaking facilities in India have been mostly coal-based, and India now has the largest share of global coal-based crude steel plant additions.

Figure 1.9 Global investment in new steel capacity by route



Investment in new steel capacity has collapsed since 2013, with coal-based capacity additions now trailing gas- and electricity-based routes for the first time in several decades.

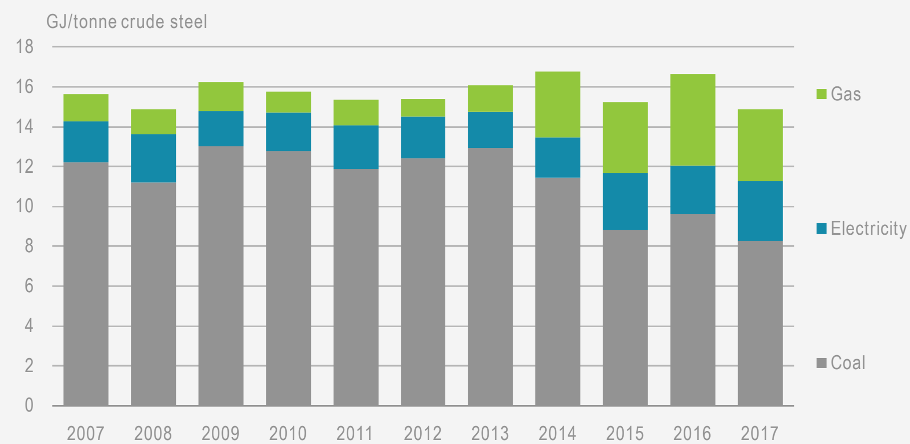
Notes: Includes equipment costs only. Steel price is annual average MEPS Composite Global Steel Price Index.
Sources: IEA ETP analysis based on PLANTFACTS (2018) and OECD (2018); MEPS (2018).

By reforming it to a reducing gas, natural gas can be used to make crude steel via the DRI route. Investment in DRI is concentrated in the Middle East and the United States, where natural gas is relatively cheap. Steelmaking capacity has been growing particularly fast in the Middle East region. If steel prices recover in coming years, DRI plants could expand further, increasing the share of natural gas in the steel sector. While DRI plants still emit CO_2, it is easier to add carbon capture and storage (CCUS) technology to DRI plants than to blast furnaces. CCUS is already in operation at a steel plant in Abu Dhabi, where the CO_2 is stored as it is used to enhance oil production.

In Europe, construction of the first completely new steel plant in 40 years started in Austria in 2018. The EUR 350 million highly digitalized plant with a capacity of 200 000 tonnes per year will be centred on an EAF that will process scrap steel using purchased renewables-based electricity. As more scrap steel becomes recoverable, future EAF plants are likely to be located close to low-cost sources of electricity, though the Austrian project demonstrates that there is also value in siting plants close to a skilled workforce, value chains and scrap collection points.

Recent trends in steel investment have led to a dip in the average energy intensity of new steelmaking capacity coming on line and a shift in the fuel mix. The lower share of blast furnaces in new steel capacity reduced the average energy intensity of new capacity by around 10% between 2014 and 2017 to 15 gigajoules (GJ) per tonne (Figure 1.10).

Figure 1.10 Estimated average energy intensity of new crude steel capacity



The lower share of blast furnaces in new steel capacity and the increased share of EAFs has reduced the average energy intensity of new capacity by around 11% since 2014.

Note: Estimations based on average energy inputs for the main crude steelmaking routes.
Sources: IEA ETP analysis based on PLANTFACTS (2018) and OECD (2018).

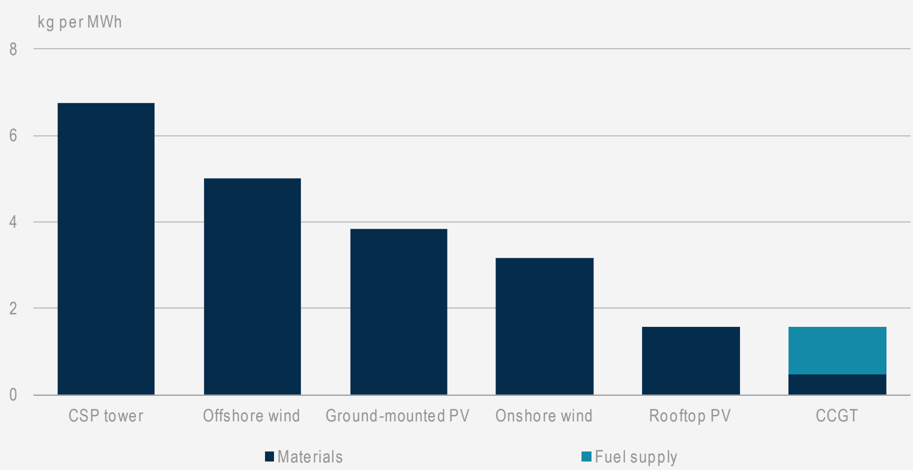
Coal remains the leading energy source for new capacity but electricity now has a share of 20% and the share of natural gas has risen to 24%, almost triple its share prior to 2014. The average energy intensity of new capacity may rebound in the coming years if the current context of overcapacity recedes, steel prices recover and investment in blast furnaces picks up. But this might not happen soon: of the 50 Mt of capacity in the planning phase around the world today, just 40% is based on the blast furnace route.

Trade and climate policies will undoubtedly play a growing role in future investment decisions about steel capacity through their impact on steel and energy prices – the two most important factors for the viability of any steel project (Box 1.2). In the longer term, there are several options for reducing greenhouse gas emissions from steel production, including CCS. In Japan and Korea, investments have been made in testing carbon capture at blast furnace sites, including techniques for enriching the reducing gas with hydrogen. In Europe, a variety of demonstration projects are under way to demonstrate DRI using hydrogen produced with electricity in Sweden, coke-free iron reduction with CCS in the Netherlands and plasma heating and reforming of steel plant gases and natural gas to substitute coke in France.

Box 1.2 The importance of steel in energy investment

Steel is a vital input to many types of energy projects and its costs will be affected by the introduction of tariffs on steel imports by major trading partners in 2017 for as long as these tariffs are in place. For example, in the second quarter of 2017, the United States placed a 25% tax on imports of a wide variety of steel articles and China announced a 15% tax on imports of steel piping. In the oil and gas sector, refineries and other midstream facilities are very dependent on steel for their structural frames and pressure vessels. For example, an LNG plant can require up to 100 000 tonnes of steel, while pipelines are almost entirely made of steel. Power plants also make use of a lot of steel.

Figure 1.11 US average steel requirements for electricity generation by technology



The steel intensity of electricity generation varies widely by technology, with concentrated solar and wind power being the most vulnerable to any increase in steel costs.

Notes: CCGT = combined-cycle gas turbine. Calculated on a levelised basis across the lifetime of the plant.

In the United States, rising oil and gas production have greatly boosted steel requirements. Capacity constraints in US steel production for making pipelines mean that more steel now has to be imported. Annual demand for pipelines has increased by 1 500 km since the start of the unconventional gas boom with the need to connect new sources to demand centres, in addition to the need to replace several thousand kilometres of old pipelines each year. Unconventional oil and gas wells are also very steel-intensive, requiring 200 tonnes to 400 tonnes of steel depending on the depth and the length of the lateral section for well casing. As with pipelines, special corrosion-resistant steels are needed. Up to half of current needs for these steels are now met by imports.

With increased reliance of the US oil and gas industry on imported steel, higher import costs threaten to raise oil production costs. Some domestic steel production could be expanded at costs below those of imports, including import taxes, but if steel prices in general were to increase by 25%, then this report estimates this would lead to an increase in the upstream costs of unconventional oil production of around USD 0.80 to USD 1.00 per barrel. Pipeline transport fees would also rise by around USD 0.20 per barrel. Other parts of the supply chain, from rigs to refineries, would also experience cost rises. Given relatively low profit margins and the high leverage of the sector, such cost increases could have an impact on the attractiveness of investment. The situation for LNG fed by unconventional gas is similar: a 25% increase in steel costs would raise LNG prices by USD 0.20 to USD 0.50 per million British thermal units, with 90% of the increase coming from gas production.

The steel intensity of electricity generation projects varies widely. Concentrating solar power (CSP) and wind turbines have steel requirements of 5 kilogrammes (kg) to 7 kg per MWh of electricity generation (Figure 1.11). By contrast, rooftop PV and gas plants have lower steel intensity, typically below 2 kg per MWh, including steel used in fuel supply. While utility-scale solar plants use some steel for structural foundations, there is often a preference for aluminium, which is a viable alternative. This report estimates that a 25% increase in steel prices would raise the levelised cost of producing electricity for a new US plant by USD 0.80 to USD 2.60 per MWh depending on the technology, with the biggest increases for wind and CSP.

Electricity and renewables sector investment

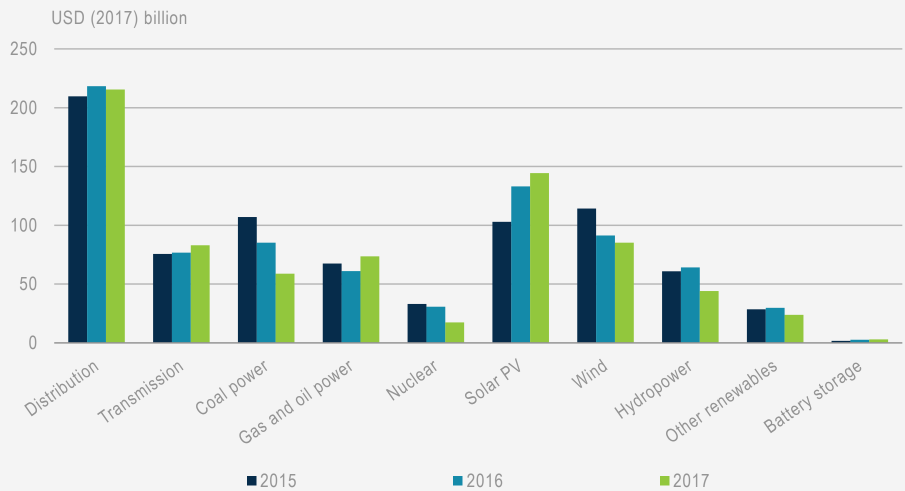
Global power sector investment fell by 6% to USD 750 billion in 2017.[20] Investment in power generation capacity slumped by 10% – a much steeper decline compared with the previous year. The relationship between electricity demand and investment continues to evolve, with the power sector becoming more capital-intensive. Over the past decade, the ratio of global power sector investment to demand growth more than doubled with policies

[20] Unless otherwise indicated, the power sector investment data in this report measures overnight capital expenditures on new assets, attributed to the year an asset becomes operational. This year's data take account of upward revisions in some historical estimates and expanded coverage. In particular, power generation investment now includes small-scale diesel and gas generating sets, long-term operation extensions for nuclear power plants, updated networks investment in China and the United States, and prior-year revisions to capacity additions in some technologies, notably coal power, hydropower, solar PV and wind.

to encourage renewables and efforts to upgrade and expand grids, but also due to more energy efficiency. The share of investment in less capital-intensive thermal generation continues to decline.

In 2017, most of the fall in investment was due to fewer new coal-fired power plants being commissioned in China and India (Figure 1.12). The decline in coal power investment to its lowest level in ten years and continued falls in final investment decisions (FIDs) for new plants suggest that investment may have reached an all-time peak in 2015 (IEA, 2017a). Retirements of existing coal-fired power plants offset nearly half of new coal plant additions, while the fleet of inefficient sub-critical plants continued to contract. By contrast, investment in gas-fired generation capacity rose by 40%, led by the United States and the Middle East/North Africa.

Figure 1.12 Global investment in the power sector by technology



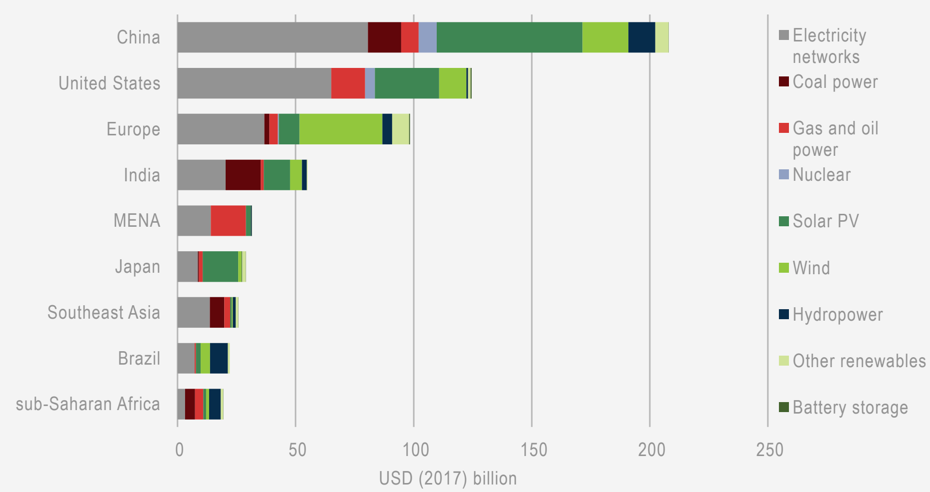
Total power investment slumped by 6% in 2017, mainly due to a 10% fall in spending on generating capacity – despite record investment in solar PV and more spending on electricity networks.

Notes: Gas and oil-fired generation investment includes utility-scale plants as well as small-scale generating sets and engines. Hydropower includes pumped hydro storage.
Source: Costs for solar PV, wind and hydropower based on IRENA (2018).

Investment in renewables-based power generation capacity fell by 7%, though trends varied widely by technology. Solar PV investment rose to record levels, even with investment costs declining by nearly 15% globally, as the share of deployment in historically low-cost regions, such as China and India, continued to rise. Offshore wind investment also rose to record levels, with the commissioning of nearly 4 GW of new plants, mostly in Europe. On the other hand, onshore wind investment fell by nearly 15%, with lower deployment in the United States, China and Brazil, though one-third of this decline stemmed from falling investment costs. Investment in hydropower fell by 30% to its lowest level in over a decade, with a slowdown in China, Brazil and Southeast Asia. Investment in greenfield nuclear power stations declined to its lowest level in five years, though spending on lifetime extensions for existing plants rose.

The share of low-carbon energy sources (renewables and nuclear) in global power generation investment maintained a high level above 70%, with renewables making up over 65%. In most major countries and regions, low-carbon generation investment exceeds that for fossil fuel-based power, and in India, renewable investment topped that for fossil fuel generation for the first time. However, Southeast Asia and the Middle East/North Africa remain the main exceptions (Figure 1.13). The expected annual generation from the new low-carbon generating capacity installed in 2017, at around 460 TWh, is equivalent to about 70% of the 3% increase in global electricity demand. By comparison, expected output from low-carbon investments was 10% higher in 2016, and was equivalent to about 90% of the increase in demand. This lower role for low-carbon investment, in terms of generation, reflects falls in nuclear and hydropower investment, which more than offset record deployment of solar PV and offshore wind, as well as the stronger demand picture.

Figure 1.13 Power sector investment by major country and region, 2017



The share of low-carbon sources in power generation investment maintained a high level at 70% globally, exceeding that in fossil fuel based power in most major countries and regions.

Note: MENA = Middle East and North Africa.

Global spending on the electricity network continued to grow steadily in 2017, but rose only 1%. The network's share of total power sector investment grew to 40% – its highest level in nearly a decade. This reflected continued expansion of grids to meet new demand

and the replacement and upgrading of ageing assets. China remained the largest market for grid investment, accounting for over one-quarter of the total, though grid spending declined, by 4%, for the first time in five years. The United States, over one-fifth of grid spending, led the increase in networks spending, followed by Southeast Asia and India.

Investment is rising in technologies designed to enhance the flexibility of power systems and support the integration of variable renewables and new sources of demand. Power companies are modernising electricity grids by spending more on so-called smart grid technology, including smart meters, advanced distribution equipment and electric vehicle charging, which comprised over 10% of networks spending. Although investment in stationary battery storage fell by over 10% to USD 1.8 billion, this was six times higher than in 2012. An increase of behind-the-meter installations only partly offset a slowdown in spending on grid-scale battery storage, whose decline was mostly due to lower costs. While system services have driven most investment historically, grid-scale batteries are increasingly being used to back up variable renewables and shift electricity to higher value periods of the day.

In some cases, the power sector investment data for 2017 reflect investment decisions taken several years ago (this report allocates investment to the year in which the capacity comes on line). This is particularly the case for large-scale projects. FIDs taken in 2017 are generally consistent with recent investment trends, but there are some notable changes that will likely show up in investment data that the IEA will report in the years to come. The overall amount of dispatchable generating capacity taking FID in 2017, including large-scale thermal generation, dispatchable renewables, peaking and backup plants, and electricity storage, was stable. However, FIDs for coal- and gas-fired power plants declined to their lowest levels in over a decade.

Examining the FIDs for power capacity based on their contribution to the system illustrates another trend. The share of FIDs taken for plants primarily designed to provide low-cost, bulk energy to satisfy demand, traditionally known as base-load generators, at around one-fifth, declined to their lowest level ever. Meanwhile, the share accounted for by plants designed to be available to satisfy demand and other critical system services at a given moment, including plants traditionally classified as serving peaking and back-up needs, rose to nearly half of FIDs. Plants incorporating elements of both applications accounted for the remainder of FIDs.[21] This shift reflects increasing difficulties in recovering generation investments based solely on revenues from energy sales and the increasing value of flexible

[21] This report does not track dedicated investments in demand response, which can provide an additional source of capacity from a system perspective under appropriate regulatory framework and market design.

power capacity in ensuring system adequacy (the ability to meet peak load reliably) and accommodating more variable renewable energy sources.

Trends in power generation investment

Tendering schemes support larger renewable projects in some markets

Tendering schemes are playing a growing role in driving renewable power investment. Recent declines in the prices awarded for renewables-based generating capacity in competitive auctions for long-term power purchase contracts reflect a mix of complex factors. In emerging economies outside of China, and some other markets, such arrangements are generally supporting economies of scale with larger projects. In Europe, such trends are observed in offshore wind; however, the design of auctions, and other factors, has generally not resulted in larger projects there for land-based renewables.

Remuneration levels set by competitive mechanisms accounted for around 35% of global investment in utility-scale renewable power coming on line in 2017, and 50% of such investment outside of China (see Chapter 2). Governments and regulators are making growing use of this method of procuring renewables capacity as part of the process of integrated planning of the system in order to minimise the cost of projects. By 2022, auctions are expected to set the price of power from half of new renewable capacity globally, and two-thirds of capacity outside China (IEA, 2017b). This role may increase with recent announcements by the Chinese government to shift the awarding of remuneration for future solar PV and wind projects towards competitive bidding.

The average prices awarded in utility-scale solar PV and onshore wind auctions, weighted by capacity to be built in the future, have declined considerably in the past five years. In the top markets by auctioned volume,[22] the average awarded price for these solar PV projects, by year of auctioning, fell by half, from over USD 120/MWh (megawatt hour) 2013 to around USD 55/MWh in 2017; that for onshore wind dropped by 15%, from around USD 60/MWh to near USD 50/MWh, with lower prices observed in some markets.[23] These price drops have been accompanied by technology improvements – for example, solar PV module prices fell by almost 40% over the same period. While auction price levels have ostensibly improved the cost comparability of renewables with other

[22] This analysis includes markets that have tendered at least 500 MW of utility-scale solar PV or onshore wind over 2013-17. China is excluded from the analysis due to challenges in assessing project level trends there.

[23] Auction prices are adjusted to reflect consistent assumptions on contract tenor (25 years) and escalation (2% annually).

generating sources, they also suggest a need to focus on the value of delivered electricity, which may differ from underlying costs.[24]

Success by developers in auctions is often aided by scale effects and project structuring that extracts marginal gains along the value chain. Improvements in the design of auctions over time, including increased stringency of qualification, can also tend to concentrate development in well-capitalised players with effective project execution experience. The ability of project developers to extract economies of scale in equipment purchase, engineering, procurement and construction contracts, operations and maintenance contracts, infrastructure and optimising project design can support larger projects. Falling bids may be explained by a diverse mixture of lower technology costs, effective project management, and the ability of companies to manage risks over a project portfolio.

Financing and the creditworthiness of utility power purchasers remain important as well. For example, the scale-up of Argentina's renewable procurement programme over the past two years and its ability to attract private capital reflects, in part, a programme design that incorporates power purchase contracts with a central off taker that are backed by financial guarantees provided by the World Bank. Relatively large projects can be more conducive to structuring guarantees and are often more attractive to lenders, which can help project developers to negotiate better terms for debt financing. Some of these factors are examined in more detail for the case of India (see Chapter 2).

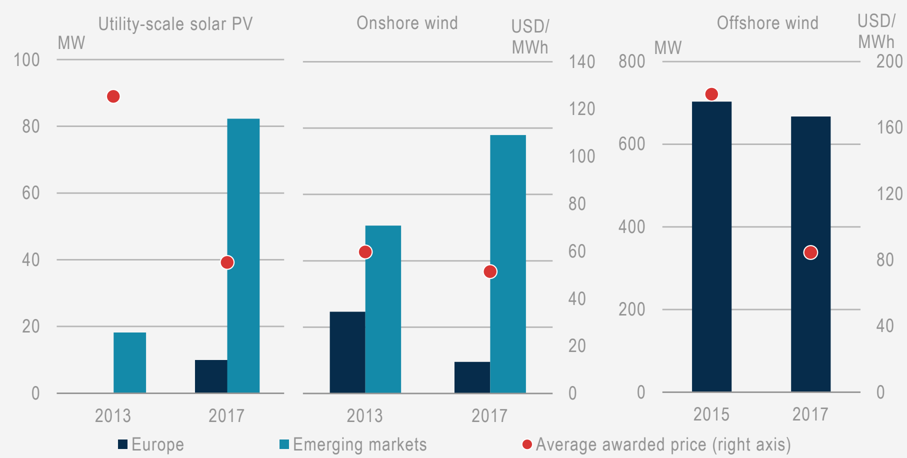
In regions outside of Europe, mostly emerging economies, the average size of utility-scale solar PV projects awarded in auctions increased four and a half times between 2013 and 2017, while that of onshore wind projects rose by half (Figure 1.14). The size of the largest projects has also risen. In Mexico, a 750 MW solar PV project secured an auction award in 2016, while a 500 MW development in Brazil – the country's largest-ever onshore wind development – was successful in 2017. The gradual increase in project size over time reflects the relative impact of new markets implementing tendering schemes, where projects tend to start out small.

Nevertheless, market fundamentals, policy objectives and other enabling factors determine tendering needs and results, suggesting that for a given market, ever-increasing auctioned volumes or project sizes are not inevitable. In Europe, policies, including feed-in tariffs and

[24] Comparing observed prices, actual underlying costs and the system value of delivered electricity is tricky, as auction bids represent assumptions on costs of projects to be delivered in the future and the economic factors driving success in auctions are complex. While auction prices are adjusted here to reflect consistent assumptions on contract tenor and escalation, other factors can influence bids, including the arrangement of land or grid connections by governments (e.g. solar parks in India), provision of additional revenue streams related to system value or environmental attributes (e.g. Mexico), degree of exposure to market-specific developments and operational risks or project-specific financing costs, sometimes backed by state sources.

tenders have consistently supported large project sizes for offshore wind, where space constraints present less of a barrier. For offshore wind, price declines have been realised with larger turbines and better financing (see Chapter 2). However, land-based projects in Europe tend to face greater challenges over local acceptance and the availability of land, which has tended to keep project sizes within tenders relatively small. Other objectives can influence the scale of projects. For example, in Germany, the design of the onshore wind auction scheme has supported winning bids by relatively small, community-based projects.

Figure 1.14 Average awarded project size in utility-scale solar PV and wind auctions



In emerging economies, tendering schemes have supported an increase in solar PV and onshore wind project scale, whereas in Europe, auctions have supported consistently large projects in offshore wind.

Notes: Data represent awarded capacity by year of auction award, for projects to be built in the future, and do not represent investment. Projects with multiple phases are treated as single projects when awarded in the same year and share a common developer. Includes markets with at least 0.5 GW tendered in the past five years: Argentina, Brazil, Chile, Denmark, France, Germany, India, Italy, Malaysia, Mexico, Morocco, Netherlands, the Russian Federation (hereafter, “Russia”), Saudi Arabia, South Africa, Spain, Turkey, United Arab Emirates, United Kingdom. China is excluded from the analysis.

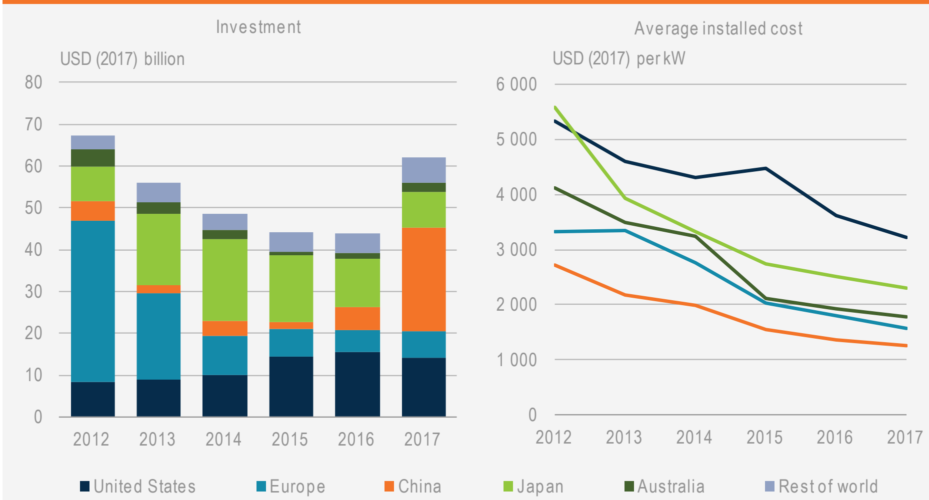
There are also limits associated with economies of scale. In the United States, the costs of utility-scale solar PV projects – where renewables-based capacity is usually contracted through bilaterally negotiated power purchase agreements (PPAs) with utilities rather than competitive procurement – are generally lower with greater scales of up to around 100 MW, but higher costs have been observed for larger projects (Bolinger, Seel and LaCommare, 2017). This may reflect that larger projects have long development times and that the equipment contracts were signed several years ago, as well as increased permitting requirements. Larger projects may also be more susceptible in the case of cost overruns or construction delays, which present a risk particularly to those whose bids incorporate a small profit margin. In

South Africa, a two-year delay by the country's single buyer utility in the signing of PPAs for projects awarded in 2015 raised risks for investors (Lee, 2018). In Saudi Arabia, recognition of the risks associated with developing large infrastructure projects may have contributed to the selection in 2017 of the winning bid for a 300 MW solar project of USD 24 per MWh at a level nearly one-quarter higher than the lowest offer (Gnana, 2018).

Investment in distributed solar PV rebounded in 2017, mostly due to China

Global investment in distributed solar PV (grid-connected residential and commercial installations) which had been in decline in recent years, rebounded in 2017 to over USD 60 billion – its highest level since 2012. This growth propelled overall solar PV investment to its highest level ever, as investment in utility-scale projects was stable. Capacity additions in distributed solar PV doubled to a record level of over 35 GW, as unit costs continued to fall. On average worldwide, the cost of installing distributed solar PV per kilowatt fell by 55% between 2012 and 2017. This fall was most pronounced in commercial and industrial-scale applications in China, stimulating a near five-fold surge in spending to almost USD 25 billion. In the rest of the world, distributed solar PV capacity additions grew by 15% in 2017, while investment remained stable. Investment was concentrated in the United States, Germany, France, Australia and Japan, though in Japan deployment and investment slowed markedly in the commercial segment (Figure 1.15).

Figure 1.15 Distributed solar PV investment and average installation costs



Distributed solar PV in China surged, driving global investment to its highest level since 2012. Installation costs declined in major markets, but differences remain in part due to varying "soft costs".

Note: Includes grid-connected installations for residential and commercial/industrial applications; cost estimates reflect the weighted average of residential and commercial/industrial deployment.
Source: Cost estimates based on IRENA (2018).

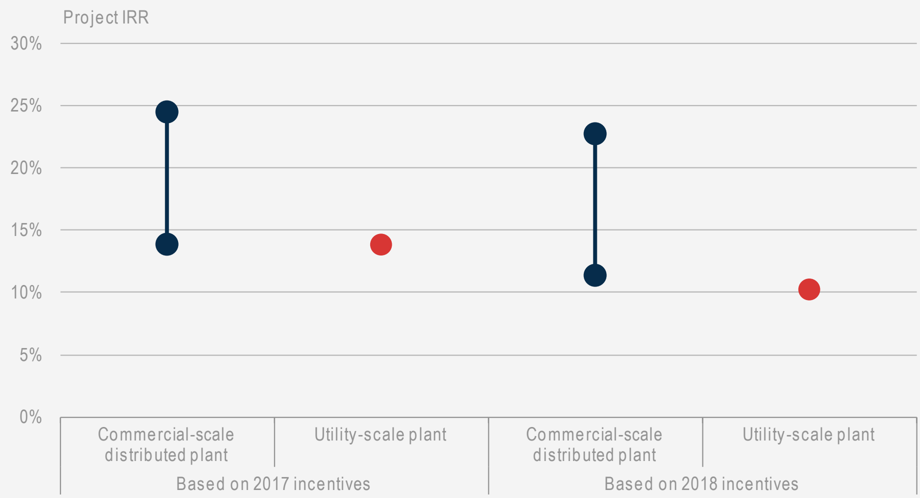
Although installation costs continued to decline in all major markets, sizeable differences remain between markets. This stems in part from varying local equipment costs, but also from different costs of labour, permitting and customer acquisition (so-called “soft costs”). The viability of distributed solar PV investments depends on several factors, including the amount of self-consumption and the value of the retail electricity consumption (and fixed charges) avoided, the price of electricity sold to the grid, and the ability and willingness of households and businesses to finance a long-term capital-intensive asset. Incentives for pairing solar PV installations with behind-the-meter battery storage to increase opportunities for self-consumption, as in Germany, and the evolution of different financing models, as in the United States, can also support development (see Chapter 2). Investment in some mature markets has slowed with falling feed-in tariffs as well as adjustments to net-energy metering schemes, which provide a credit against the retail price. This trend reflects lower installation costs and a re-evaluation by regulators of the system value of distributed solar PV. In more nascent markets, the relatively higher cost of distributed solar PV compared with grid-sourced electricity (particularly where the latter is subsidised), uncertainty surrounding regulations related to self-consumption and feed-in tariffs and difficulties for small-scale entities in obtaining credit can impede investment.

In China, a combination of unique project characteristics and favourable market and regulatory conditions, including robust incentives and improved debt financing, have enhanced the economics of commercial-scale distributed solar PV projects and boosted investment.[25] Nearly 60% of China’s solar PV deployment took place in East and Central provinces in 2017, where the bulk of load is concentrated and where curtailment remains at much lower levels compared with Northeast and Northwest provinces. Availability of a central government incentive of CNY 420 per MWh (USD 50 per MWh), available through 2017, which is added on to the avoided retail price for self-consumed electricity or the wholesale coal-fired tariff for electricity sold to the grid, has resulted in very attractive rates of return for such projects, even at minimal levels of self-consumption, compared with selling power solely under the traditional utility feed-in tariff (Figure 1.16). For a 10 MW ground-mounted installation in Zhejiang – an eastern province with one of the highest solar

[25] The term commercial-scale applies to projects serving either commercial or industrial consumers. By contrast, the development of projects serving residential consumers remains slow due to the limited availability of credit, lack of suitable rooftops and lower retail electricity tariffs for households. Projects are sized in line with voltage connections: up to 20 MW for a 35 kilovolt (kV) connection, 6 MW for a 10 kV connection and 500 kW for a 400 V connection. In other countries developments tend to be less than 1 MW. As such installation costs for larger distributed projects in China can be closer to that for utility-scale developments than traditional rooftop installations. In this sense, projects are more akin to “community-scale” solar PV. These projects also enjoy integration advantages to plants classified as utility-scale, including an absence of deployment caps, priority in receiving payments for sales to the grid and less susceptibility to curtailment as they are easier to site near demand centres, such as industrial parks.

PV deployment rates – the estimated project internal rate of return (IRR) in 2017 for an investment in a distributed plant ranged from 14% to 25%, depending on the level of self-consumption (ranging from zero, i.e. all electricity fed into the grid, to high), with a payback period of five to nine years (Figure 1.16). The returns for the distributed solar PV plant are also aided by availability of a province-level incentive for power that is fed into the grid.

Figure 1.16 Project IRRs of solar PV options in Zhejiang province, China



Robust incentives, ease of integration and debt finance availability supported rapid growth in investment in distributed solar PV in China. But marked policy changes may slow activity in 2018.

Notes: Financial analysis of an indicative 10 MW ground-mounted plant built in Zhejiang province in 2017 under revenue models for operation as distributed PV serving a commercial consumer and a utility plant solely selling into the grid. The ranges for the IRR for the commercial-scale plant corresponds to minimal (0%) and high (80%) rates of self-consumption. The cost of debt finance is assumed to be 4.9% and the cost of equity 9%. IRRs include national and province-level performance incentives, but exclude any tax or fees-based incentives.
Sources: Calculations based on IEA-PVPS (2017), IRENA (2018) and Sicheng (2014).

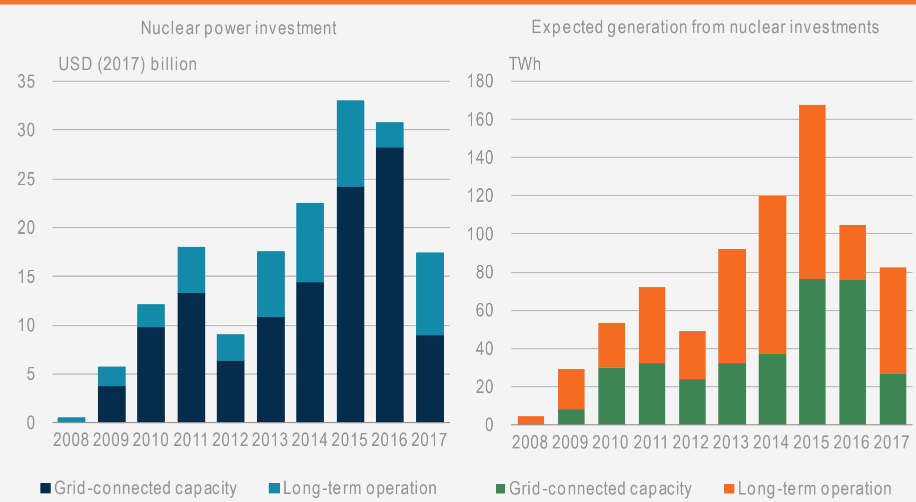
Nevertheless, the government announced in June 2018 marked changes to policies that would, reduce the incentive level almost 25% below 2017 levels and encourage local authorities to allocate projects through competitive bidding mechanisms, in addition to reductions in incentives and the introduction of competitive bidding mechanisms for utility-scale plants. In the first quarter of 2018, China had already installed nearly 8 GW of distributed solar PV – almost 40% of the total amount installed in the whole of 2017. Although economics would remain attractive based on incentive changes, authorities would limit development of distributed solar PV to 10 GW in 2018.

Ongoing reforms to China's electricity market may continue to support business models for distributed solar PV development, including pilot projects for direct selling by distributed generators to industrial and commercial consumers across the local distribution grid. Regulatory changes involving a decoupling of distribution company revenues from energy sales may improve the receptiveness of utilities to development. Chinese authorities will need to balance the benefits of rapid deployment of distributed solar PV with its implications for recovering the costs of investment in the grid and the equitable distribution of such costs among consumers. The government is reportedly considering requirements to pay a fixed charge to support distribution network costs. Continued progress will also depend on the evolution of local factors related to licensing, land and the availability of space on rooftops.

Fewer new nuclear plants, but more spending on upgrades of existing ones

Global investment in nuclear power declined by nearly 45% to USD 17 billion in 2017, due to a 70% fall in spending on new plants coming online during the year to USD 9 billion, which more than offset an increase in spending on existing plants (Figure 1.17). Of the four new reactors commissioned, three were in China. Over 5 GW was retired in 2017, leading to a net reduction of about 2 GW in total nuclear capacity worldwide. Capacity was still about 10 GW higher than in 2007. Nuclear additions over the past ten years have occurred mostly in Asia, led by China and Korea, while retirements of nuclear capacity were mainly in Europe, the United States and Japan, where nuclear fleets are older and face higher economic pressures from lower electricity market prices, in addition to local acceptance issues. While around 60 GW of nuclear power remains under construction worldwide, new construction starts in 2017 totalled just over 3 GW (Figure 1.18).

Figure 1.17 Nuclear power investment in new and existing plants

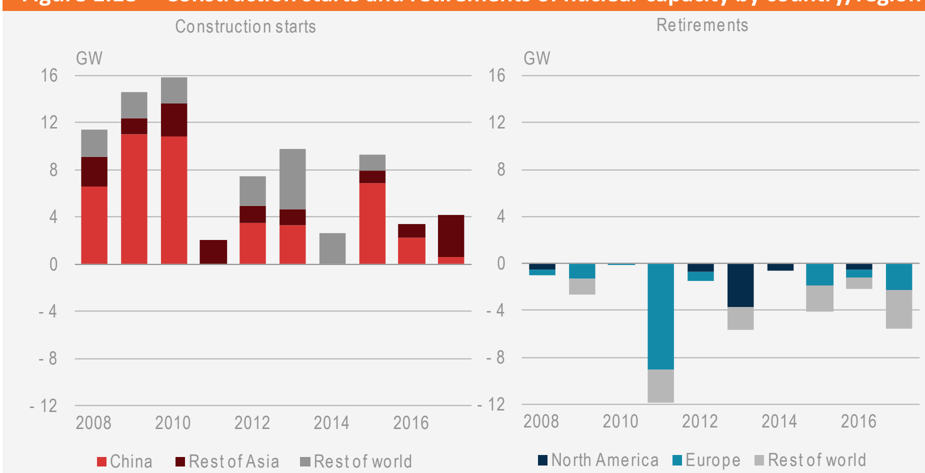


Investment in nuclear power fell by nearly 45% in 2017 as fewer new plants came on line, though this was partially offset by increased spending on existing plants for long-term operation.

Note: Generation calculation assumes long-term operation of ten years.
Sources: Calculations based on IAEA (2018), NEA/IEA/OECD (2010), NEA/IEA/OECD (2015) and OECD/NEA (2012).

A growing share of nuclear investment is going to upgrades of existing reactors, which now represents around half of total nuclear investment.[26] Large investments have recently been made in OECD countries to extend lifetime operation and power uprates of the existing nuclear fleet. In general, spending on existing plants yields more output per dollar invested. Over the last five years, plants with a total capacity of over 40 GW have obtained permission to extend their operational lifetime beyond 40 years. Investment over that period averaged around USD 7 billion – three times more than over the previous five years. Assuming these plants run an extra ten years, generation from lifetime extensions over the past five years is equivalent to 15% of expected lifetime output from solar PV and wind investments over the same period, at just 3% of the cost. At 20 years of long-term operation, the output from these upgrades would be equivalent to one-third of expected lifetime output from the solar PV and wind investments. This implies that lifetime extensions could be a cost-effective transitional measure for maintaining low-carbon generation in the face of uncertainties for new nuclear plant development or that for other low-carbon sources. However, such extensions require supportive regulatory and technical factors, notably regarding safety approvals for older reactor designs, as well as electricity price conditions that may not be conducive in all markets.

Figure 1.18 Construction starts and retirements of nuclear capacity by country/region



New construction starts totalled only over 3 GW while over 5 GW were retired in 2017, though 60 GW of nuclear power remains under construction.

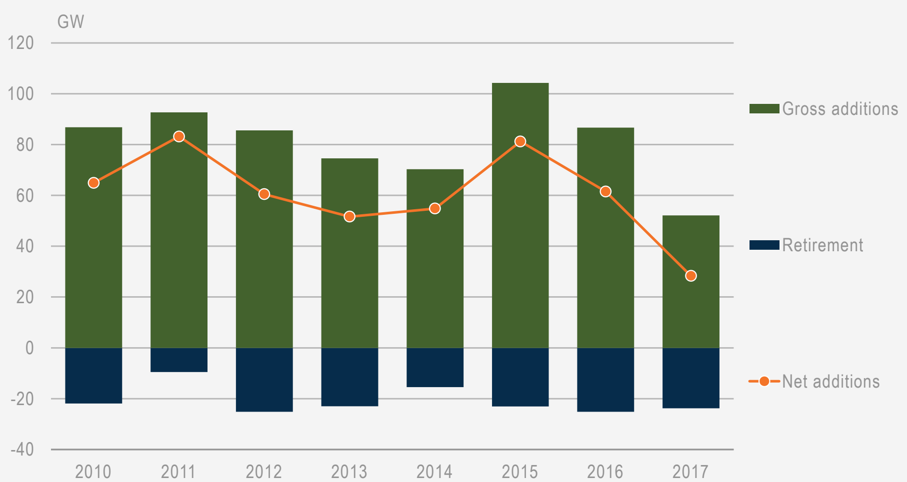
Source: Calculations based on IAEA (2018).

[26] Investment in existing plants is estimated by reviewing plants reaching a 40-year lifetime in a given year and assessing their reported operational plans going forward. In the absence of specific information about the timing of upgrades, investments are calculated on an overnight basis at the 40-year mark with cost assumptions from NEA (2012).

Retirements are driving a contraction in the fleet of inefficient coal plants

The fall in global investment in coal-fired power plants in 2017 was accompanied by a continuing high rate of retirement of existing plants, contributing to a further decline in net additions to capacity. A total of 24 GW of coal capacity was retired, compared with 25 GW in 2016 (Figure 1.19). Gross additions amounted to about 52 GW, resulting in net additions of 28 GW in 2017 – down from over 60 GW in 2016. The vast majority of retired capacity in 2017 were relatively inefficient and polluting subcritical plants, which are located in the United States, China, India and Europe (primarily Germany and the United Kingdom). Globally, subcritical plants, excluding co-generation[27] plants, now make up just less than half of global coal-based power capacity with an average age of about 25 years. The global capacity of these plants has been reduced for two years running, reflecting the government policies to tackle local pollution and, in some cases, economic factors.

Figure 1.19 Global additions and retirements of coal-fired power generation capacity



Globally, net additions of coal-fired plants contracted by over 50% in 2017. Most of the retired capacity is relatively inefficient and polluting subcritical plants.

Source: Calculations based on Platts (2018).

[27] Co-generation refers to the combined production of heat and power.

The drivers of coal-fired power retirements differ starkly by region. Over half of the coal capacity that was retired in 2017 was more than 40 years old (Figure 1.19).[28] Nearly 70% of them were in the United States and Europe, and were retired on environmental and economic grounds. Some of these retired plants have been replaced with renewables and (in the United States) gas-fired generation *in situ*, taking advantage of existing grid infrastructure, permits and trained local workers. For example, in the United States a utility is planning investment in a wind farm and a dedicated transmission line in Oklahoma, close to the site of a coal-fired plant that is being retired. In Massachusetts, the new owner of the retired Brayton Point plant, once the largest coal plant in the US Northeast, plans to use the site to create an industrial port and staging grounds for offshore wind development.

In emerging Asian economies, the average age of coal stations that are being retired is much younger. In China, the retirement age averaged only 20 years in 2017, substantially shorter than the standard economic life of a coal-fired plant (typically 40 years). More stringent environmental and capacity controls are driving retirements there, as well as economic factors as some areas are seeing the introduction of more efficient market dispatch giving priority to electricity with lower marginal costs of production. Nonetheless, early retirement does not always mean that these plants lose money, as the paybacks on investment are very short, at an estimated nine years thanks to low capital costs, favourable financing conditions and attractive regulated power pricing. Consequently, Chinese power companies have not encountered major financial problems as a result of these retirements, though this picture may change as market conditions evolve (see Chapter 2).

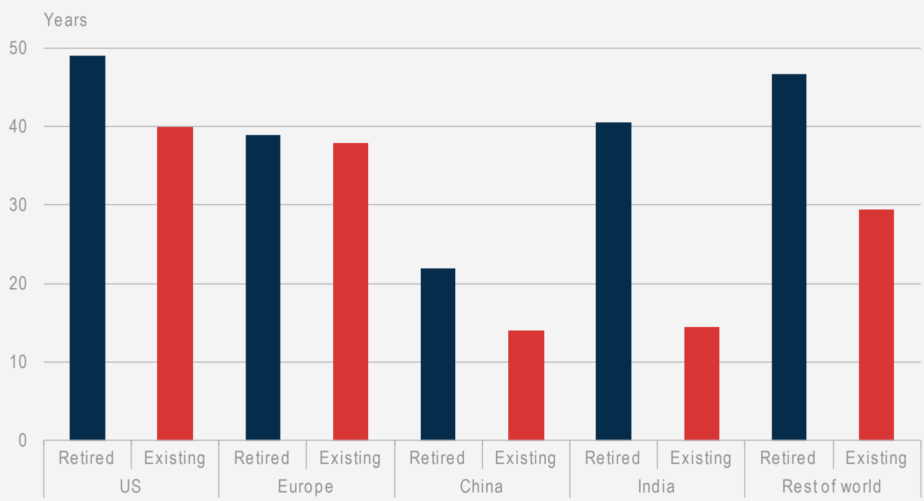
Retirements of subcritical coal plants in India began only in 2017. The average age of these plants was around 40 years. India's subcritical coal-fired fleet is young at 15 years old on average and represents nearly 15% of the global total. Declining load factors, unreliable availability of coal and unreliable power purchase by distribution companies in some cases have also contributed to an increase in financially "stressed" (as categorised under the Reserve Bank of India framework) thermal assets (see Chapter 2). These "stressed" plants are typically fairly new; older plants with depreciated assets are generally still able to make money selling power at low prices to cash-strapped distribution companies.

The outlook for coal retirements will depend on government policies and economic conditions. Coal power plants in Asia are relatively young, with an average age of less than 15 years. Globally, around 35% of sub-critical coal plants are at least 30 years old (mostly in

[28] Assuming an economic lifetime of 40 years, this would suggest the retired plants are fully depreciated from an accounting perspective; their ability to generate economic value for their owners beyond this period would depend on project-specific circumstances.

mature markets) so many of them might be retired in the next decade. However, this will depend on market conditions, including the evolution of demand needs and the ability of such plants to earn adequate remuneration for providing energy, capacity and flexibility services. In the longer term, climate change policies will not necessarily force coal plants to retire prematurely if these policies make investment in retrofitting carbon capture technologies financially attractive. However, this occurring before the plants reach retirement will also depend on early investment in CO_2 storage solutions, support for sufficient load factors for retrofitted plants and political commitment to overcoming public perceptions of CO_2 storage and climate change risks in some regions (see Chapter 3).

Figure 1.20 Average age of sub-critical coal power capacity (2017)



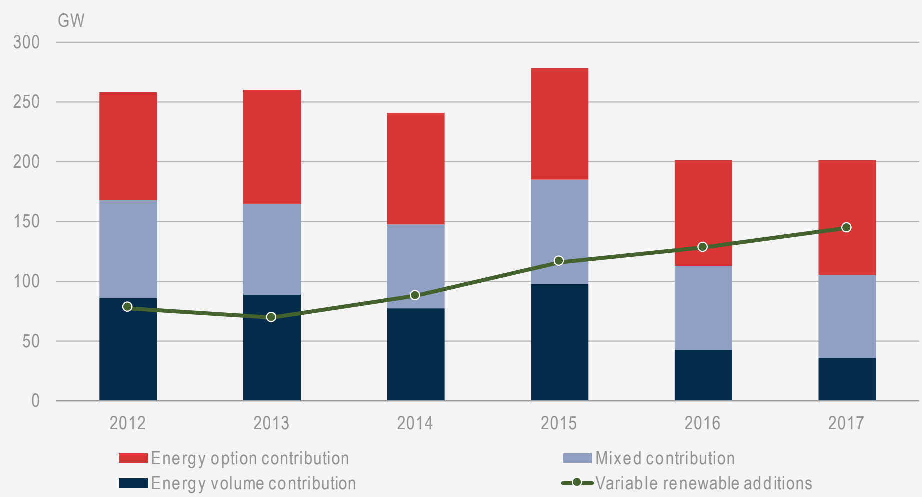
While coal power plants in Asia are relatively young, 35% of global sub-critical coal plants are at least 30 years old, suggesting they may face retirement decisions in the next decade, subject to market conditions.

Note: Retired projects refer to those that have been permanently decommissioned or converted to another fuel.
Source: Calculations based on CoalSwarm (2018).

Stable FIDs for dispatchable power, but less demand for new large thermal plants

The total capacity of dispatchable power – sources of electricity that can be dispatched at the request of power grid operators or plant owners according to market needs, including large-scale thermal generation, peaking and backup generators and electricity storage – subject to a FID remained stable at around 200 GW in 2017 (Figure 1.21).[29] However, the choice of technology and power application, in terms of their typical contribution to the system, continued to evolve.[30] The share of FIDs taken for plants primarily designed to provide low-cost, bulk energy to satisfy demand (i.e. plants primarily making an energy volume contribution and traditionally known as base-load generators), at less than 20%, declined to their lowest level ever.

Figure 1.21 Dispatchable power generation capacity subject to FID, categorised by main system contribution, versus variable renewables capacity additions



A rising share of dispatchable power FIDs is designed to be available to satisfy demand and system services at a given moment, reflecting the value of flexible capacity for adequacy and integration goals.

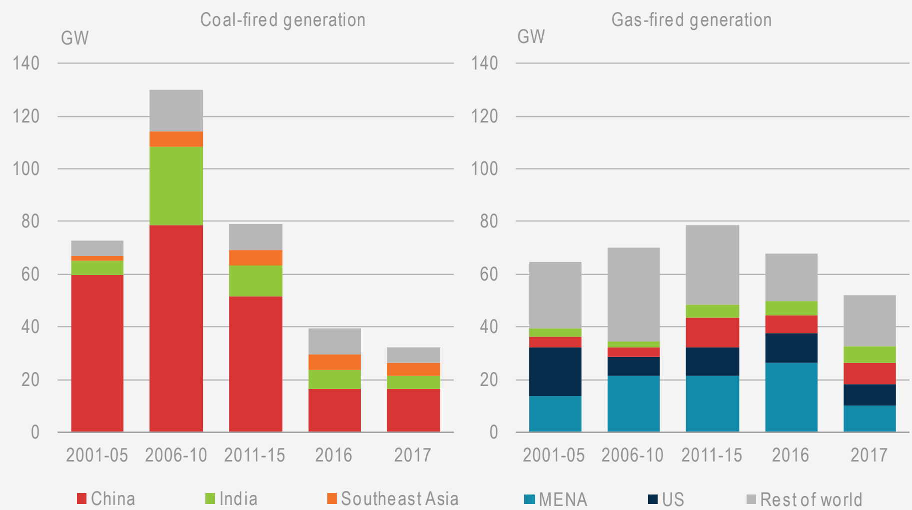
Notes: Capacity for dispatchable power is estimated on the basis of awarded equipment contracts (coal, gas and hydropower), deployment of small-scale generators and battery storage, and construction starts for nuclear power. Energy option is defined as that used primarily for peaking (open-cycle gas turbines [OCGT]), back-up (small-scale generator sets, generally below 5 MW) and storage; energy volume is defined as coal power, nuclear power and geothermal. Other sources, including CCGTs and hydropower are classified as mixed.
Sources: Calculations for investment decisions based on IAEA (2018), *Power Reactor Information Systems* (PRIS), and McCoy Power Reports (2018); variable renewables capacity additions from IEA (2018d).

[29] In the *WEI* report, investments are recognised in the commissioning year. This section analyses the trend of sanctions, a leading indicator of future investments. For an explanation of how FIDs are estimated, please see the *WEI* Methodology: www.iea.org/media/publications/wei/WEI2017MethodologyAnnex.pdf.

[30] The framework for classifying power plants based on system contribution is adapted from IEA (2018e).

Meanwhile, the share accounted for by plants designed to be available to satisfy demand and other critical system services at a given moment (i.e. plants primarily making an energy option contribution, including those traditionally classified as serving peaking and back-up needs) rose to nearly half.[31] One-third of plants, in terms of their typical system contribution, incorporate elements of both categories. This shift reflects increasing difficulties in recovering generation investments based solely on revenues from energy sales and the increasing value of flexible power capacity in ensuring system adequacy (the ability to meet peak load reliably) and accommodating more variable renewable energy sources.[32]

Figure 1.22 Coal-fired and gas-fired power generation capacity subject to a FID by region (annual average)



In 2017 newly sanctioned coal power fell again, driven by a slowdown outside of China. Gas power FIDs fell to their lowest level in over a decade, with fewer projects in the US, Middle East and North Africa.

Notes: MENA = the Middle East and North Africa region. Capacity is estimated on the basis of awarded equipment contracts; data does not include all projects below 5 MW.
Source: Calculations based on McCoy Power Reports (2018).

[31] This report does not track dedicated investments in demand response, which can provide an additional source of capacity from a system perspective under appropriate regulatory framework and market design.

[32] Such objectives can also be achieved by configuring and operating existing assets in a more flexible manner.

The project pipeline of coal-fired power plants has shrunk in China and other emerging countries. The capacity of coal plants under construction amounted to 195 GW in early 2018 (equivalent to three times that commissioned in 2017), down from 215 GW a year earlier as construction starts slowed and more projects were cancelled or shelved in China and India. FIDs taken in 2017 to build coal-fired plants involved 30 GW of capacity – down by 18% on the previous year and the second consecutive year of decline (Figure 1.22). Outside of China, fewer FIDs were taken in India. Other developing Asian countries, notably Indonesia, saw fewer projects, and there were no new FIDs for very large projects, such as the Hassyan plant in the United Arab Emirates, which was given the green light in 2016.

The capacity of gas-fired plants taking FID is also in decline, falling by over 20% to near 50 GW in 2017, although it remained larger than that of coal. FIDs were particularly weak in the United States and MENA despite their abundant cheap domestic gas and good pipeline infrastructure. These regions collectively accounted for half of global sanctioned capacity over the last decade. In the MENA region, this change may be due to a large backlog of plants already in the development pipeline, but also form a rise in procurement for renewable capacity in Egypt, Saudi Arabia and the United Arab Emirates. Declines in these regions more than offset an increase in China, where a large expansion of gas power is planned under the 13th Five-Year Plan, and Europe, where sanctioned capacity recovered slightly from a record low in 2016. Nearly 80% of global sanctioned gas capacity in 2017 was for large CCGT plants, though the absolute capacity of these plants declined by one-quarter. The capacity of OCGT plants (used largely for peaking purposes) was relatively stable.

Trends in investment decisions concerning large-scale dispatchable low-carbon generation vary by technology. Hydropower capacity that was sanctioned in 2017 amounted to 37 GW – a marked increase on the 12 GW that was sanctioned in 2016, which was the lowest level in more than a decade. This increase was due mainly to new large plants and pumped hydro storage in China. However, this uptick may not reflect major change in underlying economic conditions or the policy environment that would point to a longer-term resurgence in hydropower development. In nuclear power, only three reactors – in China, Bangladesh and Korea –- began construction in 2017.

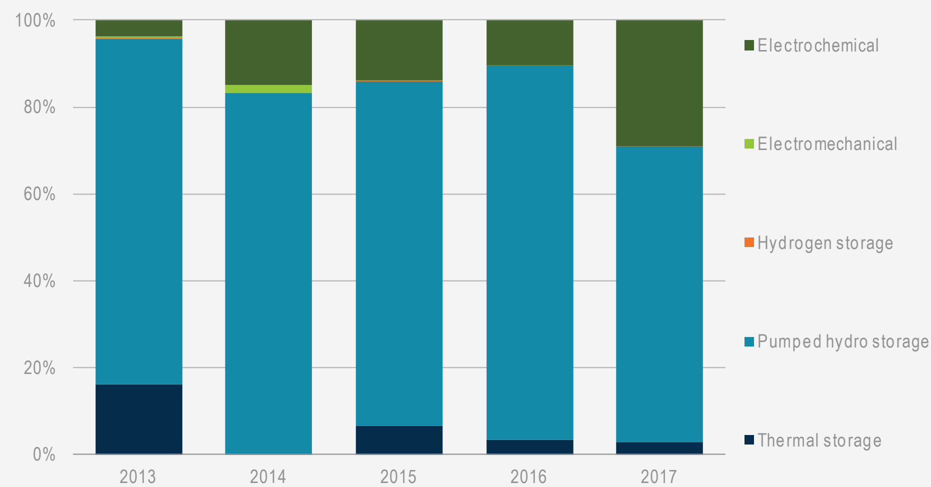
Investment in stationary electricity storage

The commissioning of new electricity storage capacity decreased around 60% in 2017, largely due to fewer new pumped-hydro[33] storage power (PSP) projects. Traditionally, PSP

[33] PSP storage accounted for over 2 GW commissioned in 2017 while thermal storage was above 100 MW. PSP technology investments are considered in the renewable generation investment data as part of hydropower, and thermal storage investments as part of CSP, respectively.

projects have constituted the bulk of electricity storage, and remained the largest new source in 2017, largely due to new projects commissioned in China (Figure 1.23). However, the share of electro-chemical battery storage[34] has been growing fast. Although such projects remain smaller than PSP facilities, their modularity and relatively quick construction times are attractive to regulators and system operators seeking flexible capacity with fast response times that can enhance grid stability and provide back up in the face of potential power outages. These features led South Australia to procure one of the largest such installations to date, at 100 MW, in 2017. Thermal-storage[35] projects constituted a relatively small amount of new capacity in 2017 mainly due to a thermal solar generation project developed in South Africa coupled with molten salt storage.

Figure 1.23 Share of commissioned grid scale electricity storage projects



Electro-chemical battery storage comprised nearly 30% of the market for commissioned storage projects in 2017 – benefitting from modularity, fast response capabilities and continuous decreases in costs.

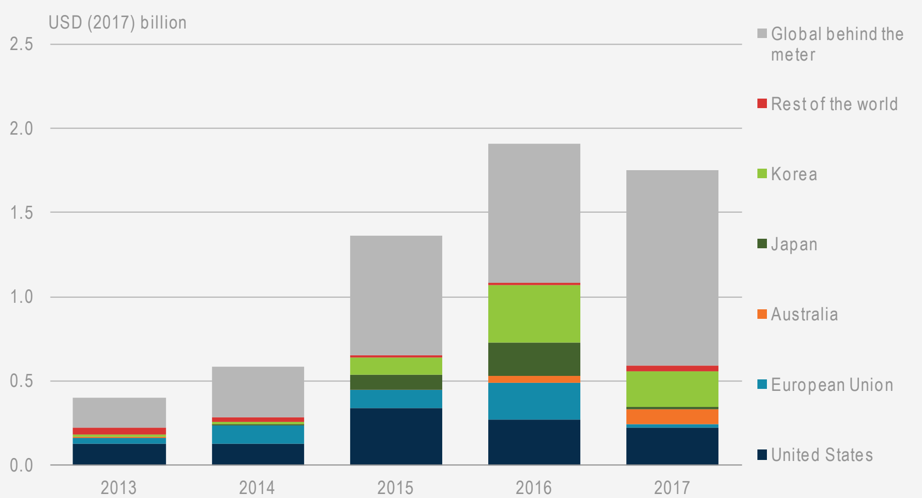
Source: Calculations based on US DOE (2017).

[34] Electro-chemical storage covers the following types of technologies: Lithium-ion, Lead-acid, flow-batteries, nickel based batteries, and vanadium and sodium batteries.

[35] CSP plants generates electricity by using mirrors or lenses that concentrates the sunlight and convert it into heat. These projects are usually associated with molten salt storage that is capable of storing heat that will be later transformed into electricity through steam generators.

Despite its rising share of storage deployment, global investment in electrochemical battery storage decreased by nearly 8% to almost USD 2 billion in 2017 (Figure 1.24). An increase in behind-the-meter storage installations only offset a slowdown in spending on grid-scale battery storage. However, with stable deployment of grid-scale battery capacity in 2017, the decrease in investment largely stemmed from falling battery costs. Batteries can be of significant value to system operators, utilities and final customers, by lowering costs and enhancing the quality and reliability of supply. Technology costs have proved an obstacle in the past, but they have been falling steeply in the last few years with improvements in manufacturing and battery chemistry (see Chapter 3 for a more detailed discussion of battery technology developments). It is estimated that the average cost of grid-scale battery projects coming on line in 2017 was just under USD 600/kWh under an average duration of four hours. Around 35% of the project cost is related to the cost of the battery pack itself, with the rest from the balance of system.

Figure 1.24 Investment in grid-scale battery storage by country/region and global behind-the-meter battery storage



Investment in battery storage decreased by 8% in 2017. While behind-the-meter battery storage investment rose, falling costs lowered investment in grid-scale batteries.

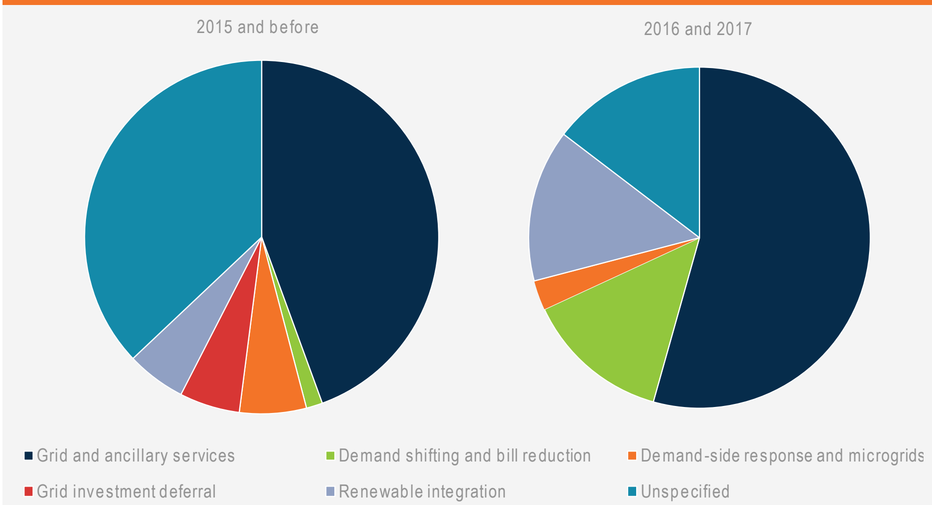
Sources: Calculations based on Clean Horizon (2018), US DOE (2017).

Investment in grid-scale battery-based energy storage fell to under USD 600 million in 2017 from over USD 1 billion in 2016. The overall grid-scale batteries commissioned in 2017 – 600 MW – remained close to that of 2016; the dip in investment stemmed largely from the reduction in battery costs. The United States retook the lead on battery storage deployment – after having been overtaken by Korea in 2016 – followed by Korea and

Australia. Asia drove most of the spending in 2016, but delayed tenders in India and fewer projects in Japan limited growth in 2017. In the United States, state policies are driving activity. California continues to lead the way, with around 100 MW coming on line in 2017 for a total of 139 MW of grid-scale batteries. Hundreds more megawatts are in the interconnection queue, which would support the state mandate, set in 2013, requiring utilities to install 1.3 GW of storage by 2020. The mandate was expanded in 2017 with an additional requirement for the three largest investor-owned utilities to install 500 MW of behind-the-meter storage at customer sites. Such procurement mandates have also been adopted by some other states, including Oregon and Massachusetts.

Policies and programmes to encourage the installation of battery storage facilities, as well as a market design that allows storage to earn a commercially attractive return, are critical to their financial viability. The investment case for grid-scale storage depends, in particular, on the ability of projects to monetise revenue streams from the provision of various energy, capacity and system services, as well as avoided grid investments. The main uses of storage projects are not always obvious. To date, at least half of the investment has been driven by expectations of projects being remunerated for providing grid and ancillary services by transmission system operators (TSOs), not driven by wholesale markets, and notably for frequency control (Figure 1.25). Batteries tend to have a faster response in energy supply than other traditional technologies such as PSP; consequently, TSOs have matured the ancillary services provided using this advanced capability.

Figure 1.25 Share of global grid-scale battery storage by application (MW)



While system services have driven most investment historically, grid-scale batteries are increasingly being used to back up variable renewables and shift electricity to higher value periods of the day.

Source: Calculations based on Clean Horizon (2018).

An increasing share of projects commissioned in the past two years, however, are designed to back up variable renewables-based generating plants, storing electricity during surplus periods and dispatching later in the day when demand is tighter, or providing demand-side services in the form of microgrids and demand response. Projects based on hybridisation of a battery storage unit co-located with wind or solar PV plants are increasingly emerging (Box 1.3). Changes in regulatory frameworks to allow the active participation of storage in electricity markets and market designs to reward the services provided by battery operators will be critical to the prospects for investment. Nevertheless, uncertainties over these factors can make it difficult to secure financing in some markets, and developers tend to favour projects with short payback periods.

Box 1.3 Growing role for renewables and battery storage projects

Investment in grid-scale battery storage aimed at firming variable renewables has risen sharply, with 15% of grid-scale battery additions over 2016-17 compared with 5% in 2015. In many cases, the battery is installed on the site of a new or existing solar PV or wind project, allowing the plants to operate like dispatchable power capacity and creating economies from the use of common infrastructure. With the right market conditions and regulatory framework, such designs can enhance the attractiveness of renewables for the investor and system. However, the revenue and financial structuring for these plants remains complex.

Interest in such hybridised plants is growing in response to a rising need for flexibility as the share of wind and solar power in total generation grows. Thanks to cost reductions, their modular structure and short lead times, batteries have become a financially attractive option for providing those services, which are provided in two main ways. First, they can provide rapid capacity-based services for a limited period of time. This includes fast response to support system frequency and reducing the need for the ramping up of generators to balance the market. Second, they can provide energy-based services to support the storing and dispatching of generation to a time of day that better matches demand needs. Financial attractiveness depends on the project structuring, illustrated by the following examples.

- In South Australia, where the share of wind and solar PV is now over half of generation, the 100 MW Li-ion Hornsdale Power Reserve Project, the largest grid-connected battery project to date, with an energy rating of 129 MWh, was commissioned at Hornsdale Wind Farm in 2017. The plant responded to a state government call to improve grid resiliency. Some 70% of rated power is contracted to the government for system services, while 30% is available to the operator to store and dispatch excess wind output to times of tighter market conditions.
- In early 2018, a 20 MW grid-scale battery (energy rating of 34 MWh) was sanctioned at the Bulgana Green Power Hub as part of a 194 MW onshore wind plant in Victoria, Australia. The business model involves a combination of power purchase contracts with different off-takers (government and a private company with a stable demand profile) as well as project finance from private sources and public financial institutions, including KfW and the Korean Development Bank.

- In Hawaii, a solar PV plant of 28 MW plus a 20 MW grid-scale battery (energy rating of 100 MWh) started construction in 2018. The project is to provide renewable firming and the ability to shift power to later periods for an island with no interconnection and renewable penetration that has reached upwards of 90% during certain periods. The project is based on a PPA between a private developer and the local utility, which is structured as a co-operative.
- In Texas, two 9.9 MW (energy rating of 5 MWh) batteries are co-located with the Pyron (265 MW) and Inadale (197 MW) wind farms and provide system services.

Finally, hybrid battery storage plants are not limited to renewables. In 2017, a FID was reached for a CCGT of 1.3 GW with 100 MW at the site of an existing plant in California. The investment was made under a project finance structure, benefiting from a 20-year PPA where the utility provides a capacity payment covering fixed operating costs, debt service and return on capital, as well as provides the gas and the electricity to charge the battery.

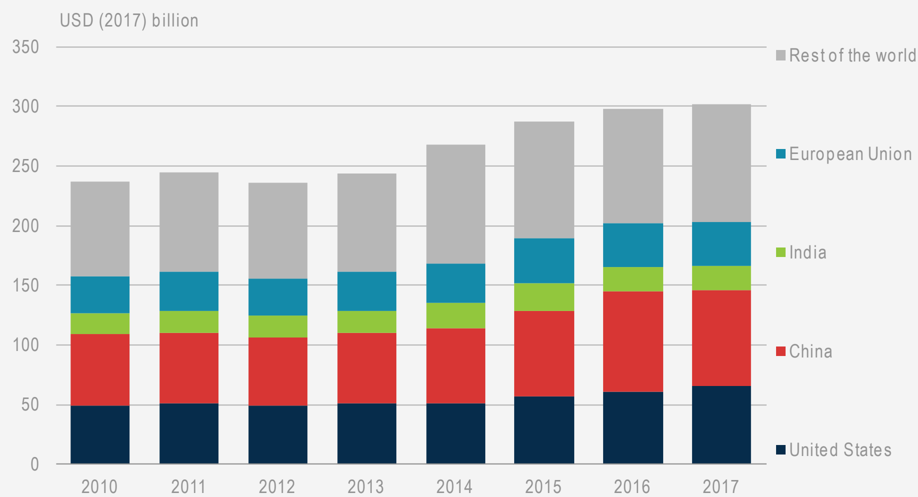
Global spending on behind-the-meter storage overtook that of grid-scale batteries in 2017, reaching over USD 1 billion. The average installed cost of a behind-the-meter-battery was estimated to be around USD 1 200/kWh, with around 40% attributable to the battery pack itself. The largest growth occurred in Korea, the United States, Germany and Australia, often supported by incentives for the pairing of a battery with a distributed solar PV installation in the residential sector. In the United States, the federal investment tax credit allows the end user to deduct 30% of the cost of installing solar plus battery storage if it is charged from a renewable energy source. The Korean government started offering incentives for installing storage systems with the solar plants in 2017. In Korea, the government uses renewable energy certificates to incentivise the deployment of distributed solar PV with storage. In Germany, the budget for incentives for storage systems combined with distributed solar PV put in place in 2016, which originally allowed customers to get a rebate of up to 25% for the system cost, was increased in 2017 to accommodate increasing applications. However, the rebate level has been reduced to 10%. Other European countries are also promoting the adoption of behind-the-meter storage. In Sweden, the government put in place in 2016 a scheme that covers up to the 60% of the system cost.

In developing countries, which are not accounted for in the investment numbers shown here, small batteries are an important means of providing off-grid electricity and backing up supplies to grid-connected customers where reliability is a problem. Until now, much of the spending on small batteries in developing countries, likely over USD 3 billion annually, goes to lead-acid batteries, but demand is shifting to lithium-ion (Li-ion) batteries as their prices fall.

Investment in electricity networks

Capital spending on electricity networks – including power lines and equipment, metering devices, smart grid infrastructure and EV chargers – has risen steadily over the last five years, reaching USD 300 billion in 2017 – 1% up on 2016 (Figure 1.26). Modernization of the grid with spending on digital technologies, supported by regulatory frameworks in countries such as China and the United States, has been a key driver for investment in networks replacement and upgrades. In addition, the distribution sector accounted for nearly three-quarters of the total, but the overall growth slowed down for the third consecutive year. New transmission line additions in China and the United States attracted the biggest investment growth in 2017.

Figure 1.26 Investment in electricity networks (transmission and distribution) by region



Investment in electricity networks grew 1% in 2017, driven in particular by an expansion of transmission networks in the United States, but the overall growth was slower than in 2016.

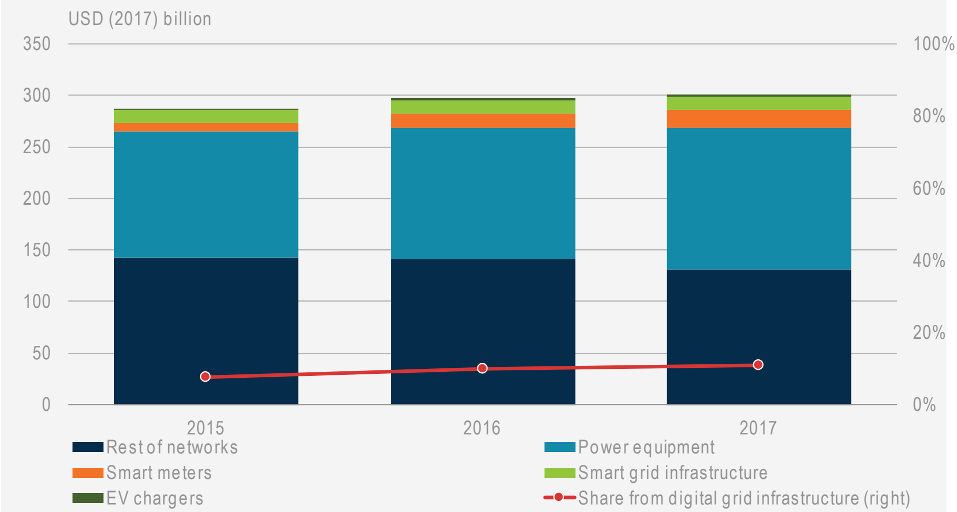
China, the United States, Europe and India together accounted for nearly two-thirds of global investment in electricity networks in 2017. Globally, nearly 60% of spending went to expanding the grid to connect new generation assets and consumers. However, about of the investment is going towards replacing existing transmission and distribution assets as they reach the end of their useful life. For example, in the United States, investment in the replacement of lines is estimated to have accounted for over 60% of total network investment in 2017, 70% of which was for distribution lines. Modernising medium- and low-voltage lines is primarily aimed at reducing the cost and frequency of annual interruptions, which has been valued at USD 60 billion – equal to 90% of US investment in networks (Eto J., 2017). In Europe, in a similar case, the 60% of the overall investment in networks went to the replacement of lines, finding its biggest share also in the distribution network – nearly 90%. China's overall investment in networks decreased by

4% to under USD 80 billion, mostly due to lower spending on distribution grids. However, the decrease in investment was partly offset by an expansion of new transmission lines.

Spending on modernising and "smartening" the grid continues to rise

Worldwide capital spending on so-called "smart grid technologies" – a wide range of new digital-based technologies aimed at improving operating efficiency and preparing the system for the growing penetration of distributed generation, which make up a growing component of investment in transmission and distribution networks – reached over USD 33 billion in 2017, an increase of nearly USD 4 billion, or 13%, compared with 2016. Overall spending on standard equipment, such as cables, transformers, switchgear and other equipment used in substations, still accounts for the vast majority of total network investment, but investment in smart grid infrastructure now accounts for 11% (Figure 1.27).

Figure 1.27 Share of spending on electricity network equipment by type



Spending on standard equipment, such as cables, transformers, switchgear and substations, accounts for nearly 90% of total network investment, but the share of smart grid technologies continues to rise.

Note: Two- and three-wheeler EV charging stations are excluded from the analysis.

The ability to leverage large amounts of data to reduce unplanned outages and to better forecast the availability of different energy sources, as well as to better anticipate demand developments, combined with a better ability for the consumer to manage their own electricity consumption can greatly enhance the reliability of the network and facilitate the integration of renewables. The availability of infrastructure for storing and transmitting data and the establishment of standardised data exchange processes, as well as appropriate regulations governing the use of data without comprising consumer data privacy and security concerns, remain key issues for the development of smart grids. Newer digital-based technologies such as the block chain[36] have the potential to facilitate the development of distributed energy sources through enabling peer-to-peer electricity trading within local energy communities, creating an ecosystem where every produced kilowatt-hour is tracked from the generation source to the point of consumption. Still, such models remain nascent for now.

China is leading the deployment of smart grids, having spent more than USD 3 billion in 2017 on networks automation and the biggest-ever roll-out of smart meters (more than 400 million metres had been installed nationwide at the end of 2017 by the State Grid Corporation of China). United States is the second-biggest smart grid investor, with spending of over USD 2 billion. Over 75 million smart meters had been installed by the end of 2017, including more than 12 million in California and over 5 million in Florida. In the latter case, this investment in smartening the grid was a crucial element in helping the state utility, Florida Power and Light, to restore electricity supply following the biggest outage in its history caused by Hurricane Irma in 2017.

Smart grids and particularly smart metering systems have received strong regulatory support in Europe, as the European Union seeks to replace at least 80% of its electricity meters with smart devices by 2020. This resulted in around USD 10 billion of investment in smart grids in 2017, 70% of which was for smart meter roll-outs. Italy and Sweden are getting ready for a second wave of roll-outs, but the United Kingdom is proceeding more slowly. Spain, with an 85% penetration of smart meters in 2017, is one of the leading countries in smart meter deployment and is aiming to complete the national roll-out by 2018. In the case of France – with a penetration rate of 25% in 2017 – the metering roll-out is envisaged to finish in 2021, totalling 35 million units installed. However, the national protection authority has raised a concern over the usage of the collected data and consumer privacy, which is holding up deployment.

Reforming the regulatory framework to incentivise spending on digital grid infrastructure will be a key factor in speeding up investment. The clean energy package proposals made by the European Commission in late 2016 emphasise the need for output-based incentive regimes for distribution operators, which would reward spending that reduces the need for more costly capital investments that would normally be recovered through the regulated portion of retail electricity tariffs. In late 2017, the European Council agreed on a directive setting out common rules to ensure more dynamic electricity price contracts

[36] The block chain is a decentralised data structure in which a digital record of events – for example the energy produced by a particular source – is collected and linked by cryptography into a time-stamped “block” together with other events. For further discussion, see IEA (2017d), *Digitalization & Energy.*

to customers, among other regulations pertaining to the internal electricity market in Europe, and specific rules for smart meter roll-outs. These contracts, along with the smart meters, are essential in allowing consumers to participate in demand response programmes.

Finally, spending on EV charging facilities, which are connected to the distribution system, held steady at USD 3 billion.[37] Some regulators are increasingly facilitating and promoting the installation of charging stations by utilities. In California, the Public Utilities Commission announced that it would invest nearly USD 750 million in transport electrification across the state, as part of the 2030 goal for clean air and greenhouse gas reduction. Meanwhile, new spending plans are emerging from a number of private actors in markets where the regulatory framework supports such development (see "Focus on EVs" above).

Investment in large-scale transmission projects is increasing

Investment in long-distance, large-capacity transmission lines and interconnectors accounted for around USD 45 billion, or 55%, of transmission investment in 2017. The investment associated with those projects was more than three times higher than in 2016 and over 25 new lines are expected to be commissioned during 2018. Together with other planned lines, a total of 155 GW of capacity is due to come on line in the next two years, mostly in China during 2018.

Large-scale transmission projects are instrumental in increasing flexibility of the electricity system by supporting the integration of variable renewable energy sources and maintaining energy security. Interconnections between national and regional markets also facilitate power trading and electricity price arbitrage, and help to improve the reliability of those markets. Of all the projects commissioned in the last five years worldwide, some two-thirds were built to transmit low-cost electricity over large distances, connecting remote large-scale generation resources to major demand centres. Another 10% were specifically commissioned to connect networks that operate under different voltage and frequency levels – asynchronous grids – and over 20% were used to tap into variable renewables-based sources of electricity, both onshore and offshore.

Nevertheless, permitting and procurement procedures can be long and costly in some countries, which may translate into development delays. An example of this occurred in the transmission connection of Kenya's 310 MW Lake Turkana wind project, expected to be completed by September 2018 (the wind farm itself is ready for commissioning). The

[37] Two- and three-wheeler EV charging stations are excluded from the analysis.

nearly 430 km transmission line has faced development challenges due to a lengthy land acquisition process and financial difficulties for the main contractor.

Around half of the large-scale transmission projects completed in 2017 and expected in 2018 are in China. Investment is being driven by the 2015-20 power grid construction and reform plan that the National Energy Administration released in 2015. These efforts are particularly important for wind and solar PV installations located in resource-rich interior provinces, where electricity demand is relatively low and transmission capacity both within and between provinces is limited. Regulatory factors related to the administrative dispatch of power plants remain a challenge to integrating this output even with an expanded transmission grid, though ongoing reforms seek to create a more efficient and flexible power system (IEA, 2017a; 2017c).

Outside of China, there are a number of notable projects in Europe, North America, Latin America, India and Africa (Table 1.2). In Europe, the European Council has set a target of electricity interconnection capacity in 2020 for member states equivalent at least to 10% of their own installed electricity production capacity, and to increase this target to 15% by 2030 to ensure security of supply and enhance sustainability. This is aimed at achieving a fully connected internal competitive energy market.

The European Commission published a list of key infrastructure projects in order to achieve its energy policy and climate objectives under the title of Projects of Common Interest (PCIs). Electricity interconnectors represent around 50% of the projects on the current list of PCIs. These projects benefit from accelerated licensing procedures, improved regulatory conditions and access to financial support. The European Commission´s Expert Group recommended through the list, released in November, using EUR 2/MWh of yearly average price difference between relevant regions as the indicative threshold for considering the development of additional interconnectors, among other specific recommendations. Increasing energy exchange among European countries allows benefiting from synergies in the generation portfolio of each country member. In 2017, Germany was the biggest electricity exporter with almost 84 TWh of gross exports to neighbouring countries, followed by France (61 TWh) and Sweden (33 TWh).

European interconnector schemes that have attracted significant investment include six projects connecting the United Kingdom with Belgium, Norway, France and Denmark involving total capacity of 6.3 GW, which are expected to come into operation between 2019 and 2022. Investment has been stimulated by an innovative cap-and-floor model in the United Kingdom, which involves the introduction of a cap and a floor on interconnector returns derived from auctioning interconnector capacity over different time frames. This allows interconnector owners to earn returns within pre-determined price boundaries, with a floor set in order to guarantee the reimbursement of a project’s debt.

Table 1.2 Major large-scale electricity transmission projects outside China

Project name	Geography	Technology	Length (km)	Voltage (kV)	Status
Champa 1&2	India	UHVDC	1 365	800	Under construction
North-East Agra	India	UHVDC	1 728	800	Under construction
Talcher-Kolar	India	HVDC	1 450	500	Commissioned
Rio Madeira	Brazil	HVDC	2 375	600	Commissioned
Nordic Europe Projects connecting to mainland*	Europe	HVDC	1 598	Various	Different stages
North Sea Link	Europe	HVDC	720	525	Under construction
Plains and Eastern Clean Line	United States	HVDC	1 127	600	Under development
Rock Island Clean Line	United States	HVDC	805	600	Under construction
TransWest Express	United States	HVDC	1 175	600	Under development
Inga-Kolwezi	Congo	HVDC	1 700	500	Commissioned (upgrade)
France-Spain interconnection line	Europe	HVAC	370	500	Under development
Italy-Libya interconnection line	Europe	HVDC	550	500	Under development
North Core transmission line	Africa	HVAC	330	875	Under development
NeuConnect	Europe	HVDC	680	500	Under development

* Includes the projects of NordBalt, SwePol, NordNed, Skagerrak and Baltic Cable.
Note: UHVDC = ultra-high-voltage direct current; HVDC = high-voltage direct current; HVAC = high-voltage alternating current; kV = kilovolt.

Mini grids offer numerous potential benefits, but investment remains small

Mini grids can play an important role on ensuring access to affordable, reliable and modern energy, and supporting the attainment of the United Nations Sustainable Development Goals.[38] Global investment in mini grids reached nearly USD 14 billion in 2017, somewhat lower than the average of the previous three years.[39] Mini grids serve an important energy access purpose by providing electricity in areas where it is challenging or costly to expand

---

[38] For further discussion, see IEA (2017e), *WEO 2017 Special Report: Energy Access Outlook*.

[39] Mini grids are defined here as small power grids supplying electricity to a limited group of customers with the additional capability of supplying electricity disconnected from the main grid. The components of the mini-grid investment numbers are included within the totals for electricity networks, generation and storage investment.

the main grid. Such off-grid connections represented 25% of the mini grids installed in 2017. However, more than half were from industrial and commercial customers where the mini grids are connected to the main grid. In these instances, mini grids are envisaged to provide back-up power to improve the reliability and the quality of supply for the end user.

Among the possible generation configurations, the most common source of electricity to date has been small-scale diesel generators, which are relatively cheap and provide dispatchable power. Gas generators are expanding their applications due to the lower cost of fuel, but still remain as a more expensive option in the short and medium term, due to higher acquisition costs and challenges in expanding gas distribution infrastructure. In both cases, the economics of fuel-based mini grids depends heavily on the availability and price of fuel supplies, especially in remote regions where the cost is also affected by the local supply to the islands, which can be partly addressed by using planned distribution strategies. Nevertheless, options incorporating low-marginal-cost renewables with battery storage are becoming more attractive with falling technology costs.

Most regulatory regimes remain designed to support development of the power system through the regulated remuneration and buildout of the network in a centralised fashion. Regulatory frameworks remain a major source of investment uncertainty for mini grids in a number of markets (Table 1.3). Major barriers encountered hampering the expansion of mini grids are related to poor or missing regulatory definitions for models where utilities and third parties can share ownership, unclear expansion plans of the national grid, and lack of mechanisms to accommodate its arrival with the already existing mini grids. Additionally, the combination of limited availability of public funds for assets and the setting of tariffs that do not fully reflect underlying project costs can make scaling up mini grids difficult.

Table 1.3 Risks and potential enabling frameworks for mini-grid investment

Risk	Description	Enabler
Regulatory framework for ownership and operator model	Unclear or restrictive regulations to owning and operating mini grids by third parties	Defining regulations for models that allow utilities and third parties to own and operate mini grids
National grid extension	The possibility of the unexpected arrival of the national grid raises technical and economic uncertainties for investment	Transparency on national grid extension plans and regulatory measures to compensate operators or allow the mini grid connection to the national grid
Low availability of public funding	Limited availability of public funds to fund access-related developments	Limited financial mechanisms and licences linked to generation assets
Electricity tariffs	Non cost-reflective tariffs often hinder the expansion of mini grids beyond pilot projects	Mechanisms to balance the affordability for consumers, but also provide incentives for larger projects

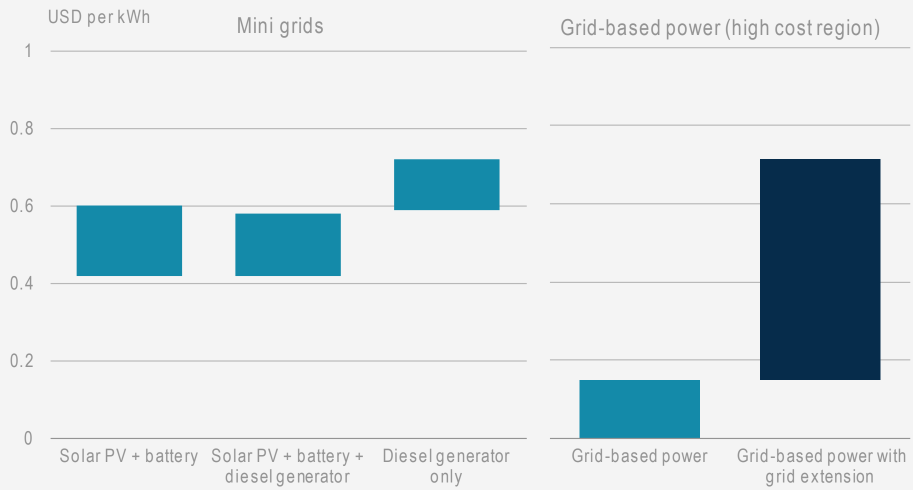
Nevertheless, more governments are adapting their policies to support mini grids. The United States has been the biggest market for mini grids in recent years, mainly for improving resilience of supply, and numerous projects were developed as part of the government's Grid Modernization Initiative since 2015. China has in place several policies aimed to the expansion of renewables and distributed generation through mini grids under the 13th Five-Year Plan that is in place until 2020. Europe has been lagging in mini-grid developments due to the presence of an already dense and relatively efficient distribution grid, but policies being developed under the proposed EU Clean Energy Package aim to promote and integrate mini grids in the coming years. Regulators have recognised that mini grids can play an important role to back up and improve the quality of energy supply and to give customers an opportunity to have a more active role on energy markets.

In Indonesia, the stated-owned utility PT Perusahaan Listrik Negara (PLN) has been successfully expanding the centralised grid and providing connections to new households, targeting 99% electrification by 2019, from 95% in 2017. Yet given Indonesia's challenging archipelago geography, as well as the constraints on PLN's balance sheet (see Chapter 2), mini grids can play an important role in complementing these efforts for remote places where the centralised grid may be slow to develop.

Currently, the economics of mini grids in Indonesia suggest they can be comparable to the average cost of supply in the highest-cost regions (e.g. around USD 150-200/MWh in places such as Papua and Maluku), in the case where consumers are relatively far from the grid (e.g. 150 km). The levelised cost of electricity for an indicative mini grid providing electricity access to serve an annual consumption of over 30 MWh – enough to supply electricity to over 50 households – can range from around USD 0.4/kWh to USD 0.7/kWh depending on configuration and fuel costs (Figure 1.28). Currently, configurations based on solar PV plus batteries are nearly cost comparable to those based on a diesel generator, but hybrid configurations involving all of these components are somewhat cheaper.

However, these comparisons depend on factors that can notably shift, such as the changing price of diesel and the technology costs for solar PV and batteries. Diesel prices remain subsidised in Indonesia, even as the level of subsidies was lowered in 2016, so there is upside risk for fuel prices should further efforts be made to pass through international oil price developments to consumers. Diesel consumers on remote islands also face persistent risks related to the transport and distribution of fuel supplies. Moreover, the costs of solar PV and batteries could decline with greater deployment, in part supported by a better enabling environment for renewables. When accounting for a possible 30% decline in the initial cost of the battery and the solar PV system and a 30% increase in the price of diesel, the economics more clearly favour solar PV plus battery options over diesel generators.

Figure 1.28 Levelised cost of electricity for different generation options in Indonesia



In Indonesia, risks associated with fuel prices and availability, combined with technology price declines, can enable the economics of renewable-based mini grids over those with diesel generators alone.

Notes: Assumes discount rate of 7%;

(a) Mini-grid size - Solar PV: 79 kW; battery: 40 kWh; diesel generator: 97 kilovolt-amperes.
(b) Mini-grid size (hybrid) - Solar PV: 67 kW; battery: 25 kWh - four hours of use; diesel generator: 14 kilovolt-amperes.
(c) Solar PV cost: USD 2 050/kW.
(d) Battery cost: USD 650/kWh initially, with replacement every 11 years at 25% lower cost.
(e) Diesel generator cost: USD 475 per kilovolt-amper; diesel cost: USD 6 per gallon (assumption of twice the market price to include transportation cost).
(f) Mini grid ranges reflect sensitivity of a 30% decrease in initial battery costs and solar PV costs, coupled with a 30% rise in diesel prices. Range of grid extension = 0-150 kilometers.

Investment in oil, gas and coal supply

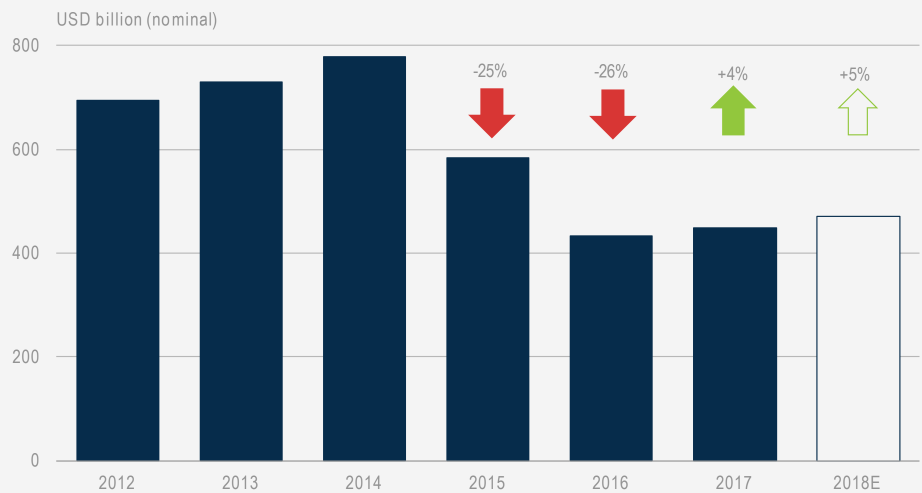
Upstream oil and gas investment

Edging back from the abyss

Investor confidence in the upstream oil and gas sector continues to recover in response to rising oil prices and sustained oil demand growth. Following a decline in excess of 40% between 2014 and 2016, upstream investment rebounded modestly in 2017 by 4% to

USD 450 billion (in nominal terms)[40] and, according to guidance provided by companies, is set to increase by 5% to USD 472 billion in 2018 (Figure 1.29). The overall trend masks some big differences in terms of assets and geography. Spending in the US shale industry continues to expand briskly after the rapid growth of investment already seen in 2017; conventional onshore investment, with a focus on brownfields, is rising modestly, driven by national oil companies' (NOCs) spending in key producing countries such as the Middle East and Russia, as well as in China; and offshore investment, with longer lead times, is set to decline again in 2018 as few new projects were sanctioned over the last three years, though there are clear signs of renewed interest in the sector in the last part of 2017 and early 2018.

Figure 1.29 Global investment in upstream oil and gas



Upstream investment is set to increase modestly in 2018 in response to rising prices and demand.

Notes: E= Expected. Based on announced company spending plans and guidance as of May 2018.

The United States remains the engine of upstream investment growth, with its overall capital spending, including shale and conventional resources, set to increase by around 10% in 2018. The shale sector remains the main driver of this growth. In Europe, interest

[40] 2% increase in real terms on a USD (2017) basis.

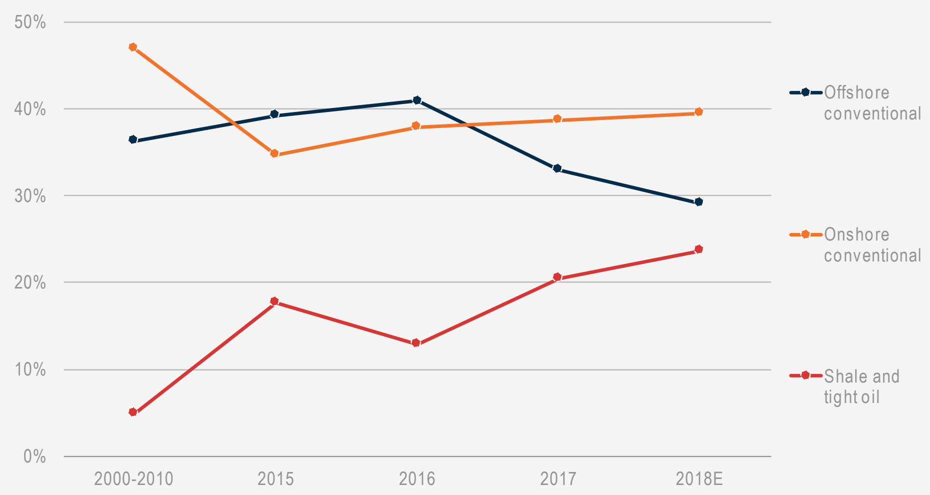
in the North Sea rose with lower costs, with several new projects sanctioned mainly by Equinor and other operators.[41] In the Middle East, where spending was least affected by the global downturn in 2015-16, there is an increasing confidence that the worst of the oil cycle has passed. Spending plans point to a modest rise this year, with a shift in some countries towards national gas resources given fast-growing domestic needs, accompanied by rising investment in the downstream and petrochemical sector to intercept higher-value added part of the business (see below). There is also an increasing focus on brownfield projects with the aim of slowing the natural decline in output at existing fields and increasing overall recovery factors (the region has the highest share of assets that have been producing for more than 40 years), requiring the adoption of more sophisticated technologies and a different approach to project management. For decades, the Middle East has enjoyed large inflows of private and foreign investment in selected parts of its oil and gas sectors, but an emerging trend, which marks a quite notable shift with the past, is the recent decision of some of the major producing countries, such as Saudi Arabia and the United Arab Emirates, to allow non-local companies to own stakes of domestic assets.

The different strategies adopted by countries and companies are determining a shift in the way upstream investment are implemented. Activities in conventional onshore assets are set to remain the main destination of investment with about 40% of the total. The offshore sector, following a steady rise in the first part of the decade, reversed its upward trend and its share on total investment has plunged steeply, with a multi-year low expected to be reached in 2018, as the recent pick up of activities will require time to translate into concrete spending. Investment in shale assets, initially in the natural gas sector and then spreading to light tight oil, rapidly grew from 2007-08 and is set to reach almost one-quarter of the total in 2018. The rapid growth of shale's weight in the global upstream investment implies that the industry is not only shifting towards shorter cycle projects able to generate cash flow faster but it is also relying more and more on assets characterised by steep decline rates, partially changing the traditional long-lead time nature of the oil and gas sector (Figure 1.30).

Reduced investment in 2015-16, the greater focus on capital discipline and the strength of the shale sector has encouraged also several oil and gas producing countries to reconsider their upstream tax regimes and regulatory frameworks in order to improve their business environment and attract foreign investment.

[41] In May 2018, Statoil changed its name to Equinor.

Figure 1.30 Share of global upstream oil and gas investment by asset type



Global upstream investment is shifting toward shorter-cycle projects and assets with rapid decline rates.

Notes: E= expected. Based on data from company reports and Rystad Energy data (2018).

Mexico is the most successful example of the importance of reform as a catalyst for boosting investment, having embarked in a comprehensive shake-up of its oil, gas and power sectors in 2013. The combination of the opening up of its oil and gas sector to national and foreign companies by eliminating the monopoly of Petroleos Mexicanos (Mexican Petroleum) (PEMEX), attractive fiscal and regulatory terms and very encouraging hydrocarbons discoveries have stimulated significant enthusiasm with most of the major international operators now present in the country. The **UK** government has reduced supplementary charges applied to onshore and continental shelf activities from 20% to 10% as a way of sustaining exploration and production investment. In April 2018, **Iraq**'s fifth licensing round introduced a new petroleum contract model including more elements typical of production sharing agreements. This marks a notable break with the past as it is the first time that blocks in the south of the country have been offered under a model other than technical service contracts.[42] **Indonesia** is also trying to encourage foreign investment in the upstream industry in an attempt to revitalise the sector, which is suffering from declining mature assets and a

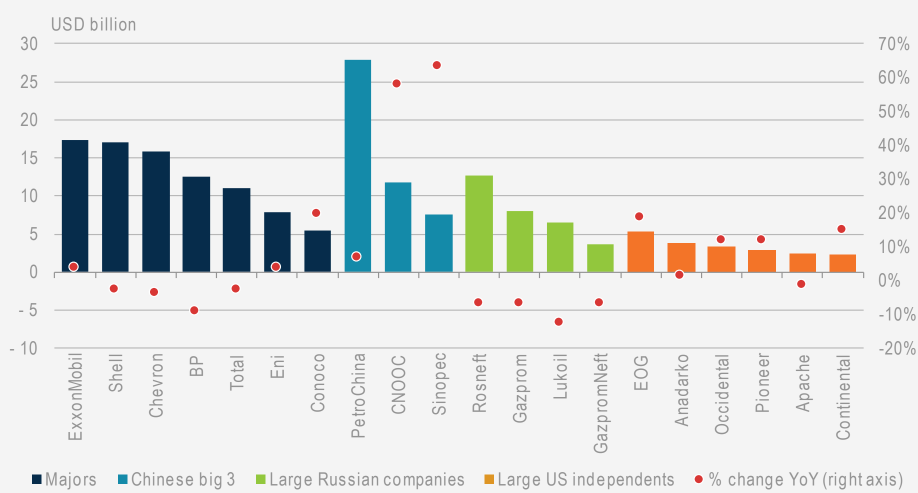
[42] Oil and gas production in the semi-autonomous Kurdistan Government, in the north of the country, already takes place under production-sharing models.

slump in exploration activity. The government is looking at further changes in the new model adopted in early 2017 based on sharing gross production between the state and operators, as the licensing round launched in February 2018 resulted in only 4 of the 24 blocks on offer being awarded. In attempt to reverse declining production, **Angola** has recently reduced the oil production tax on fields having less than 300 million barrels of reserves. The change in the fiscal regime supported Total's decision in May 2018 to sanction the Zinia 2 deep offshore project, expected to have a production capacity of 40 000 barrels per day.

The rise in upstream spending differs by company type

Trends in upstream investment vary markedly by type of company. All investors have tightened their financial discipline in response to the slump in oil prices in 2014-16, but big differences in their investment returns remain (Figure 1.31). The major oil companies almost halved their capital spending in aggregate between 2014 and 2017 and early indications suggest flat spending for 2018.[43]

Figure 1.31 Announced upstream oil and gas investment of selected companies in 2018 and change from 2017



The magnitude of the recovery in investment in 2018 differs by type of company, with Chinese companies and independent US shale operators set to raise spending the most.

Notes: CNOOC – China National Offshore Oil Corporation; (YoY) = year-on-year. Based on announced company spending plans and guidance as of May 2018. Some of results are influenced by currency exchange movements, in particular the US dollar versus the euro and the ruble.

[43] The majors are BP, Chevron, ConocoPhillips, Eni, ExxonMobil, Shell and Total.

The shift in spending towards shorter cycle investment, highlighted in *WEI 2017,* is continuing and accelerating into 2018. Companies are tending to prioritise investment in already producing (brownfield) assets (see below) and, in some cases, have expanded their operations in the US shale industry, where the investment cycle is relatively short (about 80% of total output comes in the first two years of operation). Chevron has announced that the majority of its investment in 2018 will be allocated to short cycle projects, including brownfield developments and shale production in the Permian Basin which it aims to almost triple by 2022. Earlier in 2018, ExxonMobil unveiled a very aggressive expansion plan, with a goal of boosting its US shale production to 800 thousand barrels of oil equivalent per day (boe/d) by 2025 from 200 kboe/d today and speeding up completion of its deepwater projects.

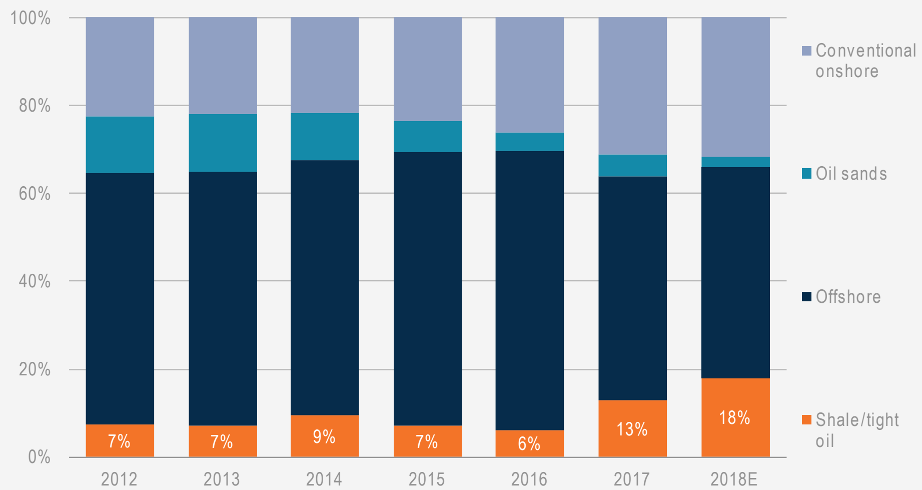
The emphasis on shorter-cycle projects has led to a shift in major's investment away from offshore and oil sands projects and towards the US shale and conventional onshore sectors. As a share of their total upstream spending, shale and tight oil accounted for 13% in 2017 and is set to reach 18% in 2018 – three times more than just two years ago (Figure 1.32). As some of majors have sold the majority of their stakes in Canada's oil sands over the last two years, the share of oil sands has slumped from around 13% of total spending in 2013 to a projected 2% in 2018. However, investment in the Canadian upstream sector is expected to remain broadly flat in 2018, although at less than half of the peak level reached in 2014, since most of the assets sold by the majors have been acquired by local companies.

The effects of measures taken by the majors to improve efficiency and restructure operations that have been implemented over the last few years are becoming clearly visible. Financial results for the first quarter of 2018 showed strong improvements in all key financial indicators (see Chapter 2). Operationally, achievements are striking. Despite a drop of 49% in upstream capital spending between 2014 and 2018, total oil and gas production is still expected to continue to rise by 11%.[44]

In contrast to the majors and other international companies, large NOCs are stepping up their capital spending. This is particularly the case for the Chinese companies, Petrochina, CNOOC and Sinopec, each of which is planning double-digit growth in spending in 2018; as a group, it is set to rise by 24%, though it will remain far below the level reached four years ago. There is a remarkable shift in Chinese investment towards natural gas.

[44] The production figure takes into account acquisitions and divestments for the companies considered. Some companies have also anticipated that today's level of capital spending will be sufficient to sustain the current level of production in the medium term.

Figure 1.32 Upstream oil investment by major oil companies adjusted by cost inflation by asset



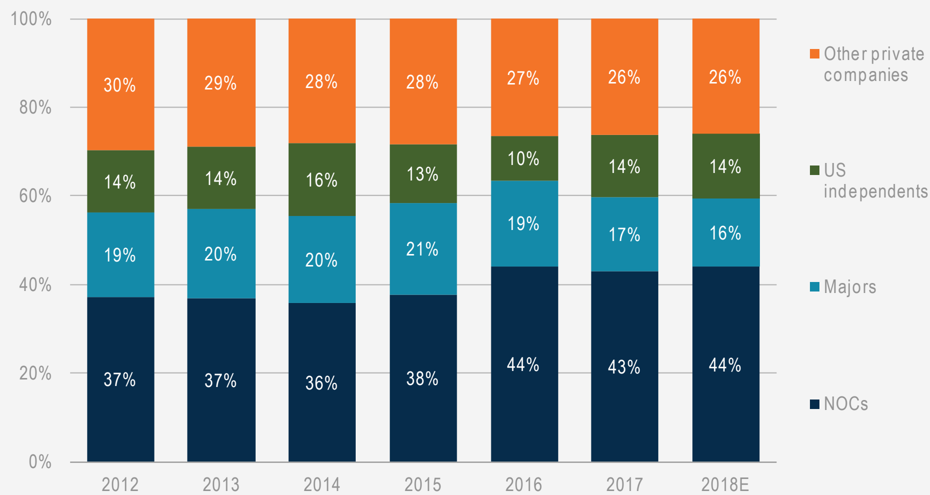
Majors continue to shift their investment towards shorter-cycle projects, notably in US shale, as a way to shorten payback periods and reduce exposure to long-term risks.

Note: E= Expected.
Source: Based on company reports and Rystad Energy (2018).

In the Middle East and Russia, NOC investment spending is rising more modestly compared with the Chinese companies, as the largest companies maintain a cautious approach. Spending is also being held down by cost deflation and improvements in efficiency over the last few years. In the US, shale-focused operators have revised upwards their investment plans for 2018, mainly due to higher prices and improved financial conditions. However, the magnitude of the growth for this group of companies is smaller compared with 2017, when investment in shale bounced back by over 50%. A key driver is the increasing priority being given to returning profits to shareholders with less focus on output growth. Most of the key players, including Pioneer, EOG Resources, Occidental Petroleum, Continental and Concho, are aiming for zero or positive free cash flow for 2018 based on the assumption that oil prices (considering West Texas Intermediate [WTI]) will average around USD 50 per barrel or lower throughout 2018 and confidence in keeping service costs under control.

The overall picture that emerges from the spending plans announced by companies around the world is the continued dominance of NOCs. Their share in total upstream spending is projected to remain at an all-time high of 44% of global upstream investment in 2018 for the third consecutive record year – a level significantly higher than the 36% share of 2014 (Figure 1.33). The share of US independents, after having bottomed out at 10% in 2016, is set to recover to 14% this year, while that of the majors further declines to 16% of the total.

Figure 1.33 World upstream oil and gas investment by company type



NOCs dominate global upstream investment, while the weight of majors continues to plunge.

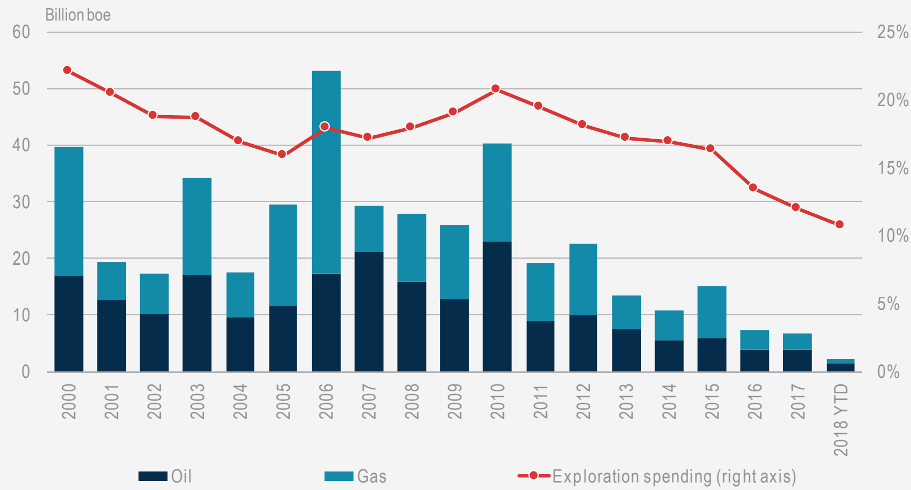
Source: Based on Rystad Energy (2018), company disclosure.

Exploration activities remain subdued, with few conventional resources being discovered

Exploration was the part of the upstream most affected by the oil price downturn of 2014-16 and the boom in US shale production. With growing shale supplies and limited budgets due to financial pressures, companies have drastically reduced their exploration activities. Globally, spending on exploration is set to total USD 51 billion in 2018, 6% down from 2017. This represents just 11% of global upstream spending – the lowest share ever. However, the decline masks a modest recovery in exploration activity, since deflation across the sector has lowered daily rig rates and the cost of seismic surveys.

Last year marked another historical low for the volume of conventional oil and gas resources discovered. The global total plunged to 6.8 billion barrels of oil equivalent (boe) compared with 7.2 billion boe found in 2016. This is barely one-quarter of the average volume of 26 billion boe found each year over the first 15 years of the current century (Figure 1.34). Oil accounted for the majority of discoveries in 2017, slightly less than 60% of the total, with seven out of the top ten discoveries being primarily oil. The lions' share of resources discovered was offshore, in line with the trend of the last few years. BP and Kosmos Yakaar gas field in the deep waters offshore Senegal was the biggest find, with 15 trillion cubic feet.[45]

Figure 1.34 Global discovered conventional resources and share of exploration in total upstream investment



Discoveries of conventional resources fell to another historical low in 2017, as the share of exploration in total upstream spending plunged for the eighth consecutive year.

Note: YTD = Year to date.
Source: Based on Rystad Energy (2018).

The reduced exploration spending is also partially contributing to the reduction of majors' total oil and gas reserves.[46] Their overall proved reserves, at around 87.5 billion boe in both 2016 and 2017, are the lowest since 2001 and 11% lower than the peak reached in 2013 at 99 billion boe. While the levels of proved reserves have traditionally been a key metric monitored by investors, currently the focus is on the cost of developing existing reserves and the quality of reservoirs. Despite the general improvement in business conditions thanks to higher prices and rising demand, companies are planning to keep spending on

[45] The discovery is expected to be monetized by BP and Kosmos through the realisation of a 14 billion cubic metres (bcm) per year Floating LNG plant to be sanctioned by end of 2018.

[46] The level of proved reserves is largely influenced by oil prices and the development of new projects.

exploration under close control in 2018.[47] Exploration activities are expected to remain robust in regions where the overall attractiveness of the geological play is already confirmed and where energy and fiscal policies are supportive. Mexico, offshore Brazil and Guyana, where large resources have been discovered in recent years, remain hotspots for exploration.

Investment in conventional oil and gas is shifting to brownfield projects

Global investment in conventional oil and gas resources is recovering slowly from the low reached in 2016. The amount of conventional oil and gas resources sanctioned in 2017 increased by 20% to around 18 billion boe and is expected to slightly increase in 2018.[48] With costs having plunged over the last few years, companies now have an incentive to move forward new projects or approve some that were delayed after the collapse of oil prices in 2014. But there are big differences in how the industry is responding to the recent recovery in oil prices compared with previous price rebounds. The majority of projects that have been sanctioned over the last three years are expansions, resizing or new phases of existing production facilities – so-called "brownfield" projects – to sustain production while minimising upfront capital expenditure. Of the more than 30 large conventional projects approved in 2017, only around one-third are considered to be greenfield.

The shift to brownfield investments is explained by the reluctance to risk large amounts of capital in major projects with long paybacks. Brownfield projects generally require less initial capital investment and generate faster paybacks, while reducing long-term risk exposure. In the first part of the current decade, several new large projects were sanctioned, with very high energy prices promising solid returns. In 2010-14, the development of more than 30 billion boe was sanctioned on average each year, almost equally split between oil and natural gas. This drove a steady increase in the share of total upstream investment allocated to greenfield projects, reaching a peak of 42% in 2013 and 2014. The steep drop of prices led to a U-turn in company behaviour, leading to an almost 50% collapse in the volume of conventional resources sanctioned on average in the period 2015-17 and the redirection of limited capital spending towards already producing assets. The split between oil and gas did not changed significantly with oil resources representing 56% of the overall total sanctioned. In 2018, this report estimates that the share of investment allocated to greenfields will drop to around one-third of the total (Figure 1.35).

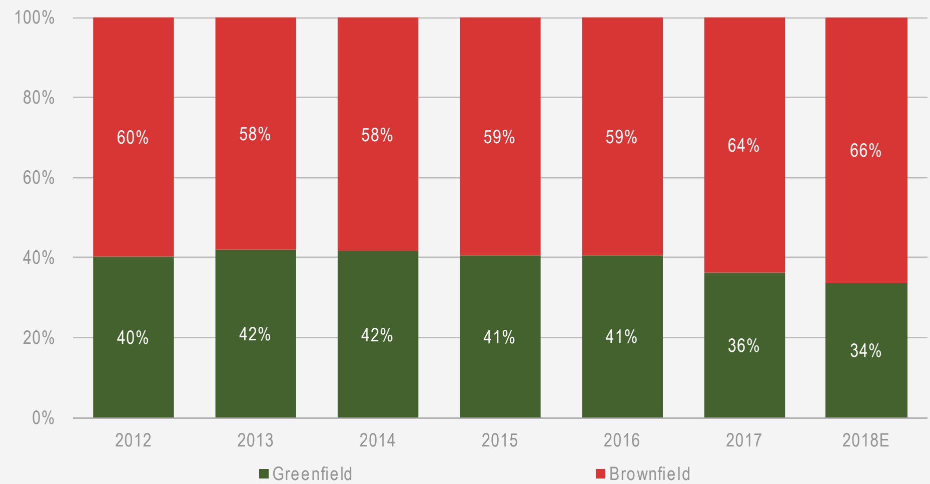
A notable consequence of this trend was a slowdown in decline rates at mature fields. With the fall in investment after 2014, it was feared that these already producing assets, in

[47] The rapid rise of oil prices in the first part of 2018 might encourage some operators to scale up exploration activities.

[48] Defined as projects subject to a FID.

particular those already in the post-peak production phase, would see acceleration in the pace of decline in their output. However, the combination of lower costs and a refocus on investment in brownfield projects, involving small injections of capital in selected assets to maximise near-term returns, led to a drop in post-peak decline rates from an average of 7% in 2010-14 to a low of 5.7% in 2017 (IEA, 2018g).

Figure 1.35 Shares of greenfield and brownfield projects in global upstream conventional oil and gas investment



As several new projects have been deferred or cancelled over the last three years, the share of investment allocated to greenfield projects is set to fall further in 2018.

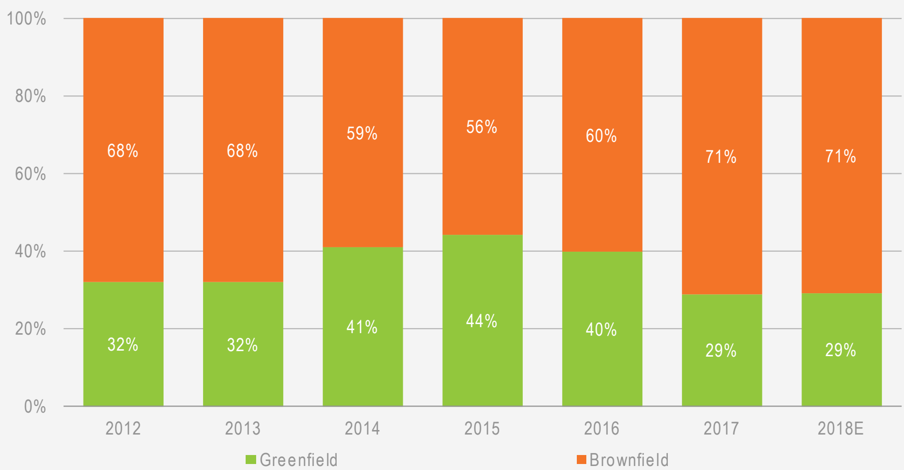
Sources: IEA analysis of data from company reports and Rystad Energy (2018).

This trend appears likely to persist in the near term, which raises concerns about the long-term prospects for production capacity, taking into consideration that each year the world needs to replace around 3 million barrels of oil per day (mb/d) of supply lost from the natural decline of mature fields (IEA, 2018g). Given the time lag between a FID and when capital spending actually starts, two years of very subdued investment in greenfield projects and no evidence of any significant shift in focus back towards those projects this year, greenfield production will not rebound in the near future. While brownfield projects boost production in the near term, effectively by bringing forward output, greenfield projects are needed to raise capacity over the medium and longer term. Furthermore, the slowing down of decline rates of mature fields typically generates an acceleration of production drop in a second stage. With global oil and gas demand expected continuing to grow over the next few years, the current trend towards brownfield investment could result in tightening of supplies in the medium term.

Box 1.4 Russia upstream operators prioritise brownfield projects to offset decline rates

As the Russian oil and gas sector reaps the long-term benefits of greenfield investments made over the past decade, companies are now moving to maximise returns from brownfield assets. While a number of companies increased capital spending in 2017, most have opted for fairly conservative programmes in 2018 with total spending across the sector likely to remain broadly flat in rouble terms. Much of this spending is being allocated to lowering decline rates at West Siberian brownfields (Figure 1.36).

Figure 1.36 Russia's upstream conventional oil and gas investment in greenfield versus brownfield



In Russia companies are allocating more resources to brownfield to manage decline rates and support production.

Source: IEA analysis based on data from company reports and Rystad Energy (2018).

Greater focus on brownfield projects involves more horizontal drilling at mature fields. This was reflected in a 10% increase in the total number of metres drilled in Russia in 2017. Several factors will drive a continuation of this trend with more of the required technology, including drilling rigs, expected to come from China. First, in April 2018 Russia's Federal Antimonopoly Service granted preliminary approval to Schlumberger to acquire a non-controlling stake in Eurasia Drilling Company, one of Russia's largest services companies, opening the door for additional support to Russian companies in modernizing services and improving efficiency of conventional reserve development. Second, companies are pursuing import substitution in response to sanctions.* Gazprom Neft is a leader in this space, undergoing a digital transformation and testing in-house capabilities for commercial development of hard-to-recover reserves.

The situation is markedly different for Russia's gas sector given its estimated spare capacity of about 100 billion cubic metres (bcm) to 150 bcm per year. Gazprom's strategy is to be flexible in production, but withhold major new upstream investments. The company is currently focusing investment on export pipelines. In 2018, it allocated USD 3.9 billion to the development of the Power of Siberia pipeline to China, USD 3.2 billion to the Turk Stream line to Turkey and USD 1.9 billion to the Nord Stream 2 project to Germany. Other major gas producers, including Rosneft and Novatek, are looking to expand their global LNG activities; Novatek is on schedule to launch a second train at Yamal LNG by the end of 2018 and further Arctic LNG expansions are already planned, although those appear to remain far from a FID.

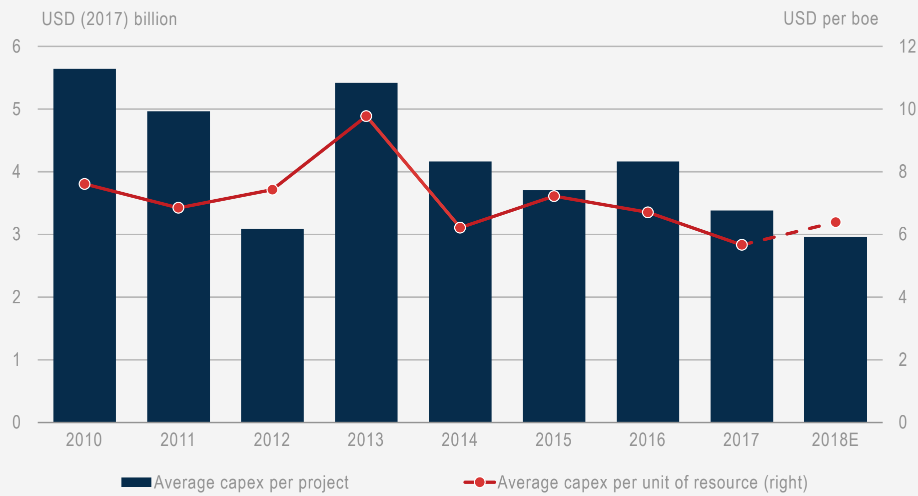
The government is testing the ability of a new excess profits tax (EPT) scheme to support development of new greenfield oil plays, including shale, deepwater and Arctic resources. It plans to roll out a pilot programme from January 2019. EPT provides additional financial incentive to oil companies to develop more difficult resources. However, the new scheme may prove costly for the state, which is heavily dependent on oil and gas tax revenues (around 40% of its total budget).

*The "Import substitution" is the official policy introduced by Russia's government in order to support increased capabilities in the development of advanced technologies used in for shale operations, Arctic, and LNG among others.

The trend in investment towards brownfield conventional projects is reflected to some extent in a fall in spending on individual projects and developing new oil and gas resources. Based on an analysis of all the major projects sanctioned since 2010, the average amount invested in the conventional upstream sector per project has been falling in recent years, especially since 2016. During 2010-14, a period characterised by high oil prices and rapid rising costs, capital spending averaged less than USD 5 billion per project. By 2017, average spending had dropped to less than USD 3.4 billion per project, a trend that is expected to continue in 2018 (Figure 1.37).[49] A similar trend is apparent with respect to capital spending per unit of barrel oil equivalent sanctioned. From an average of just under USD 8/boe in 2010-14, spending fell to less than USD 6 per boe in 2017. A key question which remains open is if the phasing-in of new projects sanctioned alongside the streamlined and simplified approach will lead to higher costs per barrel of oil equivalent produced in a second stage.

[49] The average resource size of large projects sanctioned in 2012, at just above 400 million barrels of oil equivalent (Mboe), was significantly lower than the average of the last eight years (more than 600 Mboe). This was largely due to five projects in southern Iraq, which require lower levels of capital spending given the quality of reservoir. The jump in average capital spending per project in 2016 was largely due to two mega-projects sanctioned in that year: Tengiz in Kazakhstan and Zohr in Egypt.

Figure 1.37 Average capital spending per major conventional upstream project and per unit of resource sanctioned



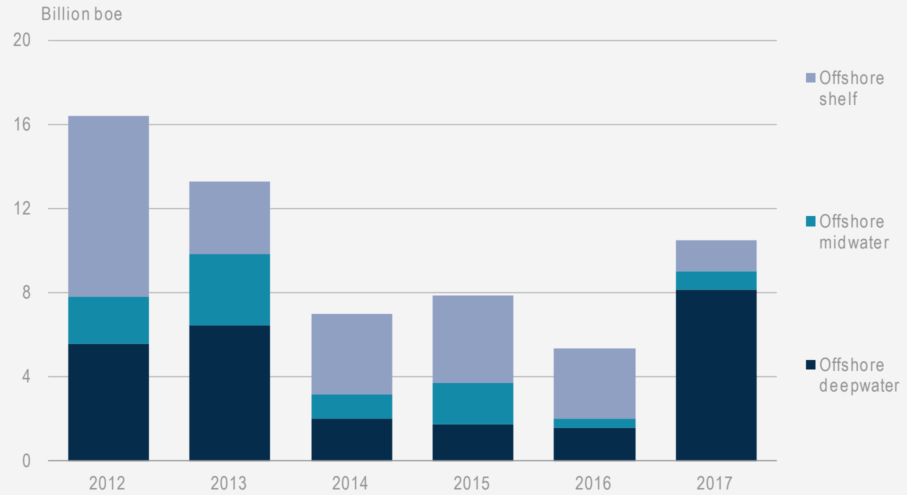
Capital discipline, cost deflation and technology improvements have driven a decline in average capital spending per large project sanctioned and per unit of oil and gas resource developed.

Notes: Capex = Capital expenditure. 2018E includes projects sanctioned as of mid-May 2018.
Sources: Based on company reports and Goldman Sachs International (2018).

Was 2017 a turning point for the offshore sector?

While investment plans for 2018 point to a continued focus on shale resources and onshore fields, 2017 appears to have been a turning point for the offshore sector. However, this is expected to not determine a rebound of investment in 2018, as the pace of development remains sluggish and spending in new projects is not sufficient to offset the decline in activity given by the completion of those projects that were sanctioned pre-2014 and have been developed over the last few years. Yet deepwater resources sanctioned in 2017, at 8 billion boe, reached their highest point since 2013, with the bulk of growth coming from oil projects (Figure 1.38). The main contributor was Brazil, where the combination of tremendous potential in its pre-salt basins and upstream policy and regulatory reforms, including a new bidding process, eased local content requirements and the abolition of Petrobras' exclusive rights to manage the pre-salt area, have created conditions for several international companies to invest in the country. Due to a wave of investment decisions taken in previous years, several new floating production storage and offloading platforms are scheduled to start production in Brazil's pre-salt basins in 2018 and 2019, making the country one of the world's fastest-growing oil producers.

Figure 1.38 Offshore projects sanctioned worldwide by water depth



The amount of deepwater resources sanctioned for development in 2017 was almost back to the level prevailing before the slump in oil price, as companies benefited from lower costs.

Sources: Based on company announcements and Rystad Energy data (2018).

The recent revival in offshore activity is characterised by two main trends. First, companies continue to avoid embarking on megaprojects in order to limit risk and capital exposure. All the projects that have been sanctioned recently, including Brazil's Libra and Guyana's Liza — as well as Israel's Leviathan and Egypt's Zohr gas fields — involve distinct development phases in order to reduce initial capital allocation, bring forward the start of production and reduce project risks over the long term.[50] Moreover, in traditional producing areas, such as the North Sea and the Gulf of Mexico, operators are also trying to leverage existing infrastructure through tiebacks rather than build new ones as a way to reduce costs. Second, operators are benefitting from the near halving of deepwater development costs over the last three years, by locking in lower costs in contracts with service companies and suppliers. They are also looking to simplify and standardise projects to further lower costs. Equinor's Johan Castberg in the Barents Sea and BP's Mad Dog II in the Gulf of Mexico are two examples of this, as the investment requirements are more than halved compared with

[50] Development in phases is also considered by companies as an efficient learning-by-doing exercise as they can bring forward development while improving knowledge of the reservoirs through appraisal and expand operations at a later stage in a more cost-effective way.

original plans.[51] Another is Shell's Vito field in the Gulf of Mexico, which was given the green light in April 2018 and is expected to produce about 100 kboe/d at peak. Shell completely re-designed the project and simplified the scope, resulting in a 70% reduction in the project's total cost and a fall in the projected break-even price to less than USD 35 per barrel. Production is set to start as soon as 2021, only three years since the sanctioning of the project, confirming the trend towards a faster execution of large projects, anticipated in *WEI 2017.*

The majors remain the key actors in the offshore sector, being involved in most of the projects approved in 2017 and early 2018. BP and Equinor were most active, with several projects in Norway, the Gulf of Mexico, and Trinidad and Tobago. The offshore sector remains critically important for the majors, accounting for the majority of their reserves and production. But projects moving ahead are those presenting high-quality resources, suitable for implementation of modern technologies and – in some cases – where fiscal regimes support economics. On current plans, 48% of majors' total upstream investment will go to offshore projects in 2018, significantly higher than the global average.

Activities in US shale creep up

The US shale oil and gas industry remains the "hot spot" of oil and gas upstream. Thanks to a combination of improved efficiency, cost-consciousness, the deployment of new technologies and the rapidly rising contribution of large international companies that have invested heavily in the sector over the last years, output is set to grow substantially in 2018. Capital spending in US shale sector has continued to accelerate since the end of 2016 and this report estimates it is set to increase by around 20% in 2018. The estimate for 2018 spending in the sector is slightly higher than what would result in just compiling capital spending for 2018 anticipated by operators, as companies in the first quarter of 2018 accelerated their activities more than expected encouraged by rising prices. As a result, the IEA estimates that investment in shale projects will achieve the highest growth in 2018 among key producing areas, confirming a trend already experienced in 2017 (Figure 1.39).

The US shale industry has responded quickly to changes in market conditions in recent years, thanks to the abundance of small and agile companies, small projects, and widespread use of short-term contracts. Since late 2016, rising and relatively stable oil prices have given operators the confidence to scale up their activities and restart drilling programmes.[52] In June 2018, oil and gas rig counts in the United States were up 13% on a year earlier, reaching the highest level since March 2015. Companies have prioritized the

[51] On 11 June 2018, Norway's parliament approved the plan for development and operation of the Johan Castberg field.

[52] The reference oil price for the US shale sector is (WTI) throughout this section.

utilisation of more efficient and powerful equipment, with horizontal rigs accounting today for almost 90% of all the rigs in use, compared with less than 70% four years ago.

Shale development activity and production growth is now heavily concentrated in the Permian Basin (in particular in the Delaware and Midland sub-basins), which accounts for about 45% of total rigs operating in the US market. In the first quarter of 2018, horizontal permitting activity there, one of the key indicators on short-term activity reached a record high, more the three times above the low reached in mid-2016. However, the evacuation infrastructure for oil and associated products has lagged the surging production in the Permian Basin, representing a major element of concern for producers until new takeaway capacity enters into operation in mid-2019. The sector appears to have entered a more mature phase of its development, although several challenges and potential downside risks remain (see Chapter 2). There are significant differences in terms of break-evens and productivity levels among shale basins and individual companies, as the quality of reservoirs, transportation costs and operational efficiencies vary. For the sector as a whole, production costs have been kept under control. For almost 50 US leading independents, this report estimates that the average lifting cost per barrel of oil equivalent produced increased by only 2% in 2017 despite higher oil prices and the rising cost of oilfield services after plunging by about 30% in 2014-16 (Figure 1.40).[53] According to company quarterly results for the first quarter of 2018, production costs increased by about 6% from the same period in 2017.

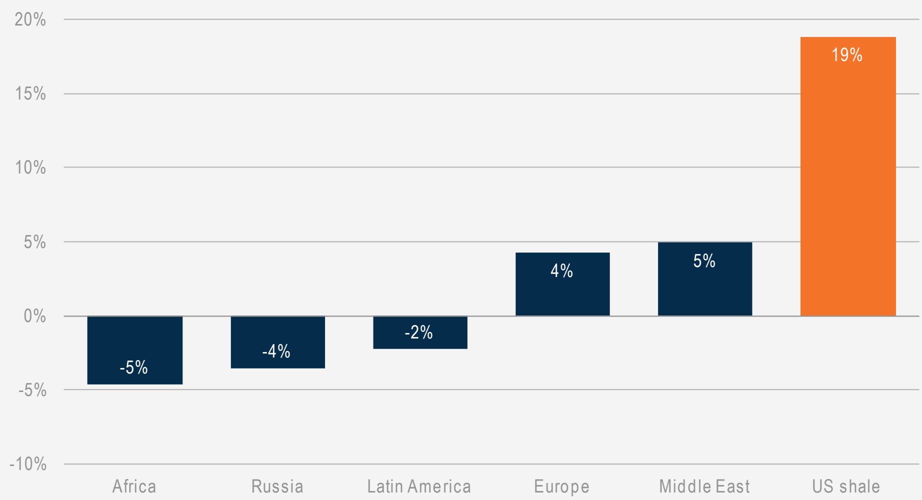
The biggest uncertainty in the US shale sector concerns its ability to improve its financial health in a sustainable way. Over the last few years, the industry has rarely been able to generate positive returns on the capital employed, being forced to rely on external sources of finance such as debt, equity raising or divestment of assets. With oil prices around USD 65 per barrel at the time of writing, shale companies face a dilemma: should they stick to their commitment to focus on near-term profitability, or accelerate spending and output growth in order to try to take advantage of higher prices? Recent indications generally point to the former, with enhanced focus on efficiency gains of operations and returning money to investors, though some shale operators continue to outspend the cash generated (see Chapter 2 for more detail). Some independent players have announced increased dividend payments and share buyback programmes.

A notable shift in the US shale industry is the composition of players operating in the sector. Until very recently, the US shale industry was dominated by myriad private investors, land

[53] The total lifting cost includes operating and maintenance costs for production (lease operating expenses), gathering, processing and transportation costs, and production taxes. It does not include costs of finding and developing proved oil and gas reserves or general and administrative expenses, interest expense and income taxes.

owners and small to medium-size companies.[54] There has since been a wave of consolidation in the sector, with companies trying to optimise operations and assets. In addition, some of largest international oil and gas companies, including the majors, have increased their investments in US shale. Chevron's first quarter of 2018 provides evidence of the efforts the company has been implementing in the sector. Its shale production in the Permian increased to 250 kboe/d, more than 65% growth compared with one year before and the company forecasts a 30-40% annual growth through 2020. ExxonMobil's production in the Permian and Bakken shale basins increased 18% in first quarter 2018 compared with the previous year, and the company is operating more than 30 horizontal rigs. ConocoPhillips expanded its unconventional production to 250 kboe per day, 20% growth from the previous year. Two European majors have also increased their presence in US shale. Shell mainly operates in the Permian and Appalachian basins and the company announced in its 2018-20 capital guidance that it plans to invest between USD 2 billion and USD 3 billion per year in the sector. BP operates in five US onshore basins, producing more than 300 kboe/d in the first quarter of 2018 (mainly natural gas).

Figure 1.39 Change in upstream investment by selected region, 2017-18



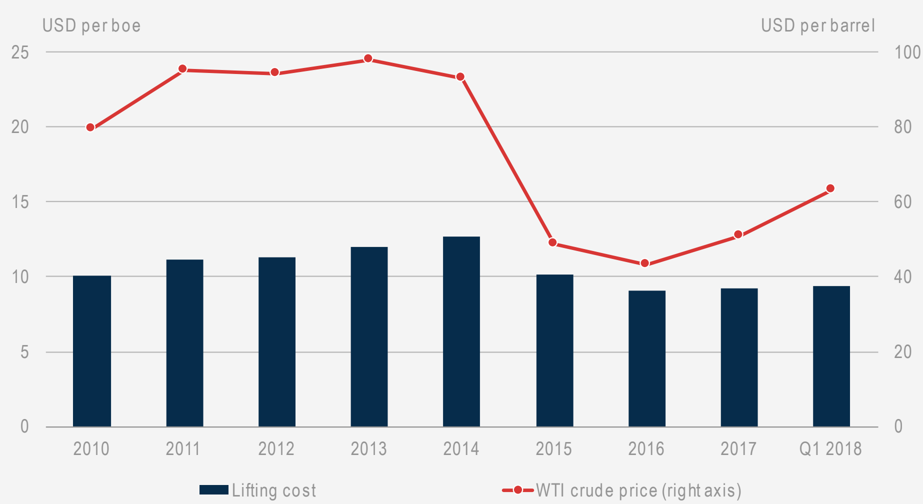
As in 2017, the growth in US shale investment is set to outpace all other key producing regions in 2018.

Sources: Based on company reports.

[54] Preliminary indications in the first quarter of 2018 show a revival of interest from private operators. These small companies tend to have assets in less prolific sub-basins and consequently their level of activity is more sensitive to oil prices movements.

It is too early to assess the potential impact on the sector of the growing involvement of large international companies, but their renewed interest in shale production might support a consolidation of the shale industry. Favourable elements include the economies of scale, including ability to consolidate acreage, that big companies tend to enjoy; an enhanced focus on vertical integration given the rising importance of pipeline and storage systems to accommodate growing production volumes; and the trend to drill several wells per pad which requires higher upfront investments that not all small-medium companies can afford.

Figure 1.40 US independents total lifting cost and international oil price



Despite inflationary pressures coming from the tightening of the service sector and rising fuel and labour costs, independents are managing to keep shale production costs under control.

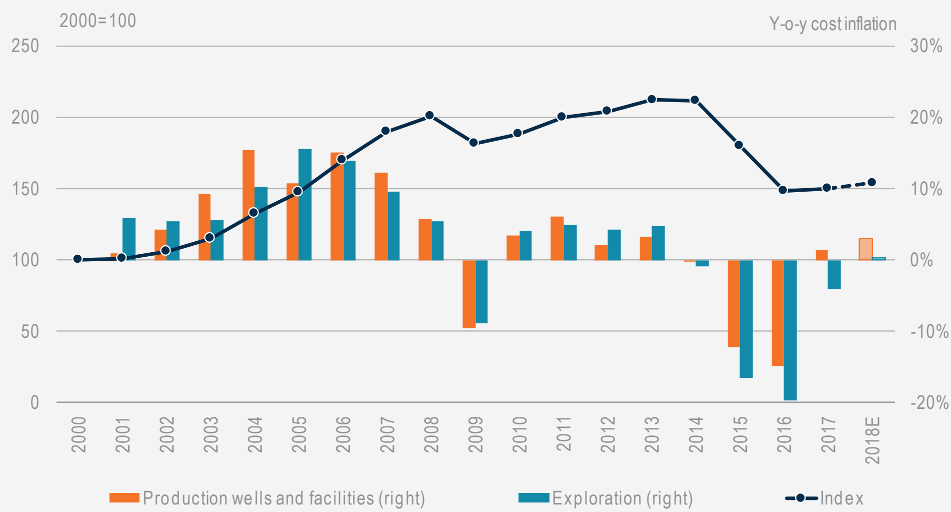
Notes: Lifting cost is total production costs divided by total production volume of about 50 US independent companies. It includes transportation costs.
Sources: Based on company filings and Bloomberg Terminal (2018).

Trends in upstream costs

Drilling costs are on the rise again, but only slowly

The last three years have been extraordinary for the entire oil and gas industry. The upstream business rapidly adjusted to the lower price environment, with the oilfield services sector taking the bulk of the burden of project deferrals and cancellations and reduced pricing for their services. In the period 2014-17, global upstream costs plunged by about 30%, according to the IEA Upstream Investment Cost Index (UICI), reversing a long period of rising costs amid increasing demand for a range of services and equipment and higher oil prices.

Figure 1.41 Global upstream investment cost index

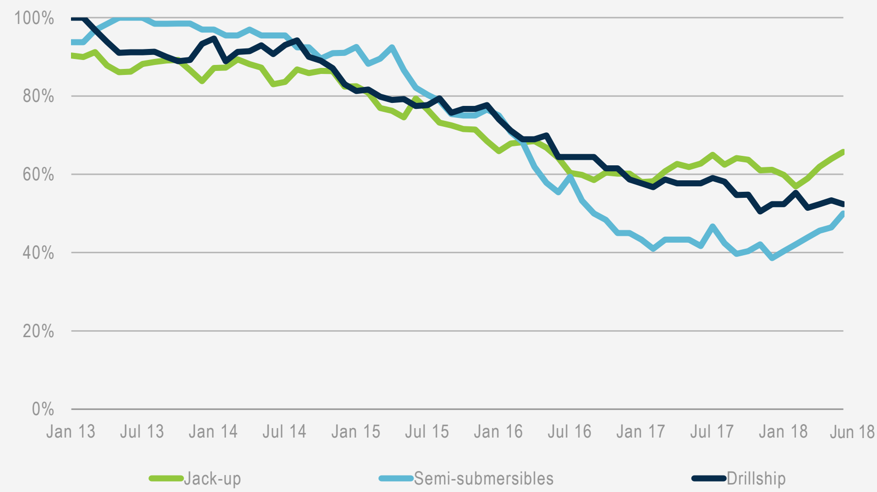


Global upstream costs are expected to rise only marginally in 2018 as modest cost increment in onshore activities is mostly offset by oversupply capacity in the offshore sector.

While the oil market has worked off excess stocks in the past 12 months the industry appears to have maintained its focus on keeping costs under control and not ramping up capital and operational expenditures too quickly. Most private companies report that the vast majority of the cost savings achieved over the last three years have been of a structural nature and are set to remain regardless of future oil price trajectories. But the services industry has been hit hard by the fall in upstream activity and the pricing concessions they were obliged to make. Overall, it will be the battle between further efficiency gains and potential cost inflation that will largely determine the shape of oil and gas supply cost curves.

This report projects that average unit costs of upstream exploration and development worldwide will increase at a modest rate of around 3% in 2018 (Figure 1.41). The picture varies across regions and sectors. A common trend is increasing costs for steel and raw materials. International prices for hot rolled coil and ferrous scrap steel have increased by up to 10% in the year to May 2018, having increased at the same rate in 2017. Steel prices are climbing in response to a modest uptick in demand, though supply remains ample (OECD, 2018). A key uncertainty, especially for the US shale industry, concerns the potential impact from the decision of the US administration in June 2018 to impose a 25% tariff on steel and aluminium imported in the United States from selected countries (Box 1.2). Even assuming that this measure translates into a 25% increase in the total cost of steel used into the US upstream industry, its impact on shale development costs would remain marginal at less than USD 1 per barrel, though it would be an additional component to an already highly leveraged sector that has been so far characterised by negative or limited profitability (see Chapter 2).

Figure 1.42 Utilisation rates of offshore drilling equipment



Offshore drilling equipment remains largely underutilised, although utilisation rates appear to have bottomed out with a pickup in activity in late 2017.

Sources: Based on Rigzone data accessed through Bloomberg Terminal.

The offshore sector has been hit hardest by the market contraction. At the start of the downturn in activity in 2015, the services industry had a large backlog of orders for new equipment and vessels that were sanctioned earlier in the decade when market condition and expectations were very different. Although there is some optimism from the recovery in demand for offshore services seen since the fourth quarter of 2017, there is a general consensus that 2018 will remain challenging for those companies most heavily involved in the sector. Some signs of inflationary pressure are starting to emerge in the offshore industry, especially in those parts of the supply chain such as equipment, pipelines and logistics that are most dependent on materials and labour. However, this may be more than offset by persistent overcapacity in other parts of the industry, including drilling ships (where the average utilisation rate, at less than 60%, remains far below the 90% level in 2013) and other offshore vessels (Figure 1.42). The decline in daily rates for jack-up and semi-submersible rigs and drillships accelerated in 2017 to around 20%, and they fell further in the first months of 2018. Rates for deepwater drillship have fallen the most since the downturn: daily rates have plunged from a peak of almost USD 600 000 per day in 2013-14 to around USD 150 000 per day at the time of writing.

Consolidation in the offshore services sector is continuing, with some operators forced to declare bankruptcy as day rates barely cover operating and depreciation costs. Service companies have been trying to reduce oversupply by scrapping or mothballing offshore rigs and vessels. But this process will take time. This report does not expect costs in this sector to rebound in 2018. The key challenge for the offshore sector over the medium and long term is preserving its competitiveness against other sources of energy supplies even in a potentially low energy price environment. Holding down costs as activity picks up will be vital to the future of the industry. Significant gains might come from further technology improvements, including digitalization, as well as from new business models with stronger cooperation among operators and along the entire supply chain.

US shale costs rebound but are compensated by technological and operational efficiency gains

Costs in the US shale industry are driven by a somewhat different set of factors than those in the conventional upstream industry, due to the diversity of investors and the unique characteristics of the services industry and financing in the United States, though some cost drivers are common to both. Costs in the sector are set to increase on average by 11% in 2018, according to the IEA Upstream Shale Investment Cost Index (USICI), following a 9% increase in 2017, driven by rising costs for well drilling and completion (Figure 1.43).[55] These figures should discount the fact that while most of inflation elements are common across the industry, the level of activities and capacity of service sectors differ by basins.

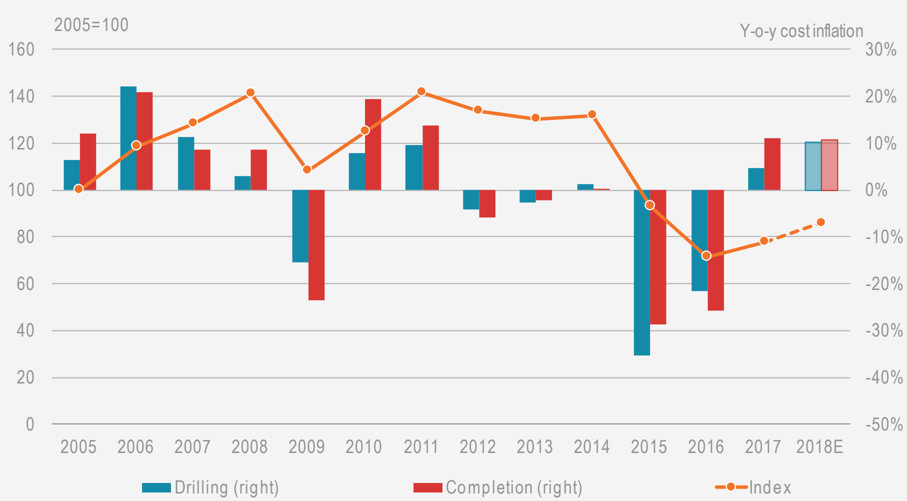
Over the last few years, the shale industry has seen some major changes in the way it operates. The number of wells drilled per pad has been increased significantly, yielding economies of scale. Currently, the vast bulk of demand for drilling equipment is for so-called high-spec rigs, which have more than 1 500 horsepower, in order to speed up operations and cope with the increased complexity and length of wells. These rigs have the additional advantage of having integrated some automated systems and can be moved within the pad from well to well without being dismantled. In the Permian Basin, the day rate for such rigs increased by more than 10% in 2017 as a result.

The lateral length of perforated wells continues to rise, and there is a growing share of wells exceeding 10 000 feet with indications of further extension. The fracturing intensity per single well has increased more than four-fold since 2012, the number of perforated clusters per well rising from about 70 units to over 300 units. Although there is some evidence that some operators are beginning to pull back on their proppant loading per well due to the trade of cost and productivity, the trend towards significant growth of

[55] The USICI for 2017 was revised down compared with *WEI 2017* due to a smaller-than-expected rise in drilling service costs.

the amount of proppants used in shale operations generally continued over 2017, pushing up costs by about 20% in 2017 in some regions (notably the Permian) with a further rise expected in 2018. There are basically three different types of proppant: 1) frac sand, by far the proppant mostly used; 2) resin-coated sand, more expensive than frac sand given that the resin coating tends to improve effectiveness of the product; and 3) ceramics, which is the most expensive being manufactured using bauxite. The increase in proppant costs and the risk of shortages have prompted companies to implement various measures. These include reducing proppant intensity (measured as proppant quantity per lateral feet); buying up sand suppliers either through takeovers of mining companies or managing directly operations in mines; procuring supplies of sand from local mines (as the cost of transportation, together with sand quality, is a key component for overall sand costs); and using new chemical products that help reduce the consumption of proppant.

Figure 1.43 Upstream Shale Investment Cost Index



US shale capital costs are expected to rise on average by 11% in 2018, but the picture varies across basins according to level of drilling activity.

The overall result of different factors affecting the shale industry is that, while unit costs per shale well have increased by over one-fifth since the second half of 2016 (taking into consideration the increased average lateral length of wells), companies have been successful in mitigating inflationary pressures through efficiency gains, higher well productivity, and optimisation of the supply structure across all components. The persistent uptake of advanced technologies, coupled with new project designs and more sophisticated well construction facilities has been crucial in offsetting the impact of rising prices of oilfield services. Consequently, the strong increase in shale operations and rising labour and fuel costs led to only a very modest increase in well-head break-even prices in 2017 and early 2018.

While production is expected to continue to rise in the near term, the rate of growth remains subject to a number of uncertainties. On one hand, higher spending anticipated by most players suggests rising output supported by the expansion of drilling and completion activities and the rapid diffusion of digital technologies (Box 1.5). On the other hand, there is increasing evidence of overheating in the sector especially from the service and supplier industry. The number of rigs deployed has increased substantially compared with the previous year (by 30% in the Permian Basin) and the rising number of drilled but uncompleted wells (DUC) pinpoints bottlenecks on completion side due to rising difficulties in rapidly delivering fracking equipment and providing work crew as well as rising costs for materials. According to discussions held with local operators, the service industry is scaling up its ability to perform completion activity that should rapidly transform DUCs into production, helping to sustain the growth. At the same time, there are some looming constraints on the infrastructure side that might threaten the pace of production growth in the short term. Further to the need to expand capacity and size of oil pipelines in the Permian Basin, a key element of growing concern is related to natural gas and wastewater infrastructures, since the boom in crude output is accompanied by rapidly rising volumes of associated products that require scaling up of takeaway pipelines.[56] Current bottlenecks in the Permian Basin infrastructure are already affecting operations and financial returns of some companies given wide discounted crude pricing between Midland and Houston (see Chapter 2).

Box 1.5 Digitalization makes inroads in the upstream sector

With upstream activities having partially recovered since reaching bottoms in mid-2016 and the service industry trying to reduce equipment oversupply and adapt to changed market conditions, companies have been increasingly shifting their focus to the implementation of modern technologies as a way to keep the positive momentum in reducing costs, strengthening operations and improving margins. Although at an early stage and with different levels of deployment across the industry, the digitalization is increasingly transforming the oil and gas sector, with all key players scaling up capabilities and investment in this sphere both in conventional and unconventional operations (IEA, 2017d).*

[56] Different sources indicate that Permian operators produce up to four barrels of water per one barrel of oil produced. Furthermore, due to natural gas pipeline bottlenecks, recent data indicates a steady increase of gas flaring in the region, although it remains a small fraction (around 3%) of total gas produced

A key driver for companies is trying to avoid repeating the mistakes of the past when the rebound of activities following downturn periods was accompanied by cost inflation and vanishing the efficiency improvements implemented during the bottom of the cycle. As explored in the 2017 edition of *WEI*, we believe it remains evident that the global oil and gas cost structure has rebased, with a not-marginal component of cost deflation materialised in the 2014-16 period set to be captured also on future projects. However, several risks remains and companies increasingly believe in digitalization, big-data analytics and deployment of automation technologies as the next frontier for further cost reductions or as a way to offset inflation pressures coming from other components of value chain.

Several key operators in conventional activities and in US shale are rapidly increasing investment in digital technologies. Every day, hundreds of wells are drilled generating huge amount of data that so far have been in most of cases poorly utilised. With deployment of data analytics and technologies, the benefits expected are multi-fold and include:

- Improving the understanding of the resource base by subsurface mapping.
- Optimising drilling by ensuring lateral wells are positioned accurately and improving completions field operations.
- Maximising and fast-tracking production in order to payback investment in shorter period of time.
- Standardising operations by replicating best production processes already implemented in other fields.

The deployment of more modern technologies and data analytics have already proved to deliver important results to operations, with reported examples of very rapid increase in performance of wells drilled or strong growth of production levels per well once adjusted for lateral lengths. It is also worthy to note that the utilisation of such new tools throughout the sector remains for the time being uneven and companies will strive to replicate the successes of those having led so far, helping an acceleration of these techniques in the oil and gas sector. In addition to small-medium size independents, which typically have a more agile structure able to adapt own business models and organisational structures quicker, large integrated companies are prioritising digitalization in the way they design and execute projects, with the aim of reducing upstream costs and operating expenses, increasing reliability of their activities and keeping headcounts limited.** The ongoing trend appears to lead to three overarching implications:

- As oil and gas companies move into different territory, there is increasing co-operation among hydrocarbon players and information technology companies to scale up opportunities in terms of developing artificial intelligence options, high-performance computing technologies, and tools for remotely operated activities.
- New business models among oil and gas players and service companies emerge, as service companies develop new technologies aimed to optimise and automate operations and enable predictive actions aimed at reducing downtimes and maintenance while facilitating decision making.

- Digitalisation techniques and procedures accelerate throughout the entire sector with spill-over effects across different components of the industry.

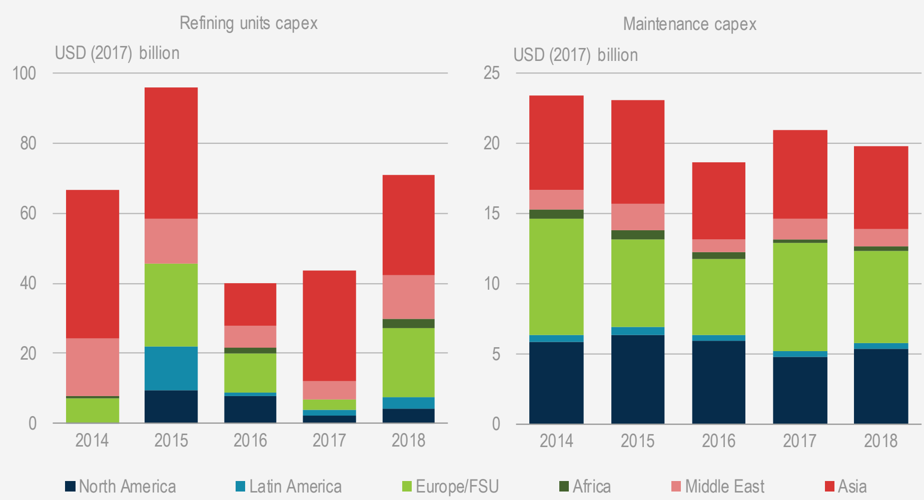
* A recent example is Repsol's 2018-20 strategy indicating its upstream division aims to achieving USD 1 billion dollars of additional free cash flow per year by 2020 through new efficiency and digitalization program.
** Another example is the realisation of unmanned platforms which are designed to be mainly remotely operated with limited or lack of personnel. Equinor installed its first unmanned platform on the Norwegian Continental Shelf in summer 2017.

Investment in refining and petrochemicals

Refining investment – especially in secondary units– is bouncing back

Recent trends in global investment in oil refining differ somewhat from those in the upstream sector, mainly due to long lead times and the weaker link between oil prices and profit margins in refining.

Figure 1.44 Investment in oil refineries by region

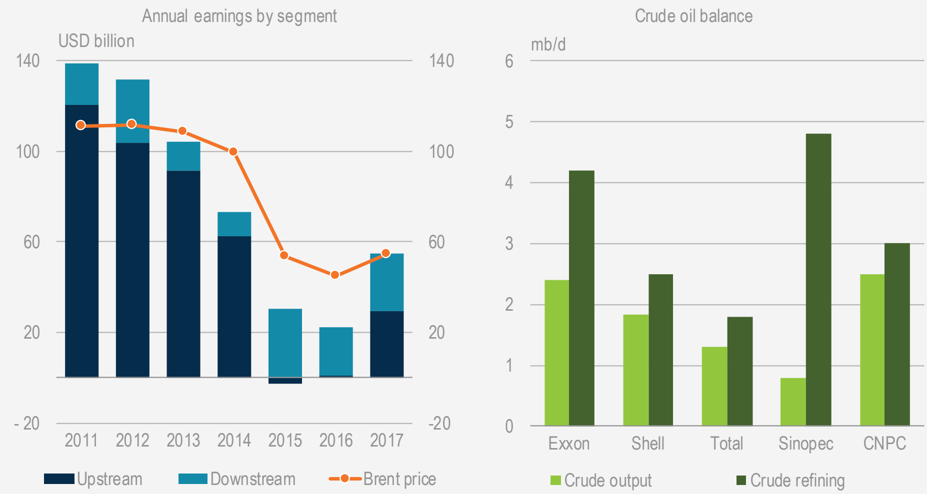


Refining investment in total rebounded by 10% in 2017 and is set to rise by another 40% in 2018, driven by rising demand in the emerging economies and improved profitability.

Notes: FSU = Former Soviet Union. Calculations based on overnight investments. Maintenance capex is included as most of the spending is capitalized for accounting purposes.

Total investment increased sharply by over 30% in 2015, before falling back by more than 50% in 2016. It rebounded by 10% in 2017 and is set to rise by another 40% in 2018 to about USD 90 billion (Figure 1.44). The bulk of investment continues to go to the construction of new units in regions either with strong demand growth perspective or oil industry diversification objectives.[57]

Figure 1.45 Refining profits and crude oil production and refining balance of selected companies



Refining profits have increased sharply in respond to lower crude oil prices, providing a natural hedge and protecting the financial health of the majors and other integrated oil companies.

Notes: CNPC = China National Petroleum Corporation. Annual earnings data include BP, Exxon, Shell and Total.
Sources: Data from company reports.

The slump in international oil prices in 2014-16 highlighted the potential benefits of vertical integration for companies. While upstream segment profits plunged, refining margins, boosted by lower feedstock costs, remained healthy and provided a natural hedge against crude oil price volatility, protecting the profits of the integrated companies (Figure 1.45).

Most of the Western majors, like their Asian peers, refine more oil than they produce, even if many of them, especially European oil companies, have closed down or sold refining assets over the last 10-15 years. Refining profits were also helped by the earlier

[57] In the refining industry, periodic maintenance programmes are generally classified at capital rather than operating expenditures.

shutdowns of the least-performing sites. Decelerating, or even declining domestic demand, combined with road fuel specification changes that required large investments into refinery modernisation, contributed to decisions to permanently shut some 2.6 mb/d of refining capacity in Europe over the ten years to 2017. In North America, closures amounted to 1.6 mb/d, while in OECD Asia, mostly Japan and Australia, another 1.7 mb/d of capacity was permanently closed. Lower oil prices since 2015 have helped reverse the long-term decline in demand in OECD countries, though diesel demand in North America is still below the 2007 peak, and the same is true for gasoline demand in Europe. Demand growth in non-OECD countries has been very strong.

Refining capacity additions were relatively muted in 2016 and 2017, which explains the fall in IEA investment estimates, but they bounced back in 2018. Asia, where oil product demand is growing fastest, continues to dominate refinery investment. The Middle East has been actively building refineries not only to displace product imports but to become a net refined product exporter. In Europe and Eurasia, most investment is going to secondary processing units, while North America continues reaping the benefits of shale growth in terms of cheaper feedstocks for both refining and petrochemicals.

In **Europe**, the only new refinery that has been built in the last two decades is a 200 kb/d unit in Turkey, which is scheduled to come on line in 2018. This is likely to be the last new refinery in the region. Most investment is going to secondary units such as heavy fuel conversion and crude de-asphalting units to meet the tighter bunker fuel specification changes mandated by the International Maritime Organization that are due to come into force in 2020.

In the **Middle East**, the willingness to increase the vertical integration of NOCs and to diversify oil revenue streams are important factors in the drive to increase refining capacity (Figure 1.46). Several Middle Eastern NOCs are also involved in overseas projects, predominantly in the growing Asian markets. Saudi Aramco, which has announced the most ambitious programme for downstream expansion, also consolidated the ownership of the largest refining complex in the United States, the Motiva site in Port Arthur, Texas, reaching a deal with joint-venture partner Shell in 2017.

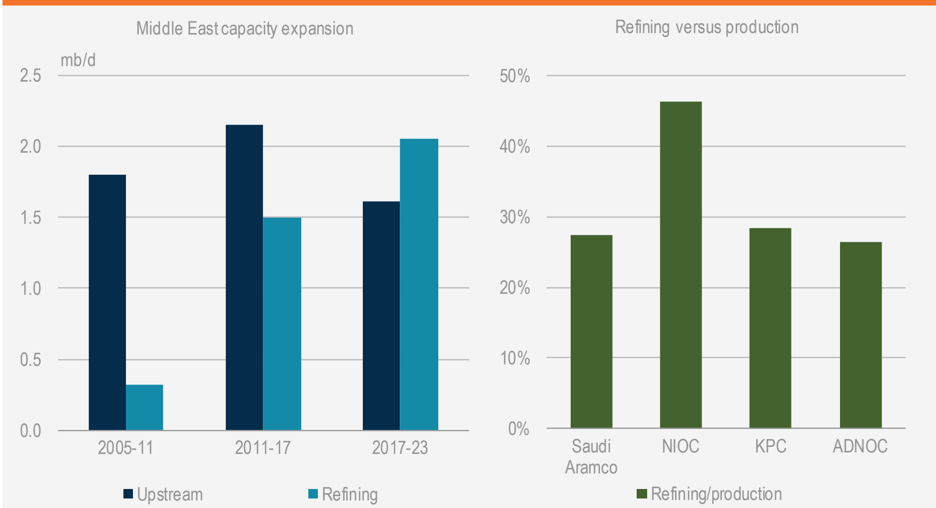
In the **United States**, refinery shutdowns that started in the mid-2000s have been reversed with the help of the shale revolution. US refiners enjoy some of the highest margins in the world, helped by cheap domestic feedstock and surging demand for exports to Mexico and South America. Domestic light tight oil accounts for about 30% of the US Gulf Coast refinery intake, having replaced not only light crude oil imports, but also Venezuelan and Mexican heavy grades. [58] The surge in production of ethane and

---

[58] See IEA (2018f), *Oil 2018: Analysis and Forecasts to 2023*, 16 May 2018, p. 45.

liquefied petroleum gases from shale has led to a petrochemical construction boom (see section below). The latest example of the US downstream dynamism is the recent announcement of a USD 23 billion acquisition of Andeavor, the country's fifth-largest refiner, by Marathon Petroleum, currently ranked number two. This largest-ever refining merger will allow Marathon Petroleum to overtake Valero to become the largest US domestic refiner with 3 mb/d of capacity, comparable in size to Saudi Aramco's domestic assets. In **Mexico and South America,** underinvestment in refinery maintenance has forced refiners to cut operating rates and resort to product imports. **Brazil's** downstream capacity programme, which was originally targeting 3 mb/d of additions has been dramatically cut back, with no new capacity brought online since 2015. Petrobras also wants to sell its 100 kb/d facility in Texas. Mexico, Venezuela and Brazil have reduced their refining throughput by a combined 1.6 mb/d since 2015, explaining the 2.3 mb/d increase in US refined products exports into this region. With the exception of Brazil, the other two countries have also seen lower crude output, and the reduction in domestic crude oil use has helped to maintain crude exports.

Figure 1.46 Oil refining and crude oil production capacity expansion and production ratios in the Middle East



Middle East producers have accelerated downstream capacity additions in a bid to diversify oil revenue streams and exploit downstream opportunities.

Notes: NIOC = National Iranian Oil Company; KPC = Kuwait Petroleum Corporation; ADNOC = Abu Dhabi National Oil Company.
Source: Based on IEA Oil Market Report.

Africa has also suffered from a lack of investment in its ageing refining industry, creating opportunities for both European and US product exporters. The only notable investment is a major refinery upgrade in Egypt and a small addition in Cameroon, both completed this year, as well as the construction of a new 500 kb/d refinery at Lekki in Nigeria, which is due to come on line in the next two years. Sonatrach has also agreed to purchase ExxonMobil's 180 kb/d refinery in Sicily given the delays in its own capacity expansion programme at home. In **Russia**, the recent focus of refining investment has been on secondary processing such as cracking and desulphurisation units to increase clean product yields. Fuel oil yields were above 20% on average prior to the start of a massive, government-mandated modernisation programme, but have already fallen below 17% (though this is still high compared with the global average).

Asia continues to be the global leader in refining capacity additions to meet growing demand. Despite sitting on some 4 mb/d of unused distillation capacity, more than any other country in the world, China continues to build new refineries. More than half of the unused capacity is in landlocked provinces, where crude supply and product movement logistics are complicated. Instead, new and better-equipped facilities are being built in the logistically advantageous coastal provinces. The only greenfield project that came on line in 2017 was CNPC's 260 kb/d refinery in Yunnan province, which has a dedicated 800 km pipeline to deliver crude oil from a port in Myanmar. The role of Chinese independent refiners has increased after the partial liberalisation of crude oil imports and refining in 2016. Some of the largest new sites are being built by independent refiners, sometimes in co-operation with local governments and foreign oil companies. The independents have also been adding secondary units to improve the quality of fuel output.

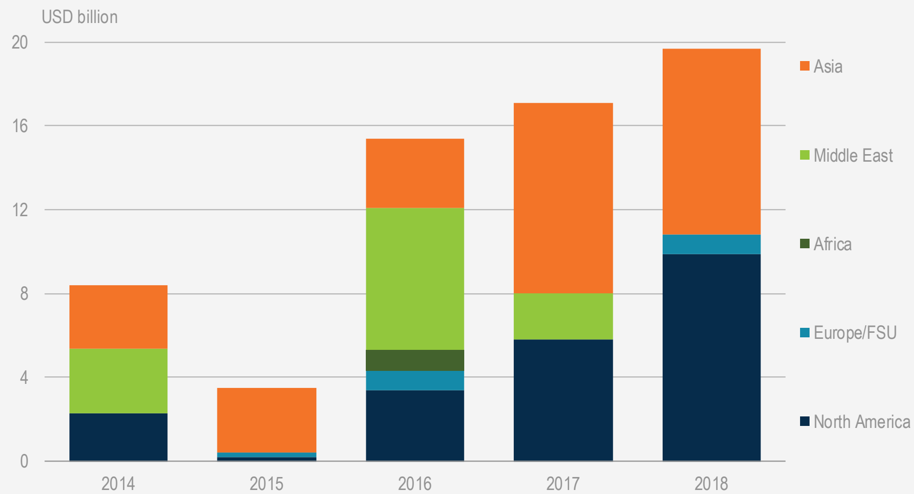
India has also seen a relative slowdown in construction of greenfield refineries, as most of the largest projects have been completed. Recent investments have focused on capacity extensions at existing refineries. Elsewhere in Asia, the only notable additions in 2017 were condensate splitters in South Korea and Chinese Taipei, while Japanese refiners concluded the second phase of a government-mandated capacity optimisation programme by shutting down another 250 kb/d.

United States leads investment in petrochemicals

Investment in petrochemicals – which is closely tied to oil refining and production of natural gas liquids (NGLs) – continues on a brisk upward trajectory, following a temporary downturn in 2015, driven by strong demand growth, especially in Asia. Total investment is set to reach almost USD 20 billion in 2018, a rise of 15% (Figure 1.47). Asia and North America each account for close to half of global investment in 2018, with Europe/Eurasia taking the remaining share.

Condensate splitter additions are one of the manifestations of the growing petrochemical orientation of the refining industry, as usually they are geared to produce naphtha to feed crackers. Moreover, almost all the greenfield refining sites under construction or consideration include petrochemical units. Globally, NGLs (ethane, LPG and natural gasoline) account for more than half of feedstock input, in volume terms, with the share of naphtha and other refinery products less than half. But three-quarters of global naphtha feedstock consumption is in Asia, where NGL output is only 1 mb/d, far below the regional feedstock requirement. This is why the level of refinery/petrochemical integration is higher in Asia compared with other regions. In China, more than three-quarters of ethylene cracking capacity is owned by refineries, for example.

Figure 1.47 Global petrochemical investment



Regions with either low-cost feedstocks or growing demand drive the petrochemical investments boom.

Notes: Investments into olefins capacity only. In China, methanol-to-olefins and coal-to-olefins projects are included. Based on overnight investments.

While steam cracking of naphtha, LPG or ethane into ethylene and propylene is the traditional route for integrating petrochemicals into oil refining operations, oil companies are more and more interested in bypassing the refining route. This is especially the case in the United States, which has recently overtaken the Middle East and Asia for petrochemical investment for the first time in recent decades. The availability of cheap ethane and LPG from shale oil and gas production provides attractive petrochemical returns. Several oil majors have built or are building ethane crackers on the US Gulf Coast, lured by heavily discounted prices of abundant feedstocks. The US shale boom has also inspired petrochemical investments in other regions, as US ethane is now being exported to Europe and India, with China likely to become yet another destination.

The resurgent interest in petrochemical projects by oil majors and NOCs alike is probably not just an opportunistic rent-seeking driven by cyclically high petrochemical margins. For many of them, it is a strategic move, where market growth is more assured even in a decarbonising world. In the Sustainable Development Scenario in the latest IEA *World Energy Outlook*, petrochemicals is the only end-use sector that sees any growth in oil demand after 2020. In addition, petrochemical demand generally grows faster than the overall economy. GDP multipliers for gasoline and diesel demand on average are below parity, sometimes as low as 0.4; the ethylene demand multiplier tends to be higher than 1. Unlike the transport sector, oil use in petrochemicals is mostly for feedstock, as a material input, not energy, and as such has few viable and scalable alternatives. In contrast to gasoline or diesel, there are only very few countries with any tax imposed on disposable plastic products. Moreover, the products of the chemical industry contribute in some cases to achieving material and energy efficiency targets via lighter materials or thanks to special insulation and other properties.[59]

Petrochemical integration for oil and gas companies is not a strategy that can work everywhere. For example, Europe is not well-placed to invest in direct cracking of NGLs, as most of the feedstocks are imported. And the level of operational integration is already relatively significant – more than 40% of naphtha steam cracking capacity is owned by refineries. Further increases mean either asset acquisitions from pure petrochemical companies, or investments in new projects, entailing a risk of regional overcapacity.

Investment in LNG liquefaction plants

Investment in new (LNG) liquefaction plants has remained subdued over the last two years as a result of a decreased level of FIDs after the large wave of projects mainly from Australia and United States were sanctioned in the first half of the current decade. According to construction times and expected entrance into operations, those projects will add over 150 bcm of nameplate capacity by 2020, equivalent to almost one third of global liquefaction capacity at the end of 2017. Spending on LNG peaked in 2014 and 2015 at around USD 35 billion per year and has been declining ever since. It reached USD 20 billion in 2017 (Figure 1.48).[60]

On the basis of projects sanctioned at the time of writing, investment is projected to fall to around USD 15 billion in 2018 and, in the absence of new projects, to continue to fall thereafter. Apart from some temporary disruptions caused by Hurricane Harvey, US-projects under construction appear to be advancing as planned. The construction of Yamal LNG in Russia was ahead of schedule despite the challenging geographical conditions

[59] A more in-depth discussion of the sector's prospects will be included in the upcoming IEA report entitled, *The Future of Petrochemicals*, (IEA, 2018g) to be released in September 2018.

[60] Investment estimates for LNG liquefaction terminals represent annual project spending. Upstream components of integrated projects are not included.

and started operations in December 2017. On the other hand, there were further project delays at some Australian projects, although most of those under development are expected to be on line by the end of 2018.

Given the current overcapacity in the market, many companies have been adopting a wait-and-see approach to new LNG investments. This is consistent with the reduced incentive to embark on large and multi-billion dollar projects due to financial constraints affecting the upstream oil and gas sector (see above). Companies are increasingly focusing on smaller, modular and short-cycle projects. Since mid-2016, when BP sanctioned Phase III of Tangguh LNG plant in Indonesia, only three new liquefaction plants have received a FID. They include Eni's USD 4.7 billion 3.4 Mt/year Floating LNG Coral project, in Mozambique, which will exploit a small portion of the large resource base discovered offshore East Africa.[61] The choice of the floating technology minimalizes the complex engineering conducted in remote locations which is often the source of project management problems. Another technological solution for the "small, short cycle" strategy is modular LNG. The first such project using several 0.2 Mt/year size factory-manufactured modules started construction in late 2016 at Elba Island in the United States. In May 2018, Cheniere Energy announced it was proceeding with its Corpus Christi Phase 2 plant, which includes the addition of another 6 bcm per year liquefaction train to the two already commissioned.

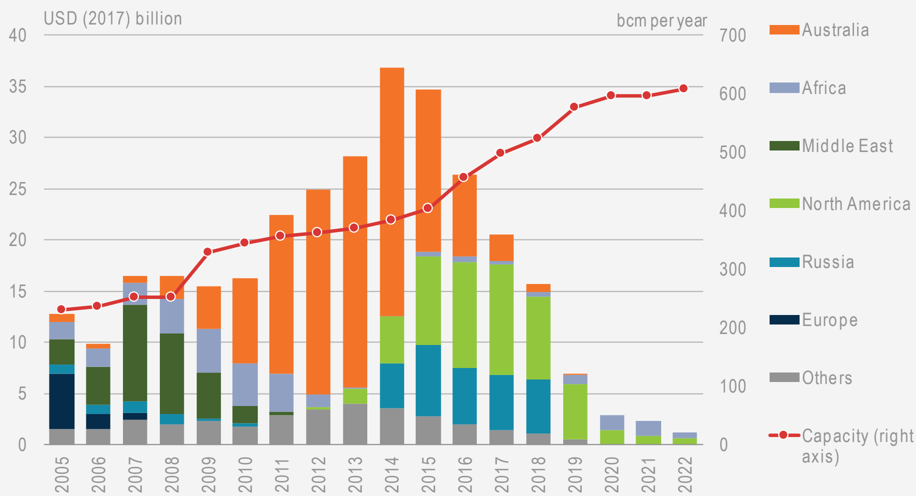
Global LNG trade expanded at a record rate of 11%, or almost 40 bcm, in 2017. All regions contributed to LNG growth trade, with China emerging as fast-growing region as a result of policies aimed to improve its air quality incentivising a progressive coal-to-gas shift. Other key LNG-importing regions including Europe and Korea experienced a significant increase of LNG volumes, while Japan's imports in 2017 were flat. Several new LNG plants are under consideration, with the bulk of those in pre-FID stage concentrated in the United States, Qatar, Australia, Canada and Mozambique. In the United States, four projects have been already approved but no construction works have started at the time of writing. Following its decision in early 2017 to lift the moratorium on expanding its super-giant North Field, Qatar confirmed in February 2018 its intention to expand its LNG capacity from 77 Mt to 100 Mt (about 135 bcm per year) through the construction of three new 7.8 Mt LNG trains to come into operation by the end of 2023.[62] Given its very prolific resource basis and low costs, additional volumes from Qatar would be well-placed to compete in international LNG markets.

[61] ExxonMobil's acquisition of a 25% stake in Mozambique's Area 4 from Eni in December 2017 and indications coming from ExxonMobil's strategy guidance released in April 2018 suggest that a decision on sanctioning a large LNG onshore plant in East Africa will be likely taken soon.

[62] Qatar has also recently awarded contracts propaedeutic to the commencement of a drilling campaign in 2019.

However, although the world's gas demand and global LNG trade is expected to increase substantially in the medium to long term, companies continue to implement a cautious approach in embarking into new projects, due also to buyers' reluctance to commit to new long-term contracts. In the absence of the sanctioning of new LNG liquefaction projects over the next 12-18 months, the LNG market could significantly tighten by 2023 (IEA, 2018h).

Figure 1.48 World LNG liquefaction investment by country/region



Spending on LNG plants peaked in 2014 at around USD 35 billion per year and has been declining ever since, with the completion of the wave of projects sanctioned in the early 2010s.

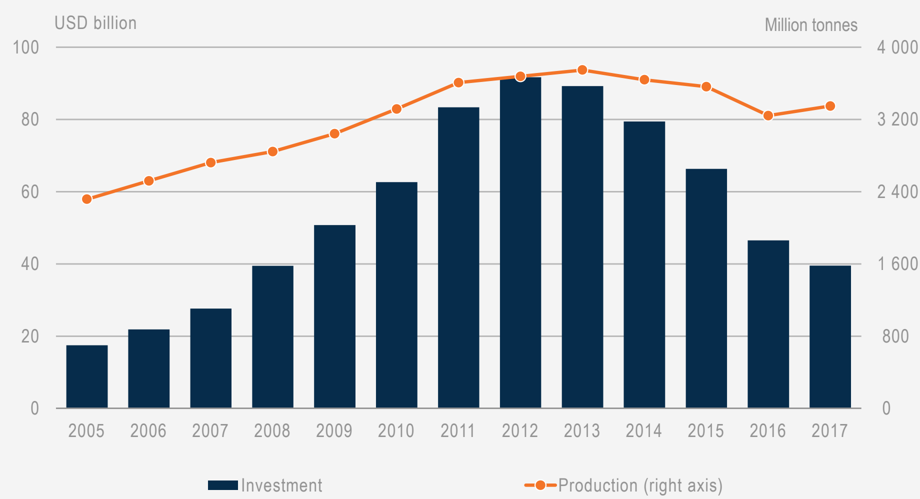
Note: The investment estimates shown here correspond to the actual capital spending in the year that it occurs and are calculated considering 49 projects sanctioned since 2000 up to June 2018.
Sources: IEA analysis based on company reports and Goldman Sachs data.

Investment in the coal sector

Despite two years of higher prices, global investment in the coal industry sector remains depressed. Global investment in coal mining and infrastructure in 2017 was USD 79 billion — 13% less than in 2016. China, which dominates the global coal industry, is the main driver of this trend. Chinese capital spending in coal mining and washing totalled USD 40 billion (CNY 267 billion) in 2017, down 15%, though this was a smaller decline than the 30% fall in 2016 (Figure 1.49).

The continuing reluctance on the part of coal investors is partly because of the risks of oversupply as a natural part of the "boom and bust" cycles. But the main threat for the coal industry comes from risks associated with technological development, including falling costs of renewables, and the potential policy and regulatory changes that could put a brake on coal demand. Due to its high carbon intensity and competition with other electricity-generating technologies, thermal coal is exceptionally exposed to climate policy: in the IEA SDS, coal demand declines by more than half by 2040 (IEA, 2017b). While overall the energy system is not yet on an SDS pathway, the prospect of stronger policies and intensifying technological competition increasingly influences investment decisions. It is quite illustrative in this regard that some of the coal-producing companies report to their shareholders the possibility that coal assets could become "stranded". Moreover, major banks especially from Europe are increasingly reluctant to lend to coal projects, and a broadening group of equity investors refuse to hold shares in mining companies whose business is dominated by coal.

Figure 1.49 Investment in coal mining/washing and production in China



Coal supply investment in China declined in 2017 for the fifth consecutive year, after a decade of continuous growth.

Source: IEA analysis on data from China's National Bureau of Statistics.

Another factor making investors cautious – indeed, this concern is not only about coal, but also refers to other commodities – is China's market dominance. On the one hand, as proved in the past, policy changes in China have far-reaching consequences for the global market. On the other hand, uncertainty on future coal demand in China persists, but it is generally accepted that the era of sustained growth of coal in China is over. India, once considered a potential replacement of China in the seaborne market, does not offer reasons for optimism for the coal exporters, owing to the government's push to reduce imports as much as possible.

The Chinese coal sector is undergoing an ambitious reform trying to increase safety, reduce costs and improve profitability. This has forced the closure of inefficient old mines and their replacement with modern capacity. More than 3 000 mines have been closed since 2015. In 2017, more than 180 Mt per year of capacity was shut down, following closure of 290 Mt in 2016. Around 200 Mt of new capacity came on line in 2017.

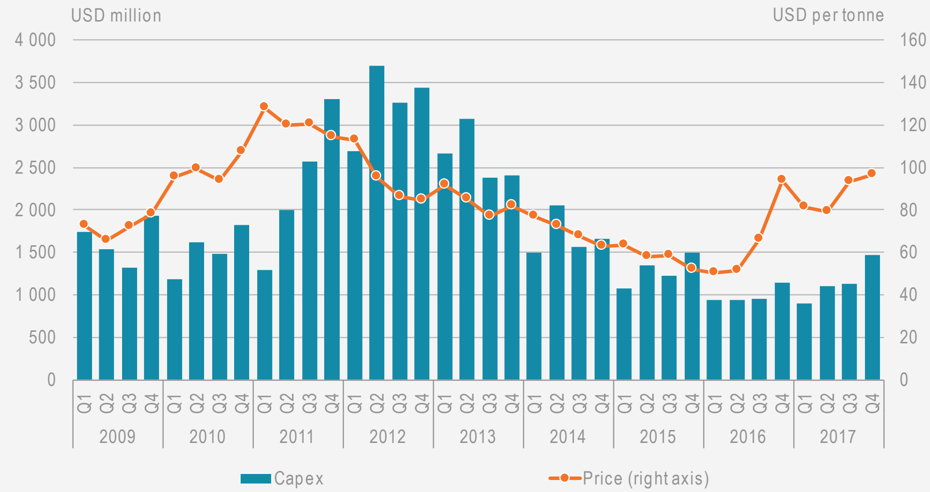
In India, the government is sticking with its ambitious targets to increase coal output. The cornerstone of this strategy is state-owned Coal India, which currently accounts for 80% of domestic output. It has set a target of increasing production in the coming years to 1 billion tonnes (Bt) per year by 2020 from 560 Mt in 2017. The government's target for national production is 1.5 Bt. Reaching this target requires significant investment in coal mining and washing.

Investment trends in Australia, the world's largest coal exporter by energy and value, are indicative of those in other export-oriented producers. Capital expenditure more than doubled in 2012 compared with 2009-10 levels, driven by high prices and the expectations of sustained growth in exports to China (Figure 1.50). But when prices dropped in 2014, investment held up to some extent as projects under development were completed. Once projects were commissioned, few new projects were launched and capital spending slumped. There was a small rebound in 2017, but investment remains far below the levels of 2011-13. Whereas both demand and prices have been strong in 2017, investments did not follow. Although profits returned to the sector, after a few years of losses producers have focused on reducing debt and paying dividends to their shareholders rather than expanding capacity. The few that are increasing capacity are pursuing brownfield expansions and avoiding the risks associated with greenfield developments, which require large amounts of capital for new infrastructure.

In contrast to investment, mergers and acquisitions (M&A) in the global coal sector increased substantially in 2017, reaching USD 8.5 billion – more than double the 2016 level. Contrary to the big M&A deals at the beginning of this decade, when the goal was to cash in on the Chinese-driven super-cycle, the main driver for a growing number of companies is asset divestment.

Rio Tinto, which in 2017 sold its Hunter Valley Operations and this year has sold the rest of its coal assets, is becoming the first major international miner to exit coal completely. Anglo American, once believed to be following the same strategy following the sales of the Drayton and Eskom-tied mines in South Africa and the New Largo project, recently suspended sales of coal assets. Among the big diversified mining companies, only Glencore seems to be willing to expand its coal business, as proven by the recent USD 1.7 billion purchase of the Hail Creek mine from Rio Tinto. Interest from buyers is focused on producing assets rather than whole projects, another indication that risks and uncertainties associated with the future of coal markets are making investors cautious about committing to greenfield developments.

Figure 1.50 Investment in coal and prices in Australia



Investment in Australian coal remains far below the levels of 2011-13 despite the recent rebound in prices, as producers focus on reducing debt and paying dividends to their shareholders.

Source: IEA analysis on data from the Australian Bureau of Statistics.

References

Bloomberg LP (2018), Bloomberg Terminal (accessed 2 July 2018).

Bolinger, M., J. Seel and K.H. LaCommare (2017), *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, Lawrence Berkeley National Laboratory (LBNL), Berkeley.

BSRIA (Building Services Research and Information Association) (2018), *Heat Pump World Overview 2017/2018*, Bracknell.

China News (2017), "China's electric bicycle has 250 million stock", retrieved from *China News*, www.chinanews.com/sh/2017/03-15/8174691.shtml.

Clean Horizon (2018), dataset provided to the IEA.

CoalSwarm (2018), *Global Coal Plant Tracker*, CoalSwarm, San Fransisco, http://coalswarm.org/trackers/india-coal-plant-tracker-map-and-table/.

EC (2018), "Proposal for post-2020 CO_2 targets for cars and vans", https://ec.europa.eu/clima/policies/transport/vehicles/proposal_en (accessed 6 June 2018).

EESL (2018), *Detailed invitation for bids for procurement of 10,000 nos. of electric car including complete system warranty under faster adoption & manufacturing of electric vehicle in India of MNRE govt. of India*, New Delhi, https://www.eeslindia.org/DMS/Procurement%20of%2010000of%20Electric%20Car.pdf (accessed 3 July 2018).

EMMY (Registre National des Certificats d'Economie d'Energie) (2018), "Cotation du kWh cumac" [Ratings of kWh], EMMY [National Register of Energy Saving Certificates], Paris, www.emmy.fr/public/donnees-mensuelles?precarite=false, (accessed 4 July 2018).

Eto, J. (2017), *The National Cost of power Interruptions to Electricity Customer – A Revised Update*, Distribution Reliability Working Group 2017 IEEE PES Joint Technical Committee Meeting, New Orleans.

GME (Gestore Mercati Energetici [Energy Market Manager]) (2018), *Energy Efficiency Certificates – Sessions* (database), GME, Rome, www.mercatoelettrico.org/En/Tools/Accessodati.aspx?ReturnUrl=%2fEn%2fStatistiche%2fTEE%2fStatisticheTEE.aspx (accessed 4 July 2018).

Gnana, J. (2018) "Saudi Arabia shortlists bidders for first solar power project", The National, Abu Dhabi.

IAEA (International Atomic Energy Agency) (2018), *Power Reactor Information System (PRIS)*, IAEA, Vienna, Austria, www.iaea.org/pris/.

IEA (International Energy Agency) (2018a), *The Future of Cooling: Opportunities for Energy-Efficient Air Conditioning*, OECD/IEA, Paris, www.iea.org/cooling/.

IEA (2018b), *Global EV Outlook 2018*, OECD/IEA, Paris, www.iea.org/gevo2018/.

IEA (2018c), *Nordic EV Outlook 2018*, OECD/IEA, Paris, www.iea.org/publications/freepublications/publication/NordicEVOutlook2018.pdf.

IEA (2018d), *Renewables 2018: Analysis and Forecasts to 2022*, OECD/IEA, Paris, forthcoming.

IEA (2018e), *Status of Power System Transformation 2018,* OECD/IEA, Paris, https://webstore.iea.org/status-of-power-system-transformation-2018.

IEA (2018f), *Oil 2018: Analysis and Forecasts to 2023*, OECD/IEA, Paris, www.iea.org/oilmarketreport/omrpublic/.

IEA (2018g), *The Future of Petrochemicals*, OECD/IEA, Paris, forthcoming.

IEA (2018h), *Gas 2018: Analysis and Forecasts to 2023,* OECD/IEA, Paris, www.iea.org/gas2018/.

IEA (2017a), *World Energy Investment 2017*, OECD/IEA, Paris, www.iea.org/publications/wei2017/.

IEA (2017b), *Renewables 2017: Analysis and Forecasts to 2022*, OECD/IEA, Paris, www.iea.org/publications/renewables2017/.

IEA (2017c), *World Energy Outlook 2017*, OECD/IEA, Paris, www.iea.org/weo2017/.

IEA (2017d), *Digitalization & Energy*, OECD/IEA, Paris, www.iea.org/digital/.

IEA (2017e), *WEO 2017 Special Report: Energy Access Outlook,* OECD/IEA, Paris, www.iea.org/energyaccess/.

IEA-PVPS (IEA Photovoltaic Power Systems Programme) (2017), *National Survey Report of PV Power Applications in China 2016*, OECD/IEA, Paris, http://iea-pvps.org/index.php?id=93&no_cache=1&tx_damfrontend_pi1[showUid]=822&tx_damfrontend_pi1[backPid]=93.

IHS Markit (2018), *Vehicle Registrations and Other Characteristics at Model Level* (database), IHS Markit, London.

IRENA (International Renewable Energy Agency) (2018), *IRENA Renewable Costing Alliance*, dataset provided to the IEA, www.irena.org/costs/IRENA-Renewable-Costing-Alliance.

Machinchick, T. and B. Freas (2017), *Energy Efficient Buildings Global Outlook*, Navigant Research, Chicago, www.navigantresearch.com/research/energy-efficient-buildings-global-outlook.

Marklines (2018), "Automotive industry portal", www.marklines.com/portal_top_en.html.

McCoy Power Reports (2018), dataset, McCoy Power Reports, Richmond.

MEPS (2018), *Global Composite Steel Price Index*, MEPS International Ltd, Sheffield.

MIIT (Ministry of Industry and Information Technology of the People's Republic of China) (2018), *Deepen Structural Reform on the Supply Side and Create a New Situation for the High-quality Development of China's Iron and Steel Industry*, MIIT, Beijing, www.miit.gov.cn/n1146290/n1146402/n1146440/c6001246/content.html (accessed 1 June 2018).

MIIT (2017), "Parallel management regulation for corporate average fuel consumption and new energy vehicle credits for passenger cars", retrieved from www.miit.gov.cn/newweb/n1146295/n1146557/n1146624/c5824932/content.html (accessed 4 July 2018).

NEA/IEA/OECD (Nuclear Energy Agency; Organisation for Economic Co-operation and Development) (2015), *Projected Costs of Generating Electricity 2015*, OECD Publishing, Paris, https://doi.org/10.1787/cost_electricity-2015-en.

NEA/IEA/OECD (2010), *Projected Costs of Generating Electricity 2010*, OECD Publishing, Paris. https://doi.org/10.1787/9789264084315-en.

OECD (2018), *Recent Developments in Steelmaking Capacity*, OECD Publishing, Paris, www.oecd.org/industry/steelcapacity.htm (accessed 4 July 2018).

OECD/NEA (2012), *The Economics of Long-term Operation of Nuclear Power Plants*, Nuclear Development, OECD Publishing, Paris, https://doi.org/10.1787/9789264992054-en.

Platts (2018), *World Electric Power Plants Database*, Platts, Washington, D.C.

Rystad Energy (2018), *UCube* (database), Rystad (accessed 14 May 2018).

Sicheng, W. (2014), *Announcement of the New Solar PV Subsidy Policy Promising But More Detailed Rules Expected to Guarantee Smooth Implementation*, Energy Research Institute of National Development and Reform Commission, Beijing.

Stahlinstitut VDEh [Steel Institute] (2018), Extract from PLANTFACTS (database), Stahlinstitut VDEh, Dusseldorf.

UK BEIS (United Kingdom Department for Business, Energy and Industrial Strategy) (2017), *Non-Domestic RHI and Domestic RHI Monthly Deployment Data*, London.

US BLS (Bureau of Labor Statistics, United States Department of Labor) (2018), *Labor Statistics Database*, https://data.bls.gov/cgi-bin/dsrv?ce (accessed 15 May 2018).

US DOE (United States Department of Energy) (2018), *DOE Global Energy Storage Database*, US DOE, Washington, D.C.

2. Energy financing and funding trends

Highlights

- **More than 90% of energy investment is initially financed from company and household balance sheets**. Project finance makes its biggest contribution in power generation, where it accounts for 17% of investment, but was 20% smaller than in 2012 due to the contraction in thermal power. Project finance for renewables rose moderately, and with more diversification across regions. Rising United States (US) interest rates may impact the attractiveness of highly leveraged structures based on US dollar loans.
- **Although stable over 2016-17, the share of private-led energy investment, in terms of ownership, declined in the past five years**. Despite the growing roles of renewables, where private entities own nearly three-quarters of investments; energy efficiency, which is dominated by private sources; and private-led grid investment, the share of investment from national oil companies and state-owned enterprise (SOE) thermal generators has risen by more. In terms of financing, public financial institutions underpin the largest thermal power investments in emerging economies; nearly all nuclear investments rely on state-backed finance.
- **Despite recent large oil price swings, most upstream oil and gas companies have not changed their approach to financing.** The industry is now on more solid financial footing with a substantial improvement in operating cash flows since late 2016. The largest 20 institutional equity holders continue to expand their stakes in the major oil companies, which rose from 24% in 2014 to 27% in 2017.
- **Higher prices and continuous operational improvements lead the US shale sector to be on track to achieve positive free cash flow in 2018 for the first time ever**, but downside risks remain, due to inflationary pressures and pipeline bottlenecks in the Permian area. Although in decline, the leverage of US shale companies remains high but the average interest rate paid to finance their debt – around 6% – has been stable as the market takes into account the industry's financial improvements.
- **Over 95% of power investment in 2017 was made by companies whose revenues are fully regulated or with mechanisms to manage the revenue risk associated with variable prices on competitive wholesale markets.** Even in wholesale markets where thermal power investments are occurring, revenues are often supplemented by capacity remuneration mechanisms. While most utility-scale renewable investment is underpinned by contracted pricing, outside, half of this was set by competitive mechanisms, outside the People's Republic of China (hereafter, "China"). Offshore wind investment in Europe has benefited from low interest rates and improved risk premiums; lower cost of debt reduced generation costs by nearly 15% over 2013-17.

- **Changing business models and an evolving competitive landscape for utilities are having a big impact on investment in the power sector.** Networks investment is very sensitive to regulation of retail and use-of-system tariffs, which determine the ability of utilities to recover their costs. In some emerging economies, regulated tariffs are still too low to ensure the financial viability of the power system and support investment. Utilities in mature electricity markets are finding that their thermal power generation assets exposed to wholesale market pricing are becoming less profitable or even unprofitable and are seeking profitable opportunities in other areas, such as renewables and networks. The share of acquisitions related to businesses focused on the distribution sector and distributed energy resources rose sharply in 2017.
- **In India, renewable power investment, at nearly USD 20 billion (United States dollars), topped that for fossil fuel generation for the first time in 2017,** driven by a doubling of solar and record wind spending. However, persistent risks – e.g. technology price uncertainty, low power price expectations, availability of land and infrastructure, and unreliable payment by cash-strapped state distribution companies – are hurting investor confidence. Better risk management, through policy reforms and limited financial measures, would enhance the financing picture.
- **The green bond market rose to record levels in 2017, and energy efficiency now accounts for the largest share of energy-related issuance**. The value of green bonds issued primarily for energy efficiency uses nearly tripled to USD 47 billion. Green banks are also playing a growing role, investing USD 430 million in energy efficiency in 2017. To help expand energy efficiency investment to new consumers, financial and regulatory innovations are easing the financing of energy service companies and standardising the accounting for their contracts.

Overview

This chapter examines the financing and funding models driving the energy investments described in Chapter 1. The approach is to track the sources of finance and then to analyse the policy, market and financial factors that influence the allocation of capital within the oil and gas sector and the power sector and for investments in energy efficiency. As such, there is a focus not just on how investments are financed, but also on the business models, government policies and corporate performance that determine how they are funded.

The chapter first examines the sources of finance across all energy investments, assessing the trends for different financial structures, forms of ownership and special topics, such as the role of public financial institutions, capital markets and the impact of a changing interest rate picture. It then explores how oil and gas companies are funding their investments in the face of volatile oil prices, with a particular focus on the financial performance of US shale producers. This is followed by an assessment of trends in remuneration models for power sector investments, with a focus on the interaction of policies, power purchase contracts, and the financing of renewables and nuclear. The

World Energy Investment (*WEI*) series continues to track in depth the financial performance of utilities, which play a crucial role in enabling network and generation investments. This section features a focus on the financing of India's power sector, where generation investments are changing rapidly. Finally, the *WEI* series features, for the first time, an in-depth analysis of the financing of energy efficiency investments, examining the growing role played by energy service companies (ESCOs), green banks and green bonds.

While the analysis largely centres on the primary sources of finance, themes related to the secondary financing of assets and mergers and acquisition activity demonstrate how investors outside the energy sector, as well as energy companies active across sectors, can provide a supplementary source of finance, which can influence the direction of physical investment. This analysis is based on reported data on financial transactions, supplemented with sectoral knowledge. Given the difficulties in synthesising complex financial data, which are not always complete or transparent, the results should be seen as providing a broad indication of trends.

Global trends in energy financing

Sources of finance for new investments

The primary financing of energy investments continues to come largely from capital incorporated into a company's balance sheet or from private individuals' own assets (Box 2.1). In 2017, balance sheets accounted for 94% of the USD 1.8 trillion invested globally in energy (including energy efficiency), supported by the use of retained earnings or savings as well as corporate fundraising through borrowing or equity. The rest came from project finance structures, where risks are shared among funding providers in vehicles largely held off the balance sheet of the project owners (Figure 2.1).[1] These shares have remained broadly stable in recent years. Public sources, such as state-owned enterprises (SOEs), accounted for 42% of the capital invested in energy projects in 2017, flat from 2016. Over the past five years, even as private-led investment in renewables, energy efficiency and electricity infrastructure has risen, the contribution of national oil companies (NOCs) and SOEs in thermal generation[2] has grown by more (see "the share of private-led energy investment has declined" below).

[1] Based on disclosed deals. The true size of the market may be significantly larger since some deals are not disclosed. A description of the methodology and the data sources used to estimate all sources of finance can be found at www.iea.org/investment .

[2] Thermal power generation refers to coal, gas and oil-fired generation and nuclear power.

Box 2.1 Primary sources of finance for energy investment

WEI broadly categorises the sources of finance for new energy assets into balance sheet financing and project financing. This provides an indication of the importance of earnings and capital fundraising in financing investment.

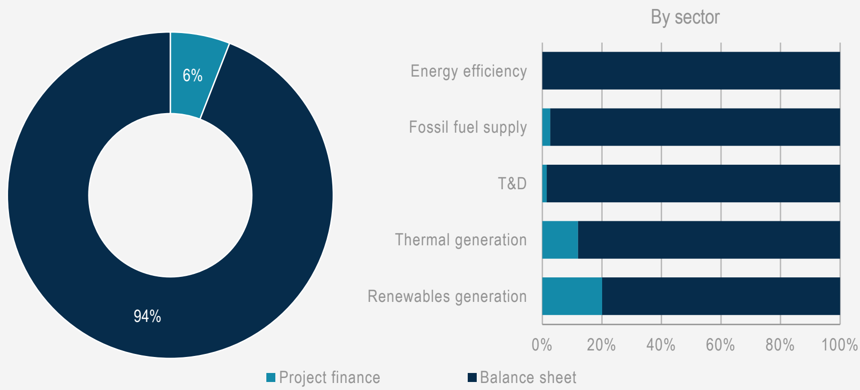
Balance sheet financing involves the explicit financing of assets on a company's balance sheet using retained earnings from business activities, including those with regulated revenues, as well as corporate debt and equity issuance in capital markets. To some extent, it measures the degree to which a company self-finances its assets, though balance sheets also serve as intermediaries for raising capital from external sources. In this analysis, balance sheet financing includes household spending financed from savings and loans, public financing from tax revenues and bonds, and investments made by holding companies, such as yieldcos, master limited partnerships and real estate investment trusts. The funds available from this type of financing depend on the business performance and creditworthiness of the entire corporate entity rather than on an individual energy project.

Project financing involves external lenders – including commercial banks, development banks and infrastructure funds – sharing risks with the sponsor of the project. It can also involve fundraising from the debt capital markets with asset-backed project bonds. In practice, project finance is generally used in the case of complex and large projects where the industry may be relatively less mature, but financiers have a high level of understanding of the government policy that underpins the business model. These financing structures are generally more complex than investments made on a balance sheet. They often involve non-recourse or limited-recourse loans where lenders provide funding on a project's future cash flow and have no or limited recourse to liability of the project parent companies. However, some project finance transactions are also made by investors without the use of debt.

In the fossil fuel supply sector, over 95% of investment, or more than USD 700 billion, was financed by company balance sheets in 2017, primarily through operating cash flows supplemented by debt, equity and asset sales (Figure 2.1). In the upstream oil and gas industry, which accounts for most fossil fuel supply investment, balance sheet financing is usually preferred due to the financial strength of most oil and gas companies, cheaper financing costs and the fact that spending on upstream projects is usually spread over a number of years. US independent shale producers, which have traditionally relied on a high degree of leverage, also rely on asset sales to finance their investments. The perception of the debt market improved for these companies compared with a year ago, in part due to better operational performance.

Balance sheet financing predominates in the refining industry too, because of the relatively high risk associated with volatile crude oil and product prices and the limited use of long-term purchase agreements to secure sales volume and prices. Moreover, most of the new downstream investments are taking place in developing Asia and the Middle East, where project finance is less developed. LNG liquefaction projects, on the other hand, usually raise financing through project finance given the large scale of the initial capital required. About three-quarters of the LNG investment in 2017 was financed in such a way, including the Coral floating LNG development in Mozambique – the only LNG project that obtained a final investment decision (FID) last year. Its project finance structure involves nearly USD 5 billion of debt almost entirely insured by five public export credit agencies (ECAs).

Figure 2.1 Sources of finance in 2017 global energy investment by financing mechanism



The overwhelming bulk of energy investments continue to be financed by company balance sheets while the power sector accounts for nearly all energy investment based on project finance structures.

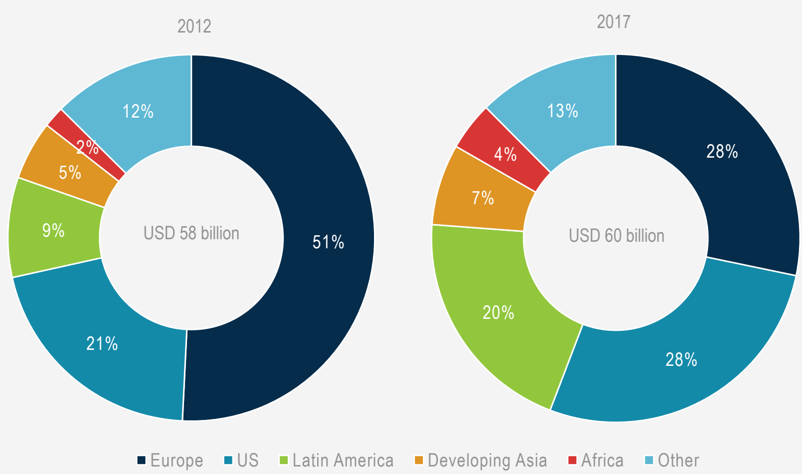
Notes: T&D = electricity transmission and distribution. Fossil fuel supply includes oil and gas upstream, liquefied natural gas (LNG), midstream (storage and transportation), and downstream (refining).

Energy efficiency investments in buildings, transport and industry are nearly all financed by corporate and household balance sheets, supplemented by public financing (ultimately backed by tax revenues), bond issuance and, increasingly, loans from green banks (see "Financing energy efficiency investments" below). Financing provided by ESCOs is playing a larger role and financial and regulatory innovations are enabling their financing and standardising the accounting for their contracts.

The green bond market rose to record levels in 2017, with issuance of USD 160 billion. Those intended to finance or refinance energy efficiency projects accounted for the largest share of energy-related issuance. While many of these bonds were issued to fund companies directly carrying out energy efficiency investments, a financial intermediary, the US Federal National Mortgage Association, was the largest single issuer across all sectors, through its offering of green mortgages. The largest issuance of green bonds across all sectors came from the United States, but there is rapid growth among European markets, China and other emerging economies. In Europe, initiatives such as the EU High-Level Expert Group on Sustainable Finance are seeking to further strengthen the role of environmental factors in the financial system and in financial products.

Electricity remains the leading sector for investment based on project finance structures, even though almost 90% of total financing in that sector is initially provided by balance sheets. The balance sheets of utilities play an important role in power sector investment, both as the primary financers of the electricity network and the main purchasers of bulk power from independent power producers (IPPs) as well as direct investors in generation. In the power sector, project finance for renewables was particularly robust in 2017, in part due to its growing use in offshore wind investments in Europe as well as a larger role in emerging economies, boosted by policies to help manage risks. Access to both direct and indirect government finance remains vital for investments in nuclear power, with nearly 90% of investment decisions since 2000 based on balance sheet finance by state-owned power companies and equipment suppliers. Project finance for renewable power grows, but falls for thermal generation.

Figure 2.2 Project finance for renewable electricity investment by region



Project finance for renewable power has increased slightly in absolute terms and its share of total investment has been stable, with growing importance in the emerging economies.

The value of project finance transactions relating to global energy investment in 2017 amounted to around USD 100 billion – a fall of one-quarter compared with 2016 and a third lower than five years ago. The decline is due to a sharp fall in project financing of thermal generation while that for renewable power rose. Over the past five years, primary financing through project finance has averaged around USD 200 billion across all sectors of the global economy, with energy projects accounting for roughly 60%.

While total investment in thermal power generation increased marginally between 2012 and 2017, the share of project finance in that investment declined by half to under

USD 20 billion. Coal-fired generation accounted for three-quarters of the decline, as new investment in the technology halted in the United States, where project finance schemes were often used for financing. The use of project finance also fell more rapidly than the decline in total investment in India and Indonesia. In these countries, this is thought to reflect difficulties faced by generators stemming from declining utilisation rates, constraints on the availability of international commercial debt finance for coal-related investments in general, and insufficient progress in addressing risks related to reliable power purchase from IPPs by cash-strapped utilities. For the largest thermal generation projects in emerging economies that were sanctioned in 2017, public finance institutions played an important role in providing direct or indirect financing (Box 2.2).

In renewable power generation, the value of project-financed projects increased by 13% in 2017 to USD 60 billion – 2% higher than in 2012 (Figure 2.2). Project finance contributed 20% of total investment in the renewables sector. In Europe, project finance transactions for onshore wind, solar photovoltaic (PV) and solar thermal declined between 2012 and 2017, but this was partially offset to some degree by a more than doubling in financing for offshore wind projects in Northern Europe to USD 10 billion, as the maturity of the technology increased and risks have fallen thanks to mechanisms such as auctions and the system operator assuming risks related to grid connections.[3] Increasingly active European markets in secondary financing and acquisitions for offshore wind have also emerged, facilitating the refinancing of projects with cheaper debt, which is enhancing the ability of developers to step up investment and reduce the overall cost of generation.

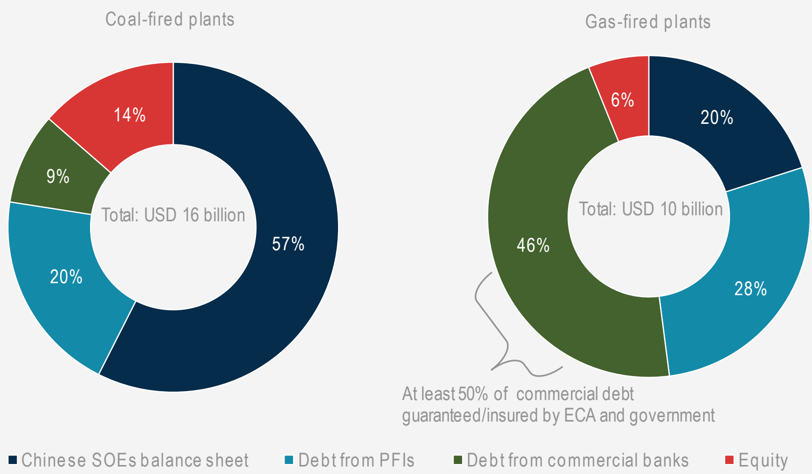
Box 2.2 Public sources of finance underpin large thermal power investments in emerging economies

Financing from public financial institutions (PFIs), such as national development banks and export credit agencies (ECAs) plays an important role in the largest investments in thermal power generation in emerging economies, given their risk profiles and the generally large amount of capital required. For the country providing financing, such projects can also provide opportunities for exporting technology. This is especially the case with coal and gas-fired power plants and LNG projects. In the case of upstream oil and gas developments and LNG projects in emerging economies, financing from foreign PFIs is often provided where the project can bring energy security benefits to the financing country. The role of multilateral development banks (MDBs) is relatively limited in the upstream oil and gas sector apart from exceptional cases involving very underdeveloped countries or reconstruction after a war or a natural disaster.

[3] This is also reflected in lower debt premiums (see below).

In electricity generation, seven out of the ten largest coal-fired plants in terms of capacity that came online in 2017 in emerging markets are located in China. They were all developed by SOEs, benefiting from loans from state-owned policy and commercial banks, such as the Bank of China and the Industrial and Commercial Bank of China, that offer favourable interest rates. The 1.6 gigawatt (GW) Medupi power plant in South Africa was partly financed by the World Bank and African Development Bank as well as a German PFI, which approved the loans for the project in 2009-10. The 1.3 GW Sahiwal power plant in Pakistan was financed with loans arranged by the Industrial and Commercial Bank of China with equity participation of a Chinese IPP. These PFIs not only provide funding but also facilitate external capital flows from commercial banks by offering loan guarantees or insurance, as well as facilitating the participation of the financing country's industry as project sponsor or equipment supplier

Figure 2.3 Sources of financing for the 10 largest power plants that started operation in emerging economies in 2017



Public financial institutions play an important role in providing direct and indirect finance and mobilising private finance for thermal power generation in emerging economies.

The picture is similar in gas-fired power but PFIs mobilise more private capital. Of the ten largest gas-fired plants that came online in 2017 in emerging markets, three are in China. They were developed by SOEs which, again, are well positioned to benefit from cheap financing from state-owned banks. Of the remaining seven plants, three totalling 8 GW of capacity are located in Egypt. With the procurement of gas turbines from a German manufacturer, the finance was arranged by KfW, a German development bank, which facilitated financing from about 15 commercial banks covered by a German ECA and guaranteed by the Egyptian government. The other two are independent water and power plants in Qatar and the United Arab Emirates, with a small part financed by German and Japanese PFIs as well as PFIs from the host country, mobilising more capital from the commercial banks.

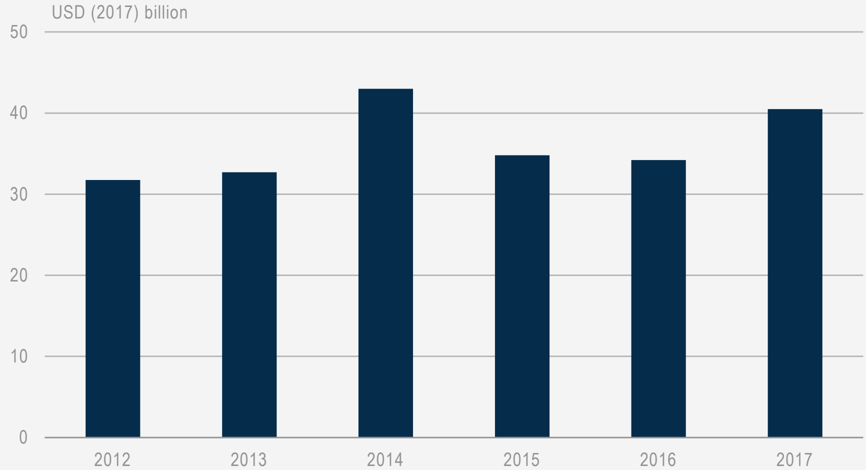
Many LNG liquefaction projects also involve public financial institutions, notably ECAs from LNG consuming countries with policies to enhance the security of energy supply. Out of 17 LNG projects under construction in 2017, at least 11 involve financing by ECAs from Japan, Korea and China, which together are responsible for nearly 60% of global LNG demand. In many cases, companies from the financing country take a stake in the project or sign a purchase agreement for the project output.

In the United States, project financing of renewable power investments increased by about 35% between 2012 and 2017, driven by tax equity financing. Solar PV accounted for most of this increase. By contrast, project financing of wind power declined after 2012, when developers rushed to commission their projects amid the uncertainty over the extension of renewable electricity production tax credit. Tax code changes in late 2017 may affect the appetite of tax equity investors, thereby pushing down project finance transactions. Solar PV projects backed by project finance schemes increased in emerging markets, notably India and the Middle East. In these countries, supportive policies and contractual structures that guarantee predictable long-term cash flows are generally essential in obtaining access to debt financing. In Latin America, a large hydropower project in Brazil was the main contributor to increased project finance transactions in 2017.

Project finance structures are generally more highly leveraged than with corporate balance sheets, yet they can enjoy a lower financing cost as the cost of debt is inherently lower than the cost of equity. The average debt-to-equity ratio in project finance has generally been around 80:20 for both renewables and thermal power generation projects in the past five years, though in certain sectors it is higher (e.g. utility-scale solar PV in Europe). In offshore wind it is lower, but has increased in recent years. The ratio of debt for electricity sector balance sheets averages around 60%. Nevertheless, rising US interest rates may begin to affect the attractiveness of highly leveraged capital structures based on US dollar-denominated loans (see "The impact of rising US dollar interest rates on energy investments" below).

There are some cases where project bonds – an alternative debt funding avenue in project financing for infrastructure-related projects – are issued to allow project sponsors to tap into funding from the capital markets and institutional investors, though their contribution remains moderate for primary financing, and the use of project bonds is more common in refinancing a project after construction. In the electricity sector, at least about 50 projects raised primary finance of USD 15 billion via bond issues in the five years to 2017. A total of USD 4 billion of power sector investment was provided via project bonds in 2017, including two large-scale transmission line projects in Canada and a coal-fired plant in Malaysia (in the form of an Islamic bond). The use of project bonds as a primary financing instrument remains much more prevalent in the transportation sector, e.g. roads and mass transit systems, than in energy, but they are also becoming more common in the United States for LNG investments that benefit from tolling agreements that generate stable cash flows.

Figure 2.4 Financial commitments for energy investments by the top 7 MDBs



Over the five years to 2017, financial commitments for energy investments by the seven large MDBs climbed by around one-third to USD 40 billion.

Source: Based on annual reports and communication with banks.

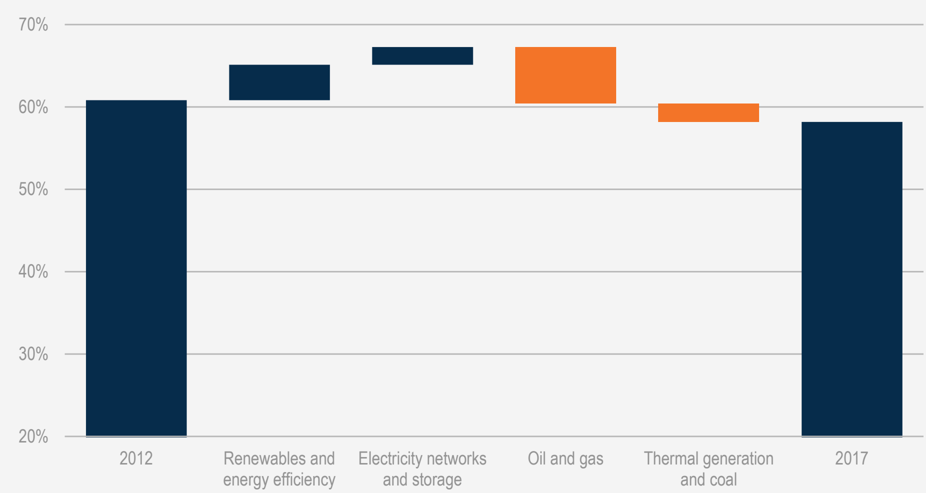
The vast majority of the debt for project finance transactions comes from commercial bank loans, though public finance institutions (PFIs) – including MDBs, bilateral and national development banks, green banks, and ECAs – play a crucial role in catalysing other sources of finance and managing risk, particularly in emerging economies. In the case of fossil fuel-based projects, some MDBs and bilateral development banks explicitly state their strategies to slow down financing over environmental concerns. However, public sources from some national development banks and ECAs still underpin financing for the largest thermal power generation investments in emerging economies, most of which are loans for project finance except in China (Box 2.2). In the energy sector overall, annual financial commitments by the seven large MDBs, mostly in the form of sovereign and non-sovereign lending but also including grant, guarantee and equity, rose by around one-third to USD 40 billion over the five years to 2017 (Figure 2.4).[4]

[4] The seven large MDBs are: the African Development Bank, the Asian Development Bank, the European Bank for Reconstruction and Development, the European Investment Bank, the Inter-American Development Bank Group, the Islamic Development Bank, and the World Bank Group.

The share of private-led energy investment has declined

This report's analysis on the initial ownership of the investment, as a proxy for the type of organisations investing in new energy assets, shows that although remaining stable over 2016-17, the share of private-led energy investment has declined in the past five years due to the increased role of SOEs in some sectors (Figure 2.5). There has been a growing role for renewables, where private entities own nearly three-quarters of investments; energy efficiency, which is dominated by private spending; and private-led grid investments in overall energy investment. But private-led investments in absolute terms fell by 15%. Public sector bodies are playing a strong role in energy investment globally. The share of those bodies, including SOEs, in total energy investment rose from 39% in 2012 to 42% in 2017, while broadly flat from 2016, even as their absolute level amounted to USD 750 billion, about 10% lower than in 2012.

Figure 2.5 Changes in the share of private-led energy investment, 2012-17



Despite a growing role for clean energy and electricity infrastructure led by private actors, the share of energy investment from NOCs and state-owned thermal power rose by more over the past five years.

SOEs in the electricity sector account for a large share of public investment. A sharp decline in investment by Chinese SOEs in coal-fired generation, which dropped by over a third, and networks, which fell more modestly, was the main reason for the fall in the absolute level of total public investment worldwide in 2017 from 2016. However, in emerging markets outside China, the role of SOEs in electricity sector investment increased between 2012 and 2017, with increased investment in thermal generation by SOEs, notably gas-fired plants in Egypt and coal-fired plants in Viet Nam and Pakistan. Investment in coal-fired plants by SOEs in Korea and Poland also increased.

The electricity sector investment by the private sector and consumers declined faster than that of SOEs in 2017 from 2016, mainly due to a decline in capacity additions of coal-fired power in emerging markets such as India, Turkey and the Philippines and thanks to cost reduction in renewables generation globally. Their share in global electricity investment slightly declined to 53% in 2017 from 55% 2016, continuously dropping from 59% in 2012 when there was a significant level of investment in coal-fired power in the United States and coal- and gas-fired power in Europe, where private businesses play a major role. In terms of the overall impact on private-led energy investment, this decline was somewhat offset by a rise in distributed solar PV and an increase in household spending on energy efficiency, even as the private share attributed to total renewable investment remained relatively stable.

In the upstream oil and gas sector, the share of NOCs in total investment worldwide fell by one percentage point to 43% in 2017, as spending in the Middle East and the Russian Federation (hereafter, "Russia"), where NOCs dominate, increased less than in other parts of the world, notably in the United States, where private companies are important (see Chapter 1). This share is still higher than before the oil price collapse in 2014 as large private oil and gas companies, including the major oil companies, cut back spending more heavily in 2015 and 2016.

The impact of rising US dollar interest rates on energy investments

The costs of energy investment are highly influenced by the cost of long-term debt and equity. The determination of financing costs is complex and stems from changes in risk-free rates (i.e. government bond yields) and project-specific risk premiums, among other factors. Interest rates based on the US dollar play a disproportionately important role in setting the cost of financing for energy investors. The United States itself represents 16% of global energy investment. In addition, the US dollar plays a unique role in the global financial system, with energy investment outside the United States being denominated in dollars to a considerable degree. Investments that serve a US dollar-denominated commodity market such as oil or LNG very often rely on US dollar financing. Even for electricity, in emerging countries where financial systems are underdeveloped, US dollar-based project financing for power generation projects is common.

Over the first half of the current decade, energy investment took place in an environment of historically low interest rates, not only in the United States but in the euro area and Japan, as major central banks reacted to the 2008 financial crisis with monetary easing. There are indications that liquidity generated by loose monetary policy fed into debt and equity access of the energy industry.

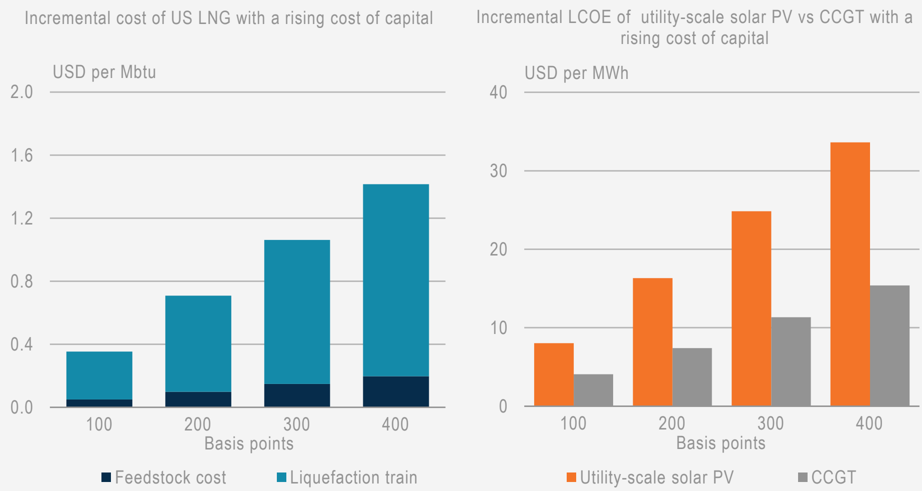
As the world economy recovered from the financial crisis in late 2015, the US Federal Reserve executed its first interest rate hike since the financial crisis, followed by several more in 2017 and early 2018. As growth brought the US economy closer to full employment, financial markets priced-in further rate hikes. The European Central Bank has also tightened its monetary policy, reducing its quantitative easing programmes, and real rates for euro-denominated government bonds have increased. While the normalisation of monetary conditions is likely to be a gradual and uneven process, especially in the case of the US dollar, the prospect of higher future rates may increasingly feed into investment decisions, though rates remain low by historical standards for now. Financial conditions, despite tightening somewhat in the past year, remain broadly accommodative in both the United States and the rest of the world, and leverage remains high (IMF, 2018).

The impact of rising US dollar interest rates will be small and indirect for some energy investments. For example, most investments in upstream oil and gas are made on balance sheet, and major oil companies have an internal "hurdle rate", an expected internal rate of return that is used for evaluating projects financially. None of the majors revised down their hurdle rate during the down cycle of interest rates. This approach to smoothing the cost of capital is likely to persist in the interest rate up cycle. Similarly, government-funded energy projects aimed at improving energy efficiency would be affected only if higher interest rates led to fiscal constraints. The impact of rising interest rates on independent oil and gas companies in the US shale industry may also be small (see "Independent US shale producers" below). At the same time, utilities normally operate with hurdle rate that takes into account the cost of capital plus a surcharge, meaning that their expected internal rate of return may increase with rising interest rates. For investors outside the energy sector, such as pension funds, rising rates could raise the opportunity cost of energy investments in some cases.

Changes in interest rates may have a greater impact on the economics of energy investments that rely more on project finance, such as utility-scale power generation or gas infrastructure (Figure 2.6). Existing LNG projects usually have their proprietary hedging strategies, but projects at the stage before financial close (i.e. when all the project and financing agreements have been signed and all the required conditions contained in them have been met) could be affected as tighter monetary conditions spill over into higher debt costs. Higher rates may also have a bigger impact, both direct and indirect, on low-carbon power generation investments, which are also capital intensive. Nuclear power plants have exceptionally long lead times and project lifetimes, so returns on investments in those plants are very sensitive to the interest rate. But almost all new nuclear developments are undertaken by state-owned vertically integrated utilities (VIUs) relying on finance from state-owned banks, so the impact of US dollar interest rates is probably minor.

With the bulk of distributed solar PV investment coming from the balance sheets of households and non-energy commercial and industrial companies, higher interest rates would raise the opportunity cost of investments if the yield on savings were to increase. Solar leasing schemes, in which high upfront capital spending is funded by corporate borrowing, are also likely to become more expensive with higher interest rates. Higher rates have not affected such schemes appreciably so far: in 2017, issuance of asset-backed securities (ABS) for refinancing existing distributed solar PV installations reached a record high in the United States (Box 2.3).

Figure 2.6 Impact of higher cost of capital on energy projects with USD debt



Rising interest rates are likely to have greater impact on capital intensive infrastructure and power generation investments that rely on project financing, versus those with higher share of operating costs.

Notes: MBtu = million British thermal units; LCOE = levelised cost of energy; CCGT = combined-cycle gas turbine; MWh = megawatt hours. X-axis shows change in the after-tax cost of capital as measured in basis points. 1 basis point = .01 percentage point change.

For utility-scale wind and solar, most investment is backed by long-term contracts or regulated pricing, with project financing accounting for around 20% of the total. The required rates of return for such projects would generally be lower, all other things equal, than projects with exposure to variable wholesale market pricing or those only partially covered by a power purchase agreement (PPA). It remains to be seen how the awarding of PPAs in auctions would be affected by pricing in the impact of higher interest rates, particularly given the prevalence of these mechanisms in emerging economies where different mixtures of US dollar and local currency financing are used, or in markets such as Northern Europe where the cost of debt remains relatively low (see "More diversified financing has boosted offshore wind investment to record levels" below).

Higher interest rates could make it more challenging for renewables to recover their costs through marginal-cost based power pricing, to the extent that generators are exposed to such prices in order to enhance their value from a power system integration perspective. The impact of rising debt financing costs on the generation costs of a new solar PV plant would be higher than the impact on a gas-fired plant due to the higher capital intensity and lower load factor of solar plants (Figure 2.6). In North America, the impact of any change in debt financing costs on generation costs would come from the capital recovery of the plant itself rather than the cost of the fuel.

Rising interest rates could undermine the attractiveness of household investment in energy efficiency, which generally involves an initial capital investment that is then recovered from fuel savings. Higher rates directly increase the costs of that investment. An example of this is a consumer loan to buy a car. In the United States, typical car loan rates collapsed after 2009 and started to recover from 2015, but are still around 300 basis points below 2006 levels. Branding heavily influences car pricing, making price comparisons difficult, but several models such as the Volkswagen Golf have a conventional and an electric version where the main difference is the engine. In a case where the electric version is on average USD 6 000 more expensive, and assuming an average length of car loan, this report calculates that a return of interest rates to 2006 levels would increase the cost of ownership of the electric model by USD 92 per year. Based on typical driving patterns, this is equivalent to a 10 cent per litre increase in the gasoline price or a USD 12 per barrel increase in the price of crude oil. As a result, for a given oil price, rising interest rates improve the relative attractiveness of conventional vehicles.

Key financial indicators for the upstream oil and gas sector

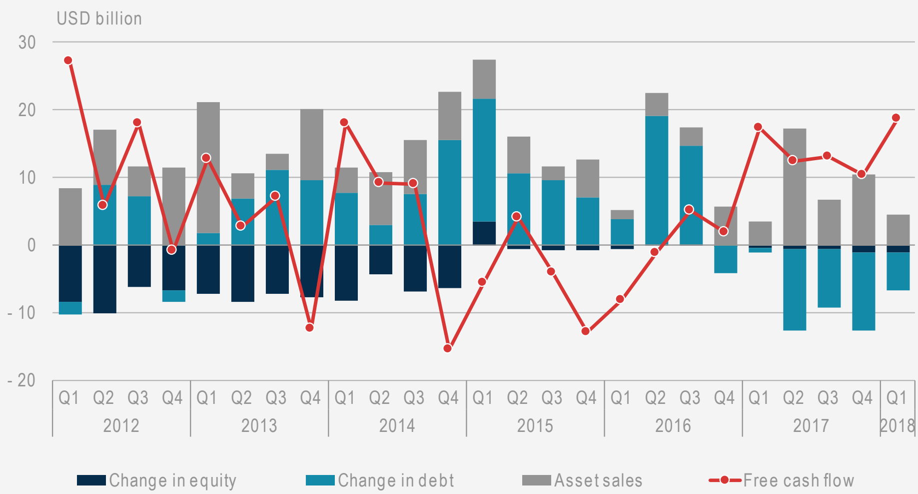
The rollercoaster journey of oil prices over the last four years has not significantly changed the way the upstream oil and gas sector finances its operations, but there have been some notable adjustments in selected parts of the industry. The majors continue to fund their investments primarily through cash flow and have maintained high dividend yields compared with those on equity, though this has come at the price of a rapid rise in debt and leverage. US independents have kept their traditional reliance on high levels of external financing, but the relative weights of debt, asset sales and equity continue to fluctuate with market conditions.

The major oil companies

The major international oil companies are “back to black”, with operating cash flow largely exceeding capital spending and dividends combined. The plunge in crude oil prices in 2014 drove down the majors’ cash flow by 35% in 2015 and 55% in 2016 compared with 2014, but they maintained their dividends per share, resulting in a rise in average dividend yield to 4.6% in 2017 compared with 2.5% for the energy sector as a whole. Total dividend payments remained practically unchanged at USD 10 billion to USD 12 billion per quarter during 2012-17. However, companies were forced to reduce share buybacks from USD 30 billion in 2012 to less than USD 1 billion in 2016, though they rebounded to USD 2.5 billion in 2017. Overall, majors redistributed about USD 370 billion to capital markets during the period 2012-17.

Despite big cuts in capital investment, the lower revenues that resulted from lower oil and gas prices led to negative free cash flow between mid-2014 and the end of 2016. The majors’ considerable efforts to improve efficiency and cut costs, together with higher prices in the second half of 2016 and during 2017, boosted operating cash flow by over 50% in 2017. The acceleration of oil prices in the first part of 2018 led a further improvement in the health of their balance sheets; first-quarter financial results showed the highest level of free cash flow since the first quarter of 2012 (Figure 2.7). Under current conditions, some of the largest companies have been considering raising dividends and plan to increase share buybacks.

Figure 2.7 Sources of finance for major oil companies

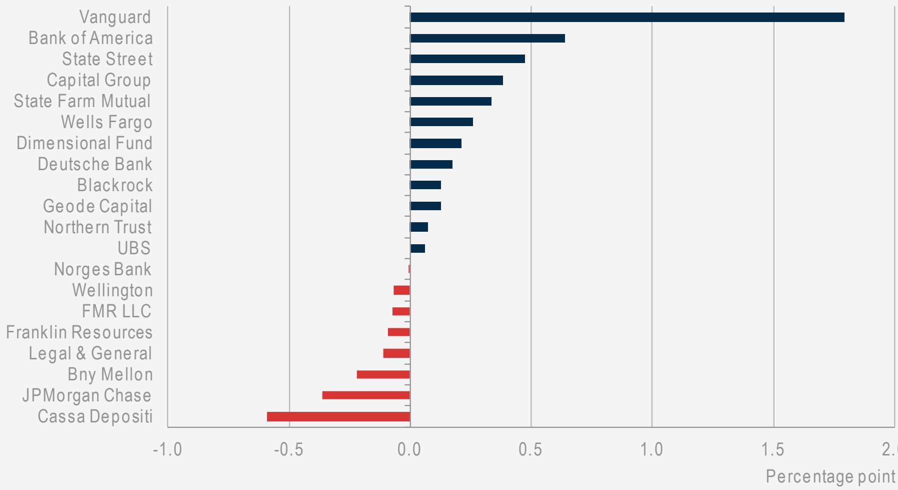


The majors have seen a big improvement in their financial health since mid-2016 thanks to a combination of higher prices, improved efficiency and lower costs.

Notes: Q= quarter. Free cash flow indicates operating cash flow excluding change in working capital less capital expenditure.
Sources: Based on company disclosures and Bloomberg LP (2018), Bloomberg Terminal.

The majors' financial discipline and portfolio restructuring strategies led to a deleveraging of their balance sheets throughout 2017 and the early part of 2018. Several companies embarked on massive divestment programmes, including Shell and ConocoPhillips. Portfolio rationalisation is nothing new for majors, which have been masters of mergers and acquisitions (M&As) over the last decade. After four consecutive years of increasing net debt, which surged by about 2.5 times between the end of 2012 and the end of 2016, companies reduced their net debt position by 14% to USD 214 billion in 2017. While there is an increasing number of shareholder resolutions focusing on the need for companies to diversify their investments towards other energy sources as well as evaluating the risk exposure to potential stranded assets, it appears that the majors remain attractive to equity investors, in part due to high and stable dividends. The shareholdings of the top 20 institutional investors in the majors increased from 24% in 2014 to 27% in 2017 (Figure 2.8).

Figure 2.8 Change in shareholdings in major oil companies of the top 20 investors (2017 versus 2014)



Most of the leading institutional investors have expanded their equity stakes in the majors, encouraged by high and stable dividends.

Source: Based on Bloomberg LP (2018), Bloomberg Terminal.

National oil companies

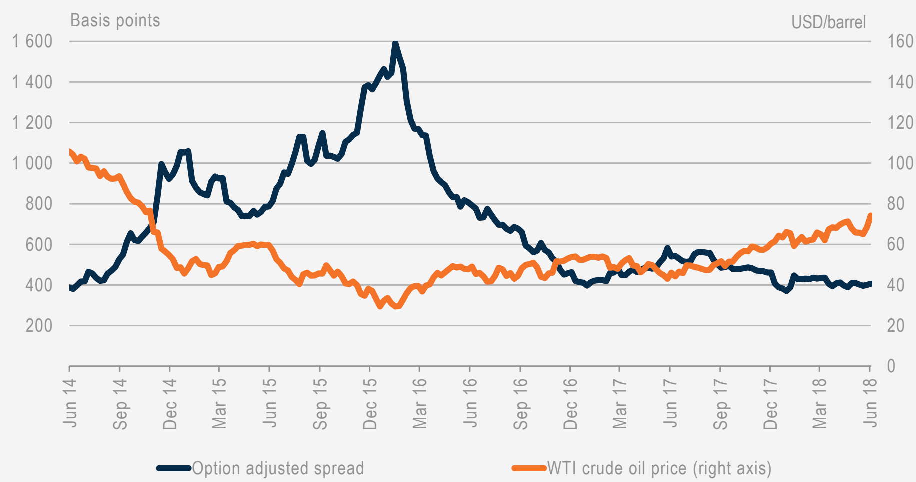
For unlisted NOCs, capital spending is usually controlled by the government, with decisions about how much to invest being affected by broader domestic economic and social priorities. Some of largest Middle East NOCs are targeting inflows of foreign investment in their structure, either through initial public offering (IPO), as in the case of Saudi Aramco and Oman, or through participation with a minority stake in selected parts of their business, as planned by Abu Dhabi National Oil Company (ADNOC) and Qatar Petroleum. Equity raising is emerging as a new source of financing across the region, driven by tighter government budgets and a strategy of business diversification, though its contribution to total financing is expected to remain small.

In Russia, Western sanctions have driven the NOCs there to turn to domestic markets for the lion's share of their financing, launching regular ruble bond issues to fund investment needs, refinance existing loans and cover debt repayments. Russian companies more broadly are increasingly looking to form partnerships with non-Western entities, particularly in China, Saudi Arabia and other Asian and the Middle Eastern countries, to participate in and finance Russian upstream operations and overseas acquisitions.

Independent US shale producers

The financing model underpinning the US shale oil industry is fundamentally different from that of large companies producing predominantly in conventional oil. Small and medium-size independent producers, which dominate the US shale industry, generally have much higher leverage with high levels of debt and hedging.[5] Since its inception, the industry has been characterised by negative free cash flow as expectations of rising production and cost improvements led to continuous overspending in the sector. Over the last few months, the industry as a whole has seen a notable improvement in financial conditions, though the picture varies markedly by company, and the overall health of the industry remains fragile.

Figure 2.9 Option-adjusted spread for US high-yield energy sector corporate bonds and crude oil price



The risk premium that US shale companies have to pay to finance their debt remains correlated with oil prices, but that correlation has weakened over the last two years as financial conditions have improved.

Notes: The option-adjusted spread is weighted by the market value of corporate bonds in the USD high yield energy sector, which is made up largely of shale producers. The spread indicates how much additional return over the risk-free rate (the USD Libor three-month interest rate) is required to compensate for the additional risk associated with those companies.
Source: Based on Bloomberg LP (2018), Bloomberg Terminal.

[5] To protect against commodity price volatility, independents typically hedge a significant portion of their own production through derivatives including swaps and call/put options by fixing a price for future production. While hedging provided relief to financial conditions of companies during the oil price downturn, it has prevented some companies from profiting from higher prices since 2016.

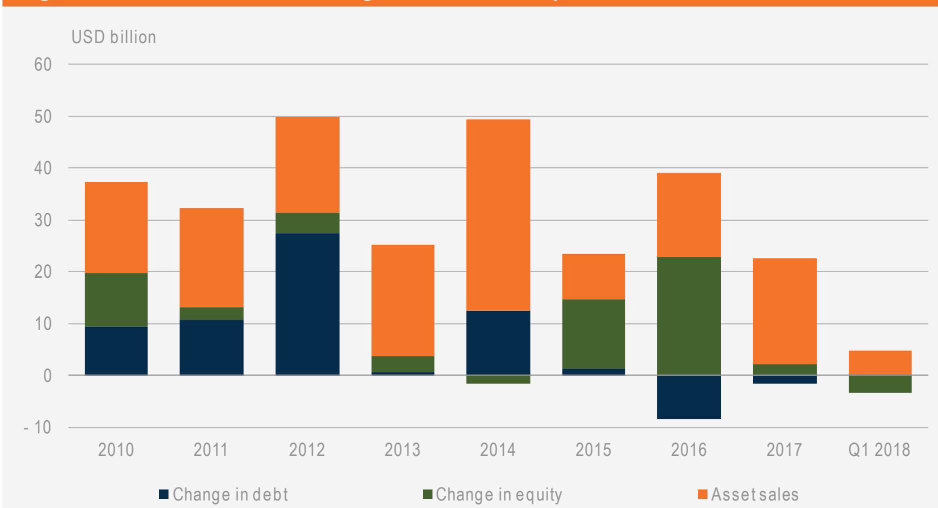
A key question is whether this improvement in financial health is simply the result of higher prices or a change in the way industry operates. While it is difficult to clearly separate elements that are strongly interlinked, the correlation between oil prices and the risk "premium" the corporate bond market applies to high-yield US energy assets, which are dominated by shale companies, suggests that higher prices are only part of the reason (Figure 2.9). Considering the same level of oil price – around USD 60 per barrel on the West Texas intermediate (WTI) exchange – the spread today is on average 300 basis points lower than three years ago to compensate for the risk, indicating a much improved confidence of capital markets towards the sector.

In order to try to assess as precisely as possible the developments of shale industry throughout the decade, this report has identified four distinct phases that have characterised the shale industry since 2010: a start-up phase from 2010 to 2014, a survival phase in 2015 and 2016; a consolidation phase from 2017 and the current situation.

2010-14: The start-up phase

In the 2010-14 period, technology developments and high and stable oil prices triggered a massive investment wave in the US shale sector. Investment more than quadrupled, leading to an eightfold increase in shale oil production, from 0.44 million barrels per day (mb/d) to over 3.6 mb/d – the fastest growth in oil production in a single country since the development of Saudi Arabia's super-giant oilfields in the 1960s.

Figure 2.10 Sources of financing for US shale independents



US independents initially relied heavily on asset sales, the bond markets and equity raising to finance their operations, but the need for external financing has fallen since 2016 with improved cash flow.

Sources: Based on company filings and Bloomberg LP (2018), Bloomberg Terminal.

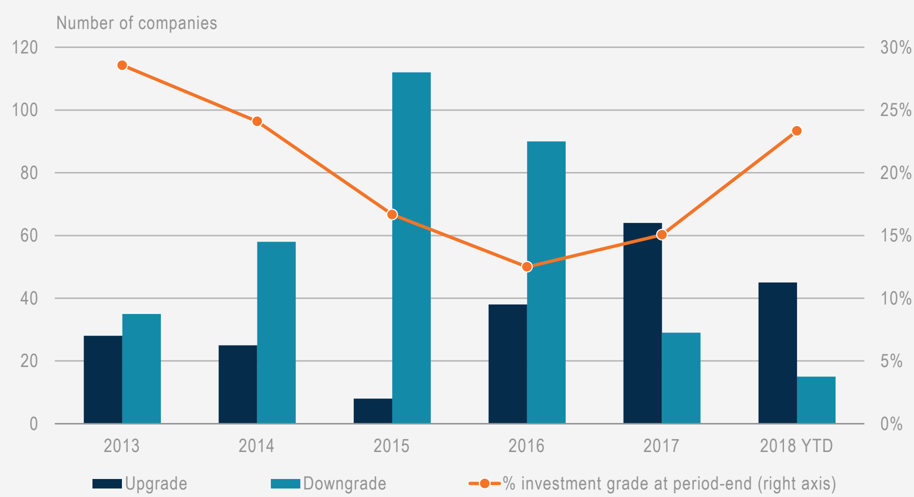
However, the growth came with a huge bill. The sector as a whole generated cumulative negative free cash flow of over USD 200 billion over those five years. Throughout this phase, companies were forced to rely extensively on external sources of financing, predominantly debt and receipts from the sale of non-core assets, in order to finance their operations (Figure 2.10). In addition to issuing bonds, companies benefited from the reserve base lending structure – a bank-syndicated revolving credit facility secured by the companies' oil and gas reserves as collateral. This structure was used heavily by small and medium-sized companies with non-investment credit rating that did not have as easy access to the corporate bond market (Azar, 2017).

The rapid rise of US shale production attracted non-US companies that started to acquire assets as a way of entering the sector. European oil companies, including Shell and Repsol, as well as China National Offshore Oil Corporation (CNOOC) and India's Reliance Industries among many others acquired assets from US independents.

2015-16: The survival phase

The collapse of prices in the second half of 2014 and throughout 2015 and early 2016 had a major impact on the way the shale industry operates. Companies switched to survival mode, focusing on improving efficiency and cutting costs. The number of firms declaring bankruptcy and filling for Chapter 11 protection, a form of bankruptcy involving reorganisation, skyrocketed to almost 100 in 2015-16.

Figure 2.11 Change in credit rating of US exploration and production companies and share of companies rated at investment grade



The number of credit downgrades far exceeded upgrades for US oil companies in 2015-2016, but the trend has reverted since 2017, with the share of them enjoying investment grade surging.

Source: Based on data from Bloomberg LP (2018), Bloomberg Terminal.

The fall in prices also changed the way the shale industry was financed. Debt finance dried up as banks were unwilling to lend during a period of market turmoil, with bond yield spreads widening to over 1 000 basis points and the credit rating of the majority of companies being downgraded (Figure 2.11). Asset sales also dropped by 70% in 2015 as owners were unwilling to part with assets at the much lower prices on offer. While the main buyers of the assets were US independent companies, the market turmoil discouraged bank lending, opening up opportunities for financial firms such as private equity firms, which typically have a higher risk profile. Those firms accounted for around 30% of reported asset deals over 2015-16. Available funding from the reserve base lending structure also declined as the value of proved reserves for collateral shrank with lower oil prices. The net result was that companies were obliged to raise equity to finance their operations – a more expensive option.

Despite the slump in revenues throughout this period, the shale industry actually saw an improvement in free cash flow as a result of huge cuts in capital spending and costs. Between 2014 and 2016, investment fell by 70% and costs by around half. Cost reductions helped to offset the impact of less investment, such that shale oil production declined only modestly in 2016.

2017: The consolidation phase

The recovery of oil prices since mid-2016 following the collective decision by the Organization of the Petroleum Exporting Countries (OPEC) and some non-OPEC producers to cut output led to a revival in confidence in the US shale sector. Further advances in technology, huge efficiency gains and cost reductions, and an upward revision of the shale resource base triggered an increase of 60% in investment in 2017 (see Chapter 1). In the meantime, the shale industry proved that its upstream cost structure had been rebased as it was able to offset inflationary pressures coming from overheating of the supply chain, further reducing the overall costs per barrel produced.

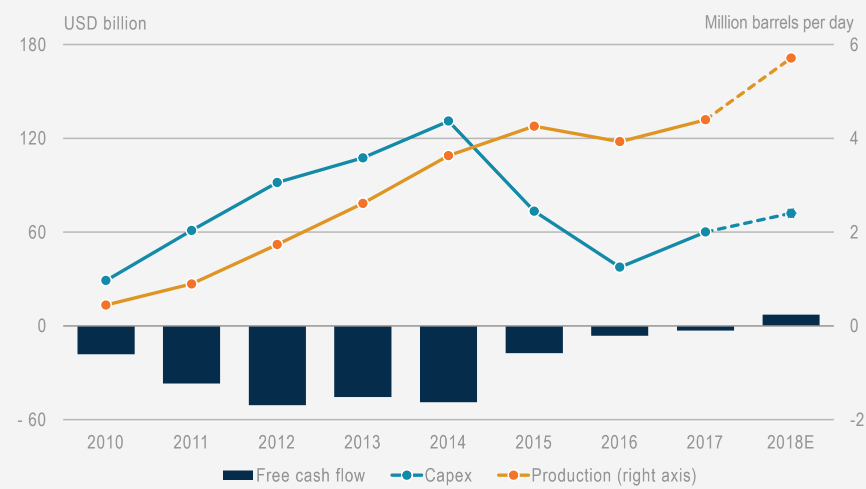
Despite the improvements achieved, however, the shale sector continued to slightly over-spend the cash flow generated from its operations, with 2017 cumulative free cash flow remaining overall negative.

Asset sales once again became the main source of financing operations, with most transactions occurring between US independent companies. The reported value of acquisitions by non-US companies declined to one-fifth of the average annual level during the start-up phase. Asset sales involved mainly acreage rather than whole companies, as companies sought to do relatively small deals as a way of making gains in operational efficiency. The confidence in the shale sector, traditionally dominated by private investors and small and medium-sized companies, received a boost from announcements by large US oil companies of their intention to make substantial investments.

2018: Profitability at last?

Current trends suggest that the shale industry as a whole may finally turn a profit in 2018, although downside risks remain. Thanks to a 60% increase in investment in 2017 and, based on company plans, an estimated 20% increase in 2018, production is projected to grow by a record 1.3 mb/d to over 5.7 mb/d this year (IEA, 2018a). Several companies expect positive free cash flow based on an assumed oil price well below the levels seen so far in 2018 and there are clear indications that bond markets and banks are taking a more positive attitude to the sector, following encouraging financial results for the first quarter. On this basis, this report calculates that the shale sector as a whole is on track to achieve, for the first time in its history, positive free cash flow in 2018. This result is all the more impressive given the context of rising investment (Figure 2.12).

Figure 2.12 US light tight oil production, investment and free cash flow



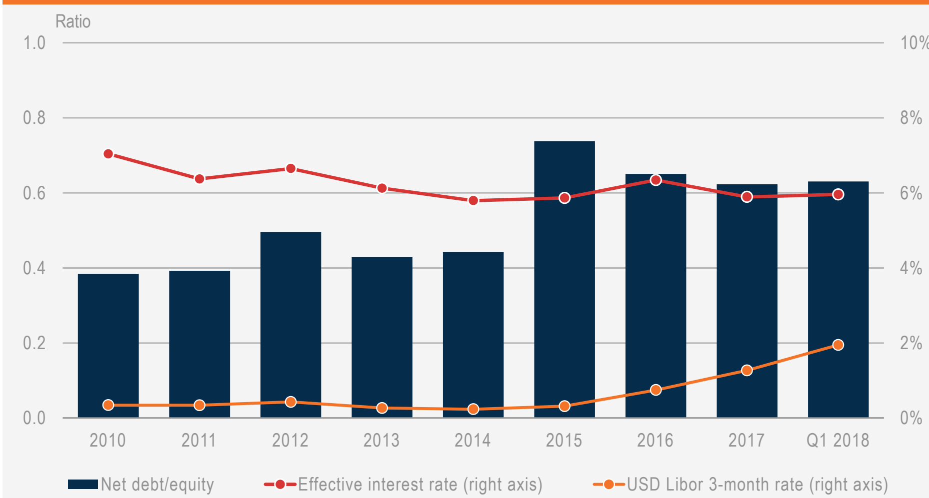
Higher oil prices, continuing efficiency improvements and technological advances have put the US shale sector on track to achieve, for the first time, positive free cash flow in 2018.

Notes: E = estimated; capex = capital expenditure. Free cash flow for 2018 is estimated on the basis of first-quarter 2018 company earnings and an average crude oil price of USD 65 per barrel on average for the full year, and a discount of USD 7 per barrel.

Structural changes also augur well for the sector. Recent consolidation, such as the recent USD 9.5 billion Concho-RSP Permian merger, and the increased participation of the majors and other international companies could bring significant economies of scale and accelerate technology developments, including through digitalization. Larger companies generally have a more robust financial structure and rely less on external sources of financing, so their shale investment will be less vulnerable to future downswings in oil prices and financial conditions.

The potential risks for shale independent from rising interest rates are currently attracting a lot of attention. The impact of rising interest rates on independent oil and gas companies in the US shale industry may also be small. Most companies are highly leveraged, benefiting from the ample availability of low-cost bond finance. However, given the high depletion rate, the time horizon of shale projects is so low that the discount rate has only a minor impact on the net present value of a given project. Rising interest rates often coincide with tighter lending conditions, which may make it harder for companies to service their debts and refinance their operations. But this risk can be managed through asset sales to less-capital-constrained companies, such as the majors, and increased reliance on equity raising through IPOs and private equity.

Figure 2.13 Financial leverage and effective interest rate for US shale independents



The average interest rate paid by US shale independents on their debt remains significantly higher than that by conventional oil producers, but it has been stable despite rising interest rates generally.

Note: The effective interest rate is calculated by dividing total interest expenses of 40 US independent companies by their total debt.
Sources: Based on company filings from Bloomberg LP (2018), Bloomberg Terminal.

A lot of attention has been focused on interest expenses – the cost of repaying debt. The development of shale production has been accompanied by constantly rising interest expenses, which has impeded companies from generating profits sustainably.[6] For the first

[6] For the top 50 US shale companies by production, aggregate interest expenses doubled between 2010 and 2016 to USD 10 billion.

time, the overall amount of interest expenses paid by shale companies declined in 2017. While US shale companies remain far more leveraged (measured by the net debt/equity ratio) than traditional operators, leverage is falling from its peak in 2015 and the average interest rate paid by shale companies – currently around 6% – has been broadly stable in recent years despite rising interest rates generally since the end of 2015, though they still pay more than conventional oil producers. Improving financial conditions mean that shale companies are able to borrow more cheaply than before (Figure 2.13).

The US shale industry seems to have reached a turning point with the recent significant improvement in its financial sustainability. But major uncertainties and important downside risks to the future of the shale industry remain:

- Above-ground constraints: With production rising very rapidly in certain basins, such as the Permian, timely investment in takeaway capacity and pipeline infrastructure will be vital to the further expansion of the industry. At present, several producers in the Permian Basin are forced to discount their crude oil by more than USD 15 per barrel compared with the price on the Gulf Coast due to a lack of pipeline capacity. No significant pipeline capacity expansion is expected before 2019.[7] The importance of infrastructure applies not only to oil but also to associated gas production, wastewater and other products. In the absence of new pipeline capacity, companies might be forced to curb drilling or ship their production using trucks or rail, which are usually much more expensive.[8]
- Further productivity gains: The continued ability of the companies to offset inflationary pressures with improved productivity stemming from technology or improved project execution remains very uncertain. In most active basins, especially the Permian, there are clear signs of overheating and bottlenecks in skilled labour, materials and equipment. In addition to the potential for further technological advances, there may be scope for more efficiency gains, for instance by expanding operations in continuous acreages, improved understanding of the resource base and more accurate spacing of wells.
- Grabbing the fruits of the "digital revolution": Companies are putting more effort into developing and adopting innovative digital technologies and big-data

[7] Some US shale operators, including Noble Energy, Carrizo, EOG Resources and ConocoPhillips, have recently indicated that they are considering partially shifting their activities to outside the Permian Basin, notably to the Bakken and Eagle Ford basins. Oil services in those areas are subject to less inflationary pressure, resulting in higher netback values compared with the Permian, averaging around USD 6-8 per barrel.

[8] This report estimates that to replace a 100 000-barrel-a-day pipeline, it would require the use of almost 700 trucks working 24 hours a day, seven days per week.

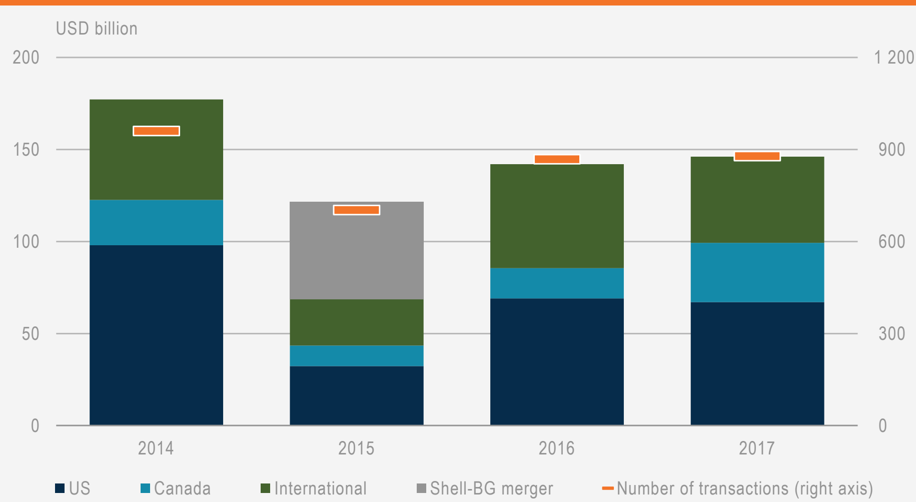
analytics in order to reduce costs, by optimising operations, improving reservoir modelling and enhancing processes.

- Competition from other sources of oil: The US shale sector has not been alone in reducing its costs and will need to continue to do so to remain competitive in international markets. Most onshore resources, especially in OPEC countries, cost less to produce than shale oil, while the bulk of new deepwater projects are competitive with the cheapest shale basins. Consequently, the US shale industry is required to keep improving.

Mergers and acquisitions in the oil and gas sector

Recent M&A activities in the oil and gas sector have mirrored the trend in oil prices. Following a steep plunge in 2015 and early 2016 (despite Shell's USD 53 billion acquisition of BG), activity started to rebound in late 2016 and throughout 2017. The total value of upstream M&A deals in 2017 rose slightly to USD 146 billion – the highest level since 2014. The number of deals remained unchanged at close to 900 (Figure 2.14). The number of large deals (above USD 10 million) also rose, from 346 in 2016 to 379 in 2017 (EvaluateEnergy, 2018), with the 10 largest accounting for about 40% of the total value of oil and gas M&A. Most of the deals involved asset sales rather than company takeovers, as companies sought to optimise asset portfolios and raise capital to fund operations.

Figure 2.14 Number of value and global upstream mergers and acquisitions



The total value of upstream M&A transactions rose in 2017 in line with oil prices, with the United States remaining the most active country due to the shale industry.

Note: Includes announced and completed deals in which the transaction values were disclosed.
Source: Based on PLS (2018).

North America remained the most dynamic region, accounting for two-thirds of the global value of deals in 2017. Canada accounted for 30% of the value of North American oil and gas M&A, with deals in shale and oil sands. In Canada, deals were worth a total of USD 32 billion, with local operators acquiring oil sand assets that international players, including ConocoPhillips, Shell, Marathon Oil, Equinor and Murphy Oil, decided to divest. In the United States, listed companies remained the leading buyers, accounting for two-thirds of deal values. The share of financial firms, mainly private equity, in total US upstream M&A transactions by value increased to 24% in 2017 from 22% in 2016 and 12% in 2015 (PLS, 2018). Unlisted, privately owned companies accounted for less than 10% of total value as buyers but 21% as sellers in 2017, taking advantage of the buyer's market. Prominent deals included ExxonMobil's acquisition of Permian Basin assets from the Bass family for USD 6.6 billion and Noble Energy's acquisition of Clayton Williams Energy for USD 2.7 billion in early 2017.

Outside North America, the North Sea was a hot spot for M&A: Total bought Maersk Oil for USD 7.45 billion; Neptune Energy Group acquired a 70% stake in Engie E&P, which also had assets Southeast Asia and North Africa, for USD 3.9 billion and Chrysaor bought a package of assets from Shell for up to USD 3.8 billion to become the leading independent oil and gas company in the United Kingdom (UK) sector of the North Sea.

In contrast to the rest of the oil and gas industry, the value of M&A activity in the upstream services sector fell in 2017, though the number of deals remained high. Deals in 2016 were dominated by two landmark transactions – the mergers of Technip and FMC Technologies, and GE Oil & Gas and Baker Hughes – while 2017 saw generally smaller deals, including Schlumberger's acquisition of the US company Weatherford's pressure pumping business and the Transocean-Songa tie-up. A number of deals in engineering, procurement and construction, including the Wood Group and Amec Foster Wheeler merger, were also completed.

The value of midstream[9] M&A deals fell heavily from USD 140 billion in 2016 to USD 30 billion in 2017 (Deloitte, 2018). As in previous years, the United States was the leading country, where the largest deal was Pembina's acquisition of Veresen for USD 7.1 billion. Private equity was also active in US midstream M&A. Blackstone acquired an interest in the Rover Pipeline and Eagle Claw Midstream as part of its USD 7 billion purchases along the natural gas value chain. Other significant deals included the Global Infrastructure Partners acquisition of Medallion Gathering & Processing in the Permian Basin and Alta Mesa's acquisition of Kingfisher Midstream in Oklahoma.

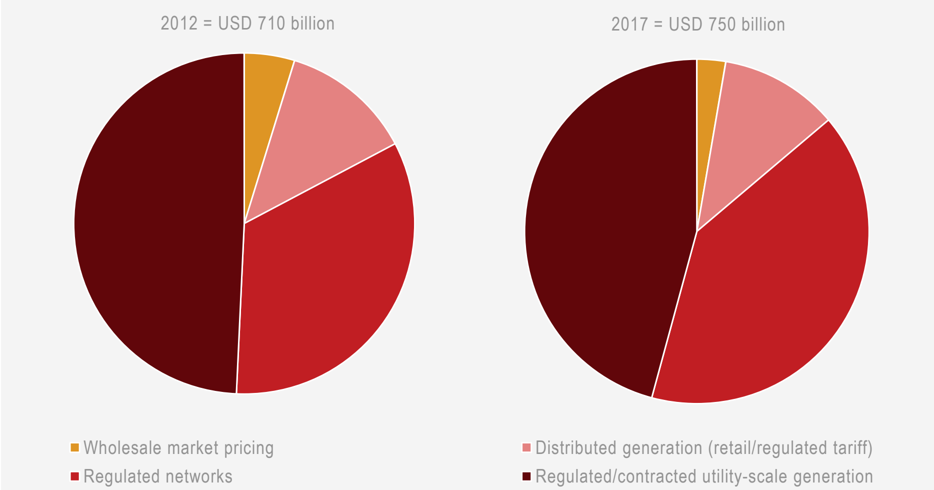
[9] The transportation by pipeline, rail, barge, oil tanker or truck, storage and wholesale marketing of crude or refined petroleum products.

Financing power sector investments

Financing and funding trends supporting power sector investment

Over 95% of power sector investment, including generation, networks and storage, in 2017 was made by companies operating under fully regulated revenues or mechanisms to manage the revenue risk associated with variable wholesale market pricing – the same share as in 2012 (Figure 2.15). In countries organised around competitive wholesale markets, prices on short-term markets are currently too low to provide an incentive to invest in the most capital-intensive assets, such as renewables and nuclear.[10] As a result, a combination of government policies, contractual purchase arrangements and capacity remuneration mechanisms are necessary to facilitate financing.

Figure 2.15 Global power sector investment by remuneration mechanism



Over 95% of power sector investment in 2017 was made by companies operating under fully regulated revenues or mechanisms to manage the revenue risk associated with variable wholesale markets.

Note: Investments classified under wholesale market pricing may included capacity remuneration mechanisms, which were not separated in the analysis. Remuneration for distributed generation is largely determined by the design of retail electricity tariffs.

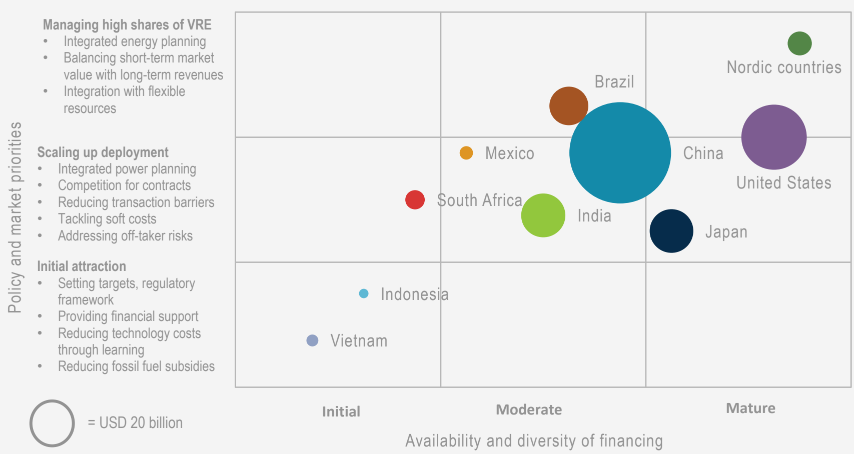
[10] See the IEA publication *World Energy Outlook 2018* (forthcoming) for more information on the role of competitive markets in providing long-term price signals for investment; the impact of market reforms on the outlook for different technologies, including new sources of flexibility; and estimates of the potential gap in revenues for power systems arising from the difference between production costs and marginal cost pricing.

Policy, market and financing development for renewable investments

The way the nearly USD 300 billion that was invested in renewable power in 2017 was financed varied markedly across countries according to the stage of policy and energy market development and the availability and diversity of financing. Roughly 80% of renewable investments were made on balance sheet, with project finance structures accounting for the rest. These shares were little changed from 2016.

At least two-thirds of renewable power investment occurred in countries at the middle stages of scaling up deployment and with financing environments that offer a moderate to mature level of availability and diversity of capital (Figure 2.16). As such, much of the policy focus globally is on actions that help incentivise investment in a cost-effective manner, but also set the conditions for successful system integration at higher shares. Introducing competitive mechanisms for pricing power, addressing issues related to the financial sustainability of purchasers and planning investments in renewables in concert with the rest of the power system remain areas of focus for policy makers, in addition to reducing the cost of capital and tapping into a wider variety of private-based sources.

Figure 2.16 Stages of policy, market & financing for renewable investment, selected countries in 2017



Addressing policy and market priorities, in addition to robust and liquid financing markets, can help improve the bankability of renewable projects and improve the availability and diversity of financing.

Notes: VRE = variable renewable energy. The size of each bubble is equivalent to 2017 renewable investment levels. Explanation of stages of availability and diversity of financing:
Initial = reliance on development bank concessional finance and SOE finance with some private sources; limited availability of domestic debt; structures reflect a mix of balance sheet and full-recourse financing.
Moderate = good availability of blended finance from private and public sources; mostly domestic debt with some international sources; guarantees from domestic and international public sources; structures reflect a mix of balance sheet and some partial recourse/non-recourse project finance; some secondary financing through capital markets and institutional investors.
Mature = mostly private finance; full diversity of domestic and international sources with targeted financial guarantees; structures reflect balance sheet and non-recourse project finance; well-developed secondary financing through capital markets and institutional investors.

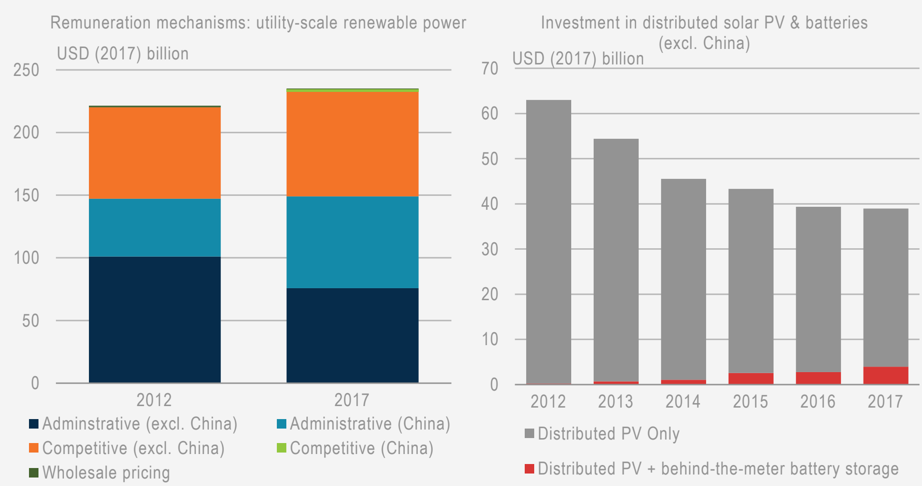
A number of countries remain at the initial stage of deploying renewable power. The focus of policy makers there is on putting the framework conditions in place to attract investment and reducing technology costs through learning and the development of local supply chains. A lot of financing is state-backed at this point. Projects may also tap into concessional sources of finance from development institutions to help manage risks for investors. For newer technologies, this may mean managing risks related to construction and operational performance. But for most investments at this stage, risk management most often means addressing issues related to the credit worthiness of power purchasers, currency risk, and regulatory and policy-related risks, among others, in order to secure financing. Countries where renewables already account for a large share of the power generation mix face a different set of concerns, including operational and technical issues related to developing and managing a flexible power system, and pricing renewables in a way that optimises their value in the short term and long term. Limited financial guarantees may still be needed to cover some residual project risks.

The evolution of business models and market designs for renewables provides one indicator of progress. In general, markets continue to shift from administratively determined remuneration for renewables (e.g. through feed-in tariffs [FiTs]), to those determined by competitive mechanisms. In 2017, around 35% of utility-scale renewable investment, which accounted for over half of total power generation investment, was underpinned by contracts and instruments in which prices are set by competitive mechanisms, notably government- and utility-sponsored tenders, and bilateral power purchase agreements (Figure 2.17). Such mechanisms have enabled developers to increase investments and benefit from economies of scale (see Chapter 1). This share was little changed in 2017, in large part due to the outsized role of China, where most renewables are still remunerated on an administrative basis, but it did increase over the previous four years. Outside of China, the share rose from 40% in 2012 to 50% in 2017.

Nearly all contracts for renewable power are long term (15 years or more), based on a fixed price per unit of generation. This long duration helps to reduce risks during the operational phase of projects and facilitate financing. But fixed pricing does not provide an incentive to producers to provide electricity at times when it is most needed or locations where it is most valuable. For this reason, regulators are looking at ways of incorporating short-term marginal pricing. For example, the 15-year contracts offered by Mexico for remunerating energy incorporate time- and location-based incentives, with exposure to market pricing at the end of a project’s lifetime. The tendering process offers developers the opportunity for further revenue streams from providing environmental attributes and capacity. Recent offshore wind tenders have resulted in winning bids that incorporate a high degree of exposure to short term market pricing.

Policy makers often face trade-offs when it comes to designing mechanisms that reduce investor risks and simultaneously support system-friendly development. Business cases that combine a degree of revenue certainty with exposure to some short-term market signals during operation can increase the complexity of the revenue model and can impact the ability of developers to attract financing. One emerging trend involves combining battery storage with solar PV and wind power on site, allowing those plants to operate more like dispatchable power plants (see Chapter 1). New approaches to contracting involving financial agreements with corporate buyers can provide a diversity of options for managing power purchase risks over the lifetime of a project, in some cases, after the conclusion of the original PPA (IEA, 2017). Non-energy corporations are a growing alternative to utilities in the purchase of renewable power, contracting a record amount of new capacity in 2017. FIDs for renewables based on corporate PPAs rose to nearly 3 GW in the United States in 2017, with another 2.5 GW facing investment decisions in 2018 (RMI, 2018). Corporate PPAs existed in just a handful of markets five years ago, but were used in 35 countries in 2017 (IRENA, 2018).

Figure 2.17 Renewable power investment: remuneration and business models



Around 50% of utility-scale renewable investment outside of China was underpinned by contracts and instruments in which prices are set by competitive mechanisms. The role of business models based on distributed solar PV plus battery storage is rising.

Note: Excl. China = excluding China.
Source: Calculations for remuneration mechanisms based on IEA/IRENA (2018).

Small-scale generating capacity connected to the distribution grid or completely off-grid, which made up around 20% of renewable power investment in 2017,[11] is mostly financed

[11] Small-scale solar PV only.

by the balance sheets of the electricity consumers and commercial/industrial end users that build it. That investment is often funded by bank loans, or third-party installers, including IPPs and utilities. In general, such projects are too small to attract project finance, though in the United States there is a rising issuance of ABS, which bundle projects into larger transaction sizes (Box 2.3). In the case of off-grid systems, nearly all investments are made by third-party developers that offer the output in exchange for a stream of fixed payments by the consumer – so-called "pay as you go" financing models (REN21, 2018).

All of the business models for distributed generation strongly interact with the regulatory design of retail tariffs and the remuneration of grid-injected electricity.[12] Outside China, the main business model for distributed solar PV investments has shifted from so-called "buy all, sell all" contracts, where all the electricity generated is fed into the grid and remunerated at a pre-determined rate, to net energy metering, where consumers supply power to the grid in excess of their own consumption and receive a corresponding credit on their bill against future electricity consumption. A small but growing share of investment is based on self-consumption, whereby consumers make use of behind-the-meter battery storage to increase their autonomy to avoid having to buy power at night and sell surplus power during the day (Figure 2.17).

Box 2.3 More diversified financing for small-scale solar PV in the United States

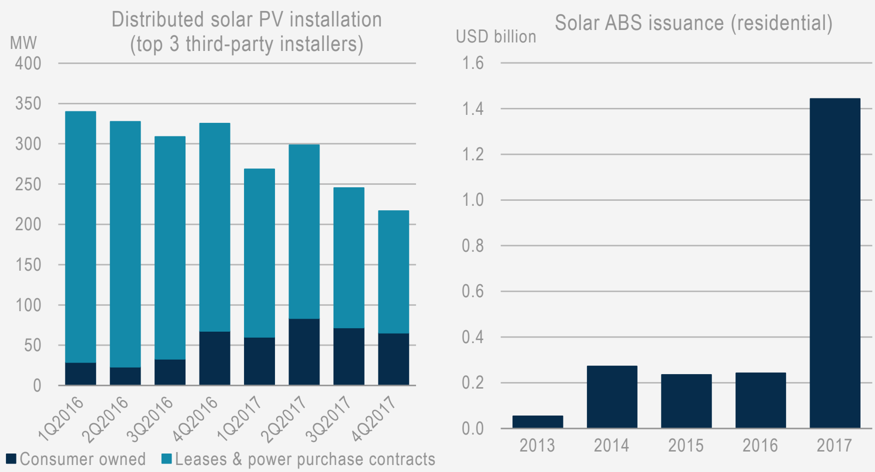
Ownership and financing mechanisms for distributed solar PV investments, which are mostly financed on company or household balance sheets, continued to evolve in the United States – the second-largest market after China – in 2017. For the first time in five years, new installations by the electricity consumer exceeded those by third parties (GTM Research, 2018). This trend reflects the growing use of loans with fixed monthly repayment schedules rather than leasing arrangement or PPAs with third-party owners, which shift upfront risks and expenses to the installer, but may lock the consumer into a long-term contract with rising annual payments. Capacity installed by the top three third-party installers, Sunrun, Tesla and Vivint, which accounted for around a quarter of the market in 2016, shrank by 20% in 2017. But the share of this capacity sold to consumers, financed most often by loans, rose to 30% by the end of the year with a sharp drop in third-party leasing and contracting (Figure 2.18).

This trend reflects increased availability of financing options for consumers, as well as a change in strategy for some third-party developers, who have experienced financial difficulties due to heavy upfront capital needs and long-term repayment schedules. As a result, distributed solar PV developers and financing companies are increasingly tapping into the secondary markets to

[12] See the IEA publication *Renewables 2018: Analysis and Forecasts to 2022* (forthcoming) for a more detailed discussion of the remuneration and system value implications of distributed renewables.

refinance leases and contracts on their balance sheets as well as portfolios of solar loans. This helps developers generate cash in the near term in exchange for interest payments to investors over the long term. In 2017, a record amount of ABS based on residential solar PV in the United States were issued, reaching over USD 1.4 billion – equal to 10% of primary financing.

Figure 2.18 Financing of US distributed solar PV



While total US distributed solar PV deployment remained stable in 2017, the role of third-party leasing and contracting has declined, as the share of consumer-owned and financed projects rose.

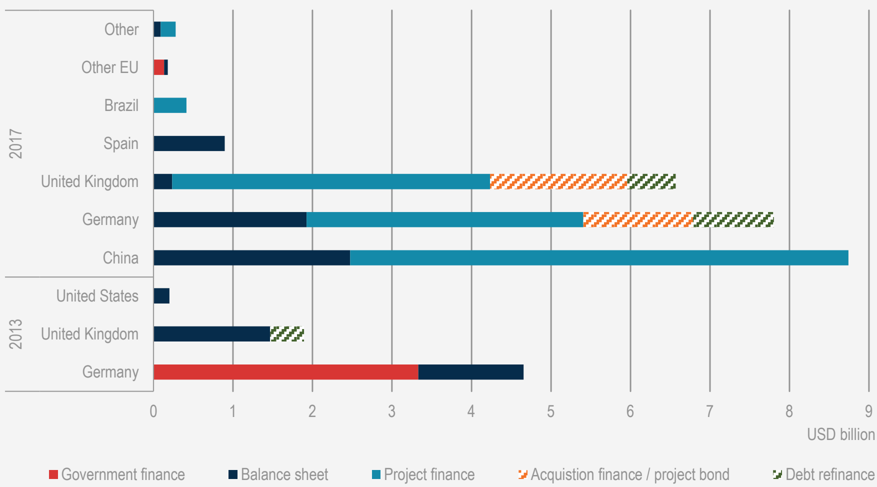
Note: MW = megawatts. ABS = asset backed securities.
Sources: Calculations based on company reports and data provded by Climate Bonds Initiative (2018).

More diversified financing has boosted offshore wind investment to record levels

Trends in financing of investment in new offshore wind farms that came on line in 2017, which reached a record USD 16 billion, reflect the mature nature of the technology (Figure 2.19). Project finance now represents the largest source of new asset financing with an active secondary financing market for project acquisitions and refinancing, effectively increasing the number of projects a developer can finance. This picture represents a stark change from a few years ago, when most finance came from the balance sheets of developers and government-backed financing. Recent auctions in Germany and the Netherlands point to continued cost declines and an expectation that projects there can earn sufficient returns selling at wholesale electricity prices or form an integral part of a least-cost supply portfolio, given the dominant role of utilities with electricity retail businesses in winning bids.

Projects in Germany, the United Kingdom and China accounted for 90% of the USD 20 billion in primary financing for offshore wind capacity sanctioned in 2017. Total investment associated with that capacity fell by about 30%. Outside of these markets, most developments were smaller offshore wind demonstration projects in new or less mature markets. The appetite from banks to finance offshore wind projects has increased as markets have matured and project developers have gained experience, with over 50 commercial banks now providing debt for projects. Correspondingly, the participation of PFIs, notably the European Investment Bank, the UK Green Investment Bank (now the Green Investment Group) and the German development bank KfW, which used to be instrumental in managing risk and attracting private capital, has declined. In Europe, the share of new projects, in terms of volume financed, benefiting from PFI capital fell from nearly half in 2013 to one-fifth in 2017.

Figure 2.19 Primary and secondary financings for offshore wind projects



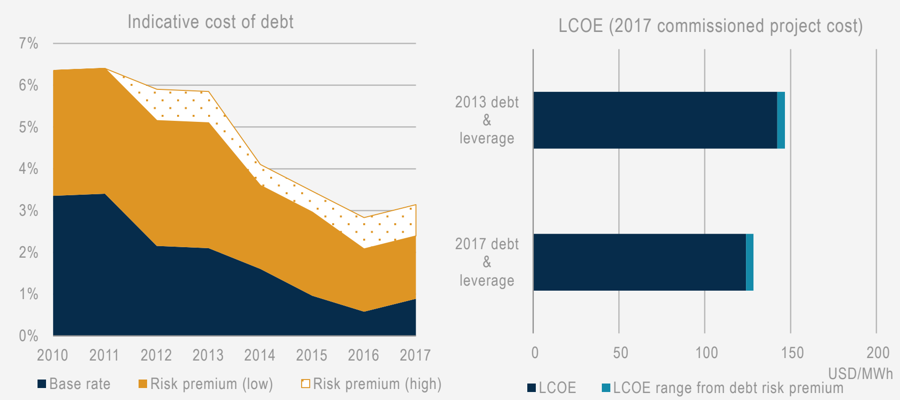
The growing diversification of finance, including greater participation by commercial banks and a more active secondary market, has supported record levels of offshore wind investment.

Note: By year of sanctioning.
Sources: Calculations based on Clean Energy Pipeline (2018); IJ Global (2018); BNEF (2018).

Project leverage has also increased, with debt-to-equity ratios averaging 75% in Europe in 2017 compared with 60% a decade earlier. Borrowing has been boosted by low interest rates and lower debt risk premiums: loans are currently priced at 150 basis points to 225 basis points above base rates – half the level of five years ago – and maturities have typically increased to around 15 years (Green Giraffe, 2017). These factors have helped to reduce the levelised cost of offshore wind power generation in Europe by nearly 15% since 2013 (Figure 2.20).

Continuous improvements in technology and project structuring have supported the financing and investment trend. As offshore wind turbine technologies develop, a trend towards larger turbines with higher capacity factors has helped to reduce average auction prices for new projects. Projects have moved further from shore, which has tended to keep overall capital costs stable in recent years, but there is also a tendency towards larger project sizes. The Hornsea II project in the United Kingdom that reached financial close in 2017 will have a total installed capacity of 1 386 MW, making it the world's largest offshore wind farm, and is expected to come on line in 2022.

Figure 2.20 Debt financing costs and impact on generating costs for new offshore wind in Europe



Offshore wind investment in Europe has benefited from low interest rates and improved debt risk premiums; the lower cost of debt reduced the cost of generation by nearly 15% between 2013 and 2017.

Notes: Base rate includes European Central Bank lending rate, six-month Euribor lending rate, and price and fees for term swap. Levelised cost of generation is expressed in nominal, before-tax terms. Calculations assume average 2017 project costs, including grid connection, and capacity factor for commissioned projects; the cost of equity is assumed to be constant at 10%; leverage is assumed to have risen from 70% in 2013 to 75% in 2017.
Sources: IEA analysis based on Bloomberg Terminal (2018) and Green Giraffe (2017).

Increased secondary financing of offshore wind investment also reflects the growing maturity of the technology. Acquisition finance and refinancing of offshore wind projects amounted to approximately USD 5 billion in 2017, compared with less than USD 0.5 billion in 2013. There has also been growing interest from institutional investors, oil and gas majors, and utilities in diversifying their portfolios by acquiring offshore wind assets. Project developers are also increasingly tapping into the capital markets for refinancing. Three offshore wind projects issued a record EUR 2.5 billion (Euros) in project bonds during 2017 for refinancing of 1.3 GW of capacity. Two of these represented the first investment-grade project bonds issued in the United Kingdom and

Belgium for projects under construction (WindEurope, 2018). The Danish company Ørsted, in particular, has also benefited from an active secondary market. In 2017, it sold 50% equity stakes in two operating projects and raised over USD 4 billion to help finance new ones, while remaining the operator and joint owner. It has also developed a green bond issuance programme to fund its balance sheet.

A rising share of offshore wind acquisitions are now also taking place during the construction phase, signalling rising confidence in the ability of developers and turbine manufacturers to complete projects on time and on budget. In the past, offshore wind developers tended to divest from projects only once a project was commissioned. The share of pre-commissioned projects in acquisition financing reached over 80% in 2017, up from around 35% in 2014. Utilities were the largest sellers of projects, while institutional investors and oil and gas companies were the most active buyers in 2017.

The means by which offshore wind projects are remunerated for their output are also changing. To date, the vast majority of such projects have been underpinned by FiTs – a fixed tariff under a long-term contract set by the regulatory authorities – or PPAs, such as contracts-for-difference (CfDs),[13] with fixed prices. Of the projects reaching financial closure in 2017, nearly three-quarters were based on FiTs while a quarter were based on PPAs. But recent auctions in Germany and the Netherlands signalled a move away from long-term fixed pricing, with Ørsted and EnBW, a German utility, winning a tender for nearly 1.4 GW of offshore wind with a bid for most of the electricity to be sold only at the wholesale price when they are commissioned in 2024-25.

The financial viability of these projects, which are inherently riskier, will depend largely on power supply-and-demand fundamentals in Northern Europe a decade from now and the extent to which improvements in technology can reduce construction and operating costs and improve utilisation rates. The developers are expecting wind turbine sizes to reach 13 MW to 15 MW by the time these projects enter the construction phase, which should yield economies of scale and higher capacity factors. Vattenfall’s wholesale price bid in the recent Dutch auction for the 700 MW Kust South 1 & 2 array, which is due to be commissioned in 2022, appears even riskier as it remains unclear how quickly manufacturers can produce larger turbines.

There is considerable debate within the industry and finance community on whether projects based on wholesale pricing, such as those in Germany and the Netherlands, will become more widespread. Given that these projects have not yet reached financial close,

[13] When market revenues fall short of the PPA strike price under a CfD, generators receive a premium so that their total remuneration equals that price; when revenues exceed the strike price, generators reimburse that difference to the contract counterparty.

the precise contract terms and financial structures are not known. The fact that they were prepared to take on pricing risks may have a lot to do with the government incentives. For example, the German and Dutch governments both provide the grid access. The Netherlands has also made a commitment to introduce a carbon floor price for the electricity sector as part of the country's strategy to phase out coal by 2030.

Financing and funding nuclear power remain dependent on government aid

Investment in nuclear power remains highly dependent on government involvement in various areas, including market structure, price regulation and financing.[14] The construction of nuclear power plants involves large upfront capital expenditures, long lead times and long payback periods. Nuclear projects are also subject to big political, regulatory and construction-related risks.

For capacity that has reached a FID since 2000, about 80% has been in regulated market structures that are based on a single buyer of electricity or a VIU (Figure 2.21). During the current decade, regulated market structures have played an even more important role in enabling nuclear investment, with close to 90% of capacity being in such markets. Around three-quarters of the nuclear capacity sanctioned this century has been in emerging economies, which are often organised under regulated market structures. Yet even in member countries of the Organisation for Economic Co-operation and Development (OECD), the majority of new nuclear plants are in regulated markets.

Moreover, investment in nuclear capacity to date has generally occurred only in cases where investment costs are paid back through contracted revenues from regulated tariffs and consumers bear part, if not all, of the construction risk. A recent example is the Construction Work in Progress tariff charged to consumers for the financing costs of the Vogtle plant and V.C. Summer plant in the United States; construction on the V.C. Summer plant was suspended in 2017.

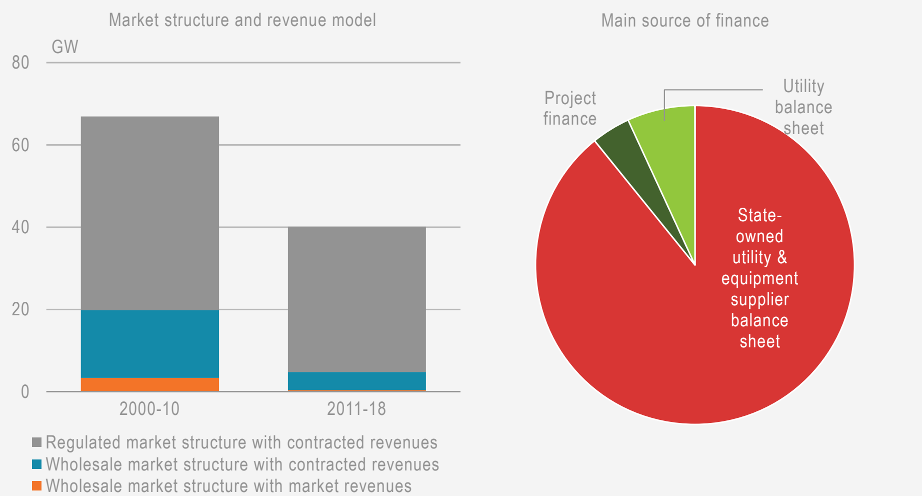
Where investment in new nuclear capacity has occurred in competitive markets, projects are virtually always remunerated by mechanisms designed to reduce electricity market risk by providing long-term price certainty under long-term contracts, PPAs, CfDs or capacity remuneration mechanisms. Only around 3% of nuclear capacity sanctioned since 2000 occurred in competitive markets without some form of contracted pricing. Nevertheless, even in these cases, some form of government involvement, such as participation by an SOE or arrangements to manage cost overruns, has been instrumental to the investment.

Access to direct or indirect government financing also continues to be an important factor for nuclear investments. Most investment in new nuclear capacity has occurred in markets

[14] This section was produced with analysis and input from the Nuclear Energy Agency.

where the government retains full ownership or a majority stake in most of the utilities. Nearly 90% of nuclear investment decisions this century have been made based on balance sheet finance by SOEs, which often benefit from explicit or implicit government guarantees. Nuclear projects in such markets have further benefited from domestic corporate bond issues, credit from public financial institutions, equity capital and cash flows from SOEs, as well as loan guarantees from public entities.

Figure 2.21 Sanctioned nuclear power by type of market and source of finance, 2000-18



Over 95% of nuclear plants taking investment decision this century are based on regulated or contracted remuneration. Government-provided finance dominates nuclear investments.

Source: Calculations based on IAEA (2018).

More recently, suppliers of nuclear technologies, which also tend to be state owned, have become involved in financing nuclear projects, in both emerging economies and OECD countries. Nuclear equipment vendors, also often fully or partially government-owned entities, have provided loans to new projects from their balance sheet or taken equity stakes. Recent examples are the provision of loans from Rosatom, the state-owned Russian company, and Chinese companies to new projects in Argentina, Pakistan, Bangladesh, India, Romania and Viet Nam. Rosatom also took a 100% share of a nuclear project company in Turkey and a minority stake of a new nuclear project in Finland. Électricité de France (EDF) and China General Nuclear Power Group are taking ownership of the company that is building the new nuclear units at Hinkley Point in the United Kingdom.

Balance sheet financing from non-state-owned sources, largely utilities, has played a notable role in Finland, Japan, the United States, France, the United Kingdom, Korea, Russia and China. In the latter five countries, however, the government has a significant stake in the utilities undertaking the nuclear new investment, thus blurring the distinction between public and corporate balance sheet financing. An additional financing structure, the so-called Mankala model, which involves project finance, has been successfully applied to investments in nuclear projects in Finland. Under this model, a pool of electricity wholesalers, energy-intensive companies and municipalities jointly invest in new generation capacity, with the expectation of benefiting from electricity at a stable cost for their own use.

Financial sustainability and changing utility strategies

Investment in power generation and the electricity network depends on the financial sustainability of utilities, i.e. their ability to cope with short-term financial stress caused by weather-related events and economic volatility, and function as creditworthy purchasers of power from IPPs. Fundamentally, sustainability is ensured by the principle of cost recovery, whereby revenues from sale of electricity and other services cover operating and capital expenditures as well as debt service cost, including a profit margin. A number of economic, financial and operational factors determine the ability of a utility to recover costs:

- the cost of producing electricity and the price paid for bulk power
- sale revenues, determined by demand and the design and level of retail tariffs
- operational efficiency and losses between generating and distributing electricity
- success in connecting, metering, billing and collecting bills from customers
- the level of debt and prevailing financing costs
- other expenses, such as salaries and administrative overhead.

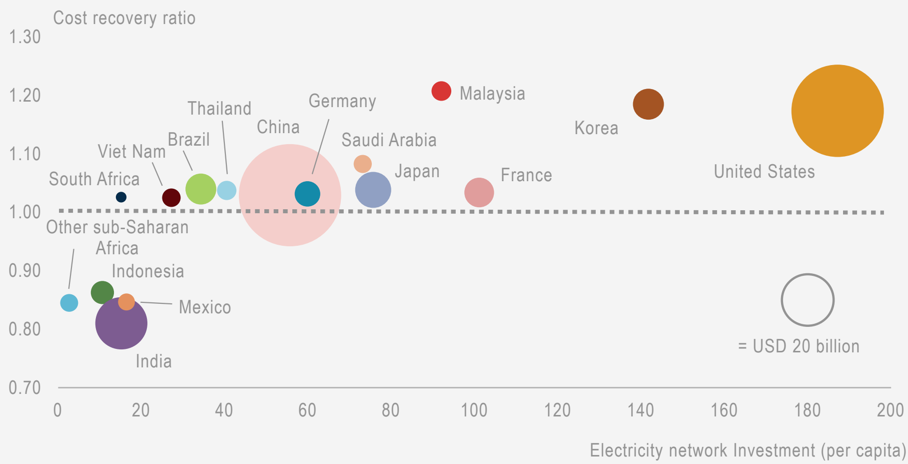
This section examines the evolution of the financial performance and business strategies of electricity utilities, and their relationship to investment in power generation and networks.

Cost recovery and investment in electricity networks in key markets

The relationship between the financial sustainability of utilities with network businesses and investment levels in that sector is very strong, based on an analysis of the cost recovery ratio – the ratio of revenues to costs, including operating costs, depreciation and financing – across several countries (Figure 2.22). The cost recovery ratio is largely determined by access to end users, operational performance and institutional capacity to set proper regulations.

Virtually all network investment is remunerated through regulation, with only a few assets, such as some large-scale transmission or mini-grid projects, developed on the basis of sales in competitive markets alone. Most regulators have put in place a cost-of-service mechanism, whereby end-user tariffs are set in a way that allows utilities to recover their fixed investment and variable costs and earn a reasonable return on equity (ROE). Setting rates to ensure cost recovery is not simple.[15] In some markets, variants of cost-of-service mechanisms, including ones that reward utilities for meeting performance goals to avoid costly upgrades and that seek to decouple cost recovery from electricity sales, are being used increasingly to align rate-making with larger system objectives, though they can be complex.

Figure 2.22 Electricity grid investment per capita versus cost recovery ratio for major utilities in selected markets



Electricity network investment depends on regulatory models and measures that address cost recovery through encouraging operational efficiency, setting cost reflective tariffs and managing financing costs.

Notes: Data reflect the latest available year for the cost recovery ratio. The size of the bubbles corresponds to the total level of network investment (transmission and distribution). Cost recovery is measured as the ratio of total operating revenues to total operating costs (including depreciation) plus net financing costs for reference utilities and excluding explicit subsidy payments.
Sources: Calculations for cost recovery are based on financial statements of reference utilities in each market. Cost recovery ratios for the United States are based on EEI (2017) and sub-Saharan Africa excluding South Africa are based on Kojima and Trimble (2016).

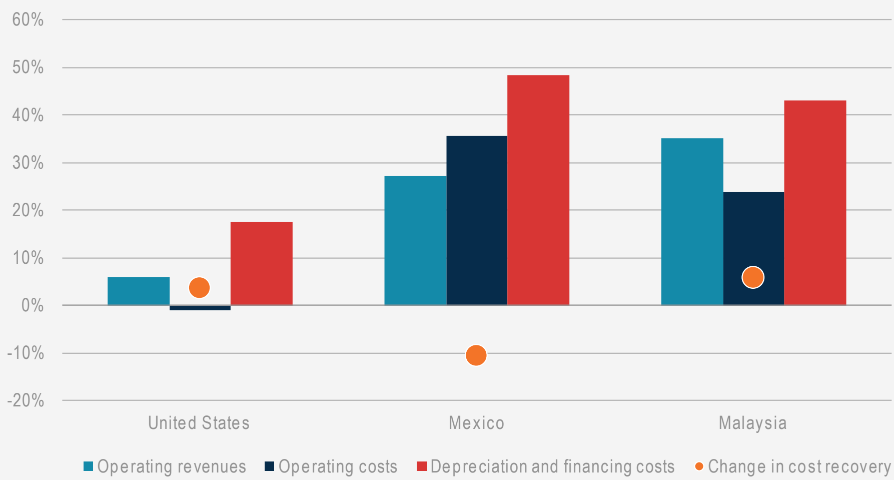
This cost-of-service model is widely used in the United States, where cost recovery ratios among investor-owned utilities (IOUs),[16] which account for around 80% of investment in

[15] Full treatment of all the regulatory options related to cost of service, rate design and cost recovery is beyond the scope of this report.

[16] IOUs include utilities operating in regulated and competitive wholesale market structures.

the grid, have remained relatively stable. This model has paved the way for a steady expansion of spending on networks to meet rising demand and system goals for reliability and modernisation, and integration of new sources of variable renewables. Grid investment per capita in the United States remains very large compared with other mature markets, though this is partly due to population dispersion. Cost-of-service studies – to determine utility revenue requirements and how to allocate these across various customer classes – also remain fragmented in the United States, requiring more timely updates, with protocols to reflect technology and market changes (Pechman, 2016).

Figure 2.23 Changes in factors affecting utility cost recovery in selected markets, 2012-17



A combination of electricity tariff adjustments, efforts at reducing generation costs and network losses, better bill collection, and financial restructuring can support cost recovery for utilities.

Notes: Cost recovery is measured as the ratio of total operating revenues to total operating costs (including depreciation) plus net financing costs for reference utilities and excluding explicit subsidy payments.
Sources: Calculations based on EEI (2017) for the United States and financial statements of reference utilities.

The ROE associated with the tariff that is set by the regulator and granted to US IOUs, which have both power generation and network businesses, has declined to 9-10% on average for the past five years, compared with 10-11% over the previous decade (EEI, 2017). Sales and energy revenues also declined during this period. Cost recovery for these utilities generally improved between 2012 and 2017 as their capital expenditures expanded, but this was largely due to a 40% reduction in natural gas costs (which lowered generating costs) and a decline in financing costs (Figure 2.23). In general, the business models of US utilities are evolving towards greater exposure to investments based on regulated and contracted pricing, both on the network and generation sides.

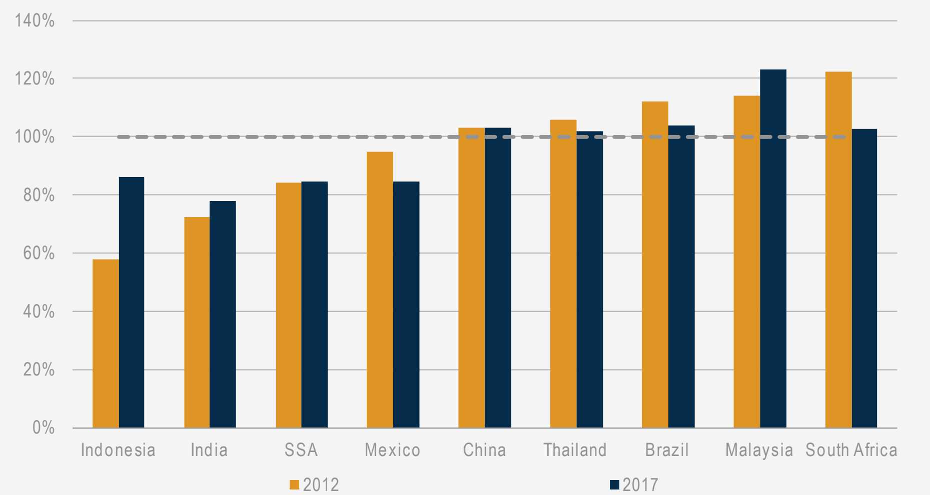
In emerging economies, which account for around 55% of global network investment, the picture varies markedly across markets (Figure 2.24). They fall into three main categories: markets with unbundled systems, those with a single buyer and those with a state-owned VIU. In the past two decades, some emerging economies have moved towards unbundled power systems and private ownership and competition in the distribution sector. In Brazil, for example, these changes boosted the profitability of distribution, though slower economic growth combined with contractual power purchase obligations have eroded cost recovery in recent years.

In the second category, generation and networks businesses have been unbundled, but the state has retained ownership of a single-buyer utility. In China, where efforts are under way to introduce more transparent network tariffs and private participation in distribution, and Thailand, where tariffs are adjusted regularly to reflect fuel costs, cost recovery has generally been adequate to pay for network development. In Malaysia, reforms have increased cost pass-through into electricity tariffs, which has boosted the cost recovery picture for the main utility even as investment and financing costs rose (Figure 2.24). However, in some of these markets, a lack of competition in the distribution sector and persistent underpricing of electricity have contributed to inefficient operations, underinvestment in infrastructure and high debt burdens, which in turn have undermined financial sustainability. In Mexico, where unbundling reforms are currently taking place, the financial performance of Comisión Federal de Electricidad (CFE), the national utility, has until now been harmed by large operational power losses (around 15% of total generation); high generation costs, with a historically large role for oil-fired generation; regulated tariffs that do not cover costs, which are only partly compensated for by the government; and large pension burdens. Although growth in costs has continued to consistently outpace revenue growth in the past five years, the shifting of some pension liabilities to the government in 2016 and a stark reduction in financing costs in 2017 helped to improve the rate of cost recovery. The implementation of the CFE plan to modernise its grid and reduce operational losses will be important to improving cost recovery.

In the third set of emerging economies, network investment is determined by state-owned VIUs that also dominate the generation business. The financial state of these utilities is often tenuous. In South Africa, the profitability of the state-owned utility, Eskom, has declined in recent years with a slowing of annual energy revenue growth, rising operating expenses and a large increase of debt, which has more than tripled net financing costs. The national utilities in most other countries in sub-Saharan Africa remain far from cost recovery; a recent World Bank study found that 40% of their persistent “quasi-fiscal deficits” were attributable to underpricing of electricity, 30% due to high network losses and 20% due to inadequate bill collection (Kojima and Trimble, 2016).

In Indonesia, the state-owned utility, PLN, has improved its financial status in recent years by increasing revenues faster than costs, thanks to government efforts to make electricity tariffs more cost-reflective, connect new customers and reduce operational losses. Its net financing costs fell by almost 30% between 2012 and 2017. Recently, the government set a special price for coal as part of a domestic market obligation in order to lower the energy cost to PLN. However, operational inefficiencies, obligations from legacy take-or-pay contracts, and persistent underpricing of electricity tariffs continue to cause big financial losses. These losses are covered by a government subsidy. Despite falling by over half in the last five years, this subsidy still accounts for 0.3% of gross domestic product (GDP) and over 2% of total government budget spending.

Figure 2.24 Cost recovery ratios for major utilities in selected emerging economies



Utilities in emerging economies have made mixed progress in improving cost recovery, with some seeing gains through cost reflective pricing, new customer connections and reduced operational losses.

Notes: SSA = sub-Saharan Africa outside South Africa; cost recovery is measured as the ratio of total operating revenues to total operating costs (including depreciation) plus net financing costs for reference utilities and excluding explicit subsidy payments. Due to data availability, SSA calculations are based on 2012 and 2014.
Sources: Calculations for cost recovery are based on financial statements of reference utilities in each market. Cost recovery ratios for sub-Saharan Africa excluding South Africa are based on Kojima and Trimble (2016).

These factors have deterred power sector investment in Indonesia, particularly in renewables. The utility's financial state creates risks for all IPP power projects that the utility will not be able to make timely payment. The situation also makes PLN reluctant to sign PPAs (current policies subject renewables to a price ceiling that varies by region) above its average cost of supply or facilitate investment in assets that may erode its existing business models (e.g. promotion of renewable mini grids that would displace diesel sales in remote areas). Because of its underinvestment in networks and grid operations, it is cautious to contract with large solar PV projects, inhibiting economies of scale. These factors mean that the development of renewables has been limited to regions where the costs of power supply are relatively high (IEA, 2017). Nonetheless, PLN has increased its network spending in recent years. Another sign of improvement is the completion of Indonesia's first wind farm, the 75 MW Sidrap project, which came on line in 2018, backed by project finance; one of the loans came from the US Overseas Private Investment Corporation, a public financial institution.

Utility generation strategies continue to change

Utilities in mature electricity markets are finding that their thermal power generation assets – which used to be their core business – are becoming less profitable or even unprofitable and are starting to close some of them while seeking profitable opportunities in other areas.

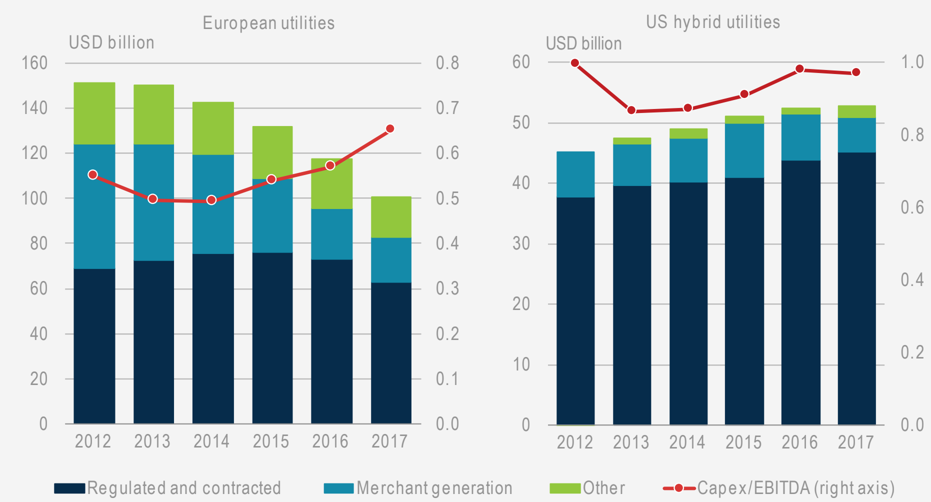
In Europe, the United States and China, among other markets, this change in strategies involves improving operational efficiencies, investing in regulated renewables, and integrating supply businesses with network assets and demand-side services, such as those related to electric vehicles (EVs).

In Europe, this strategic evolution is the consequence of structural market development and regulatory changes that started about two decades ago with the liberalisation of electricity markets, comprising the unbundling of networks businesses and the introduction of wholesale and retail competition. Policies to encourage renewable electricity have also led to competition from new market entrants, including IPPs, communities and corporations investing in solar PV and wind. These forces have weakened price signals for investment based on short-term marginal cost pricing and damaged the profitability of existing generation assets, mainly large-scale thermal power plants dependent on wholesale revenues. The investment case for thermal assets has become more difficult given unpredictable cash flow in a market with weak demand growth. In 2017, thermal generation, with revenues largely based on wholesale markets, together with payments related to capacity mechanisms, which remunerate generators for making capacity available at certain times, accounted for only 7% of generation investment in Europe, compared with 15% five years prior.

The recent financial performance of European utilities reflects these trends. In 2017, the aggregate earnings of the top 20 utilities continued to decline, reaching a level one-third lower than in 2012 (Figure 2.25). This was due mainly to the reduced profitability of merchant generating assets exposed to weak wholesale prices, as well as lower revenues due to the retirements of such plants. 80% of utility earnings in 2017 came from segments that offer more stable and predictable cash flows, including networks, renewable power and co-generation[17] as well as retail supply and services, compared with around 65% in 2012.

[17] *Co-generation* refers to the combined production of heat and power.

Figure 2.25 Earnings of the top 20 European utilities and top 10 US hybrid utilities by business segment



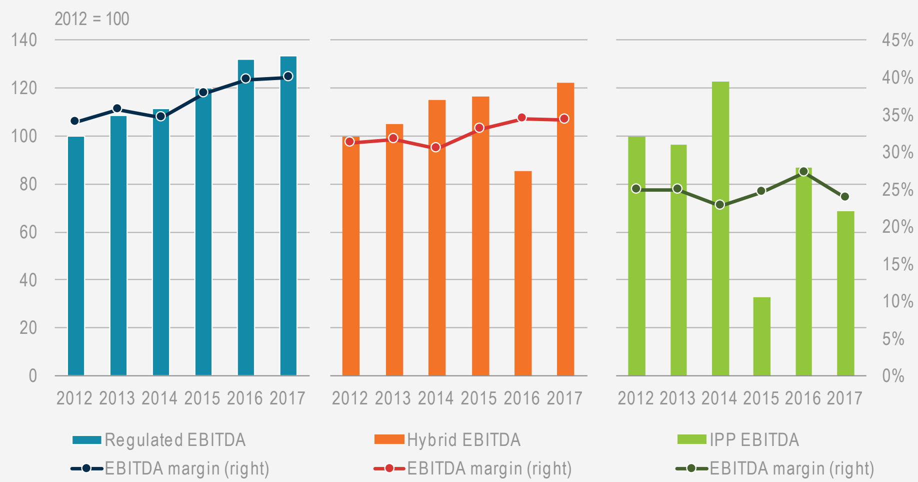
European utility earnings have shrunk by a third since 2012. Three-quarters of earnings stem from assets that benefit from contracted or regulated pricing, along with other services, while capital spending as a share of earnings has risen.

Notes: Earnings = EBITDA (earnings before interest, taxes, depreciation and amortisation) excluding abnormal income or loss items such as impairment charges. *Regulated & contracted* includes business based on regulated and contracted pricing in electricity generation and electricity and gas networks. Examples of "Other" segment in Europe include retail supply and services and in the United States gas midstream and energy trading.
Sources: Based on company filings, Reuters (2018), Bloomberg Terminal (2018).

As a result of this strategic reorientation, European utilities are becoming more capital-intensive. Utility plans involve business model transformation, enhanced operational efficiency and improved financial management, including paying down debt, as well as better integration of supply, demand and network assets; increased provision of consumer-level services; and deploying digital technologies. Recent examples include the transformation of the Danish firm, DONG Energy, now called Ørsted, aimed at basing its entire power supply on renewables, as well as acquisitions by utilities of businesses focused on distributed energy technologies (see "Lower M&A in the power sector, but sustained activity by Chinese companies" below). In 2018, German utilities E.ON and RWE entered into discussions over swapping renewables and networks assets. These changes have, in most cases, not yet resulted in higher earnings.

US utilities are also adapting their strategies in the face of similar changes. The nature of US utilities differs from European counterparts, with generally less existing exposure to generation based on marginal cost pricing. Nonetheless, they are also seeking to enhance business activities based on regulated and contracted pricing. Moreover, the shift is taking place in a more diverse way given different state policies and regulatory landscapes. Some 30 US states representing 70% of electricity demand have market structures based on competitive wholesale markets and/or retail competition, with the remainder functioning primarily as single-buyer markets providing generators with regulated returns on investment. Both utilities operating only in regulated markets (hereafter "regulated utilities") and those operating in both regulated and competitive markets ("hybrid utilities") have seen a growth in profit in the last several years (Figure 2.26). This contrasts with the trend in European markets.

Figure 2.26 Aggregate earnings of top US power companies by type



Earnings of US utilities, with relatively higher share of business derived from regulated and contracted earnings, have held up better than European counterparts, while the profitability of US IPPs has slipped.

Notes: Earnings refer to EBITDA excluding abnormal income or loss items such as impairment charges. EBITDA margin = EBITDA/revenue. The chart includes the 22 largest utilities by revenue in 2017, including 8 regulated utilities, 11 hybrid utilities and 3 IPPs.
Sources: Calculations based on company reports, Bloomberg LP (2018), Bloomberg Terminal.

The profit growth of hybrid utilities is driven by regulated and contracted businesses, such as generation in regulated markets and electricity and gas distribution, which account for over 80% of their earnings. Merchant generation markets accounted for only 20% of their earnings in 2012 and it further reduced to around 10% in 2017. The share of other business segments such as gas midstream and infrastructure and energy trading marginally increased during the same period.

Companies continue to set regulated and contracted business models as growth areas. While retaining their established regulated (or integrated) electricity (and gas) utility businesses, companies plan to increase investment on enhancing electricity networks and on renewable assets which generally have contracted pricing (e.g. NextEra, DTE), whereas some companies (e.g. Exelon, FirstEnergy) have recently suffered large write-downs for losses associated with coal- and nuclear-generation assets. Some companies operating in gas-producing states are also involved in LNG infrastructure and gas pipelines (e.g. Sempra, DTE), which are expected to contribute to profit growth with contracted pricing and expanding market. These utilities have a relatively stable capital expenditure picture relative to earnings.

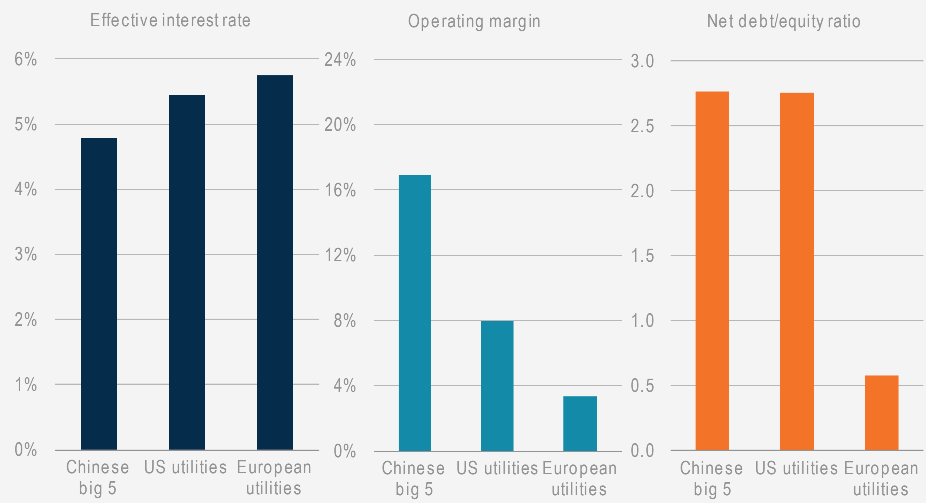
More so than in Europe, new merchant gas-fired power can still be part of the growth story for US utilities as well as IPPs thanks to cheap domestic gas, and more supportive price signals from merchant markets, sometimes supplemented with capacity remuneration mechanisms or financial risk management instruments. More gas-fired generation capacity was added in merchant markets during the period from 2012 to 2017 (33 GW) both by utilities and IPPs (versus 15 GW in regulated markets primarily by utilities) especially in Texas, Ohio and the rest of the area covered by the regional transmission organisation PJM. A hybrid utility, Public Service Enterprise, has five CCGT projects (new plants and upgrades) totalling nearly 2.0 GW in PJM and the US Northeast. The company utilises risk management instruments that the wholesale markets provide to hedge most of its electricity production.

The financial performance of IPPs has been hit hardest due to their high exposure to merchant markets. Even excluding asset impairment losses mainly related to coal assets, earning margins are low, reflecting low wholesale electricity prices and weakening competitiveness of their large-scale thermal assets. The situation has led to consolidation of the sector. For example, Calpine was bought by a group of investors, and Dynegy merged with Vistra. NRG's subsidiary (GenOn), owning over a third of the company's generation, filed for bankruptcy. Talen Energy went unlisted and was acquired by a private equity firm.

China is another region where business models of existing thermal generators have been changing, as evidenced by a rise in retirements of coal power plants in 2017 (see Chapter 1). Among the countries and regions leading global coal retirements, the profitability of China's power companies has been impacted relatively less. This stems from the relatively short payback period for coal-power investments there and continued favourable financial conditions for the country's IPPs.

The big five state-owned IPPs that own 60% of China's coal fleet accounted for just over half of the country's retirements from 2015 to 2017. They have yielded higher operating margins compared with US and European peers that have also retired significant capacity of coal assets during the same period (Figure 2.27). This strength is partly due to more supportive regulated electricity prices, but also to their consistent access to low-cost lending from state-owned policy banks to build new plants. China's big five IPPs maintain a AAA credit rating and their effective interest rates are relatively low despite higher leverage, with a net debt to equity ratio nearly three. Over the long term, however, Chinese IPPs may face additional profitability challenges, under reforms that seek to foster more efficient power dispatch, increasing competition with renewables, tighter enforcement of air pollution control and potential impacts from the establishment of carbon pricing.

Figure 2.27 Financial conditions of utilities and IPPs retiring coal power (2015-17) in China, the United States and Europe



Among companies retiring coal power, China's IPPs have maintained stronger profitability with higher leverage, in part due to more favourable power pricing and financing conditions.

Notes: Data show simple average among companies from 2015 to 2017. Chinese big five include China Datang Corporation, China Huadian Corporation, China Huaneng Group, State Power Investment Corporation and China Energy Investment Corporation (China Guodian Corporation and Shenhua Group), and first-half 2017 data were used for 2017. US utilities and European utilities are those that retired over 1.5 GW of coal fleet from 2015 to 2017 and include AES, American Electric Power, Dynegy, NRG Energy, Southern Company, Drax Group, E.ON, Engie, Iberdrola and RWE.
Sources: Company filings, Bloomberg LP (2018), Blomberg Terminal.

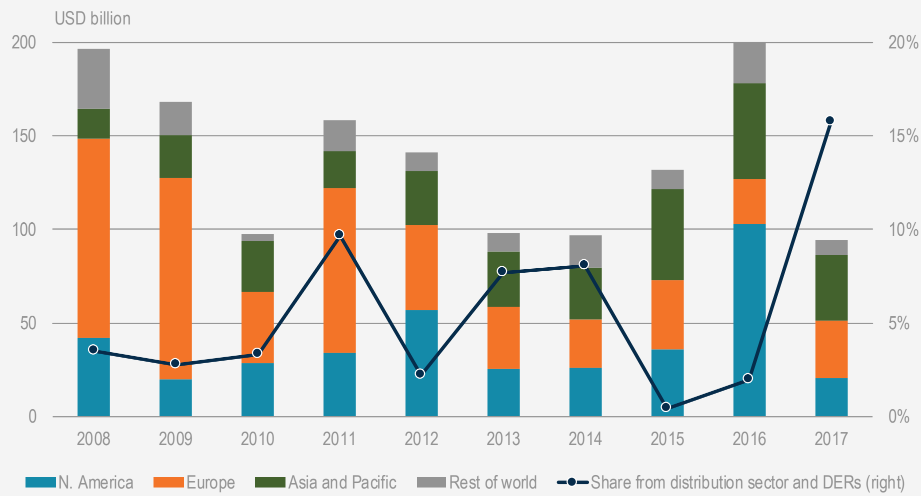
Lower M&A in the power sector, but sustained activity by Chinese companies

In 2017, global M&A activity in the power sector declined to less than USD 100 billion, more than halved from 2016 (Figure 2.28).[18] This is mainly due to a decrease in the United States, where the previous year saw some large corporate deals with transaction

[18] The M&A analysis reflects transactions with publicly disclosed values.

values of several billion dollars each. In 2017, while there were fewer large deals, acquisitions continued complementing the shift in business models observed for US utilities. All of the largest seven transactions accounting for half of the over USD 20 billion in transactions in North America involved an electric utility either acquiring assets with regulated and contracted business or selling generation assets in competitive markets or non-core business assets.

Figure 2.28 Global power sector M&A by target region



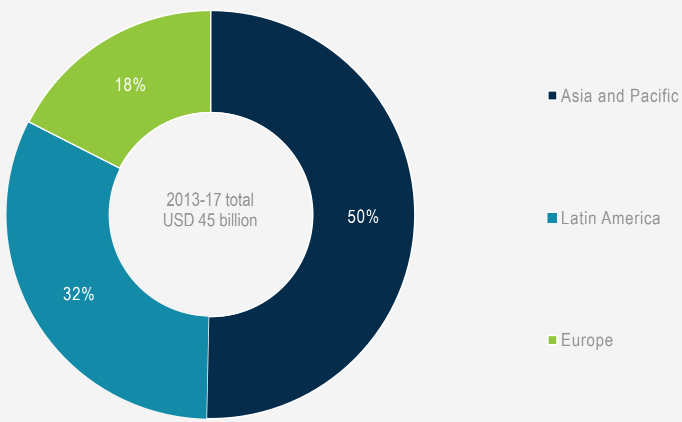
Global M&A activity in the power sector declined by half in 2017, but the share of transactions related to businesses focused on the distribution sector and distributed energy resources rose sharply.

Notes: includes the value of reported completed transactions where an electricity sector company is the seller, acquirer or target entity; includes company spinoffs and joint ventures. DERs = distributed energy resources.
Source: Based on Bloomberg LP (2018), Bloomberg Terminal.

M&A activity increased in Europe by 30% in 2017 as utilities continue to unload non-core (mostly fossil fuel-based) assets to focus on the business model shift, which drove about two-thirds of the reported transactions. Examples include divestment of upstream oil and gas assets by Uniper and Ørsted, and Engie's sale of US-based merchant gas generation. M&A activity in the region may rise in 2018 and 2019 based on Fortum's acquisition of a minority stake in Uniper, and the announcement of an asset swap between E.ON and RWE, which would focus E.ON's business on networks and customer services, such as electric mobility and distributed generation with storage, and RWE's position in renewable generation.

Overall, the role of the distribution sector, including businesses focused on networks and distributed energy resources, such as battery storage and demand response, rose to over 15% of M&A activity. This reflects the shift in utility strategies towards regulated revenues, as well as assets to support the integration of variable renewables. European utilities expanded their appetite for companies and assets that leverage digital technologies and distributed energy resources. For example, a company of Enel Group acquired demand management company EnerNOC and behind-the-meter storage operator Demand Energy. Centrica acquired REstore, which manages and aggregates demand response capacity fromindustrial and commercial consumers. Nevertheless, around two-thirds of the global distribution activity stems from a large acquisition by a Chinese company of an Australian distribution business.

Figure 2.29 China power companies overseas M&A by target region (2013-17)



Since 2012, Chinese overseas acquisitions have more than doubled. Activity has been focused mostly on renewables and networks in Asia and Pacific, Latin America and Europe.

Note: Includes the value of reported completed transactions where an electricity sector company is the seller, acquirer or target entity; includes company spinoffs and joint ventures.
Source: Based on Bloomberg LP (2018), Bloomberg Terminal.

With continued domestic consolidation and government encouragement to invest abroad, the role of Chinese companies in power sector M&A remained elevated. In 2017, their acquisitions and investment in minority stakes in a company stood at over USD 35 billion, increased by USD 10 billion from 2016. In terms of domestic activity, the merger between China Guodian and Shenhua group was approved to create China Energy Investment Group Corporation, the largest power company in the world by generating assets with combined assets valued at USD 270 billion, though this transaction was not completed as of the end of the year.

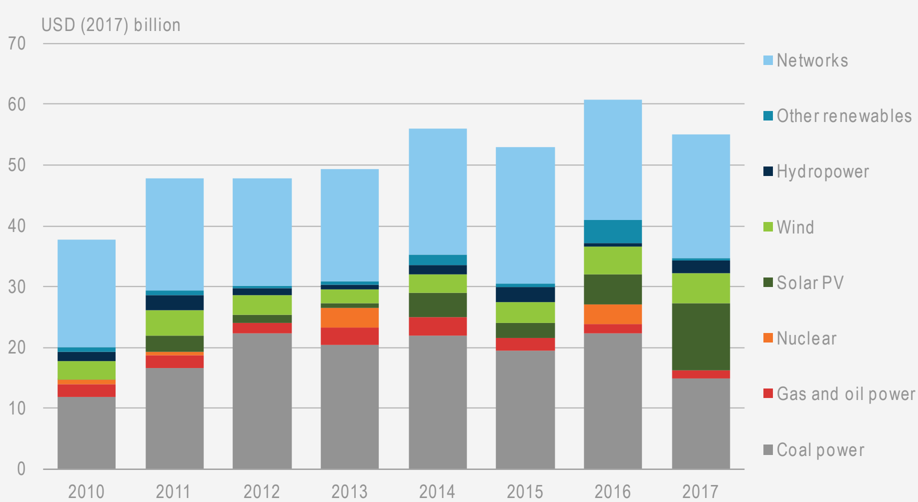
Half of these acquisitions in 2017 were made by Chinese power companies for assets located outside China, totalling almost USD 20 billion. The acquisition of Australia's Duet

Group accounted for nearly half of this. Chinese acquisitions over the past five years have focused on Europe, Latin America and other countries in the Asia and Pacific region. In particular, state-owned utilities such as the State Grid Corporation of China and the hydropower generation company Three Gorges are active in Europe, Brazil and Australia (Figure 2.29).

Focus on financing power sector investments in India

India's power sector investment is changing rapidly, and for the first time in 2017, investment in renewable power topped that for fossil fuel generation. Investment in renewables, at over one-third of total power sector investment, reached nearly USD 20 billion, driven by a more than doubling of solar PV investment and record spending in onshore wind projects (Figure 2.30). At the same time, the investment case for some thermal generation has grown more uncertain. Investment associated with the coal plants coming on line in 2017 fell by one-third to under USD 15 billion. FIDs for new coal power plants fell to their lowest level in 15 years in 2017, while thermal assets classified as financially stressed continued to rise. Investment in dispatchable renewable power plants, notably hydropower and bioenergy, as well as gas power has remained relatively low and stable. Finally, spending on electricity networks, at over 35% of power sector investment, remains near historical highs.

Figure 2.30 Power sector investment in India



India power sector investment fell by nearly 10% in 2017 due to a fall in new coal plants. Renewable investment reached a record high at nearly USD 20 billion, and networks spending remained at historical highs.

High-level policy priorities – including a 2022 target for 175 GW installed renewable capacity, provision of electricity connections to all non-electrified households, upgrading and extending the transmission grid, and improving the financial and operational performance of state distribution companies – are all driving this evolving investment picture. However, despite the supporting policy and technology backdrop, financing decisions reflect a more complex mix of project-specific risks and returns.

Renewable investments face persistent risks, but there are options to manage them

Within[19] India, there is consensus among policy makers, developers and financiers over the risks facing renewable investments, but at the same time considerable disagreement over their impact and the appropriate allocation of these risks among stakeholders involved in investments. The risks facing renewable investments generally fall into two categories: project development risks and operational risks (Table 2.1). These risks can create a challenge to investments – through reducing the availability of financing, through elevating the cost of capital or through delays to project development, for example. However, the employment of better industry strategies, policy reforms and financial instruments can create options for managing risks in order to meet high-level policy objectives.

Table 2.1 Risks and risk management for renewable investment in India

Risk	Description	Potential managing mechanisms
Power prices	States expect low power prices from renewables, with some setting ceilings near INR 3/kWh, but developers face uncertainty over technology prices and duties	Portfolio approach to project development supplemented by contracts with equipment suppliers
Bankability of PPAs	Delays in the signing of PPAs; higher-than-expected project costs relative to a fixed-price contract	More rapid timelines and better standardisation for PPAs; project structuring to exploit economies of scale and factor in contingencies
Contract renegotiation	States may seek to renegotiate power purchase contracts after seeing lower prices elsewhere	Enforcement of sanctity of contracts by regulators
Power purchase	Delays in the payment of power purchase and curtailment by off-takers	Improving the financial viability of state distribution companies and expanding options for third-party off-takers; project structuring with financial guarantees

[19] This section is jointly produced by the International Energy Agency (IEA) and the Council on Energy, Environment and Water (CEEW), with analysis based on a series of stakeholder interviews and data work carried out jointly during spring 2018. See Chawla et al. (2018) for further analysis of these topics.

Transmission infrastructure	Insufficient exchange of electricity and system services across states, which can hamper balancing	Communicating to developers about the status of major transmission projects in a transparent and regular manner; hybridisation of wind and solar plants; continued progress in transmission investment, such as through the Green Corridors programme
Land acquisition	Lack of clarity over land titles, with outdated records and fragmented landholdings; right-of-way concerns	Solar parks
Evacuation infrastructure	Availability of local grid connection and network is uncertain; no secondary market for connectivity rights	Solar parks; timely planning for grid infrastructure; penalty mechanisms to protect generators in case of transmission non-availability
Financing for small-scale projects	Lack of frameworks for evaluating creditworthiness of small companies; limited capacity of local banks, which prefer larger transactions	Lines of credit from public financial institutions for on-lending; credit appraisal methods for small consumers and capacity building for local banks; state-supported aggregation mechanisms
Transparency of asset-level risks	Lack of ongoing metrics for lenders to assess susceptibility of assets to become stressed	Developing dynamic asset-level risk assessment for projects

Sources: Based on Chawla et al. (2018) and stakeholder interviews.

Well-established industry players with access to favourable sources of finance through foreign sources of capital, balance sheet strength or by virtue of being state-owned enterprises have been instrumental in driving renewable energy deployment in India. To illustrate, the top 5 and top 10 players (in terms of share of projects sanctioned each year) have accounted for over 40% and over 60% respectively of the shares of sanctioned projects for both solar and wind generating capacity each year between 2014 and 2017 (Chawla et al., 2018). While reported shrinking profit margins amid the decline in power purchase tariffs could lead to further increases in market concentration, the design of tenders, which limit the capacity awarded to a specific parent company, could effectively limit this trend.

In terms of project development risks, the low power prices discovered in renewable auctions may post a risk for future projects (Table 2.1). In the past two years, the average price awarded in tenders for 25-year contracts for solar PV declined by around 50% to near

USD 0.05 per kilowatt hour (kWh) (INR 3.0 [Indian rupees] per kWh) in 2017, around the same price for the first tenders for onshore wind carried out that year.[20]

Figure 2.31 Project NPV of indicative utility-scale solar PV in India taking investment decision based on electricity tariff of INR 3/kWh

In 1H 2018, technology price changes amid expectations for continued low auction prices at INR 3.0/kWh raised the risk of developers not making adequate returns relative to India's high cost of equity. Future returns will depend on the evolving picture for equipment pricing, policies and financing costs.

Notes: 1H2018 = first half of 2018; NPV = net present value; GST = goods and sales tax. Calculation assumes a 100 MW solar PV plant sanctioned in 2017 where developer arranges the land and grid connection, electricity tariff of USD 0.05/kWh (INR 3.0/kWh) and 2% escalation over 25-year contract. Cost of debt = 9.5%; cost of equity = 14%; 20% reduction in return on equity = 280 basis points. Ranges reflect differences in assumed module costs, which are based on observed quarterly quotes for imported modules.
Sources: Calculations based on Chawla et al. (2018) and stakeholder interviews.

States have grown to expect low tendered power prices and some are setting tariff ceilings at levels close to INR 3/kWh. At the same time, developers face some risks over technology prices, particularly in solar PV, in part due to policy measures. In 2017, prices for imported solar PV modules started rising, a 5% goods and services tax came into effect (solar PV

[20] Auction prices are adjusted to reflect consistent assumptions on contract tenor (25 years) and escalation (2% annually).

equipment was previously exempt), and there is now uncertainty over whether plant engineering, procurement and construction activities will be taxed at the "work contract" rate of 18%. While the government has reversed plans to impose a further 7.5% tax on imported panels, there is discussion of imposing a provisional safeguard duty, of upwards of 70%, on imported solar cells.

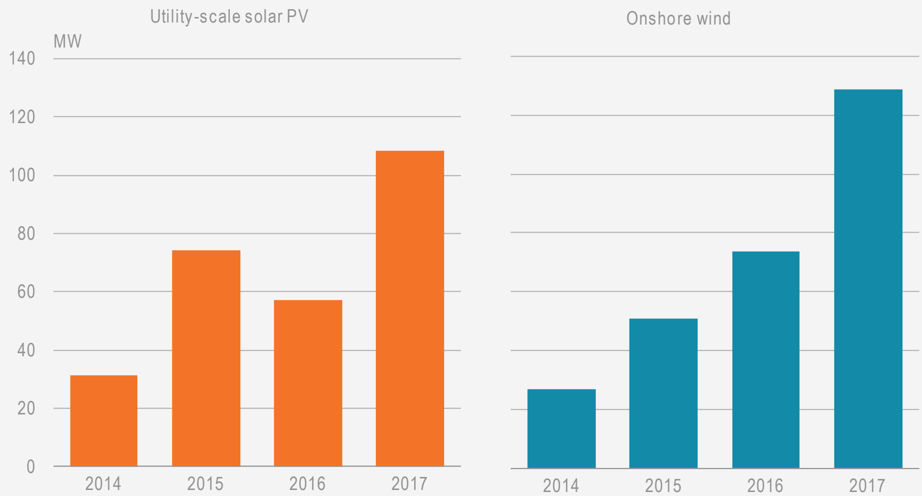
Persistent lack of clarity over technology pricing can hurt investor confidence. At the same time, expectations for continued low auction prices at INR 3/kWh can raise risks of solar PV developers not being able to propose projects that would maintain adequate returns in light of India's high cost of equity, which hovers around 14%. All things equal, returns on equity may need to decline for projects to maintain viability at 2017 power pricing levels (Figure 2.31). Nevertheless, there are expectations that downward pressure in the pricing of imported modules may emerge in the second half of 2018, owing to policy changes in China that may reduce domestic demand in that market (see Chapter 1) (Upadhyay, 2018).

Current market developments and observed prices also raise risks related to the timely signing of PPAs and contract renegotiation for already tendered projects. For example, in Jharkhand, the state distribution company delayed signing power purchase contracts for 18 months following a tender for 1.2 GW of solar PV in 2016, citing lower discovered tariffs in other states. Those contracts were ultimately renegotiated in late 2017 for 40% less capacity at 5-10% lower tariffs than those originally awarded.

At the same time, the tendering of larger lot sizes, a supportive policy environment with various fiscal exemptions for renewables and improved certainty of demand through enforcement of the state renewable portfolio obligations are helping investors to take advantage of economies of scale by sizing projects larger. The average size of projects sanctioned under renewable tenders for utility-scale solar PV has grown by over threefold since 2014 (Figure 2.32). For onshore wind, the average size of sanctioned projects has risen by almost fivefold since 2014, with a boost in 2017 from the introduction of wind auctions. This trend seen in India is similar to that witnessed in solar PV and onshore wind auctions among other emerging economies, with developers seeking to extract gains from scale in contracting, project design, operations and maintenance, and financing (see Chapter 1).

However, there may be limits for project sizes to continue growing, notably due to persistent risks related to land acquisition, right of way and availability of local infrastructure, including for evacuation of power. There is lack of clarity over land titles, with outdated records and fragmented landholdings, particularly in Jharkhand, Uttar Pradesh, Bihar and Odisha. Such local factors are a big reason hydropower investment has not grown in the past decade, despite higher central government ambitions for deployment. There are also difficulties in obtaining clearances for conversion of land from agricultural to non-agricultural purposes. Even after land acquisition, right-of-way issues pose a particular challenge for wind projects – which comprise a number of dispersed wind turbines that are connected together. Grid connections and corresponding power evacuation infrastructure were often not available in a timely manner.

Figure 2.32 Average size of renewable projects in India, by year of sanctioning



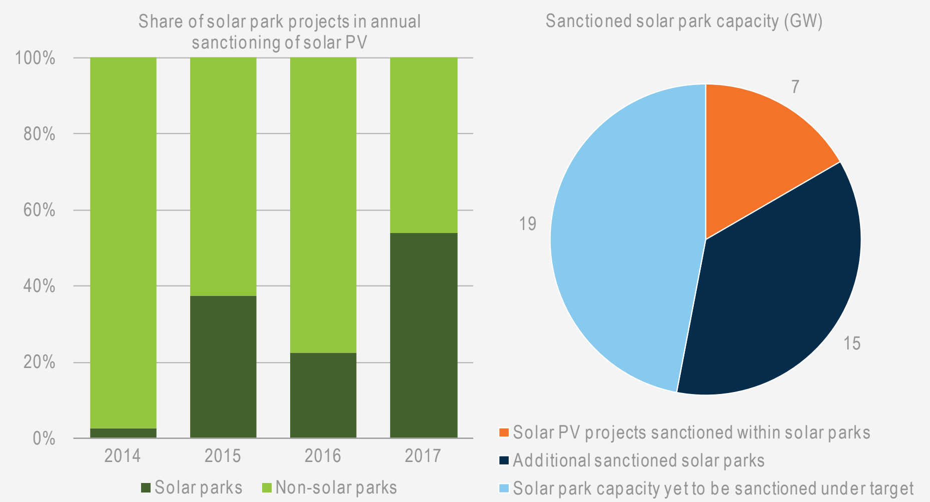
Supportive policies and tendering of larger lots help investors take advantage of economies of scale. Since 2014, the size of sanctioned solar PV has grown over threefold and wind has grown nearly fivefold.

Notes: Projects with multiple phases are treated as single projects when awarded in the same year and sharing a common developer. Sanctioning year corresponds to the year of awards under auctions, or in the case of non-auctioned projects, the estimated year of financial close. Where sanctioning date is not known but a commissioning date is available, a standard 18-month development timeline is applied for onshore wind and 15 months for solar PV.
Source: Calculations based on Chawla et al. (2018).

In combination, these development risks were leading to consistent delays in project commissioning for solar PV and wind projects beyond the timelines (15 months for solar PV; 18 months for wind) prescribed by the agencies of the central government following the signing of PPAs. The presence of these risks also explained why the government's first tenders for wind power have been designed to sell power through the interstate transmission system, rather through a specific state transmission utility. As a result, wind projects are generally being sited in relatively resource-rich and more administratively friendly states, such as Gujarat and Rajasthan.

The central government's Solar Park Scheme – which provides financial support to states to bundle together parcels of land and supporting infrastructure – is helping facilitate project development, with particular appeal to international investors. Around half of utility-scale solar PV projects sanctioned in 2017 were designed to be developed in solar parks (Figure 2.33). While the fees charged to projects vary widely, solar parks have the advantage of simplifying the process of acquiring land and infrastructure, compared with efforts by developers to arrange these items on their own. The effective price of solar power per unit can also be lower in solar parks due to more limited delays associated with project development. Recognising the risk management and efficiency benefits of solar parks, the central government approved in 2017 an upward revision to the targeted solar park capacity, from over 20 GW to 40 GW by 2020. Nevertheless, solar parks remain difficult for the states to develop. While nearly 40 solar parks, covering potentially 22 GW of capacity, have already been sanctioned under the scheme and privately, not all of these are operational. In Telangana, the state government reportedly abandoned plans in 2017 to set up a 1 GW solar park, citing its own difficulty in acquiring land.

Figure 2.33 India role of solar parks in utility-scale solar PV project development

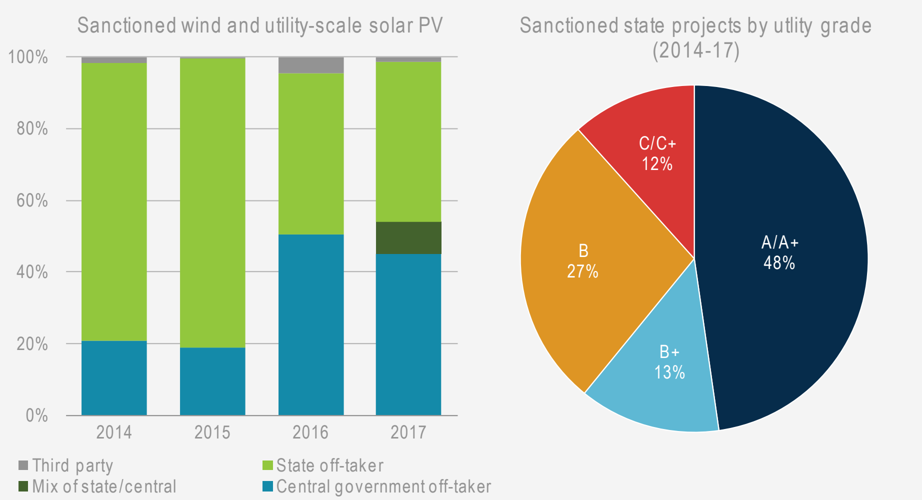


Solar parks are playing a larger role in sanctioned utility-scale solar PV projects, but their potential is not fully exploited, in part due to their relatively high prices and government land acquisition challenges.

Notes: Solar parks are defined as those sanctioned under the Ministry of New and Renewable Energy's Solar Park Scheme. Projects with multiple phases are treated as single projects when awarded in the same year and sharing a common developer.
Source: Calculations based on Chawla et al. (2018).

In terms of operational risks, security of payment by off-takers is the most significant one, but opinions are divided over how well this risk is managed with existing frameworks. The generally poor financial performance of the state distribution companies adversely impacts the reliability and timeliness of their payments for power. For tenders carried out by the central government, the payment security mechanism (PSM) provided by the Solar Energy Corporation of India (SECI) was seen as supportive, but there are some concerns over its operationalisation, and the escrow account backing the PSM may not be fully funded. Moreover, the Tripartite Agreement among the Reserve Bank of India, central government and state governments may serve as the *de facto* guarantee mechanism for payment by state distribution companies. However, these frameworks for mitigating off-taker risk do not apply to PPAs struck directly with states. Furthermore, such mechanisms would cover non-payment or delays, but would not address curtailment of renewable output, for technical or commercial reasons, which requires regulatory support, a more flexible power system and integration measures as the share of variable renewables rises.

Figure 2.34 India sanctioned wind and utility-scale solar PV by main off taker



With persistent risks over timely and reliable power purchase by state distribution companies, developers increasingly favour centrally backed off-takers and states with strong financial performance.

Notes: Projects with multiple phases are treated as single projects when awarded in the same year and sharing a common developer. Utility grades measure the operational and financial performance of state distribution companies as of 2016. A+/A = very high to high performance; B+ = moderate performance; B = below average performance; C+/C = very low to low performance.
Sources: Calculations based on Chawla et al. (2018). Utility grades are from GOI MOP (2017a).

To this end, continued investment in transmission infrastructure will be crucial to enhancing exchange of electricity and system services across states, and improving balancing. Communicating to developers about the status of major transmission projects in a transparent and timely manner as well as continued progress in transmission investment, such as through the Green Corridors programme, will be important to managing integration risks. The government's recent policy to facilitate solar-wind hybrid plants, which can include battery storage, may help to better optimise transmission infrastructure and balancing needs for renewables.

With regard to the type of off-taker, investors increasingly have confidence in central government-backed companies and agencies (e.g. NTPC, Solar Energy Corporation of India), and purchasing arrangements with these entities account for a rising share of sanctioned projects (Figure 2.34). Moreover, among states, most sanctioned projects are concentrated among off-takers with moderate (B+) to high (A) and very high (A+) operational and financial capabilities.

Looking ahead, better risk management for renewable investments is possible with a combination of short-term and long-term focused measures. In the absence of ready solutions to tackling local risks related to project development, the government may need to consider longer allowed timelines for project completion and enforce the sanctity of contracts. The use of limited public funds to provide financial guarantees as well as more creative structures for power purchase may help to manage off-take risks facing developers. For example, in Madhya Pradesh, the success of the 750 MW Rewa solar PV development tendered in early 2017 at INR 3.3/kWh (USD 0.05/kWh) was due to a combination of payment guarantees offered by the state, the availability of solar park infrastructure, participation by a multilateral development bank, and the involvement of both state- and centrally backed off-takers to manage risks. However, in the longer term, fundamental reforms to improve the financial sustainability of state distribution companies, plus efforts to improve the infrastructure and financing environment, will be needed to produce the increase in investments needed to meet high-level targets.

Box 2.4 Public finance measures seek to kick start distributed renewable investment in India

Distributed energy projects face a unique set of risks related to the small transaction size of the projects, the credit rating of the off-taker, absence of clear business models and the disaggregated nature of the market. In the solar rooftop market, credit made available for both grid-interactive and captive plants has been limited. Despite attractive self-consumption economics for commercial and industrial consumers in some states, who often face relatively high retail power prices, and policies such as net metering to support the remuneration of grid-injected power, distributed solar PV saw less than 10% of India's solar PV investment in 2017.

Financing decentralised projects, such as solar irrigation pumps, rooftop solar and mini grids, is often more difficult than for utility-scale projects despite the very large markets for these products. Local banks have limited capacity and tend to prefer the larger transaction sizes associated with utility-scale projects. Moreover, there is a lack of frameworks for evaluating the creditworthiness of smaller companies and consumers.

The slow growth in the distributed sector has resulted in more public capital and preferential lines of credit being directed at this sector. In the 2017-18 budget announcement, India announced the KUSUM (Kisan Urja Suraksha Evam Utthaan Mahaabhiyan) scheme focusing on underserved markets in rural areas, with a focus on augmenting agriculture with distributed solar applications. The large scheme, spread over ten years, will receive budgetary support of INR 48 000 crore (USD 7.4 billion), and a total collective outlay of INR 140 000 crore (USD 21.5 billion) in public spending, private capital and farmer contribution.

Additionally, for the rooftop sector, preferential lines of credit of USD 625 million have been earmarked by the World Bank, in collaboration with the State Bank of India, and another USD 100 million by the Asian Development Bank with the Punjab National Bank. While deployment of these rooftop loans is currently under way, their impact in the form of significant additional capacity is yet to be seen.

Gradual improvements in the financial sustainability of India's utilities

In India, state distribution companies have generally struggled to recover costs due to high operational losses and insufficient electricity tariffs. Investors consistently identify the creditworthiness of these entities as a top risk to developing new power projects.[21] Since 2015, reforms under the Ujwal DISCOM Assurance Yojana (UDAY) scheme seek to alleviate high debt and interest cost burdens and enforce financial discipline through alignment with state government finances, the improvement of the operational efficiency of state distribution companies, and the reduction of their cost of power. Distribution companies in the 27 states and 4 union territories under the UDAY scheme represent over 85% of nationwide energy sales.

Indian state distribution companies have gradually improved their cost recovery ratio, from 72% in the fiscal year ending 2012 to 81% in 2017 (Figure 2.35).[22] Higher revenues, reflecting rising sales, reduced operational losses and some efforts at raising electricity tariffs, have partly enabled this picture, which varies considerably across states. While isolating the precise drivers of cost recovery remains challenging given data limitations, the government assesses that a significant part of the improvements to date from the UDAY scheme appears to be from a lower financing cost burden compared with operational gains or electricity pricing reforms (GOI MOP, 2017b).

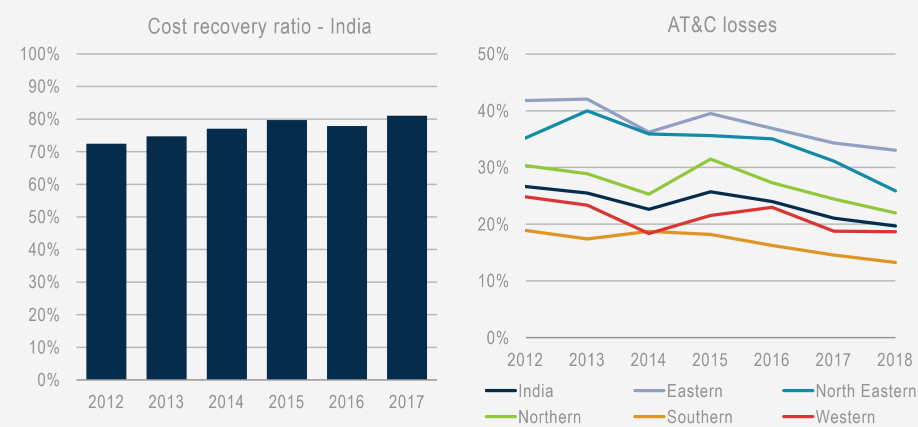
As of April 2018, roughly INR 230 000 crore, or nearly USD 35 billion, of state distribution company debt has been restructured, with state governments assuming this debt and refinancing it with bonds based on their lower cost of capital (a difference of about 400 basis points). Around INR 50 000 crore, or USD 8 billion, remains to be taken up, with

[21] India's power system is structured around state distribution companies, which function as the single largest buyers of electricity, but generation and networks are unbundled. A few private distribution companies exist, particularly in urban areas, and some consumers can purchase electricity on an open-access basis.

[22] Unless otherwise indicated, data are presented on a fiscal year (April-March) basis. While the UDAY tracking website (www.uday.gov.in/) reports state submissions, e.g. the gap between average cost of supply and average revenue (as well as other operational indicators), through calendar year 2017, these data are influenced by state subsidies. The availability of data is inconsistent across states and insufficient alone to determine cost recovery. The Ministry of Power has noted data discrepancies between provisional data from the states and final audited data (GOI MOP, 2017b).

the scheme cumulatively targeting 75% of the old state distribution company debt (as of September 2015) to be restructured in this way. Nevertheless, this debt takeover may be having impacts on the financial performance of the states themselves, with some evidence of the increased debt burden limiting the ability of states to finance capital expenditures in other areas (Usmani, 2017).

Figure 2.35 India state distribution company cost recovery and AT&C losses by region



Higher revenues, reduced operational losses and lower financing costs have enabled better cost recovery among India's state distribution companies, though progress varies considerably across states.

Notes: AT&C losses = aggregate technical and commercial losses. Cost recovery is measured as the ratio of total operating revenues to total operating costs (including depreciation) plus net financing costs for reference utilities and excluding explicit subsidy payments. 2018 AT&C losses are based on first half of year reporting.
Sources: Calculations based on Power Finance Corporation (2017), GOI MOP (2017c), and financial statements of utilities

Subsidies from state budgets play an important role for these utilities in narrowing the cost gap, driven in part by equity concerns and a desire to make electricity affordable for all consumers. On the UDAY tracking website, the gap between total costs and revenues of UDAY participants on a subsidy-received basis has reportedly narrowed to INR 330 per MWh, or USD 5 per MWh, in states submitting data as of April 2018, from INR 580/MWh at the end of 2015 (GOI MOP, 2017c). Even after the provision of subsidies, distribution companies are still not able to recover costs, and the amount and timeliness of these payments remains a risk for cost recovery. In 2016, 4% of the total subsidy booked was not released by the states.

In terms of grid modernisation, the metering of distribution lines and transformers has increased across most states, aiding in bill collection, but only 3% of targeted smart meter installations have taken place. Aggregate technical and commercial (AT&C) losses, which measure the losses between energy input and energy billed, have fallen under 20% on a national basis, but still exceeding the UDAY target of 15% by fiscal year 2019 (Figure 2.35). The central government has indicated it will propose an amendment to the tariff policy that prohibits tariff increases to compensate for financial losses resulting from AT&C losses above 15% from January 2019 (GOI MOP, 2017b).

All but two states issued updated tariff orders in fiscal year 2017. Nevertheless, the underpricing of electricity and heavy cross-subsidisation of some consumer classes, such as agriculture, persist. The central government has proposed a roadmap to simplify tariff categories as well as reduce cross-subsidies (GOI MOP, 2017b). Continued progress in tariff reform will be crucial to the financial sustainability picture going forward.

Financial issues and performance of existing assets may create headwinds for lending

The developments pertaining to investment risks for renewables and the financial viability of the state distribution companies should also be viewed in the context of the financial situation of the energy sector and the economy. In this light, addressing the issues highlighted in the first two sections may offer only a partial remedy toward financial sustainability and an enhanced environment for investment in the power sector.

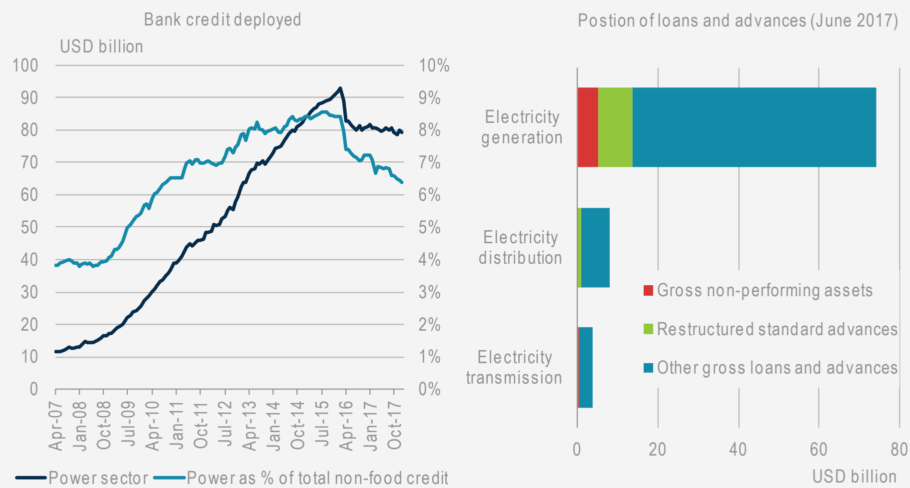
For example, there is pressure on the capacity of banks to mobilise debt for power projects. Since 2016, bank credit to the power sector has retracted somewhat (Figure 2.36). Part of this reflects a levelling off of total loans in the economy, but the share of the power sector in the total has also fallen. Sector limits prescribed to banks by the Reserve Bank of India, to guard against concentration of credit risks, limit bank loan portfolios to 20-25% across infrastructure sectors, including power, which may be constraining lending. That said, interest rates continue to decline and bank liquidity has been improving. Reduced lending to coal power projects (see FID trend in Chapter 1) also creates lending headspace for solar PV and wind projects, where sanctioned projects are growing.

Nevertheless, a deeper debate has emerged over the role of debt in the power sector and the interactions it may have with the financial system. In March 2018, the government held hearings to examine the role of stressed and non-performing assets (NPAs) and their potential implications for the banking sector and future power sector finance.[23] Thus far, the discussion has focused on thermal plants where utilisation rates for all of India have fallen from 79% to 60% over the past decade in the face of power capacity expanding by two and a half times, a

[23] Stressed assets are defined by the Reserve Bank of India as those with delays in the payment of their interest and/or principal by the stipulated date in the loan repayment schedule. An NPA, a type of stressed asset, is a loan or an advance where interest and/or principal remain overdue with respect to the term loan. An asset, including a leased asset, becomes non-performing when it ceases to generate income for the bank. Restructured standard advances, another type of stressed asset, are those loans where changes have been negotiated to the payment of the interest and/or principal, but that are still susceptible to non-payment (GOI Standing Committee on Energy, 2018).

greatly improved ability of the system to meet peak demand and lower expectations for future demand growth. These utilisation rates mask large sectoral differences, with relatively high operating hours for central government-owned plants and lower rates for private sector plants, which constitute the majority of stressed assets.

Figure 2.36 India power sector credit metrics and role of stressed assets



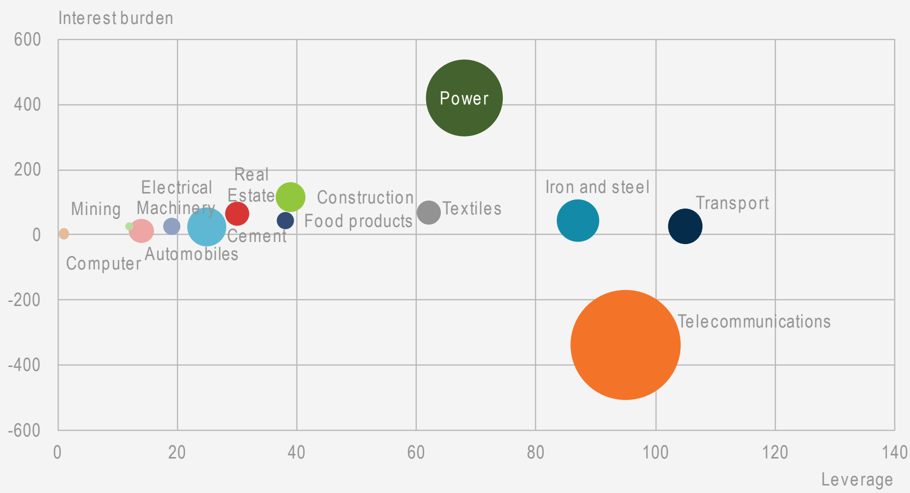
Stressed assets accounted for 18%, or over USD 15 billion, of loans outstanding in India's power sector as of June 2017. Sector lending limits and stressed assets may create headwinds for power sector lending.

Notes: Stressed assets are defined by the Reserve Bank of India as those with delays in the payment of their interest and/or principal by the stipulated date in the loan repayment schedule. All data are converted at the 2017 exchange rate.
Sources: Calculations based on RBI (2018) and GOI Standing Committee on Energy (2018).

Financially stressed assets accounted for 18%, or over USD 15 billion, of loans outstanding in the power sector as of June 2017 (Figure 2.36). Across all sectors, stressed assets accounted for around 12% of all loans, a share which has risen steadily in the past five years. While the power sector accounts for only around 10% of the economy-wide stressed loans, its share is growing, and it presents a unique risk profile as a sector with simultaneously high leverage and a high interest burden (Figure 2.37).

Some 40 GW of coal power plants (34 projects) have been identified as stressed, of which 24 GW are already commissioned (over 10% of the existing fleet) and nearly 16 GW are under construction (over 35% of the construction pipeline). The business models of these plants are generating, or are at risk of generating, insufficient cash flow to service their debts. The drivers of the stressed thermal power assets stem largely from fundamental factors in the coal supply and power sector, as well as wider financial issues.

Figure 2.37 Credit risk profiles of select industries in India, March 2017



While the power sector accounts for only around 10% of economy-wide stressed loans, it presents a unique risk profile as a sector with simultaneously high leverage and a high interest burden.

Notes: Interest burden is defined as the interest expense as a percentage of EBITDA. The size of the bubble is based on relative share of average debt of the industry unit (average debt per company) in total debt of all industries derived from non-government non-financial listed companies.
Source: RBI (2017).

First, the availability of coal supply has been insufficient for stressed assets. Although the government introduced the Scheme to Harness and Allocate Koyla (Coal) (SHAKTI) in 2017, with the intent of guaranteeing coal supply through long-term agreements, there have been delays in the implementation of the scheme and the finalisation of awarded contracts by state-owned Coal India Limited. Some power plants have received coal shipments that are different in quality and calorific value from that contracted. Still, the government has introduced differential prices for different grades and third-party monitoring of coal supplies.

Second, state distribution companies have been reluctant to enter into new PPAs or call on plants with existing PPAs to generate.[24] Of the 40 GW, less than half have PPAs. This reluctance stems from a combination of the cost recovery situation described above, increased competition from renewables, purchase of cheaper imports from power surplus states, an underinvestment in networks and affordability issues that could help to unlock demand from currently underserved consumers. At the same time, overly aggressive bidding for contracts, contract design with fuel price risk fully allocated to generators, and/or unforeseen costs and delays arising during project construction have resulted in a weakened financial case.

Lastly, banks themselves, through raising interest payments on stressed assets or strategic debt restructuring (i.e. ownership changes), have contributed to the situation. These interest penalties create a potential vicious circle for the financial performance of the stressed asset and, in the case of recourse financing, a constraint on the owner's working capital. The government is advising lenders to examine ways to support stressed assets and will propose a new rating system for assessing the credit risk of infrastructure.

Addressing stressed assets in the power sector requires a multifaceted approach across interrelated factors. In addition to resolving the issues related to the financial health of the state distribution companies, coal supply and unlocking pent-up demand, India is examining ways to enhance its electricity sector planning, operations and market design to meet the goal of integrating a large amount of new variable renewable generation over the next decade. Centralised thermal power plants originally conceived with business models based on an anticipated high number of baseload generating hours may struggle financially during the transition. However, when used flexibly, the thermal generation fleet offers considerable value to the system. A combination of better power system co-ordination, operational procedures and economic incentives that reward flexibility could better support the profitability of these assets going forward (IEA, 2018c). Moreover, in line with the government's conclusions, the expedited phase-out of old thermal power plants would help ease the financial stress on the newer plants.

Given India's need for increased investment in renewables, electricity networks and other forms of flexibility, the central government and the states will need to continue to address persistent risks related to the financial sustainability of the power system. However, there are also feedback loops between the energy and financial sectors that require monitoring and an integrated approach. For example, the revised framework of the Reserve Bank of

[24] A plant operating under a PPA should in theory be able to recover its fixed costs, even if not scheduled, due to the two-part tariff structure (fixed and variable costs) where fixed costs are paid regardless of schedule. However, some private projects have structured their price bids in such a manner where a portion of fixed costs are transferred to variable costs.

India is stringent regarding banks' treatment of stressed assets. It has also increased the potential losses that banks must guard against by holding capital in reserve, thereby creating some potential headwinds for further lending. Moreover, the financial losses by state distribution companies create risks for the development of new power projects as well as the fiscal performance of state budgets.

Financing energy efficiency investments

Balance sheet financing accounts for the vast majority of energy efficiency spending within the private sector. Household energy efficiency improvements are largely paid for with the energy users own funds, including savings and loans. Non-household spending includes tax revenues and bonds, and corporate investment of revenues, equity and debt. For companies, energy efficiency projects typically have to compete against other corporate investments, meaning that they must meet high return expectations. Securing specific lines of debt to fund balance sheet energy efficiency investments can overcome this challenge, offer lower-cost capital than reinvestment of revenue and enable faster expansion of energy cost savings. However, the ability to obtain loans or other forms of borrowing is generally dependent on the creditworthiness of the entire company, which can present a difficulty for companies that are trying to improve their energy efficiency. This can be a particular problem for companies, including municipal services, in emerging economies despite the positive impact that energy cost savings can have on creditworthiness.

To help overcome the challenge of channelling finance to energy efficiency projects that have positive NPV but are overlooked by corporate management or investors, attention to the financing models of ESCOs is increasing. Two issues for ESCOs – accounting treatment of contracts and energy savings insurance (ESI) – are discussed in the following section. The section is not a comprehensive overview of all methods of finance for energy efficiency, but outlines a few key and growing trends in the market, including a review of trends in green bank finance and green bond issuance for energy efficiency.

Securing finance for ESCO investments

The value of the ESCO market is growing and is mostly concerned with energy efficiency projects that generate value for both the client and the project developer through energy bill savings. In general, ESCOs design, install and finance energy efficiency projects – generally refurbishments – and undertake ongoing operations and maintenance. Project contract terms can range from around 7 to 20 years, depending on the types of measures. The value of the global ESCO market reached USD 26.8 billion in 2016 (IEA, 2017) with indications of continuing growth into 2017. China is the largest ESCO market, where favourable government policy settings encourage the adoption of efficiency measures through ESCOs using measures including tax incentives, a special directive and a favourable accounting system. In the industry sector in particular, this has led to rapid market expansion. In India, a single "super ESCO", Energy Efficiency Services Limited (EESL), has been responsible for much of the energy activity in recent years. It uses bulk public procurement to purchase highly efficient equipment at low prices, distribute it to consumers and reclaim costs via electricity bills, which are nonetheless lower than they would have been. By June 2018, EESL had distributed over 300 million light-emitting diodes (LEDs) and expanded the model to other devices.

Energy performance contracts can facilitate off balance sheet financing

Most agreements between customers and ESCOs are underpinned by energy performance contracts (EPCs) that establish the minimum performance of energy efficiency measures. The EPC commits the ESCO to installing the necessary equipment, provides guarantees for performance and energy saving and establishes the terms of the upfront and ongoing payments. Depending on the customer’s preference and access to capital, the project can be financed by the customer or the ESCO or a combination of the two. In both cases, the customer or the ESCO may enter into a direct loan agreement with a third-party lender to secure financing for the project. EPCs provide the customer with a guaranteed level of energy savings and the ESCO with a reliable source of revenues.

For a company wishing to pursue energy efficiency opportunities, the attractiveness of an EPC as a way to enable energy efficiency investment depends strongly on accounting rules, which vary between countries and regions. There are different models for how EPCs can be structured, which impact whether a public or private sector entity can record an EPC as on- or off-balance sheet. Reporting an EPC on the balance sheet indicates an increase in the debt or liability held by the organisation, the unattractiveness of which has been known to prevent EPCs from being concluded.

In the United States, EPCs can be structured as operating leases, which are not counted on a company’s balance sheet under the generally accepted accounting principles. In 2017 the European Commission issued a statement clarifying the terms under which an EPC can be accounted for off-balance sheet in the framework of the ESA2010 European System of Accounts (EC, 2017; EC, 2013) in an effort to increase energy efficiency investment. The European Commission and European Investment Bank have released a guide to facilitate the understanding of the statistical treatment of EPCs but, as this clarification was issued only in September 2017, its impact is still to be determined (EC and EIB, 2018).

ESI can further reduce risk associated with ESCO projects

Another factor inhibiting energy efficiency investment through ESCOs is the uncertainty associated with the performance of efficiency measures. While anecdotally this perception is changing, it remains a barrier for investors who lack the time or expertise to judge individual projects that have unique characteristics. In response, ESI has emerged as a solution offered by a small number of financial institutions and private companies as a way to demonstrate the bankability of a project to financial institutions. ESI is most appropriate for ESCOs or smaller enterprises with poor credit or who lack the means to secure third-party financing.

Typically, there are two types of insurance packages: technical and credit.[25] Under the technical package, the insurance provider covers the ESCO or technology provider in the event that promised energy savings are not achieved, assuming the technical risk associated with efficiency projects. In the credit scheme, the insurance provider assumes the credit risk of a project, thereby ensuring that repayments owed to the ESCO can continue to be made, in the case of a customer default (Figure 2.38).

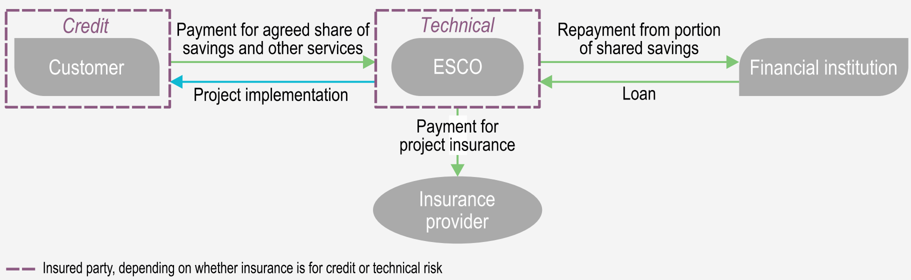
One of the main ESI providers is HSB Engineering Insurance. Since 2016 HSB, which is based in the United Kingdom but engaged in projects throughout Europe, has been offering ESI for a wide range of projects. The ESI offered by HSB is flexible and can fit a variety of projects, in varying sectors. There are several users of insurance products offered by HSB. Joule Assets provides project aggregation and facilitation services that connect ESCOs with financers and calculate project insurance. SUSI Partners, through its Energy Efficiency Fund (SEEF), has been involved in several ESCO projects using ESI. In early 2018, SEEF and Philips Lighting partnered on Light as a Service (LaaS), an initiative to provide efficient lighting systems for no up-front cost. The initial financing facility of EUR 25 million targets seven European countries.

There are other institutions, including development banks beyond Europe and North America that are also facilitating ESI. The Basel Agency for Sustainable Energy (BASE), a Swiss foundation, along with the Inter-American Development Bank (IDB), has developed an ESI model tailored to public sector investment that has been employed in Central and South America. It is also being implemented in Europe and assessed or developed in Asia and Africa. The model differs from that used by private providers such as HSB, in that it engages local insurance providers to develop an insurance product, typically a surety bond, as well as supporting mechanisms (such as a standardised contract and an external validation mechanism) to build trust between actors and lower the risk perception of energy efficiency projects. The insurance is offered for the first five years of the operation of the provided technology.

[25] Both of these can be applied to the different models for ESCO contracts and financing, including the most common models: guaranteed savings and shared shavings. In the guaranteed savings model, the ESCO assures a level of energy savings and the customer is typically responsible for securing finance. In the shared savings model, the ESCO generally secures the financing and the customer and ESCO "share" the financial savings. The shared savings model lends itself more readily to securitisation.

A leading example of this model is the ESI Colombia project, which was established in 2014 in collaboration with the IDB and the Colombian development bank, Bancoldex, with support from the CTF and the Danish government. The main focus of the programme is to facilitate energy efficiency investments in small to medium-sized enterprises, in particular hotels and hospitals. The programme is focused on six main technology improvements: air conditioning, automation systems, boilers, solar water heaters, solar pool heating systems and co-generation. The cost of insurance is less than 1% of the total value of the new energy-efficient product. It is expected to mobilise USD 20 million of investments in hospitals and hotels, to finance approximately 104 projects (IDB, 2016).

Figure 2.38 ESI applied to the ESCO shared savings model



Technical and credit risk insurance are two approaches increasingly used by ESCOs to ensure energy efficiency projects' bankability and enable customers to secure financing and guaranted savings.

In 2017, the ESI Mexico project was launched with the support of the Clean Technology Fund and the Danish government, targeting energy efficiency projects in the agro-industry sector within the country. It is expected to mobilise USD 25 million of investment in 190 energy efficiency projects in the agro-industry sector through 2020.[26]

Early evidence indicates that ESI can help an energy efficiency project to meet return expectations even if it underperforms by up to 60% in energy savings terms, providing a much higher degree of investor confidence (Micale, Stadelmann and Boni, 2015). Without insurance, a 20% underperformance can lead to a loss for the investor. Scaling up ESI will

[26] 2018 personal correspondence with BASE.

require more providers to enter the market, increasing competition and availability, which depends on a much more widespread understanding among insurers of the risks of energy efficiency projects. In Latin America, training of insurers has been a key component of ESI initiatives.

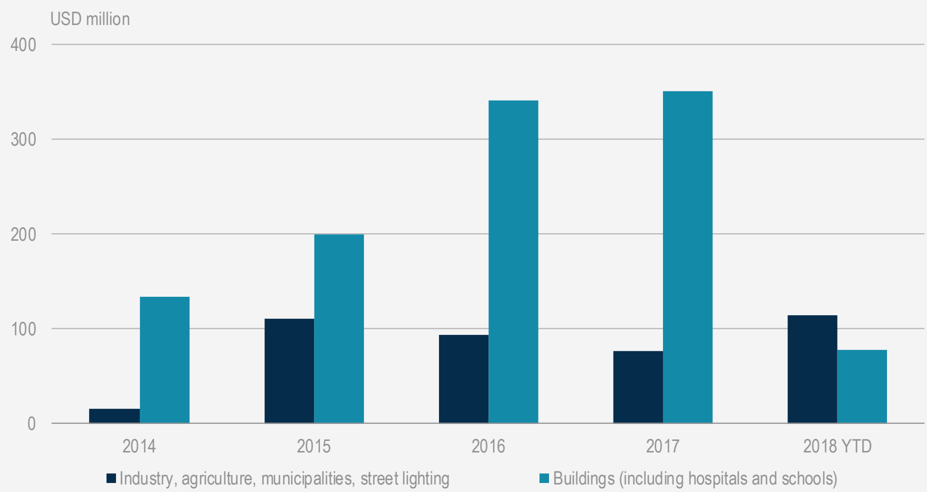
Energy efficiency financing by green banks

Green banks, a type of public financial institution, are playing an increasingly important role in funding energy efficiency and clean energy projects. Green banks are established by national or local governments to work with private lenders to leverage private investment dedicated to projects that will benefit the environment and are commercially viable but struggle to attract finance (Coalition for Green Capital, 2018). They can be public, quasi-public or private institutions with a mandate from a public authority to ensure the scope of their activities. Most green banks invest public funds in projects, alongside private capital. The first green bank, the Connecticut Green Bank, was established in 2011 and there are now at least nine green banks operating at the regional, national and international levels, of which six are members of the Green Bank Network. While there are other financial institutions that play an important role in mobilising private sector capital for energy efficiency and other low-carbon energy projects,[27] the investments reported here cover those made by members of the Green Bank Network. To date these six have invested over USD 9 billion across a variety of sectors, including energy efficiency.

Green bank investment in energy efficiency projects reached USD 430 million in 2017, a 2% decrease from levels in 2016 (Figure 2.39). The buildings sector has so far been the leading recipient of this investment, consistent with overall energy efficiency investment (see Chapter 1), reflecting the availability of low-cost and scalable energy efficiency projects. Buildings sector investment in energy efficiency by green banks reached USD 350 million in 2017. Most of this was loans to small and medium-sized enterprises for building and equipment upgrades, plus new construction of energy-efficient single-family homes. Some of the funds have been allocated to the purchasing of green bonds, however, so are spent on new or refinanced projects by third parties. Data for the first quarter of 2018 show a reversal of the sectoral shares, with higher investments outside the buildings sector, but this may be only a temporary situation. Together, the industry, agriculture, municipalities and street lighting sectors received USD 80 million in 2017. This 2017 total was below the two previous years, but has already been surpassed in the first quarter of 2018 by spending by the Australian Clean Energy Finance Corporation (CEFC).

[27] Including national and multilateral development banks. For more information, see OECD (2016).

Figure 2.39 Green bank investment in energy efficiency, 2014-18



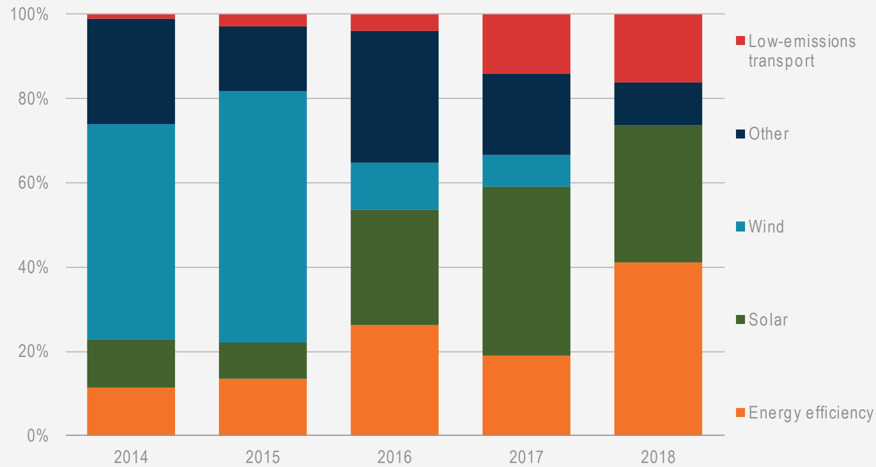
The buildings sector has so far been the leading recipient of energy efficiency investment by green banks globally, but data for the first quarter of 2018 shows a sizeable increase in industrial and service sectors.

Note: Transactions occurring in 2018 reflect closings that have been finalised through the date of the individual green banks' latest public reporting.
Source: Green Bank Network (2018).

The Australian CEFC is a significant player in green bank investment. This government-owned bank represents nearly 50% of total investment by green banks around the world to date and is responsible for almost all the investment by green banks in low-carbon transport and the increase in the share of solar and energy efficiency in green bank investment since 2016. For its energy efficiency investments, CEFC has partnered with the Australia and New Zealand Banking Group (ANZ) Energy Efficient Asset Finance programme, which has led to a reduction in finance rates for customers. CEFC has committed 150 million Australian dollars (AUD) to the programme, which allows ANZ to offer a discount of 0.7 percentage points on the standard asset finance rate for loans of up to AUD 5 million if energy efficiency requirements are met (CEFC, 2018). The CEFC funds have a term of 11.5 years and an interest rate of 3.1% (CEFC, 2017).

Renewable energy projects, specifically wind and solar, have historically dominated green bank investment (Figure 2.40). However, the share of investment for energy efficiency and low-emissions transport has been increasing. Energy efficiency represented just under 20% and low-emissions vehicles 15% of total green bank investment in 2017. At 26%, the share of energy efficiency investment was higher in 2016, but the share for low-emissions vehicles has increased substantially from 4% in 2016.

Figure 2.40 Annual investment by green banks by topic since 2014



Renewable energy, specifically wind and solar projects, has historically dominated green bank investment, but the share of investment for energy efficiency and low-emissions transport is increasing.

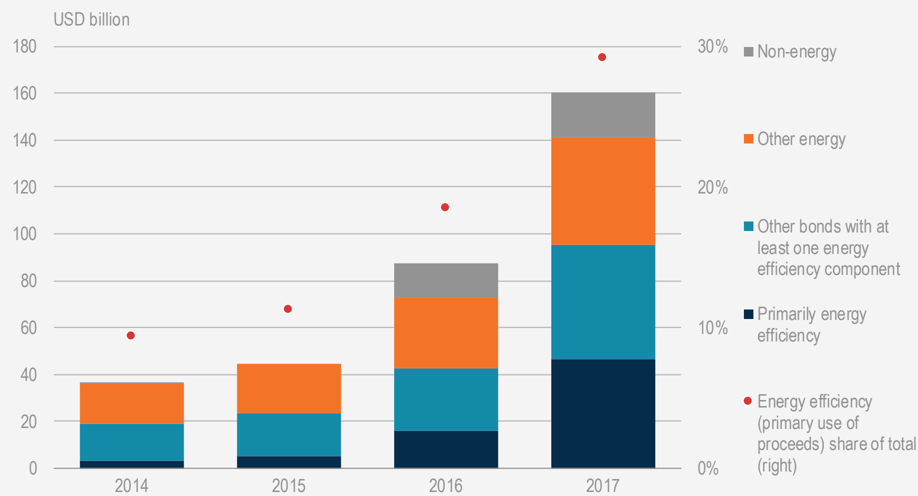
Notes: Covers six entities: Australia CEFC, Malaysia Green Technology Corporation, Connecticut Green Bank, New York Green Bank, Japan Green Finance Organisation, UK Green Investment Bank. Transactions occurring in 2018 reflect closings that have been finalised through the date of the individual green banks' latest public report release. These dates differ by bank. The "other" category are projects including waste-to-energy investments, energy storage, geothermal and smart grid technology.
Source: Green Bank Network (2018).

Energy efficiency financing by issuance of green bonds

The issuance of green bonds continues to grow and energy efficiency represents an increasing share of the disclosed uses of the funds raised. Green bonds aim to connect debt capital markets to companies and projects in energy and other sectors that have environmental benefits. They can provide investors with transparency of their investment towards a set of specific green projects or activities, either by financing new assets or refinancing existing assets. By connecting investments with the debt capital markets, they can also provide a lower-cost source of financing, or refinancing, than bank loans, thereby helping to reduce the lifetime cost of capital for projects. [28]

[28] Green bonds cover: corporate bonds; ABS; supranational, sub-sovereign and agency bonds; municipal bonds; project bonds; sovereign bonds; and financial sector bonds. In this report, only green bonds labelled to provide transparency to investors are discussed; unlabelled climate-aligned bonds are excluded. The market for "climate-aligned" bonds was estimated at USD 674 billion in 2017 (Climate Bonds Initiative, 2017). Additionally, some regions have or are developing their own standards. For example, China has a separate standard that does not always align with international green bond standards.

Figure 2.41 Global green bond issuance by use of proceeds, 2014-17



The share of energy efficiency in the total value of green bonds has risen as the market has grown and the value of green bonds issued primarily for energy efficiency passed that of renewable energy in 2017.

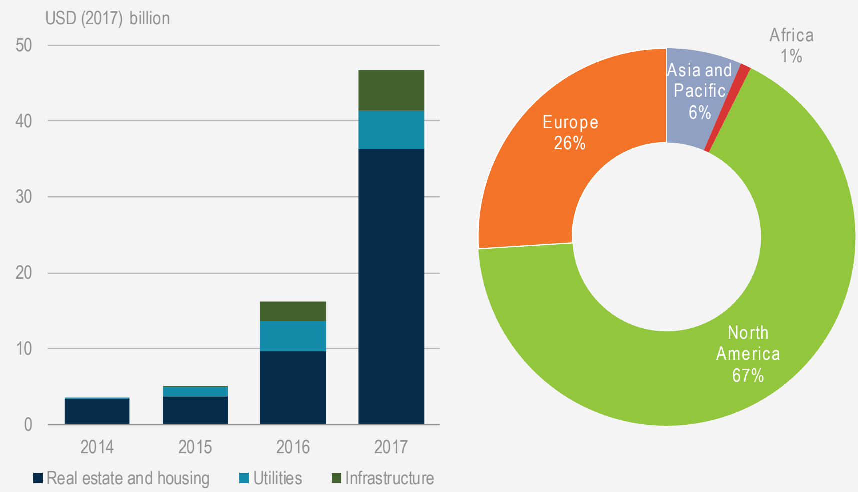
Notes: Green bonds included are those labelled under the Climate Bonds Taxonomy and Certification Scheme. Allocation by energy end use follows Climate Bonds Initiative conventions. "Non-energy" includes uses such as forestry and climate adaptation projects.
Source: Based on data provided by Climate Bonds Initiative (2018).

At USD 160 billion, nearly twice the value of green bonds was issued in 2017 compared with 2016 (Figure 2.41). The value of green bonds issued primarily for energy efficiency uses nearly tripled to USD 47 billion in 2017, from USD 16 billion in 2016, for the first time overtaking the value of green bonds issued primarily for renewable and other energy sources.[29] In addition, green bonds recording energy efficiency as a secondary component of their uses of proceeds – including those from sectors including banking, manufacturing, public transport, EVs, utilities, water and waste management and government – represent

[29] While it can be difficult to assess the percentage of a green bond's proceeds that will be dedicated to energy efficiency, this section follows the Climate Bonds Initiative conventions for allocation by energy end use. Green bonds for which the use of proceeds is allocated to energy efficiency include those that specifically target energy efficiency applications in accordance with the Climate Bonds Standard, as well as green bonds for all Property Assessed Clean Energy (PACE) ABS, rooftop solar PV ABS (which reduce energy imports to a building), and issuances from corporate and public entities in the utilities, property and transport infrastructure sectors.

an additional USD 49 billion, or 30% of the total, up from USD 26 billion in 2016. Of the remainder, nearly three quarters was for other energy applications.

Figure 2.42 Green bonds for energy efficiency, by sector and region, 2014-18



Among companies active in energy efficiency projects, the real estate and housing sector remains the largest issuer of green bonds; with infrastructure and utility companies, issuance is growing more slowly.

Notes: Real estate and housing includes real estate investment trusts, PACE ABS and mortgage lenders. Green bonds included are those labelled under the Climate Bonds Standard and Certification Scheme. Infrastructure includes, for example, transport infrastructure developers, such as airports and public transport, and manufacturers of EVs.
Source: Calculations based on data provided by Climate Bonds Initiative (2018).

Among sectors related to energy efficiency, the real estate sector continues to be the major issuer of green bonds by value, for building upgrades and new construction, but utilities and infrastructure developers have markedly increased their shares of the total. Between 2014 and the first quarter of 2018, USD 60 billion in green bonds was issued by companies and public bodies in the real estate sector (Figure 2.42). This included green bonds covering a high volume, USD 34 billion, of mortgage-backed securities arising from the US Federal National Mortgage Association's Green Rewards programme for energy and water efficiency improvements in multifamily housing in the United States. Issuance from utilities and transport infrastructure developers – including for the Mexico City airport – increased from USD 6.6 billion in 2016 to USD 10.3 billion in 2017, but represented a lower share of the total due to the rise in the issuances from the real estate sector.

At USD 54 billion, North American entities represented 67% of the green bonds issued by companies and public bodies in sectors related to the implementation of energy efficiency projects since 2012. By far the largest US issuer is the US Federal National Mortgage Association. In addition, green bonds with a total value of USD 4.3 billion were issued in North America between 2012 and the first quarter of 2018 to raise funds for refinancing to securitise small-scale PACE loans that support energy efficiency improvements in households and businesses through on-bill financing, allowing for capital to be made available for new investment. Entities in Europe accounted for 26% of the total during the same period, mostly utilities, property banks and real estate companies.

References

Azar, A. (2017), *Reserve Base Lending and the Outlook for Shale Oil and Gas Finance*, Center on Global Energy Policy, School of International and Public Affairs, Columbia University, New York.

Bloomberg LP (2018), Bloomberg Terminal, (accessed 14 May 2018).

BNEF (Bloomberg New Energy Finance) (2018), *Renewable Energy Projects*, www.bnef.com/.

CEFC (Clean Energy Finance Corp) (2018), "CEFC and ANZ $150 million program helps businesses cut energy costs through innovation", web page, Sydney, www.cefc.com.au/case-studies/cefc-and-anz-150-million-program-helps-businesses-cut-energy-costs-through-innovation/ (accessed 27 June 2018).

CEFC (2017), *Quarterly Investment Report: 31st December 2017*, Sydney, www.cefc.com.au/media/390708/CEFC-Quarterly-Investment-Report-December-2017.pdf (accessed 27 June 2018).

Chawla, K. et al. (2018), *Clean Energy Investment Trends: Evolving Landscape for Grid-Connected Renewable Energy Projects in India*, Council on Energy, Environment and Water (CEEW) and OECD/IEA, New Delhi, http://ceew.in/publications/clean-energy-investment-trends (accessed June 2018).

Climate Bonds Initiative (2017), *Bonds and Climate Change: The State of the Market 2017*, Climate Bonds Initiative, London.

Deloitte (2018), *Oil & Gas Mergers and Acquisitions Report – Year-end 2017 Working Under Pressure,* https://www2.deloitte.com/us/en/pages/energy-and-resources/articles/oil-and-gas-mergers-and-acquisitions.html (accessed 2 July 2018).

EC (European Commission) (2017), *Eurostat Guidance Note on the Recording of Energy Performance Contracts in Government Accounts,* European Commission, Brussels.

EC (2013), *European System of Accounts 2010*, Brussels.

EC and EIB (European Investment Bank) (2018), *A Guide to the Statistical Treatment of Energy Performance Contracts*, http://ec.europa.eu/eurostat/documents/1015035/8885635/guide_to_statistical_treatment_of_epcs_en.pdf/f74b474b-8778-41a9-9978-8f4fe8548ab1 (accessed 7 June 2018).

EEI (Edison Electric Institute) (2017), *2017 Financial Review: Annual Report of the U.S. Investor-Owned Electric Utility Industry*, Edison Electric Institute, Washington, D.C., www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2017.pdf.

EvaluateEnergy (2018), *Annual 2017 oil and gas M&A reaches $163 billion in the E&P sector*, Calgary, www.evaluateenergy.com/index.html (accessed 2 July 2018).

GOI MOP (Government of India, Ministry of Power) (2017a), *State Distribution Utilities Fifth Annual Integrated Rating*, MOP, New Delhi, https://docplayer.net/51622654-State-distribution-utilites-fifth-annual-integrated-rating.html.

GOI MOP (2017b), Minutes of the Conference of Power and NRE Ministers of States/UTs held on 7th December, 2017 in New Delhi, MOP, New Delhi, www.eqmagpro.com/minutes-of-the-conference-of-power-and-nre-ministers-of-states-uts-held-on-7th-december-2017-in-new-delhi/.

GOI MOP (2017c), UDAY National Dashboard, New Delhi, https://www.uday.gov.in/home.php (accessed 1 July 2018).

GOI Standing Committee on Energy (2018), *Stressed/Non-performing Assets in Electricity Sector: Thirty-Seventh Report*, Lok Sabha Secretariat, Standing Committee on Energy, New Delhi, http://164.100.47.193/lsscommittee/Energy/16_Energy_37.pdf.

Green Bank Network (2018), *Green Bank Network Investments by Technology Sector*, Green Bank Network, Washington D.C.

Green Giraffe (2017), "Offshore wind finance – evolution and outlook", Project finance and M&A (PFMA) forum for renewable energy, 11 September 2017, Berlin, https://green-giraffe.eu/file/2332/.

GTM Research (2018), *Share of Third-Party-Owned Systems at Record-Low Levels in US Residential Sector*, GTM Research Spotlight, www.greentechmedia.com/articles/read/share-of-third-party-owned-systems-at-record-low-levels-in-us-resident#gs.Gu8eDk4 (accessed 1 June 2018).

IAEA (International Atomic Energy Agency) (2018), *Power Reactor Information System (PRIS)*, IAEA, Vienna, Austria, www.iaea.org/pris/.

IDB (Inter-American Development Bank) (2016), *CO-T1332 – Mitigation of GHG Emissions through EE in the Hotels and Clinics\Hospitals Sub-Sectors*, Inter-American Development Bank, New York.

IDFC (International Development Finance Club) (2017), *IDFC Green Finance Mapping Report 2016*, International Development Finance Club, www.idfc.org/Downloads/Publications/01_green_finance_mappings/IDFC_Green_Finance_Mapping_Report_2017_12_11.pdf (accessed 12 May 2018).

IEA (International Energy Agency) (2018a), *Oil 2018: Analysis and Forecasts to 2023*, Market Report Series, OECD/IEA, Paris.

IEA (2018b), *Status of Power System Transformation 2018: Advanced Power Plant Flexibility*, OECD/IEA, Paris.

IEA (2017), *World Energy Investment 2017*, OECD/IEA, Paris.

IEA/IRENA (International Renewable Energy Agency) (2018), *Global Renewable Energy Policies and Measures Database,* www.iea.org/policiesandmeasures/ (accessed June 2018).

IJGlobal (2018), "Transaction Data", web page, https://ijglobal.com/data/search-transactions (accessed 14May 2018).

IMF (International Monetary Fund) (2018), *Global Financial Stability Report: April 2018*, IMF, Washington, D.C., www.imf.org/en/Publications/GFSR/Issues/2018/04/02/Global-Financial-Stability-Report-April-2018.

IRENA (2018), *Corporate Sourcing of Renewables: Market and Industry Trends – REmade Index 2018*, International Renewable Energy Agency, Abu Dhabi, www.irena.org/publications/2018/May/Corporate-Sourcing-of-Renewable-Energy.

Kojima, M. and C. Trimble (2016), *Making Power Affordable for Africa and Viable for Its Utilities*, World Bank Group, Washington, D.C., https://openknowledge.worldbank.org/handle/10986/25091.

Micale, V., M. Stadelmann and L. Boni (2015), "Energy savings insurance: Pilot progress, lessons learned, and replication plan", Global Innovation Lab for Climate Finance, Climate Policy Initiative, Venice, www.climatefinancelab.org/wp-content/uploads/2014/08/Energy-Savings-Insurance-Lab-Phase-3-Analysis-Summary-1.pdf.

OECD (2016), *Green Investment Banks, Scaling up Private Investment in Low-carbon, Climate-resilient Infrastructure*, OECD Publishing, Paris, www.oecd.org/env/cc/green-investment-banks-9789264245129-en.htm (accessed 7 June 2018).

Pechman, C. (2016), *Modernizing the Electric Distribution Utility to Support the Clean Energy Economy*, US Department of Energy, Washington, D.C., www.energy.gov/sites/prod/files/2017/01/f34/Modernizing%20the%20Electric%20Distribution%20Utility%20to%20Support%20the%20Clean%20Energy%20Economy_0.pdf (accessed 04 April 2018).

Platts (2018), *World Electric Power Database*, Platts, Washington, D.C.

PLS (2018), “2017 Y/E U.S. Oil & Gas Upstream M&A Review & Outlook”, PLS, Houston. www.plsx.com/pdf/presentations/PLS-YE-2017-US-Upstream-MA-Review.pdf (accessed 7 June 2018).

Power Finance Corporation (2017), *Report on the ‘’Performance of State Power Utilities for the years 2013-14 to 2015-16’’*, New Delhi, www.pfcindia.com/DocumentRepository/ckfinder/files/Operations/Performance_Reports_of_State_Power_Utilities/1_Report%20on%20the%20Performance%20of%20State%20Power%20Utilities%202013-14%20to%202015-16.pdf.

Power Finance Corporation (2017), *Report on the Performance of State Power Utilities,* Power Finance Corporation, New Delhi.

REN21 (2018), *Renewable 2018: Global Status Report*, REN21, Paris, www.ren21.net/wp-content/uploads/2018/06/17-8652_GSR2018_FullReport_web_-1.pdf.

RMI (Rocky Mountain Institute) (2018), *Business Renewables Center*, dataset provided to the IEA.

RBI (Reserve Bank of India) (2018), *Database on Indian Economy*, RBI’s Data Warehouse, New DelhI, https://dbie.rbi.org.in/DBIE/dbie.rbi?site=home.

RBI (2017), *Financial Stability Report,* Issue No. 15, Reserve Bank of India, New Delhi, www.rbi.org.in.

Upadhyay, A. (2018), “India sees record low solar prices returning on China reforms”, The Economic Times, www.economictimes.indiatimes.com/articleshow/64473786.cms?utm_source=contentofinterest&utm_medium=text&utm_campaign=cppst (accessed 01 July 2018).

Usmani, A. (2017), “UDAY May Add to ‘Worrying’ Decline in States’ Capex, Says ICRA”, BloombergQuint, www.bloombergquint.com/business/2017/09/06/uday-may-add-to-worrying-decline-in-states-capex-says-icra (accessed 9 April 2018).

WindEurope (2018), *Financing and Investment Trends: The European Wind Industry in 2017*, WindEurope, https://windeurope.org/wp-content/uploads/files/about-wind/reports/Financing-and-Investment-Trends-2017.pdf.

World Bank, ADB, IDB, IIC, EIB et al, (2017), 2016 Joint report on multilateral development banks’ climate finance, World Bank Group, Washington, D.C. http://pubdocs.worldbank.org/en/266191504817671617/2016-joint-report-on-mdbs-climate-finance.pdf, (accessed 4 July 2018).

3. Investment in R&D and new technologies

Highlights

- **Government spending on low-carbon energy R&D increased by up to 13% in 2017, passing the USD 20 billion (United States dollars) mark**, after several years of stagnation. The United States led the increase. Low-carbon energy technologies now account for 80% of total public R&D. On average, governments allocate around 0.1% of their total public spending to energy R&D.

- **Corporate spending on low-carbon energy R&D also grew in 2017, broadly in line with the five-year trend of 6% annual growth.** The automotive sector, where intense competition in alternative fuel technologies is forcing firms to step up their R&D efforts, was the main driver. Low-carbon energy accounts for two-thirds of total reported corporate energy R&D.

- **Low-carbon energy venture capital (VC) investment amounted to USD 2.1 billion in 2017** – lower than in 2016, when investment spiked with several big deals, but close to the levels prevailing before the 2012 cleantech bust. Recent growth has been driven almost entirely by clean transportation investments, but digital efficiency technology is attracting more funding. Renewables hardware VC investment remains lower than 2014.

- **Only around 15% of the USD 28 billion of public funds earmarked for large carbon capture, utilisation and storage (CCUS) projects since 2007 has been spent**, partly because commercial conditions and regulatory uncertainty have deterred private investors. A commercial incentive as low as USD 50 per tonne of CO_2 sequestered could trigger investment in the capture, utilisation and storage of over 450 million tonnes of CO_2 globally in the near term – 15 times current volumes. This would make a significant contribution to efforts to cut emissions.

- **A record number of investment decisions were taken in 2017 to build electrolysers to make hydrogen for clean energy applications.** While investment remains well below that in electric batteries for stationary storage and road vehicles, interest in hydrogen projects is growing.

- **The costs of batteries for EVs will be strongly influenced by investments outside the energy sector.** Investment in lithium mining has risen almost tenfold since 2012, while that in battery manufacturing capacity has risen more than fivefold. Governments need to set clear policies to minimise the risk of bottlenecks in the EV supply chain caused by a misalignment of investment in mining, processing, battery manufacturing and EV production.

Overview

New and better technologies will be crucial to tackling the world's environmental problems associated with energy use, alongside the adoption of existing advanced technologies. Technological innovation has the potential to reshape or entrench the competitive positions of different fuels and energy sources. It can also lead to a change in the very definition of energy investment, as technologies associated with other sectors become integrated into the mainstream energy system. Rapid technological developments in unconventional oil production and improvements in the performance of renewables-based electricity-generating technologies have already had a far-reaching impact on the global energy system since the beginning of this century. Digitalization and improved electric batteries are set to do likewise in the coming years.

International Energy Agency (IEA) analysis carried out for the annual *Tracking Clean Energy Progress* report shows that most clean energy technologies are not currently on track to deliver a sustainable energy system by 2030 (IEA, 2018a). Aviation, building envelopes, CCUS in power generation and industry, concentrating solar power, geothermal, heating and biofuels for transport are among those technologies that are off-track. Far more progress will be needed for the world to meet its energy needs almost entirely from low-carbon sources by the second half of the century.

Several trends highlight the extent of the challenge. Combined additions to wind and solar power capacity exceeded those to any other power generation technology in 2017, yet global carbon dioxide (CO_2) emissions grew for the first time for four years to their highest-ever level. The world in 2017 used around 20% less final energy per unit of gross domestic product (GDP) as it did in 1992 when the United Nations Framework Convention on Climate Change was signed, but as the global economy has grown, as much CO_2 has been emitted from fossil fuel combustion as in the preceding 50 years. As electric car sales doubled from 0.3 million sales in 2014 to over a million in 2017, there were three of the eight largest annual rises in global oil demand since 1980, driven by more oil demand for transport. In Europe, oil demand has increased since 2015 after being in steady decline for almost a decade. To counter the economic and demographic forces behind these trends and set the world on a faster decarbonisation pathway, policy makers need to take a holistic approach to innovation and technological change.

Fossil fuel emissions are increasing in several sectors, including heavy industry and transport, where low-carbon alternatives are at a much earlier stage of development and commercialisation than wind and solar power. While policy makers need to promote and track innovation across the entire energy sector, this section describes recent trends in three cross-cutting areas of technology to illustrate how investment and innovation could change the outlook for multiple sectors: batteries for electric vehicles (EVs); hydrogen as a carrier of low-carbon energy; and CCUS. The section begins with a review of worldwide spending on energy research and development (R&D) – a leading indicator of innovation.

Investment in energy innovation

Innovation is central to getting the world onto a sustainable energy path. It creates value in the economy by improving existing processes and generating new ways of meeting the needs of the different actors. It does not evolve in a vacuum: the structure of the market, public support for entrepreneurship and direct government investment all influence how rapidly new technologies emerge and are adopted. This is as true for energy as it is for other sectors of the economy. Following several years of stagnation in energy research spending, the 23 countries (plus the European Commission) participating in Mission Innovation – a global initiative launched in 2015 to dramatically accelerate global clean energy innovation – have pledged to double their baseline public funding for clean energy R&D over five years, as well as to encourage greater levels of private-sector spending. Good progress towards those goals is being made (MI, 2018).

The IEA has tracked around USD 115 billion of worldwide spending on energy R&D in 2017 – an increase of 2.5% in real terms.[1] More than three-quarters of this spending came from the private sector.[2] Overall, there is a clear but sluggish trend towards higher spending on low-carbon energy R&D across the public and private sources of funding that are tracked. While public R&D on energy technologies in total grew at an average rate of only 2% per year over the five years to 2017, it jumped by 8% last year. The general trend in the private sector is also upwards, though at a slower rate. On a sectoral basis, growth is concentrated in the transport sector, where technologies related to electrification of vehicles, powertrains and related products are seeing the biggest increases in spending. Among the leading economies, Japan remains the largest spender on energy R&D, as measured by the share of GDP, ahead of the People's Republic of China (hereafter, "China") and Europe.[3] In absolute terms, the United States (US) spends more on energy R&D than any other country.

---

[1] This section focuses on spending on R&D – the first stage in the process of innovation. In the case of public spending, it also includes demonstration projects where data are available, i.e. RD&D. Tracking and understanding the progress of innovation are much broader tasks than simply aggregating R&D spending and must incorporate other performance-based indicators, such as unit costs and technical efficiencies of products coming onto the market (IEA, 2018a). There is enormous potential for improvement in tracking progress.

[2] Public- and private-sector funding play different roles in the innovation chain, and their relative shares of spending are not directly comparable in terms of their relative value.

[3] In last year's *World Energy Investment* report, the IEA reported that China had the highest spending as a share of GDP. The change is due to the inclusion of corporate automotive spending and more private sector companies, for which Japan's reporting rate is higher.

Public sector R&D spending on low-carbon technologies jumps

Governments play a major role in energy innovation, often funding basic and higher-risk research as well as novel low-carbon technologies, which tend to be costly and have uncertain market value. Public funding can be directed at public research institutions, companies, including state-owned enterprises, or consortia of different organisations. Early-stage technological developments funded by governments are often adopted by the private sector for further refinement into commercial products, either by established companies or start-ups (see section on venture capital funding, below).

According to preliminary IEA estimates, government funding for low-carbon energy R&D globally in 2017 rose by 13% to USD 22 billion (IEA, 2018b). Total public spending on all energy R&D rose by a more modest 8% to USD 27 billion (Figure 3.1). Government funding for low-carbon energy R&D in 2017 accounted for four-fifths of total public funding for energy R&D (including fossil fuel extraction and supply). The biggest falls in overall public spending in 2016 occurred in Europe, where budgets for low-carbon energy R&D fell by around USD 300 million, and in China. The rise in 2017 mostly reflects growth in North America and a surge of spending on renewable energy research in China. In North America, spending on CCUS increased by around 65%, on energy efficiency by around 30% and on renewables by around 15%. Further increases in 2018 are likely, with the US government passing a spending bill in March 2018 that raises the budgets of the Advanced Research Projects Agency – Energy (ARPA-E) and the Innovative Technology Loan Guarantee Program. In total, the US budget for energy research (including energy-related defence research) is expected to rise by 10-15% in 2018.

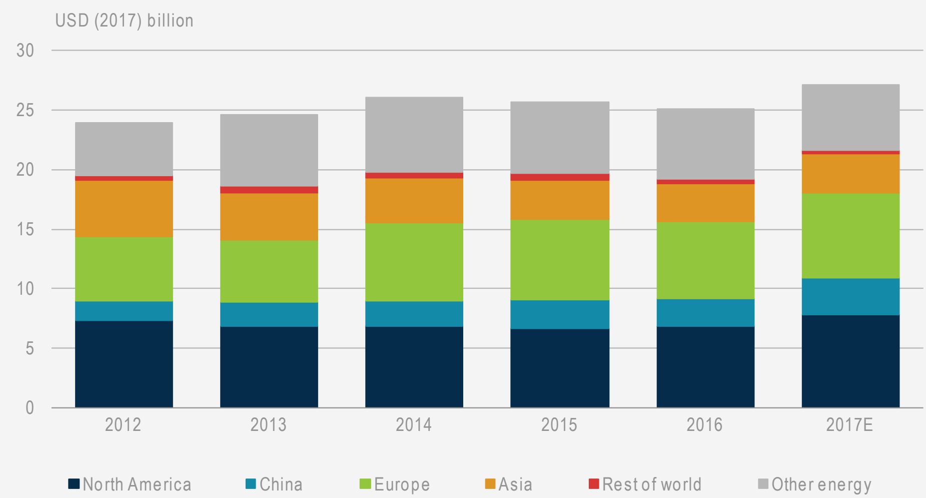
The five leading countries for public spending on energy R&D are the United States, China, Japan, France and Germany. Spending by these five countries alone accounts for 70% of all such spending worldwide. The governments of IEA member countries, for which data are most complete, spent over USD 17 billion on energy-related R&D in 2016 and, based on preliminary estimates, almost USD 19 billion in 2017.[4] In these countries, energy-related research as a share of total R&D spending has remained stable at around 5%. However, while the share has been stable in recent decades in North America and Europe, it fell from 12% in 2000 to 6% in 2016 in Asia Oceania. In total, spending by IEA governments on energy R&D takes up just 0.1% of their total public spending, a share that has changed little over recent years.

In addition to direct government spending R&D, many governments encourage private businesses to undertake R&D through tax incentives. The value of such incentives varies widely by country. It is equal to 10% or more in France, Ireland, Hungary, the

[4] Including the European Commission's energy RD&D budget.

Russian Federation (hereafter, "Russia") and the United Kingdom (UK), but is 5% or less in Italy, the Netherlands, Spain and the United States. Governments also encourage innovation through market-oriented (so-called "market pull") policies that incentivise private investment in technology development and improvement. An important aspect of public innovation policy is establishing an effective balance between encouraging the development of new technologies and supporting the deployment of existing technologies, which can lead to innovation through learning-by-doing (IEA, 2017a). Combining these two approaches can yield cost reductions and improved performance in the most cost-effective manner.

Figure 3.1 Government spending on low-carbon and other energy R&D by region



Public spending on energy R&D grew by an estimated 8% in 2017, following a slight dip in 2015 and 2016, with most of the growth coming from the United States and China.

Notes: 2017E is an estimate based on best-available data. In accordance with IEA (2011), the type of best-available information varies per country and includes budgets appropriated, planned expenditure or actual expenditure in the given year. More information for IEA member countries is available (IEA, 2018b). For China, relevant R&D spending by major energy-related state-owned enterprises is estimated and included.
Sources: IEA (2018b) and national sources.

Corporate energy R&D spending is recovering slowly

The private sector remains the largest single source of funding for energy R&D, despite lower spending in recent years. This report estimates that total public reported corporate spending on energy R&D amounted to USD 88 billion in 2017 – 3% up on 2016 but still 3% down on 2014 (Figure 3.2).[5] Most of the decline since 2014 can be attributed to reduced budgets in the oil and gas sector in the wake of the fall in the oil price in 2014. The trend in corporate spending of the past three years has been towards low-carbon energy technologies.[6] Spending on those technologies rose by 5% in 2017 to USD 58 billion, close to the average 6% rate of growth of the past five years. Low-carbon energy may account for as much as two-thirds of total reported corporate energy R&D spending. This share may drop in the coming years if oil and gas companies respond to the recent rebound in oil prices by raising their R&D budgets.

The automotive sector accounts for a large and growing share of total corporate energy-related R&D spending. In the five years to 2017, estimated R&D spending by automotive companies related to more efficient vehicles and alternative fuels has risen by around USD 10 billion to almost USD 40 billion. This is the single biggest contributor to higher spending on energy technologies. It reflects obligations on carmakers to meet tighter fuel economy standards and expectations of strong growth in demand for EVs. These firms have a long tradition of heavy spending on R&D generally, but this has been exacerbated by the technological and regulatory uncertainty in recent years, as well as the rise of new companies in the emerging economies, notably China. Of the top ten biggest carmakers globally, four had R&D budgets larger than their reported capital expenditure (capex) in 2017 and for another four the R&D budget was over 80% of the level of reported capex.

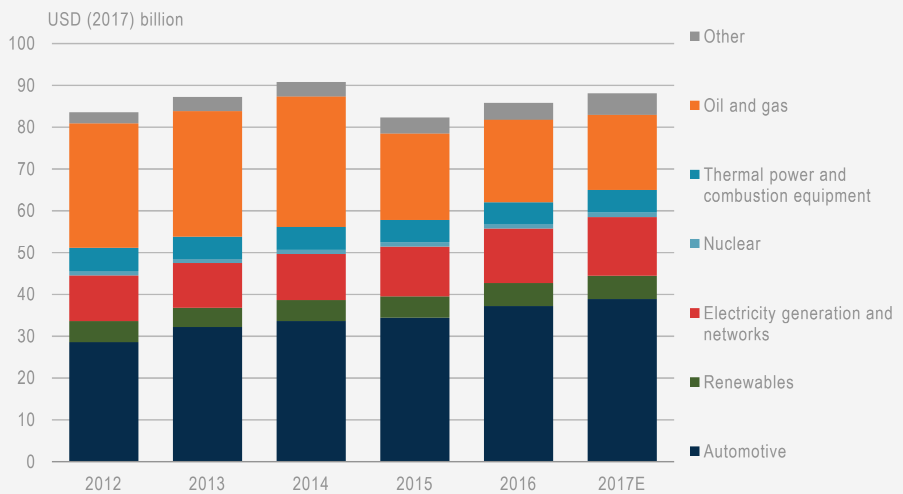
There are big differences across sectors with respect to the ratio of R&D to total corporate revenue, reflecting differences in the threat to market share and revenues from competitors with new technologies and product offerings. Automotive companies tend to spend around 4% to 5% of their revenue on R&D, including product development. While oil and gas companies account for a sizeable chunk of corporate energy R&D, their R&D

[5] Depending on the jurisdiction and company, publicly reported corporate R&D spending can include a wide range of capitalised and non-capitalised costs, from basic research to product development and, in some cases, resource exploration. It is not unusual for the development of like-for-like substitution products and problem-solving for well-established technologies to dwarf research into new technology areas. Data availability does not allow normalisation across the dataset to account for these differences. For more information about the methodology used here, see www.iea.org/investment.

[6] The estimates shown here cover a much larger number of companies compared with last year's edition of this report. In particular, they include spending on EV, biofuel and fuel economy technologies by automotive manufacturers, whose spending far exceeds that of the biggest spenders on R&D in energy supply. Given the amount of R&D being conducted by automotive companies directly relevant to low-carbon energy, it makes no sense to exclude these companies from this report's dataset. Spending by automakers alone represents over two-thirds of the USD 48 billion increase compared with the much more limited and energy-sector-focused coverage reported last year for 2016. See www.iea.org/investment for more information about the methodology and the difficulties faced in collecting information on private energy R&D spending.

intensity (spending relative to total corporate revenue) is around 0.4% – a similar level to that of electricity utilities. Manufacturers of thermal power-generation equipment and clean energy companies spend around 3.5% of their revenue on R&D. Higher revenue can raise corporate energy R&D, and so can an uncertain technological outlook. In 2017, this report estimates that a 4% increase in R&D spending in the electricity sector and better fuel combustion technologies also contributed to the rise in low-carbon energy R&D, but the rate of growth in spending by utilities in these areas slowed slightly. Spending on electricity storage, smart electricity systems and energy efficiency, including insulation and lighting, has continued to grow strongly in recent years. At the same time, some energy companies are pursuing strategies for higher innovation performance without raising R&D budgets.

Figure 3.2 Global corporate R&D spending in energy-related sectors



Following a big reduction in oil and gas sector R&D in 2015, corporate energy R&D is recovering slowly, reaching around USD 88 billion in 2017, buoyed by growth in the automotive sector.

Notes: Classifications are based on the Bloomberg Industry Classification System. All publicly reported R&D spending is included, though companies domiciled in countries that do not require disclosure of R&D spending are under-represented. To allocate R&D spending for companies active in multiple sectors, interviews with company decision-makers and, in the absence of other data sources, the shares of revenue per sector were used. “Other” comprises CCUS, electricity storage, insulation, lighting, other fossil fuels and smart energy systems.
Source: Bloomberg (2018).

Trends in corporate energy innovation management

To respond to increased technological and corporate competition in many parts of the energy system, traditional energy companies have been reorienting some of their R&D

and innovation activities. This, in turn, has implications for government policy and is not captured by reported data on R&D spending.

By the end of the last century, the model of large corporate research labs undertaking path-breaking basic research and handing it over for development elsewhere in the company was waning. In part, this was a response to the loss of market power for many of the largest companies; basic research is a luxury that monopolies can afford more easily. In addition, boardrooms often encouraged the view that long-term research has insufficient near-term value to shareholders. R&D became less centralised and more integrated with product development in individual business units, directed at improving firms' existing portfolios of technologies in order to retain their market share. Today, unlike public R&D, many of the major companies active across the energy system devote no more than one-tenth to one-third of their total R&D budgets to new technologies, with the bulk of spending going to incremental improvements of existing technologies. This situation is changing again as a result of the pace of energy innovation through digitalization and uncertainty about which families of technologies will be dominant over coming decades.

Tomorrow's successful companies are likely to be those that can respond nimbly to technological change and adopt new ideas before they undermine the firm's core business. This requires human capital and systems for "horizon-scanning" for emerging technologies, and an ability to take risks to learn about them – not typically the core skills of corporate R&D departments. Furthermore, many new technologies – especially those relating to digital, modular and consumer goods – have shorter development lifecycles and do not need extensive corporate resources to reach the stage of commercialisation. This calls for companies to place more small bets on emerging technologies and to be open to changing direction quickly. In this environment, the timing of an investment in a new idea or human capital is of higher strategic importance.

Digital innovation is very different to traditional hardware innovation

Energy companies are devoting more R&D resources to digital technologies in order to improve competitiveness. Digitalization of the energy sector involves the expanding application of data, analytics and connectivity to increase automation, improve problem-solving and enable real-time participation of a wider set of stakeholders in energy and transport markets (IEA, 2017b). This has numerous advantages for corporate energy R&D and several implications for how innovation is conducted in energy companies.

New technologies for software and digital-based products have shorter innovation cycles and can be brought to the market quicker. They require less investment and fewer consumables, and they can be prototyped more quickly and tested in a variety of environments simultaneously and do not need costly manufacturing facilities or value chains to be deployed. The result can be a lower unit cost of innovation, which is especially valuable where digital solutions can directly solve problems that would otherwise have required a physical alternative. But it also changes the nature of competition. It becomes vital that products be brought to the market quickly to reduce the risk that competitors, including those outside the sector or in start-ups, acquire customers first. This is important for digital technologies because when multiple services are offered through a common platform or app, or machine learning is used to analyse user information, the products improve with the number of participants ("network effects"). As digital technologies can be relevant to all business units of a company, it can be more efficient to develop technologies that can be shared with all teams, which requires new approaches to collaboration and open innovation.

New approaches to corporate energy innovation in a fast-changing and uncertain technology environment

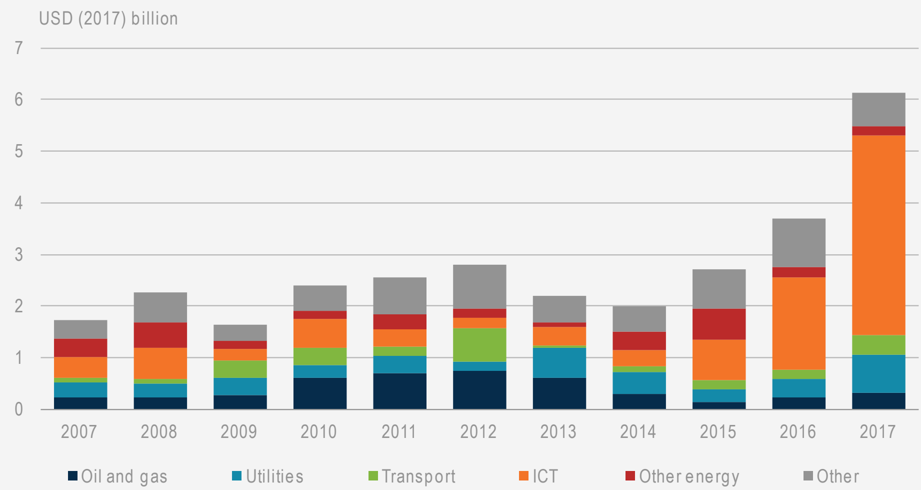
A growing number of energy companies are separating the teams that are focused on innovation outside their core competences, and that could in some cases undermine their existing businesses, from the governance structures of typical corporate R&D. Rather than having large budgets for research linked to sustaining existing businesses, these teams generally pursue a wider range of innovation management activities, often with lower capital requirements. These activities include VC funding, internal innovation competitions, pilot testing of competing options and more strategic partnerships with firms outside their traditional sectors. To manage risks in highly uncertain and unfamiliar technology areas, collaboration with technology suppliers or customers tends to play a larger role than in traditional corporate R&D. As an indicator, corporate involvement in early-stage energy technology companies is growing rapidly.

There is more corporate involvement in early-stage energy tech companies, increasingly from outside the energy sector

Analysis of recent deals to fund energy technology start-ups shows rapid growth in the involvement of established companies alongside investors from the financial sector, such as VC funds and banks, and governments. In 2017, corporations invested USD 6.1 billion (Figure 3.3). Traditional energy sector companies, including oil and gas and utilities, all increased their investments, though transport and information and communication technologies (ICT) companies increased spending most. In some cases, the entry of firms from sectors such as ICT into parts of the energy industry is forcing companies to change their perceptions of who they should consider their competitors to be, making it harder to benchmark R&D performance against other companies in their sector using metrics such as R&D spending as a share of revenue.

There are several reasons large established companies provide capital to early-stage technology companies. They might see it as a good investment on a purely financial basis, but more commonly it is seen as an investment in learning about a technology, acquiring human capital, and building a relationship with the technology owner that would smooth the path to licensing or buying the technology if it is successful. In general, this approach is used with technologies that are currently outside the core competence of the corporate investor but that could add significant value to existing businesses if the market developed in that direction. Given the value of innovation to many large energy companies, corporate venture capital (CVC) finance and even growth equity (a type of private equity investment) can cost less and involve less risk than developing a technology in-house. It can also shield the developers from the strict evaluations placed on internal R&D projects that are expected to scale up in existing business units. For a start-up company, a CVC investor can provide access to know-how and customers that can give it a better chance of maturing quickly.

Figure 3.3 Global value of deals by corporate investors in energy technology companies, by sector of investor



Corporate investment in energy technology start-ups reached a record USD 6.1 billion in 2017, but energy company spending is dwarfed by that of ICT companies.

Notes: Includes seed, series A, series B, growth equity, loans, private investment in public equity and structured debt. Transaction values are splits evenly between multiple corporate investors if information on relative shares is unavailable. Excludes mobility services.
Source: Cleantech Group i3 database (2018).

Oil and gas CVC activity dropped between 2012 and 2015, but recovered significantly in 2016 and 2017. A noticeable recent trend is a shift away from technology areas that complement their existing infrastructure – such as bioenergy, CCUS and fossil fuel supply technologies – and towards technologies that could complement their broader capabilities or let them explore new business areas. During the so-called "cleantech boom", the share of investments in bioenergy, CCUS and fossil fuel supply technologies in the portfolio of oil and gas company investments was over 50% each year from 2009 to 2012, whereas in 2017 it was only 8%. With the exception of the single large deal between Essel Group and LeadCold nuclear, the biggest areas of investment for oil and gas companies were transport and renewables-based electricity, particularly solar. Notable deals in 2017 were BP's investment in LightSource solar, Castrol's investment in Peleton truck platooning, Equinor's investments in Oxford Photovoltaics and Chargepoint, and Total's investment in Sunverge.

Utilities have also increased their funding of energy technology start-ups. Worldwide, they spent a record USD 0.7 billion in 2017, surpassing the previous high of 2013 and the tail end of the cleantech boom. Solar power, electricity storage and, to a lesser extent, smart-grid technologies have been the main focus of utility funding in recent years, but growth in 2017 was driven largely by transport technologies, which took one-half of the total, and wind power technologies, which took one-quarter. Major deals in 2017 include Engie's involvement in Gogoro scooters, Edison Electric's investment in ProTerra electric buses, E.ON's investment in Kite Power Systems and Eneco's investment in Thermondo heating controls.

Since 2015, the entry of ICT corporations' VC arms and large technology budgets has eclipsed the growth in investment by other sectors, more than doubling each year in US dollar terms. Over 90% of the target companies for ICT corporate investments are in two sectors: transport and building automation and efficiency. Of these, transport is by far the largest, with investments going to both vehicle connectivity and EV manufacturers. This is a significant change from 2007-08, when these companies devoted over 40% of their investment to solar technology companies. Notable deals in 2017 include Tencent and Baidu's investments in Tesla, NIO and WM Motors; Intel's investment in Volocoptor electric helicopters; Qualcomm's investment in CargoX truck logistics; and China Mobile's investment in Ninebot electric scooters.

The pace of radical change can be constrained when existing technology sales are needed to finance new technology development

Companies in the businesses of making cars, supplying electricity generation equipment and producing hydrocarbons are all increasing their R&D spending on clean energy in absolute terms and, in some cases, as a share of their revenues. R&D spending by major automotive companies increased from 4.5% of revenue in 2012 to over 5% in 2017, while for combustion equipment such as turbines and boilers, it rose from 2.5% to 3%. These expenses cannot be covered by sales in the new technology business areas alone, which generate as yet a small fraction of their total revenues. It is typical that R&D in new technology areas is funded by revenue from existing businesses but if factors force a transition to a new technology that is R&D-intensive and undermines traditional business models, this can lead to a reduction in R&D efforts in existing technology areas.

Perhaps the starkest example of this is in the automotive sector. Internal combustion engine (ICE) vehicles remain more profitable than EVs and large ICEs are generally more profitable than small ones. During the period of phasing in EVs, the revenues of carmakers might be maintained by maximising sales of sports utility vehicles and other large vehicles in order to reinvest in EV R&D. At the same, time, R&D for improving ICE technologies that are losing market share becomes less justifiable. R&D in better diesel engines is already being scaled back. Consequently, the demands of R&D for EVs and automated vehicles may lead to higher sales of less efficient vehicles in the medium term, slowing the overall rate of improvement in ICE fuel economy. A similar pattern may emerge for gas turbines and boilers, which will remain major components of energy production and investment for decades to come. This factor will have implications for future emissions trends and the speed and shape of the transition to clean energy technologies.

Implications of the evolving corporate energy innovation landscape for governments

Changes to the ways that new energy technologies are developed and commercialised by the private sector can require changes in the ways that they incentivise and track innovation. For example, companies' needs to collaborate over short timescales with the most suitable and innovative partners globally are making companies' networks of partners more international in many cases. Having a strong ecosystem of research institutions and energy entrepreneurs can be more valuable than tax breaks and R&D funding for making a country attractive to a large company as a place to undertake novel projects. Secondly, absolute corporate expenditure on R&D may become less closely linked to the pace of corporate innovation in low-carbon technologies if developing new – often digital – solutions requires less in-house expenditure that is accounted for as R&D. The need to rapidly collaborate to test and scale up ideas can reduce companies' incentives to create and defend in-house intellectual property. These outcomes can potentially make metrics such as R&D budgets and patents less reliable for tracking progress, and affect the effectiveness of tax policies designed to incentivise innovation. Furthermore, while these broader approaches to corporate innovation can be well suited to certain types of energy technologies, policy makers may need to ensure that their national or regional policies also support the improvements to capital-intensive hardware solutions needed to tackle climate change. In these areas, patient government capital for higher-risk technologies could become even more vital.

Trends in VC funding of emerging energy technologies

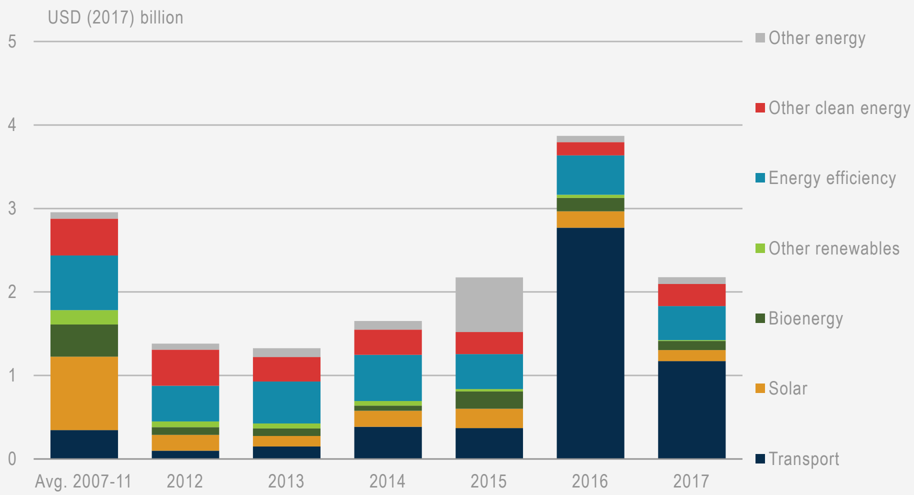
VC funding of early stage energy technology is growing

Venture capital (VC) investment in emerging clean energy companies (seed, series A and B)[7] reached an estimated USD 2.1 billion – close to pre-2012 levels, though down on the 2016 value of around USD 4 billion (Figure 3.4). While solar energy made up a significant share of transactions before the 2012 cleantech bust, recent growth has been driven

[7] These are generally the first three fundraising rounds involving external investors in a start-up. The values generally increase from up to USD 2 million for a seed round, to USD 10 million or more for a series B round, but can be smaller or much larger.

almost entirely by clean transportation investments (Cleantech Group, 2018).[8] Excluding very large transactions above USD 500 million, the average transaction in clean energy in 2017, at USD 9 million, was the highest since 2008, indicating a growing confidence that successful start-ups will become profitable and disruptive businesses.

Figure 3.4 Global venture capital investment in energy technology start-ups



VC funding of energy technology start-ups fell in 2017 but is rising and approaching pre-2012 levels, with the growth dominated by clean transport and renewables.

Note: Transport does not include start-ups developing mobility services, such as ride-hailing and other consumer service software.
Source: Cleantech Group i3 database (2018).

China's share of total VC investment in early-stage energy technology (cleantech) start-ups has risen dramatically on the back of a few very large transactions in transportation, including the USD 1.5 billion series A investment by Tencent in WM Motors, an electric car start-up. China has yet to make its mark outside transport. In terms of total transaction volume, North America continues to dominate clean energy VC activity with nearly 45% of all early-stage deals involving US-based companies, compared with under

[8] Investment in start-ups developing mobility services, such as ride-hailing and other consumer service software, is not included.

one-fifth in Europe. The share is nonetheless lower than in 2012, when North America represented three-quarters of transactions. Outside transport, investment in clean energy globally has declined slightly since 2014, mostly due to Europe, Asia and, to a lesser extent, the United States. The total value of VC transactions in electricity storage, hydrogen and fuel cells almost doubled to USD 175 million in 2017, but this is still lower in real terms than in 2014.

The VC cleantech industry generally enjoyed a very healthy year in 2017, buoyed by sectors not directly related to energy, such as digital, shared mobility and automation. Yet VC investment in start-ups developing new renewable energy hardware continues to suffer, with renewables-sector early-stage VC down 46% since 2015. Clean energy innovation and VC are often not well matched. The timeframe needed to establish the viability of energy projects can be too long, the capital requirements for technology demonstration too high and the consumer value too low. Such technologies may get attention when financial markets are hot, but not when they are risk-averse. These concerns have so far prevented energy from joining the ranks of biotechnology and software as hundred-billion-dollar VC markets. By the second quarter of 2018, Breakthrough Energy Ventures, a new VC fund directed to commercialising emerging technologies that could catalyse faster and deeper decarbonisation of the energy sector, had raised USD 1.1 billion and expects to announce its first investments later in the year.

Investments in lithium-ion batteries and EVs

The market for EV batteries is still nascent. Just over 1 million electric drivetrains, not including two-wheelers, were produced in 2017, compared with around 100 million new ICE engines. Yet the rapid growth in sales of EVs is having a major impact on the lithium-ion (Li-ion) battery industry, as most production in capacity terms is for EVs.[9] As the cost of the battery is the main determinant of the price of an EV, the uptake of EVs and their impact on oil demand will be strongly influenced by developments in the Li-ion value chain, which is currently characterised by high uncertainty.

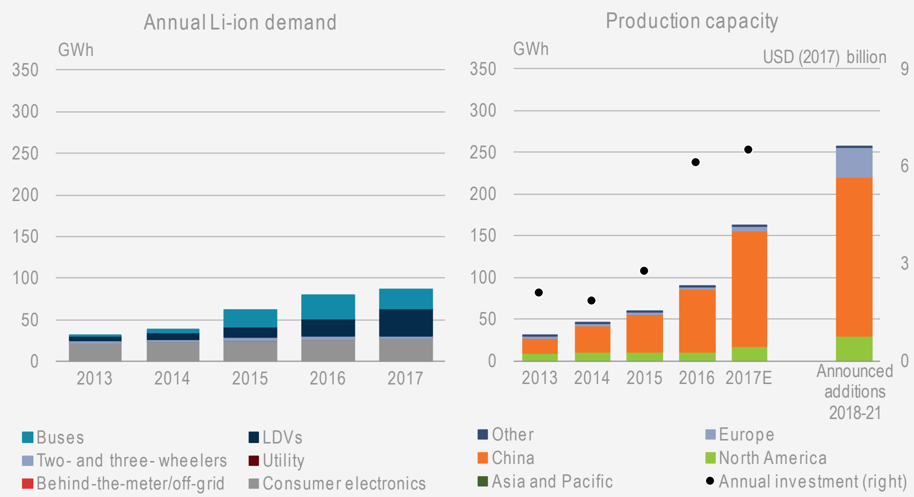
From 1991 until 2015 the Li-ion battery market was dominated by demand for consumer electronics, and in terms of numbers of individual battery packs, this remains by far the largest market. However, an electric car has around 1 000 times the battery capacity of a laptop, and an electric bus battery can be 10 000 times bigger. Today, almost twice as much Li-ion capacity is installed in new EVs than in all consumer electronics (Figure 3.5).[10] Demand for Li-ion batteries has risen 6.5 times, or 140% per year on

[9] EVs include plug-in hybrids and pure battery vehicles.

[10] See Chapter 1 for a review of EV sales and policy trends.

average, since 2013, and this has raised questions about how quickly and smoothly the supply chain for raw materials, battery precursor chemicals and finished battery packs can be scaled up.

Figure 3.5 Li-ion battery demand and production capacity by region



Li-ion battery demand has been driven by the EV market since 2015, prompting over USD 15 billion of investment in the production of Li-ion batteries.

Notes: GWh = gigawatt hours; LDVs = light-duty vehicles. Capacity data are compiled from a bottom-up database of known factories for Li-ion batteries suitable for use in EVs. Staged capacity increases allocated to the year of each expansion. Investment is estimated based on published project costs and total installed capacity.
Sources: Input from BNEF (2018) and IEA (2018c).

Investment in non-energy sectors, such as steel[11] and silicon, has long been important to the energy sector, but EVs connect the energy sector much more closely with certain commodity sectors that are relatively volatile today and could strongly influence energy demand and energy security in the decades ahead. This section considers investment trends in the main elements of the EV value chain, from the production of raw materials such as lithium and cobalt to EV manufacturing and R&D by automakers.

[11] See Chapter 1 for a review of recent investment trends in steel production.

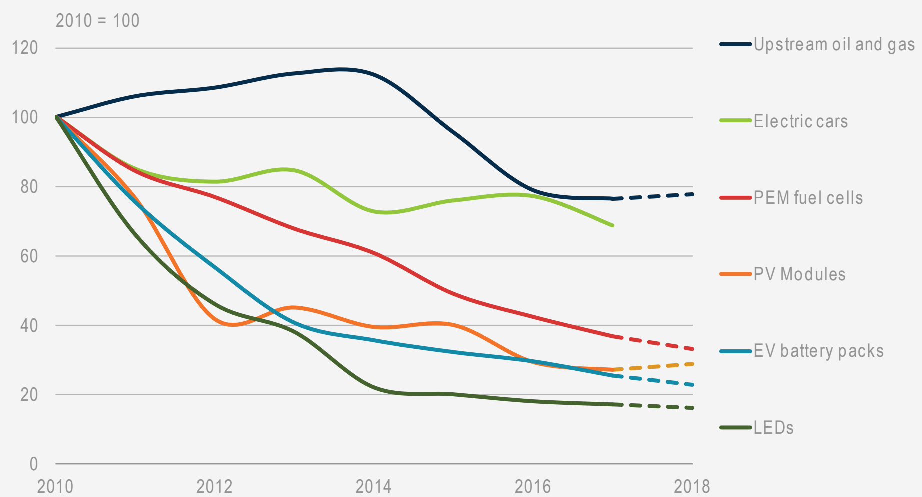
Lithium-ion battery production for EVs

Expectations of continuing rapid growth in demand for EV batteries has led to a surge in investment in new Li-ion manufacturing capacity. Total investment in new EV-suitable battery capacity is estimated to have reached USD 6.5 billion in 2017, double the average annual investment in 2013-16 (Figure 3.6). While large factories for EV-suitable battery packs have recently been built in Europe, Korea and the United States, most of the investment has occurred in China, where over 75 GWh per year of capacity is reported to have been added in 2017. China is now home to almost three-quarters of global capacity, partly in response to a national effort to secure national value chains for batteries. This effort is led by government policies that favour Chinese-produced batteries and standards for battery factories that require them to produce at least 8 GWh per year. For comparison, Tesla's Reno Gigafactory in the United States can produce around 7 GWh per year, though there are plans to raise capacity to 35 GWh. In Europe, Northvolt plans to add 8 GWh in Sweden each year between 2020 and 2023. These two plants would use electricity with lower greenhouse gas (GHG) intensity than many existing factories, improving the life cycle environmental performance of EVs.

If all announced projects for Li-ion battery manufacturing are completed, production capacity could reach as much as 500 GWh per year by 2021. This rate of expansion would maintain the apparent large overcapacity in battery manufacturing and competitive pressures on manufacturers. Alongside improvements in battery chemistry and technology, economies of scale in battery pack production have helped keep the cost of producing EV batteries on a rapid downward trajectory (Schmidt et al., 2017). While recent years have seen significant unit cost declines in many parts of the energy system, declines in costs for batteries for EVs have been among the largest in percentage terms (Figure 3.6). The applications of mass manufacturing and standardisation have played central roles in driving down the costs of batteries, as well as solar photovoltaic (PV) panels and light-emitting diode (LED) light bulbs. Policy has helped to make this possible, through R&D and by stimulating demand through consumer incentives.

Although some of the dynamics of Li-ion production mirror the growth of PV manufacturing capacity and the subsequent dominance of China in response to rising global demand, there are important differences. In particular, battery production capacity cannot be reliably compared with total demand because both battery factories and EV battery demand can be further differentiated by different battery chemistries. Not all Li-ion battery applications use the same chemistry or battery designs, so the aggregate manufacturing capacity cannot all serve consumer needs. For example, grid-scale energy storage applications have more relaxed weight and space requirements than cars and homes, but more demanding charge/discharge regimes. EV makers have tailored their vehicles to different battery types; plug-in hybrid EVs (PHEVs) have somewhat different requirements from pure battery EVs (BEVs). Investments in different types of Li-ion production capacity are based on judgements about end users' needs for energy density, power output, charge/discharge deterioration, cost, safety and temperature. The biggest area of differentiation concerns the chemistry of the battery cathode.[12]

Figure 3.6 Unit production costs in selected energy-related sectors



EV battery costs have declined more rapidly than most other emerging energy technologies in recent years.

Notes: PEM = proton-exchange membrane. Wherever possible, values shown are globally representative prices of equipment or full project costs where appropriate. Values are from relevant IEA analyses for each of the sectors, adjusted to 2017 prices in US dollars. Upstream oil and gas costs reflect the IEA upstream investment cost index (see Chapter 1). The cost of an EV is the global sales-weighted average price. PV module prices are expected to rise slightly in 2018 due to tariff and other trade issues.

Battery cathodes

The options for the type of cathode of a battery cell are increasing as researchers search for cheaper designs and ones that have hold more energy, deliver more power and operate longer without deterioration. In a Li-ion battery, the cathode is a critical component that

[12] Batteries comprise three basic parts: an anode, a cathode and an electrolyte. The cathode and anode (the positive and negative sides at either end of a traditional battery) are attached to an electrical circuit when charging or discharging useful energy. Electric current is carried between the anode and cathode by the movement of ions in the electrolyte.

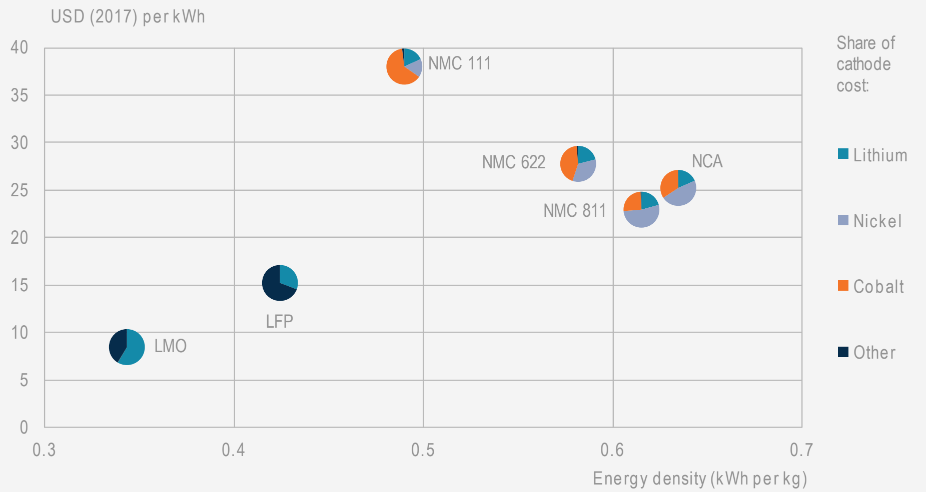
needs to be able to hold and release a high density of lithium ions while retaining its structure and integrity. There are trade-offs between these properties and the best-performing materials have novel combinations of chemicals with strong structures and chemicals with high storage capacity. The materials that work best have compositions that combine chemicals with these different properties. Some cathode material is produced by vertically integrated companies, such as LG Chem, POSCO and Samsung SDI, but much of the market is made up of unintegrated suppliers, such as BASF, Shanshan New Material and Umicore, which manage value-chain risk through partnerships. No single type of cathode has a share greater than around one-third of the Li-ion market today. While it is possible for factories to be retooled for new cathode designs as demand evolves, the choice of type of cathode is a significant risk for non-vertically integrated producers.

Cathode design has changed significantly since the first widely available car to use a Li-ion battery, the Tesla Roadster, was launched in 2009. That car used lithium cobalt oxide (LCO) cathodes, yielding a battery energy density of 1.12 kilowatt hours per kilogramme (kWh/kg). This was similar to the 2011 Nissan Leaf, which used a lithium manganese oxide (LMO) cathode. Densities have since increased significantly with changes in the type of cathode: the 2017 model of the Chevrolet Bolt uses a nickel manganese cobalt (NMC 111) cathode with an energy density of 1.38 kWh/kg, while the Tesla Model 3 uses a nickel cobalt aluminium (NCA) cathode with an energy density of 1.78 kWh/kg (Deutsche Bank, 2016). In China, lithium iron phosphate (LFP) is the most common type of cathode for cars and buses, and the BYD e6 car battery has an energy density of 1.12 kWh/kg.

Higher-energy-density batteries hold the potential for greater vehicle range and higher consumer demand, but there are trade-offs with costs. The greater the need for lithium and cobalt, which boost density, the higher the cost. The price of lithium has tripled and that of cobalt doubled over the 18 months to mid-2018. These price increases reflect expectations about EV demand. As an indication, an increase in EV deployment consistent with the goal of the EV30@30 Campaign – an initiative launched by the Clean Energy Ministerial in June 2017 to speed up the deployment of EVs, targeting at least 30% of new vehicle sales by 2030 – could represent a 300% increase in global cobalt demand and a 700% increase in lithium demand compared with 2017 (IEA, 2018c).

While NMC and NCA cathodes have higher energy density, different formulations require different quantities of lithium and cobalt, affecting unit costs (Figure 3.7). In 2016 and 2017, a number of Chinese battery factories were reportedly converted from LFP to NMC in response to demand for higher energy density, but this has raised cobalt and lithium demand dramatically. To maintain performance, the trend is now moving in the direction of variants of NMC, such as NMC-622, that reduce exposure to metal price risk. The first large-scale NMC 622 production facility reportedly began operating in late 2016 in China, while production of NMC 811 is scheduled to begin in South Korea in 2018, according to announcements by LG Chem and SK Innovation. But with other battery technologies – such as new anode and electrolyte possibilities – undergoing increasing R&D, the timing of such large investments carries significant risk.

Figure 3.7 Li-ion battery cathode cost and performance by type



Developments in the type of cathodes used in Li-ion batteries will be driven by the need to lower costs and improve performance, notably energy density.

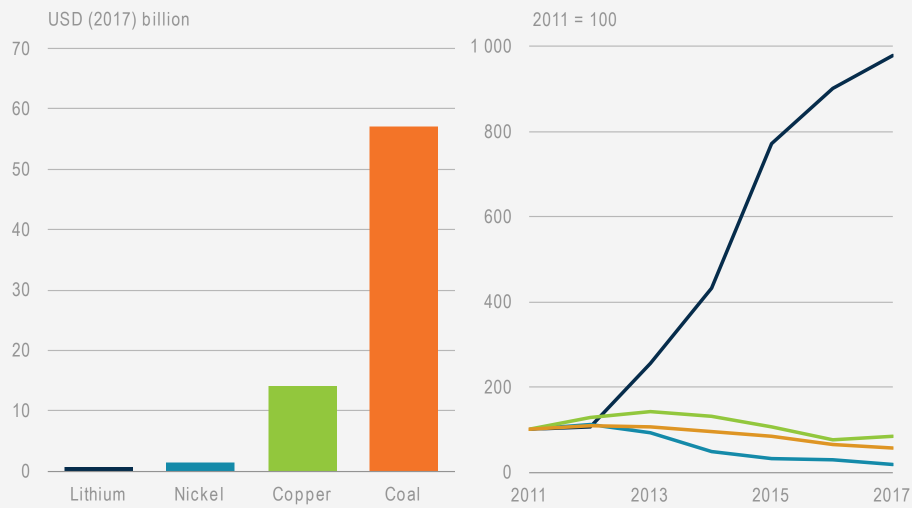
Notes: kWh = kilowatt hours. Energy density is for the cathode only. Cathode costs account for a varying share of battery pack costs. For NCA and NMC cathodes, the share is 50% to 60%. Numbers represent the ratios of the metals in the cathodes if there are different variants.
Sources: CRU Group (2018) and ANL (2018).

Lithium and cobalt supply

To avoid bottlenecks in the supply chain for Li-ion batteries that could disrupt EV cost reductions, raw material supply will need to expand in line with the pace of EV production plans. Almost all projections of EV deployment imply at least a doubling of global cobalt and lithium demand over the next decade. There will also be a noticeable effect on copper mining, partly due to the nature of cobalt as a by-product of copper extraction but also because copper use in motors and EV supply equipment could rise to become 10-15% of copper demand. Nickel demand for batteries represents a much smaller share of total demand for nickel, which is mostly used for stainless steel production.

For cobalt and lithium, the resource base is not considered to be a constraint. The ratio of known reserves to production worldwide are around 65 years for cobalt and over 300 years for lithium, while resources are believed to be much bigger (USGS, 2018a; 2018b). The question is how quickly those reserves can be exploited. High prices of these elements today reflect expectations of demand that are higher than the current production capacities of operational mines. As much as 40% more lithium may be required in 2025 than can currently be produced. For cobalt, an additional consideration is the concentration of supply and refining capacity in just a few countries. The Democratic Republic of Congo accounts for over 50% of production and reserves, while China has 60% of refining capacity, up from only 3% in 2000 (Australia DIIS, 2017; Shedd et al., 2017; USGS, 2018a). Large investments to expand production capacity are required.

Figure 3.8 Global investment in mining of selected commodities, 2017 and trend since 2011



There has been a tenfold increase in investment in lithium mining since 2012, but it remains tiny compared with copper and coal.

Source: Based on CRU Group (2018).

Recent history suggests that those investments may be forthcoming, though bottlenecks in cobalt supply could arise leading to higher EV production costs and slowing their deployment. Investment in lithium[13] supply has risen tenfold since 2012, though it remains tiny compared with that in coal and copper mining (Figure 3.8). Market prices today comfortably exceed marginal production costs. Around USD 650 million in capex was spent by the major suppliers in 2017 and this is expected to rise by 2020. In contrast,

[13] For simplicity, this report does not distinguish here between lithium carbonate and hydroxide, which have different sources and values.

cobalt supply is less sensitive to prices. Investments in copper and nickel mining, from which cobalt is obtained as a by-product, are expected to rise only slightly in coming years following major capacity expansions before 2013. While the high price of cobalt today means that cobalt sales will represent their highest-ever shares of copper project revenues, cobalt prices are insufficient on their own to trigger investments in copper and nickel mining. In addition, it takes several years to bring new mine capacity online. There is an expectation of tight supply and further price spikes into the early 2020s, and stakeholders along the value chain, including automakers, are establishing contracts to secure mine output over periods as long as a decade (FT, 2018; Nemaska Lithium, 2018; Platts, 2018a).

In the longer term, global shortages of key commodities in the manufacture of batteries are unlikely. Future bottlenecks and volatility can be eased by policies that reduce uncertainty around future battery demand, encourage more recycling and help standardise cathode requirements. On the other hand, higher prices might result from the geographical concentration of supply if long-term contracts between a few major producers and consumers represent a large share of the market. Market tightness could also result from the rapid and widespread introduction of regulations aimed at improving sustainability, in particular in the cobalt supply chain.

EV production

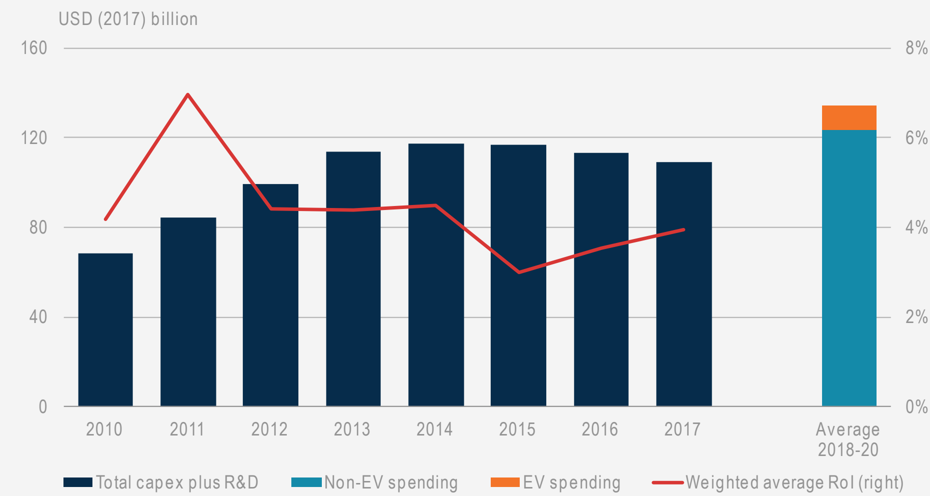
Investment in EV R&D and production is set to grow rapidly in the coming years. At least 13 of the world's largest carmakers have announced near-term increases in their capital spending on producing EVs (including R&D).[14] This is equal to around 8% of their total investment for the next three years, which is projected to rise significantly, following a modest downturn since 2015, despite the average return on investment of these companies being relatively flat since 2011 and EVs not yet being the most profitable parts of their businesses (Figure 3.8).

While new entrants could eventually become major producers of EVs, existing large carmakers are likely to be the main investors in EV manufacturing in the medium term. The extent to which today's major automakers can invest in EVs in a profitable and timely manner, and develop successful partnerships in the EV value chain, will have a significant influence on the pace of change in the sector. These companies face a strategic dilemma: if they expand EV capacity too slowly, they could lose market share and technological leadership in the long term. But if they ramp up EV capacity too quickly in response to policy and consumer interest, the aggregate capacity could overshoot

[14] These announcements do not specify the share of R&D in total spending.

short-term demand, which is highly uncertain. Furthermore, if they push the market more rapidly towards EVs, they risk undermining the value of existing assets and cannibalising revenues from more lucrative ICE vehicles.

Figure 3.9 Investment by 13 large carmakers



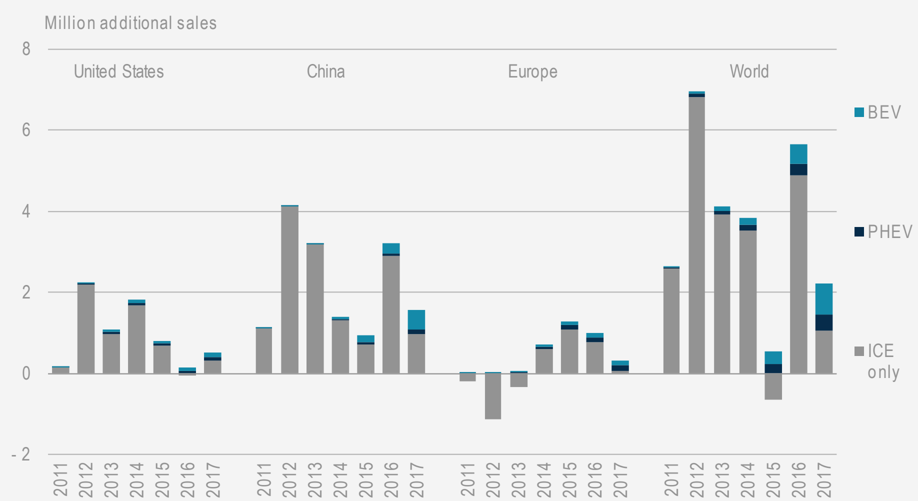
Announced EV spending over the next three years represents at least 8% of expected major carmaker spending on capex and R&D, reversing a trend of shrinking spending, despite little growth in returns.

Notes: RoI = return on investment, weighted by capex. Companies included are BMW, Chongqin Changan, Ford, Geely, Honda, Hyundai, Kia, Mahindra & Mahindra, Nissan, Renault, SAIC, Toyota and Volkswagen. R&D budgets assumed to remain constant at 207 levels in 2018-20.
Sources: Bloomberg (2018) and company announcements.

EVs are expected to remain the main driver of the passenger vehicle market worldwide. In 2017, they were responsible for around half of the absolute growth in total new vehicle sales and practically all the growth in Europe (Figure 3.10). On current trends, the market for new ICE-only passenger vehicles, after almost a century of growth, will go into decline in the coming years with EVs accounting for all the growth in sales. Sales of diesel cars are already falling following the scandal over emissions. In order to generate revenue to fund increased spending on EVs until they become more profitable, automakers may seek to take advantage of consumers' current preferences for larger vehicles, which are more profitable, and try to boost sales of these vehicles. Policy makers will need to be alert to the environmental implications of such a development and to consider the need for tighter regulations such as fuel economy standards.

Uncertainties facing automakers about future EV demand come on top of those about costs and bottlenecks in the battery value chain, technological developments, and the emergence of new competitors in the digitalization of mobility. The world's largest ICT companies are spending large sums of money on the development of technologies for automated and connected vehicles. New technologies and transport services pose threats to carmakers' existing business models if value shifts away from the vehicle itself and towards the software on-board and the data generated by users. The total market for new cars could shrink if more travellers choose to make their journeys in vehicles owned by other people ("mobility as a service"). In this case, more powerful batteries to provide longer driving ranges and data management would be needed, further raising the need for investment in battery development. The market dominance of today's carmakers could be further eroded if EVs are accompanied by new manufacturing techniques that allow batteries, motors and other components to be mass-produced separately and assembled cheaply.

Figure 3.10 Increase in new passenger vehicle sales by powertrain



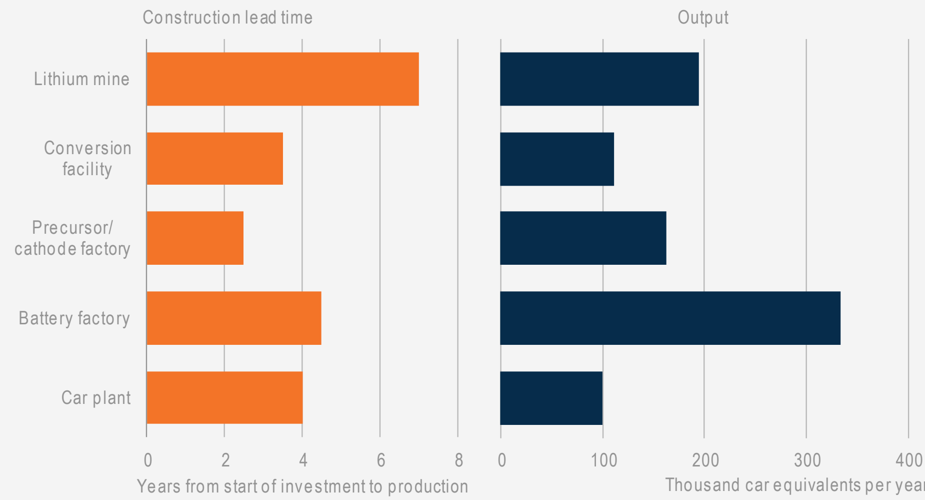
Plug-in vehicles accounted for over half of global sales growth of passenger vehicles in 2017, and almost all the growth in Europe, signalling a shrinking market for ICE-only passenger vehicles in coming years.

Sources: IEA (2018c; 2018d).

Alignment of investments in the value chain

Each element in the EV value chain faces uncertainties that raise investment risk and, potentially, costs. The long construction lead times and large sizes of new battery facilities add to these risks and increase the attractiveness of strategic partnerships. The lead time for a new Li-ion battery factory from the time of decision to invest until first production can be over four years (Figure 3.11). The output from a typical facility can supply batteries for over 300 000 cars. While this is less than the output of the world's largest engine plants, which can produce almost 2 million engines per year, it is bigger than the size of factories in other parts of the EV value chain. As a rule of thumb, the lithium to supply one 20 GWh battery factory needs more than one major mine expansion, three lithium conversion facilities, two cathode factories and over three car plants. The lead times are longest for mining and car production. The differences in lead times require careful coordination to avoid bottlenecks in the supply of components.

Figure 3.11 EV supply chain development lead times and sizes of typical facilities



Varying timeframes and manufacturing scales could lead to bottlenecks in EV supply chains.

Sources: CRU Group (2018) and IEA analysis.

Companies involved in the EV value chain face critical decisions about technology and timing. There is wide agreement that cathode and battery makers will need to shift to NMC 811 cathodes in coming years, but there is less consensus on when NMC 811 will itself be superseded. Suppliers of lithium and cobalt need to make projections about future commodity prices based on projections of EV demand and cathode chemistry. Carmakers, whose assets are mainly geared to producing ICE-powered vehicles, face a range of strategic decisions that influence the best timing to invest in EV production. The various stakeholders along the chain are increasingly looking to coordinate their investment strategies to minimise risk through long-term contracts, partnerships and vertical integration. Carmakers are hedging risks by making production lines that are capable of producing EVs and ICE vehicles. These approaches can alleviate risk but can also lock in particular designs and technologies.

Policy makers have a role to play in providing regulatory certainty over future EV demand, sustainability requirements for raw materials and recycling policies (IEA, 2018c). Some countries, especially in Europe, are keen to attract investment in particular parts of the EV value chain and appear willing to accept some of the risks associated with supply bottlenecks. Experience with mass production of solar PV has demonstrated some of the risks for higher-cost suppliers, but batteries may offer more opportunities for differentiating technology, leading innovation and integrating elements along the value chain. Yet this could slow the development of highly standardised low-cost manufacturing of battery packs and hold back cost reductions.

Hydrogen

Around 70 million tonnes (Mt) (2 200 terawatt hours)[15] of hydrogen are currently produced each year, primarily to meet demand in the oil refining, fertiliser, chemical, steel and glass industries (Hydrogen Council, 2017). While most of this is not used as an energy product, it nevertheless has an energy content equivalent to all of the natural gas demand used in buildings in Europe. Almost all of this hydrogen is manufactured from fossil fuels, using processes that emit CO_2. In most countries, the cheapest hydrogen production method uses natural gas as the main feedstock, but coal is used where natural gas is more expensive. In three hydrogen production facilities – in Canada, the United Arab Emirates and the United States – the CO_2 is captured at relatively low cost and used to enhance oil production (see section on CCUS, below).

Hydrogen has long been proposed as one way of storing and transporting low-carbon energy. As an energy carrier, it does not emit CO_2 at the point of use, it can make use of existing hydrocarbon infrastructure, and it can be produced from diverse low-carbon resources, including electricity and fossil fuels combined with CCUS. The production, storage, transport and transformation of hydrogen-based fuels compete with other technologies including battery storage, pumped hydro storage and biofuels, depending on the end-use application and location.

While EVs have emerged as the leading alternative technology for personal transport in recent years, there has been a noticeable increase in discussion of hydrogen over the last year as a means of managing the geographic and temporal availability of low-cost renewable electricity and maintaining the value of existing hydrocarbon infrastructure

[15] In chemical energy terms. All other energy and capacity values in this section refer to electrical energy.

during the transition to clean energy. Hydrogen benefits from support from stakeholders in sectors including renewable power, natural gas infrastructure and ICEs.

This section reviews developments in two areas of new technology: water electrolysis for clean energy applications and hydrogen filling stations for vehicles. Clean energy applications are those developed to reduce CO_2 emissions by using hydrogen produced from low-carbon sources, even if some of today's projects keep costs down by using hydrogen from fossil fuels or fossil fuel-based electricity. Examples of such applications include: storage and transport of renewables-based electricity, to be converted back to electricity when needed; powering road vehicles using a fuel cell; supplementing natural gas supplies (power-to-gas); combining hydrogen with a carbon source to make other liquid and gaseous fuels; and replacing hydrogen produced from coal or natural gas (without CCUS) in refining and iron and steelmaking.

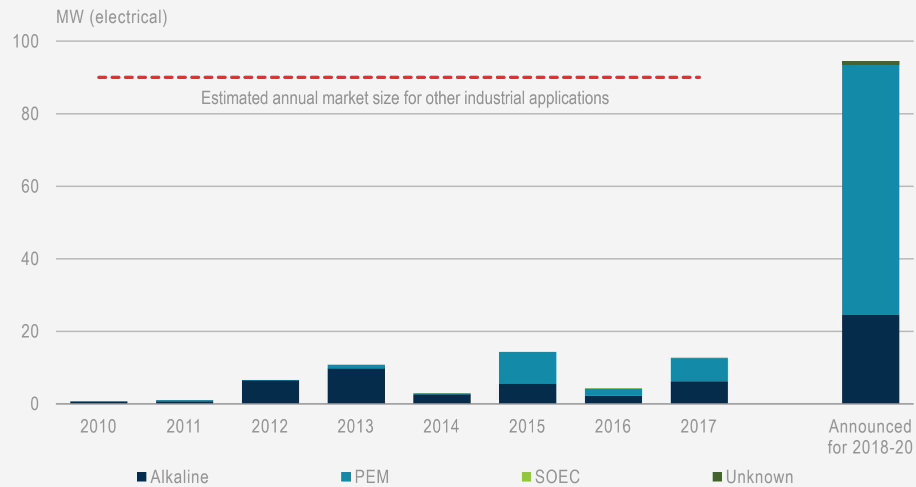
Water electrolysis

Water electrolysis involves the application of an electric current to water in order to separate out the hydrogen and oxygen. Although the process has been used for almost a century, it is currently used to make less than 1% of the hydrogen produced industrially worldwide today. In general, it is used on a large scale only where electricity is cheap and an industrial hydrogen facility is not available. Where the electricity is generated from clean sources, the life-cycle emissions from hydrogen produced by water electrolysis and used as a fuel can be near-zero. Thus, water electrolysis could play a role in the clean energy transition. For water electrolysis to produce hydrogen with fewer emissions than reforming of natural gas, without carbon capture, the emissions intensity of the input to electricity generation must be below around 400 kilogrammes per megawatt hour (MWh).

Investment in water electrolysis to produce hydrogen for clean energy applications is on the rise. More investment decisions to build electrolysers for this use were taken around the world in 2017 than ever before. Some of them use electricity produced solely from renewable energy. If these projects were all to come online by 2020, as planned, cumulative capacity will rise from 55 megawatts (MW) between 2010 and 2017, to over 150 MW (Figure 3.12). This will, however, remain well below the annual market for water electrolysers for other applications, which is estimated to be up to 90 MW globally. Total investment in water electrolysers for clean energy applications is estimated to have reached USD 17 million in 2017 and could rise to over USD 40 million per year in the next three years. Around 60% of currently installed electrolyser capacity for energy applications is in Germany.

There has been a change in the preferred route for producing hydrogen through electrolysis for clean energy applications in recent years, away from the mature alkaline electrolyser technology to the newer proton exchange membrane (PEM) technology. PEM electrolysers are expected by many to dominate this market due to their ability to follow electrical load better, their small, modular sizes and rapidly falling costs (Schmidt et al., 2017b). Installation costs have fallen by more than half over the last decade according to some sources, but are still higher than for alkaline electrolysers. SOECs, a technology that promises much higher efficiencies, are beginning to enter the market, with a handful of government-sponsored pilot projects starting up.

Figure 3.12 Global water electrolyser capacity additions for clean energy applications by type of technology



Installations of electrolysers for clean energy applications remain small but the number of planned projects signals a coming scale up based on PEM technology and supported by government programmes.

Notes: SOEC = solid oxide electrolyser cell. Clean energy applications include vehicles, electricity storage, power-to-gas grid, power-to-liquid fuel and displacement of fossil fuel in industries such as refining and iron and steel.
Sources: Calculations based in part on Buttler et al. (2018); Hydrogenics (2018); EU P2G Platform (2018).

Most existing energy electrolysis projects are small, with the average project installed in 2017 being 0.75 MW. Two exceptions, both of which use PEM technology, are the Energiepark Mainz in Germany (6 MW, installed in 2015) and the Guangdong Synergy project in China (3 MW, installed in 2017). However, several PEM projects in preparation today are in the 5 MW to 10 MW range. At this scale, which is similar in magnitude to many grid-scale battery projects, a stack of electrolysers could complement utility-scale renewables in a region by finding higher-value uses for PV and wind output if supply exceeds demand on the grid. The use of the more expensive PEM technology in these projects is contributing to rising investment in electrolysers for energy applications. Increasing the scale of PEM electrolysers is a key step in proving the technology commercially and bringing down capital costs towards USD 1 000 per kilowatt for 10 MW-scale applications (in the range of costs quoted for alkaline electrolysers today).

While many of the early energy electrolyser projects supply hydrogen vehicle filling stations, electricity storage and power-to-gas now represent over half of installed capacity worldwide. Of the announced capacity that could come online in the next three years, 40% is for power-to-gas and 28% for vehicles. The rest is for directly replacing fossil fuels in industries such as refining and steelmaking, where the demand is large and predictable. Most existing and planned installations, notably in Germany, benefit from government support, usually as grants for demonstrating electrolysis and associated technologies, such as hydrogen storage and vehicles, for a limited period of time.

Filling stations

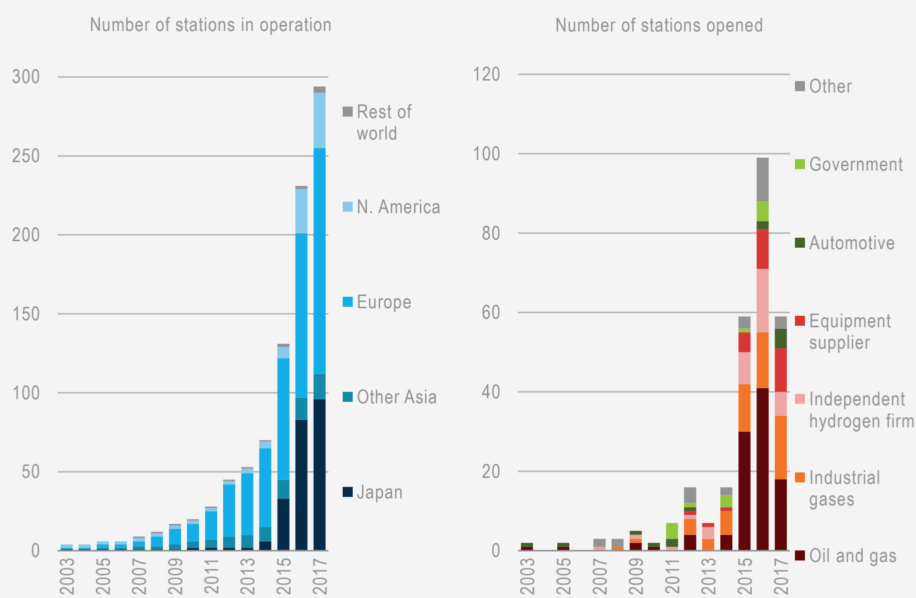
Sixty new hydrogen filling stations around the world were opened in 2017, bringing the total number in operation to over 300 (Figure 3.8). Total investment in 2017 amounted to around USD 200 million based on an average cost of USD 3 million per station. Most of the new and existing stations are in Asia and Europe. Europe's near-dominance of this sector has begun to slip, with the share of stations in Asia growing markedly. Japan dominates the Asian market, with 100 filling stations opened in the last four years as part of a push by government and automakers to encourage the sale of fuel cell vehicles that are already commercially available, such as the Toyota Mirai. In Europe, Germany is the largest market due to a series of government initiatives over the last decade.

There are signs that investment in hydrogen filling stations may be stalling. Fewer new stations were added in 2017 than in 2016, when a record 100 stations were opened. This is partly because many publicly funded demonstration programmes in Europe have now been completed. These demonstrations often involve the co-ordination of government funding at different levels to purchase vehicles and install hydrogen transportation, storage and refuelling infrastructure. Further growth in the sector may depend on attracting private investment throughout the hydrogen transport value chain. This will be difficult since hydrogen-powered vehicles remain costly and prospects for their ability to compete with EVs remain uncertain. The owners of hydrogen filling stations are varied, with oil and gas companies the leading category. Most hydrogen today is supplied from the processing of natural gas and the business model for refuelling is similar to that of gasoline and diesel. Industrial gases companies are the second largest type of owner. Both the oil and gas and industrial gases sectors have expertise that is relevant to hydrogen and stand to gain from its deployment, in particular if other hydrocarbon markets decline in value in the future. Nonetheless, for the time being, there is insufficient demand for most hydrogen filling station projects to be profitable, even with government support.

The cost of building a hydrogen filling station is similar to that of conventional liquid transport fuels, of which there are over 500 000 worldwide. For them to be profitable, the revenue from the hydrogen operations at these stations will need to match the revenue from existing businesses or the costs of the hydrogen infrastructure will need to fall. If costs fall and hydrogen demand increases, it is likely that many filling station owners will be agnostic about whether they supply diesel, hydrogen or electricity if overall profits, including from food and beverages, can be maintained.

For the 2020 Olympics in Tokyo, the Japanese government is aiming to have 160 filling stations in place to meet the needs of 40 000 fuel cell vehicles and has set aside USD 350 million to help build the infrastructure. As a result, Japan could surpass Europe for the number of stations in operation. Three types of demonstration projects have been selected to supply hydrogen to Japan, each facing different financial, technical and reliability risks: a 10 MW electrolyser in Fukushima, a natural gas reformer in Brunei and a lignite gasification facility in Australia. These last two both require shipping and handling infrastructure to be developed. The Australian project is intended to be coupled with CCUS in the future to reduce emissions.

Figure 3.13 Hydrogen filling stations by region and category of owner



The number of hydrogen filling stations in operation has been growing rapidly with investment led by oil and gas companies.

Sources: US DOE (2018) and PNNL (2018).

Encouraging investment in CCUS

CCUS is a proven technology for reducing emissions from CO_2 emissions-intensive processes, mostly involving fossil fuel combustion.[16] The potential deployment of CCUS runs to many thousands of installations and is widely regarded as a critically important component of the set of measures that are needed to prevent dangerous climate change. Yet deployment of CCUS has to date been limited and the future is highly uncertain, in large part because economic and policy conditions make the CCUS investment environment risky and complex.

Most efforts to advance CCUS deployment over the last two decades have focused on securing public and private investment in large, commercial-scale facilities to start to bring down long-term costs and learn about the technology. This is because processes for applying CCUS generally benefit from economies of scale and have lower running costs when built at large scale, such as chemical facilities and thermal power plants. Today, there are 17 such projects operating worldwide but new investment is drying up (Figure 3.14).

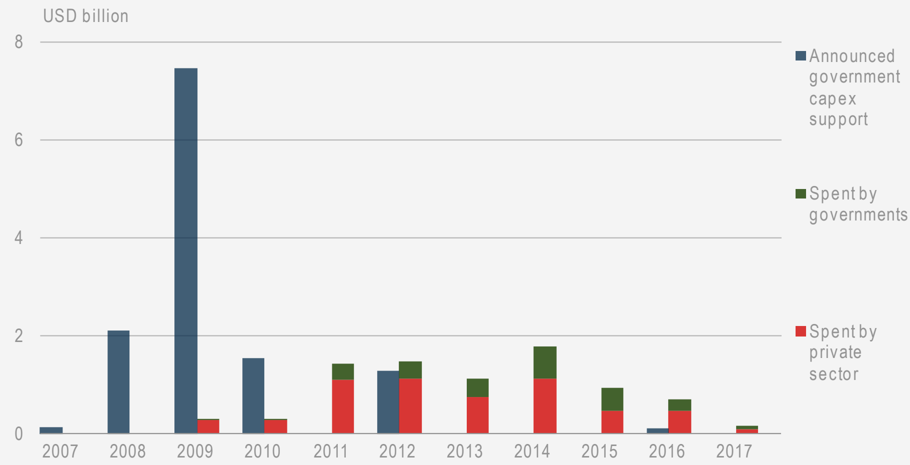
Significant amounts of public funding have been set aside for CCUS projects in the past decade but most of this money has been reabsorbed by government budgets unspent. Of the USD 28 billion earmarked for capital and operational support around the world, only about 15% has been spent, of which just two-thirds went to projects that are now in operation (Figure 3.15). Clearly, the design of public support programmes and associated policies has generally not made the commercial conditions sufficiently attractive for project developers to take advantage of available public funds and put their own money at risk.[17] In fact, the total level of funding available for CCUS over the last ten years is just 18% of that spent on subsidies for renewable power generation and 10% of that spent on fossil fuel consumption subsidies in 2016 alone (IEA, 2017d). The figures fall to 3% and 2% when considering only money actually spent.

---

[16] The term CCUS covers a range of technologies, all of which involve the capture of CO_2 to prevent it being emitted to the atmosphere or the recapture of CO_2 from the atmosphere that has already been emitted. The most common approaches capture CO_2 from industrial exhaust gases where it is in its most concentrated form. There are several options for managing the captured CO_2 so that it cannot contribute to climate change. The most prominent of these is to transport it by pipeline to a site where it can be safely and permanently stored underground at depths of over a kilometre. Geological storage like this can be combined with oil extraction. Other approaches involve using the CO_2 in chemical processes to make products or substances that can displace more carbon-intensive fossil fuels, usually on a smaller scale.

[17] In some cases, project developers, service providers and equipment manufacturers have put money at risk in anticipation of funding that has not materialised or been withdrawn for reasons outside their control. This has contributed to greater caution in planning new investment and subsequent projects.

Figure 3.14 Investment in large-scale CCUS projects



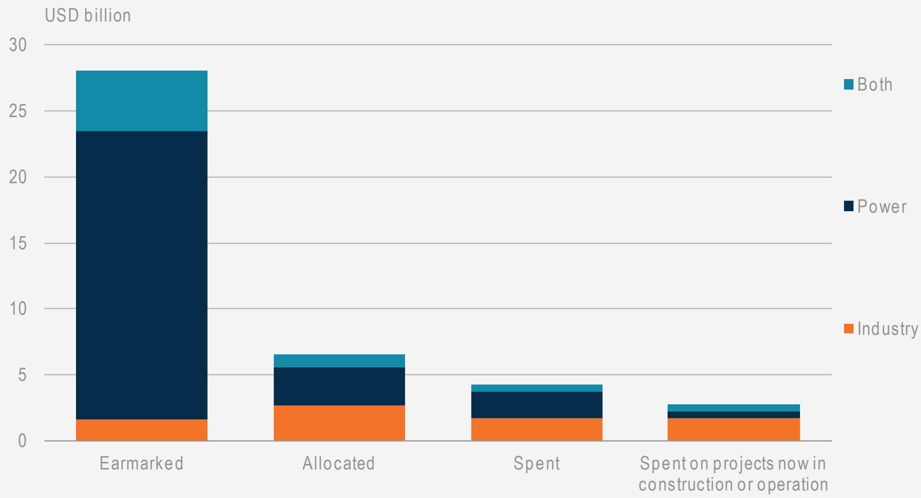
Investment in large-scale CCUS projects has declined markedly in recent years as government funding commitments for new projects, which peaked in 2009, have dried up.

Notes: Spending per project allocated to spending year where known and annualised in all other cases. This is a different approach from Figure 3.5 in *World Energy Investment 2017* (IEA, 2017c), which allocated spending to the year of entry into operation (in line with other investment estimates in this publication).

Projects that have reached financial close have often benefited from policy measures that ensure that the additional operational costs associated with CCUS facilities are covered, such as a tax credit or payment for stored CO_2 or an increase in regulated electricity rates. Thirteen of the 17 large-scale projects currently operating rely on revenue from selling CO_2 for use in enhancing oil production. To provide investors with confidence in the financial viability of a project over several years, certainty of a sufficient revenue stream can sometimes be more important than capital funding support. Providing public funding to cover the revenue gap for CCUS projects as operational support transfers some of the investment risk from the private sector.

This section explores how policy makers can encourage more investment in the near-term in the most promising CCUS opportunities. These are generally where the gap between the technology's net present value and its value in today's market is smallest. This includes not only the large-scale projects that have generally been the focus up to now but also smaller-scale businesses where a market can be created for captured CO_2 to be used in industrial processes and not emitted to the atmosphere. Many of these opportunities are in industrial sectors rather than power generation. These projects have been much more successful in securing investment to complement public funds, largely due to their lower technology and commercial risk profiles. While the most attractive near-term opportunities for investment are expected to be mostly in certain industrial sub-sectors, there is a near-universal expectation that a much larger CCUS industry will need to be built to tackle emissions in heavy industry and power generation sectors in the longer-term if climate goals are to be achieved.

Figure 3.15 World public funding for large-scale carbon capture, utilisation and storage projects by target sector, 2007-17



Between 2007 and 2017, governments earmarked USD 28 billion of public money to support early commercial CCUS projects, of which only 15% was ultimately spent by project developers.

Notes: Based on government spending and budget reconciliations. Earmarked funding includes all announced operational and capital support for large or commercial scale CCUS projects. This includes the UK Contract for Differences, which the UK National Audit Office estimated at 9 billion British pounds over 15 years for two projects. All values are in nominal USD. Support is deemed to be allocated when an agreement is struck with a given project.

Investment in carbon capture

Public and private sector investments in carbon capture[18] – the first step in the CCUS process in which CO_2 is separated from other flue gases or other sources before it enters the atmosphere – are motivated by different aims. In general, the public motive to invest in commercial-scale CCUS is to drive improvements in the technology, lower costs in the long term and avoid future costs of environmental damage. The private sector generally has a shorter time horizon and will consider investing in carbon capture only if it means it can avoid near-term regulatory or social costs associated with CO_2 emissions, sell CO_2 to a third party or charge a higher price for a low-carbon version of its product. There have been several examples of companies investing in carbon capture based on short-term economic motives alone. But in most cases, the public sector has provided co-funding to plug the gap between short-term costs and benefits and, by boosting innovation, reduce the time it will take to eliminate the gap.

The first carbon capture projects involving private investment alone were in the 1970s in the United States. Since 1972, the extra costs of processing the CO_2 separated from natural gas deposits in West Texas have been less than the price paid for the CO_2 by oil companies who use it for enhanced oil recovery (CO_2-EOR), making it profitable.[19] In 1996, Statoil (now known as Equinor) started capturing carbon at its Sleipner offshore oil and gas production facility in the Norwegian North Sea because the cost of reinjecting it deep underground was, and still is, lower than Norway's offshore CO_2 tax. These, and other carbon capture operations, have strongly benefited from their proximity to an existing market for CO_2 for CO_2-EOR or from the carbon capture operator having the capacity to develop and manage a geological CO_2 storage site. These factors can dramatically reduce costs and risks, cutting the need for government funding, sometimes to zero.

Another major factor determining the attractiveness of a carbon capture project is the ease with which CO_2 can be separated from other waste gases. There are a number of industrial processes, often found in the oil and gas industry, that create relatively pure streams of CO_2 in normal operation. These include purifying natural gas, making hydrogen from fossil fuels and

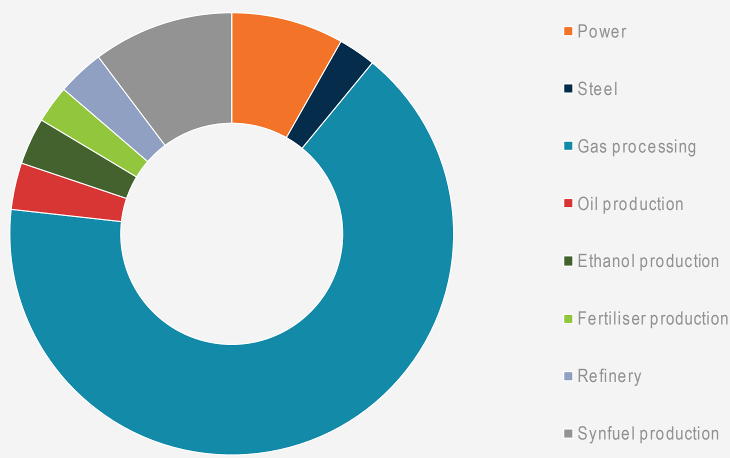
[18] While this section does not discuss the direct capture of CO_2 from the atmosphere – direct air capture – this could be an important component of climate change mitigation strategies in the future.

[19] CO_2-EOR is a tertiary oil recovery method involving the injection of CO_2 into a mature field to drive further production of the original oil in place. Most commonly, the injected CO_2 mixes with the oil, increasing its viscosity and pushing the oil towards production wells. A portion of the CO_2 remains trapped underground while the remainder is produced with the oil. The produced CO_2 is then separated from the oil and reinjected, creating a closed loop in which more and more CO_2 is incrementally stored. Over time, due to the closed nature of the process, the CO_2 injected into the formation is permanently stored. Operators of CO_2-EOR consider CO_2 a valuable commodity and contract for purchases of millions of tonnes of CO_2.

manufacturing bioethanol. Capturing CO_2 from these sources is mature and generally only requires the CO_2 to be purified or dehydrated before it is compressed and transported. Other sources of CO_2 are much more capital- and energy-intensive. The cost of capturing CO_2 tends to be fairly small proportional to the total operational costs in these industries, lowering the risk of investment and lessening the impact of the facilities competitiveness.

Of the 30 Mt of carbon capture capacity currently in operation around the world, around 90% comes from processes with highly concentrated CO_2 streams (Figure 3.16). An estimated 80% are in the oil and gas sector (two-thirds in natural gas processing, where separation of CO_2 is a necessary step in the preparation of natural gas for injection into the pipeline network) and 70% are in North America, largely due to its mature CO_2-EOR industry.

Figure 3.16 Sectoral shares of global CO_2 captured in large-scale CCUS facilities, 2017



Two-thirds of the CO_2 captured at CCUS plants today comes from the processing of natural gas, where separation of CO_2 is a necessary step in the preparation of the gas for injection into pipeline networks.

Sources: Incorporates information from GCCSI (2018); BNEF (2017); MIT (2018).

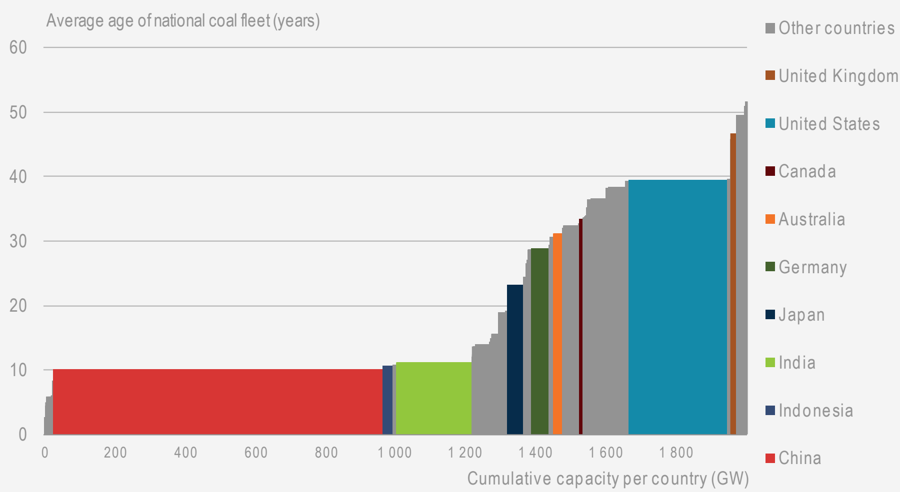
All but one of the CCUS projects in operation have entailed adding carbon capture facilities to an existing industrial facility or power plant. It is harder to reach financial close on greenfield projects that incorporate both a new industrial facility and a carbon capture plant from the outset due to the accumulation of capital requirements, longer lead times and technical risks associated with integrating the capture facilities. In the power sector, both of the large-scale plants with CCUS in use have involved retrofitting carbon capture to existing coal units. Retrofitting will be needed to cut emissions from the large fleet of young coal and gas-fired plants, especially in Asia. CCUS retrofits could reduce the need for retirements, maintain valuable dispatchable generating capacity and lower the cost of decarbonising the overall energy system (Box 3.1).

While carbon capture tends to have strong economies of scale for individual projects, widespread investment in CCUS would benefit from standardisation and replication. Of the 17 commercial projects in operation, 13 have a capacity of 1 Mt of CO_2 per year or less, reflecting the lower level of project risk associated with smaller plants and the fact that more concentrated streams of CO_2 are often found at smaller plants. However, offers of public funding have often specified a minimum scale higher than this (the US 45Q tax credit is an exception [Box 3.2]). In situations where a reliable off-taker for CO_2 storage or use is available, raising funds for a sequence of smaller, repeatable carbon capture units has proven more feasible than for a large one-off unit, even if total costs per tonne of CO_2 captured are higher.

Box 3.1 Retrofitting carbon capture on coal-fired power stations

Retrofitting carbon capture facilities at recently built power plants could extend the life of coal and gas power generation fleets while lowering emissions, which could be of particular value where coal and gas form the backbone of the current grid. In general, capturing carbon at coal plants costs less than at gas plants as the CO_2 content of the flue gases is higher.

Figure 3.17 Average age and size of coal-fired power fleets by country



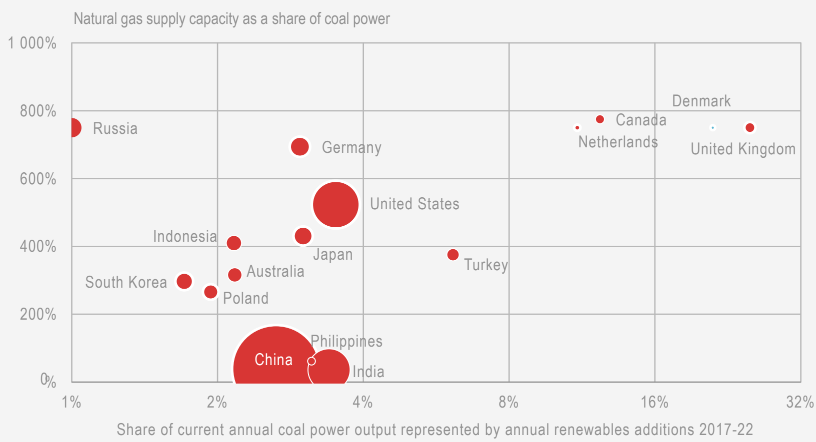
More than half of the world's coal-fired power generating capacity is in countries where the average plant age is less than 11 years old, much of which is in China, where retrofitting with carbon capture could significantly reduce national CO_2 emissions.

Note: X-axis ordered by average age of national fleets.
Sources: CoalSwarm (2018); Platts (2018b).

While it has been politically feasible to announce the phase-out of coal plants without carbon capture in countries such as Canada and the United Kingdom, this partly reflects the ready availability of natural gas infrastructure to help substitute for coal and a market with a share of renewable power that is growing and already meeting a significant share of demand. In a number of countries that have relatively young coal fleets, such as China, India and Indonesia (where the average age is between 6 and 11 years), the availability of gas is much more limited and renewables are not growing fast enough to permit coal-fired capacity to be shut down (Figures 3.17 and 3.18).

There is tremendous potential for retrofitting power plants with carbon capture facilities in China. IEA analysis has identified around 310 gigawatts (GW) of coal-fired capacity that could be retrofitted, including 100 GW at a cost of under USD 50 per MWh, which would need to be covered by some form of market mechanism or subsidy (IEA, 2016). Size, load factors and proximity to a high-quality storage resource are key cost determinants. As capacity factors at existing thermal plants fall over time, the costs and risks associated with retrofits will tend to rise, so there is merit in acting sooner rather than later.

Figure 3.18 Natural gas supply capacity and pace of renewables growth compared with coal-fired generation per country



Phasing out unabated coal power is easier in countries with ample existing gas supply infrastructure, rapid growth in renewables-based electricity and smaller coal fleets.

Notes: Bubble areas proportional to the size of the installed coal power generation capacity, with US capacity at 279 GW. Natural gas infrastructure estimated on the basis of national annual production plus pipeline and liquefied natural gas capacity. Natural gas capacity converted to coal generation equivalence using a 60% efficiency factor. Renewables growth represents the annualised growth forecast to 2022 in IEA (2017c).
Sources: IEA (2018e); IEA (2017c); CoalSwarm (2018); and Platts (2018b).

It is not certain how competitive retrofitting power stations will ever be with other mitigation options. Commercial decisions to retrofit power plants with carbon capture will be largely driven by policy measures targeted at reducing emissions, such as emissions performance standards or carbon pricing. Such measures also encourage increased deployment of renewables and switching from coal to gas in power generation. Combined-cycle gas turbines plants fuelled with natural gas produce only around half the emissions of a supercritical coal generation plant, with a cost of electricity generation that is often only slightly higher than using coal, depending on fuel prices. In some regions where coal-to-gas switching is feasible, coal generation is likely to be phased out before emissions constraints increase sufficiently to justify retrofitting coal with carbon capture (IEA, 2016).

As emissions constraints grow tighter and the costs of emissions are implicitly or explicitly raised, coal-fired power plants will become increasingly costly to operate. At some point, owners may face a decision on whether to continue operating for limited periods, retrofit them with carbon capture facilities or retire them. The decision taken will depend on the revenue they can expect to generate with and without carbon capture, and the level of competition from other plants. Even if a reliable outlet for the CO_2 can be found, such an investment would require a strong degree of confidence that the plant will operate for long enough periods to cover the additional cost of generation with carbon capture, including providing a return on equity and servicing debt. Debt could include outstanding debt on the power plant for younger plants, which may need to be recouped over fewer operating hours than foreseen, either with or without CCUS. As retrofits would have among the highest short-run marginal costs on the system, the plant's operating hours would be shorter in competitive markets in the absence of a high CO_2 price or some dispensation that guarantees that the plant is dispatched (related to the so-called "merit order effect"). In regulated markets, individual plants might have more certainty about load factors. In these markets, regulators could balance investments in CCUS against the costs of an alternative portfolio of low-carbon generation and the legacy costs of phasing out coal and gas-fired assets more quickly. Careful and timely policy planning is needed to stimulate investment in carbon capture retrofits that are valuable to system reliability and lower overall costs.

Investment in CO_2 storage and transport

For carbon capture to be part of a long-term strategy to mitigate climate change, the vast majority of the captured CO_2 must be stored permanently in underground geological sites or, potentially, integrated into durable materials. Today, there are very few providers of CO_2 storage services and limited existing infrastructure available for storing CO_2 underground. The exception is the United States, where the government supported the development of a CO_2 pipeline network in the 1970s to connect CO_2 sources with CO_2-EOR opportunities in mature oil fields. It has since expanded to cover over 6 000 miles. As a result, CCUS investments face much lower value-chain complexity and risks where connection to the existing CO_2 network is possible.

Creating a national framework for investment in exploring for and building CO_2 storage sites, plus stepwise build-out of pipelines, will be critical to the long-term prospects for CCUS. Ensuring that dependable storage services are available to potential carbon capture operators vastly reduces value-chain risk. There is a strong case for government taking a lead in developing network infrastructure, especially where CO_2-EOR is not an option. Exploration, development and permitting of a new CO_2 storage site can sometimes take up to a decade. The economic rewards for storing CO_2 are currently low and storing CO_2 as a waste management service is likely to remain a low margin business. In addition, the parallel development of widespread carbon capture is uncertain.

Governments have a vital role to play in allocating the economic, technical and regulatory risks appropriately, and identifying cases where private incentives can be leveraged to reduce the funding gap that taxpayers need to fill – for example, where industrial CO_2 emissions can be captured at low cost and a well-understood, high-quality CO_2 storage site is nearby. The cost profile in these cases can be sufficiently favourable that a relatively modest financial incentive can trigger investment in projects for CO_2 storage and transport, as well as capture. This is expected to be the effect of the United States' 45Q tax credit, expanded in 2018 (Box 3.2). Although many of these opportunities to date have been related to CO_2-EOR in North America, there are other places where adjusting the cost-benefit balance could trigger investment. In China and the Middle East, many millions of tonnes of CO_2 from coal-to-chemicals facilities, hydrogen production or gas processing could be stored via CO_2-EOR with relatively low costs and lead times.

Many of the opportunities for storage and transportation are in the same industrial sectors as the carbon capture operators, reducing the problems of allocating costs and benefits in the value chain between companies with different risk profiles. Among existing projects, the carbon capture facilities and the storage resources have been developed and operated by companies in the oil and gas industry in almost two-thirds of them. This sector emits large quantities of CO_2 and has the skills, knowledge and experience in gas handling and subsurface operations, plus existing assets that can be repurposed, including offshore platforms in the case of the North Sea. Likewise, capturing CO_2 from cement production to reduce emissions while creating value from the CO_2 in new products through CO_2 mineralisation, an area of rising interest for production of low-carbon construction materials, could keep the value chain within the sector.

In regions where CO_2 storage resources have not yet been identified – for example, as a part of oil and gas operations – and where CO_2-EOR is not likely to be practised, a different policy approach is required to trigger investment. In Europe, the best storage resource is expected to be deep under the North Sea, where costs, risks and times for exploration are higher. Nonetheless, these types of dedicated storage resources are integral to most climate mitigation scenarios. Governments can invest directly in exploration and characterisation of the geology. The greater the level of characterisation that is made publicly available, the lower the risk facing project developers during the exploration phase and the shorter the lead time. Upfront public investment can potentially be recouped through royalties for future use of the network infrastructure. In some cases, it will be possible to restructure existing royalty systems for fossil fuel extraction to direct a modest portion of the income to CO_2 storage development. In all cases, robust regulatory frameworks that clearly define the ownership of storage space, the holder of liability for stored CO_2 and how stored CO_2 will be treated under climate change legislation will be necessary to provide confidence in long term storage of CO_2 and make investments in storage projects bankable.

Box 3.2 Creating a CO_2 market: The case of the US 45Q tax credit

The 2018 US budget bill contains a provision that could trigger the largest surge in carbon capture investment of any policy instrument to date by expanding incentives to companies that can use captured CO_2 and reduce emissions as a result. It is an example of how relatively small policy incentives can tip the scales towards investment when the infrastructure and industrial conditions are already in place, as the United States is leveraging an existing market and pipeline network for CO_2-EOR.

It raises the existing so-called 45Q tax credit for storing each tonne of CO_2 permanently underground from USD 22 today to USD 50 in 2026. In the case of CO_2 stored via CO_2-EOR, the tax credit has been increased from USD 10 to USD 35. It also lowers the eligibility of carbon capture facilities to 0.5 Mt per year for power plants and 0.1 Mt per year for other sectors. The tax credit could lead to capital investment of around USD 1 billion over the next six years, potentially adding 10 Mt to 30 Mt per year of CCUS capacity and increasing oil production by 50 000 to 100 000 barrels per day (IEA, 2018f). This would increase global carbon capture by around two thirds. The annual cost to the US taxpayer by 2026 is estimated at USD 800 million.

By guaranteeing 12 years of effective revenue for companies that can use or store CO_2, the 45Q tax credit is supporting investment in these activities as well as encouraging the same investors or others to build or help initiate the carbon capture projects with which they will be able to contract for CO_2 supplies. The 45Q incentive should reduce the market price of CO_2 from carbon capture facilities to a level in line with that from natural CO_2 deposits and unlock demand that is currently limited by the constraints on natural CO_2 supply. Over time it could help phase out the use of natural CO_2 for CO_2-EOR. The policy encourages companies to seek carbon capture from the cheapest sources, which are likely to be hydrogen plants at refineries, natural gas processing facilities and bioethanol mills, especially those located close to existing CO_2 pipelines for transportation to oilfields.

The overall impact of the 45Q expansion remains to be seen, but the approach of providing known revenue for using or storing CO_2 is likely to be an effective policy approach to driving up widespread investment in CCUS. The ultimate success of this measure will depend strongly on CO_2 demand for CO_2-EOR, which is influenced by the oil price, and by CO_2 demand for geological storage, which depends on the speed with which dedicated CO_2 storage sites can be developed. It will also depend on demand for tax credit sales at a time of reduced tax burdens in the United States, other support schemes for CCUS and whether the measure is extended beyond 2030. As the measure also supports CO_2 utilisation for other uses at smaller scales and lower rates, as well as direct capture of CO_2 from the atmosphere, these sectors may also see an increase in investment if complemented by other incentives.

Developing CO_2 utilisation to support investment in carbon capture

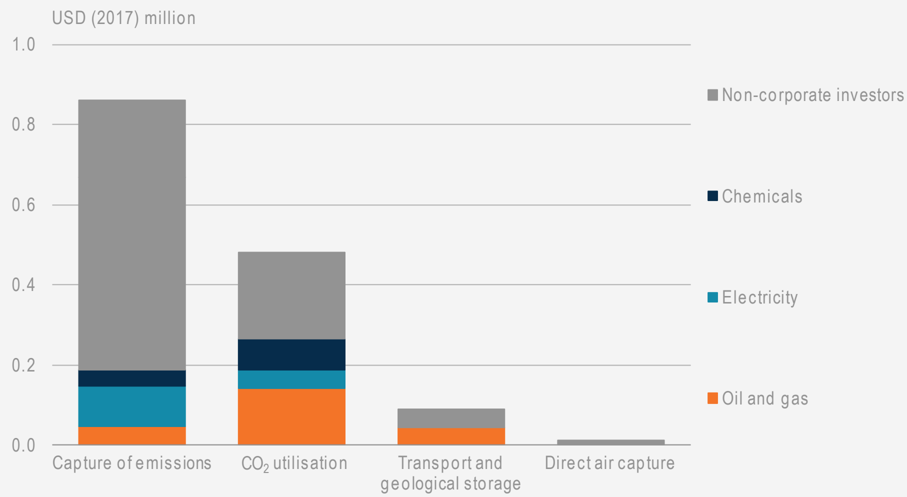
There is growing interest in technologies that can convert the carbon in captured CO_2 to products that have a market value in addition to their value in mitigating climate change. Unlike CO_2 used for EOR, these processes integrate the carbon chemically into final products including plastics, construction materials, fuels and high-value chemicals. One advantage is that carbon capture for this type of use would be driven more by market forces and could be less exposed to the policy and regulatory risks associated with investments in carbon capture for geological storage. Furthermore, the past decade has seen improvements in technology that have reduced the costs of some processes, including electrochemical catalysis to split CO_2, which has benefited from progress in PEM electrolysis (see section on hydrogen, above). While the expected market size is small in the medium term, there is speculation that incremental investments in innovative projects could stimulate progress in this area and provide a significant boost to carbon capture.

The investment proposition for CO_2 utilisation technologies is very different to that for the other capture, transport and storage options discussed above. The business models of companies that are scaling up their CO_2 utilisation technologies are generally underpinned by the near-term potential market value of a new product. By contrast, with the exception of CO_2-EOR, the business model for carbon capture and geological storage is generally founded upon the risk that the market for an existing emission-intensive product will be harmed by future climate policy and shifts in public perception. In fact, in most cases, CO_2 utilisation businesses are not motivated by reducing emissions from large emitters. Their products are designed to solve other challenges, such as converting renewable electricity to be compatible with fossil fuel infrastructure and reducing the CO_2 impact of chemicals and materials production. For these goals, CO_2 procured from power plants and industrial facilities can be less attractive compared with CO_2 procured from biofuels production or even the air.

It is easy to see how this changes the perspectives of investors. An investor in a CO_2 utilisation company must assess whether there is a growing market for the chemical, construction material or fuel based on its costs and attributes, including any value from its lower-carbon manufacturing process. Today's market could be very small but still profitable, involving relatively low capital outlay in the first instance. In comparison, when a power generator, refinery operator or steel manufacturer invests in carbon capture at its facility, it is likely to be in anticipation of various factors that can be difficult to manage, such as the timing of future climate policy, the regulatory regime for the technology, reputational benefits and the ability of the chosen technology to scale up by several orders of magnitude to cover much of its sector's emissions.

The attractiveness of potential utilisation technologies is reflected in the higher amount of VC and growth equity funding that has been channelled to companies developing them compared with those developing CO_2 transport and geological storage technologies in recent years (Figure 3.19). Cumulative funding for utilisation start-ups was close to half that for carbon capture from emissions sources and more than five times that for storage and transport over the 11 years to 2017, though the sums in total are not large. Oil and gas companies have invested more in CO_2 utilisation companies than carbon capture companies Utilities, on the other hand, have invested more of their money in carbon capture start-ups. While this is not reflective of overall spending on these technologies in corporate R&D departments and other partnerships, it does indicate that companies that are looking to cut their emissions see a near-term opportunity in CO_2 utilisation. Oil and gas companies, whose subsurface know-how would form the basis of a CO_2 storage industry, have also invested in companies using CO_2 in the production of cement, concrete, chemicals and synthetic hydrocarbon fuels at much smaller scales. Overall, the high share of corporate investment alongside more tradition VC funds and backers reflects expected low or negative returns over five to ten years, but strategic interest from companies facing long-term technology challenges.

Figure 3.19 Global cumulative funding for CCUS technology start-ups by type of investor, 2007-17



Most VC funding of CCUS start-ups has been directed to carbon capture, but corporate backers, including oil and gas companies, have invested more in CO_2 utilisation.

Notes: In the absence of detailed information, values are split equally between investors when there is more than one investor in the deal. Only deals with known transaction values are included.
Source: Cleantech Group (2018).

Despite the promise of utilisation technologies, the total market for most products that could be made from CO_2 is likely to remain very small even in the long term, making only a minor contribution to global emissions reductions that CCUS contributes in most climate models (ICEF, 2017). A possible exception is CO_2 utilisation for concrete and carbonate materials, but doing this on a large scale is very complex.

Governments can identify where CO_2 utilisation, starting at small scales, can be supported to help build up a carbon capture industry so that it matures over the coming decade and is ready for widespread investment. One approach is to make utilisation options that deliver emissions reduction eligible for incentives alongside CO_2 storage options and to complement this with specific market support tools, such as public procurement. The US 45Q tax credit is an example of the first element (Box 3.2). If captured CO_2 is sold or provided to a user of CO_2, the tax credit could be granted at a rate consistent with the verified emissions reductions, which in most cases will be lower than for geological CO_2 storage or CO_2-EOR. While many CO_2 utilisation projects require much lower upfront investment than geological storage, costs per tonne of CO_2 avoided are generally much higher. To bridge the gap, government support via public procurement can be used to stimulate demand for materials that have lower carbon footprints (Box 3.3).

Box 3.3 Creating markets for low-carbon products

Public- and private-sector interest in procurement of renewables-based electricity has not yet spilled over into the procurement of low-carbon materials and fuels. Yet the carbon embedded in the supply of construction materials and transport fuels – so-called "scope 3" emissions – can be significant. As carbon pricing of internationally traded industrial production remains underutilised internationally (OECD, 2016a), governments can find other ways to reduce their environmental impact and spur innovation by creating local markets for new products.

The Netherlands and Canada have implemented public procurement rules that favour material inputs with low-carbon footprints for construction projects. In the Netherlands, tenderers can have their bids evaluated with a price reduction of up to 5% if their performance meets certain criteria (OECD, 2016b). The government of Ontario is looking at how to account for the emissions embedded in cement and concrete in public procurement rules (ECO, 2017). These measures can make the difference for CO_2 utilisation start-ups making building materials, such as CarbonCure, Solidia and Carbon8. The large size of public contracts for these types of materials could help establish significant and sustainable markets worldwide.

Fuel standards can play a similar role, potentially at a larger scale. In California, a quantification methodology for the Low Carbon Fuel Standard is under development for oil products produced with CO_2-EOR that would reflect their better GHG performance due to the CO_2 stored in the process (ARB, 2017). As fuel suppliers have to meet a declining target for the GHG intensity of the fuel supplied, fuel with lower upstream emissions, including oil products originating from CO_2-EOR, could have a higher wholesale value. This approach could be replicated not just in other jurisdictions, but potentially for other products, from steel to chemicals.

Policies to boost investment in CCUS

Some important lessons can be drawn from recent experience with CCUS for governments seeking to leverage large-scale investment in this technology. These include:

- The importance of addressing uncertainty and risk throughout the value chain in maximising the impact of public funding.
- The need to ensure that the operational costs of CCUS are covered by revenues, which can sometimes eliminate the need for investment subsidies.
- The concentration of low-cost carbon capture opportunities in certain sectors, such as gas processing, hydrogen production and bioethanol production.

- The success of less complex and risky projects, including retrofits rather than greenfield projects, well-known storage sites that require less investment, projects that make use of existing transport infrastructure, and projects that involve companies from sectors with competences throughout the value chain.
- The effectiveness of markets for CO_2 utilisation – whether CO_2-EOR or novel products – in driving investment and seeking low-cost CO_2 sources at commercial scale.

Taking these lessons into account, this report proposes several high-level recommendations for policy makers to encourage investment in CCUS (Table 3.1). The objective of the recommended measures, which are not intended to be exhaustive, is to exploit the most attractive near-term opportunities – "low-hanging fruit" – where public support can most effectively leverage private capital for a succession of projects to scale up the separate elements of carbon capture, utilisation and storage.

Table 3.1 Policy focus areas for triggering investment in scaling up CCUS

Recommendation	Example of existing policy and approaches
1. Target the low-hanging fruit	Capture high-purity CO_2 which would otherwise be vented such as from natural gas processing, as in projects in the United States and Norway
	Where possible use existing storage resources, such as CO_2-EOR or depleted oil and gas fields, and existing infrastructure such as oil and gas pipelines
2. Create a market for captured CO_2 through targeted incentives for CO_2 storage and use	Tax credits per tonne of CO_2 stored or used innovatively, high enough to trigger investment in carbon capture from hydrogen production or ethanol plants, as in the United States
	CO_2 tax applied to oil and gas production in Norway
3. Stimulate demand for low-carbon materials and fuels	Use public procurement to favour construction materials with a low CO_2 footprint, as in the Netherlands
	Low Carbon Fuel Standards that value transport fuels made using CCUS, as in California
4. Spur investment in CO_2 storage development including CO_2-EOR	Underwrite a share of the risks associated with early CO_2 storage. Invest in exploration and pipelines as a public good, as in the development of other network industries
	Consider adjustment of oil and gas royalty regimes to promote CO_2 storage and its development, including through CO_2-EOR

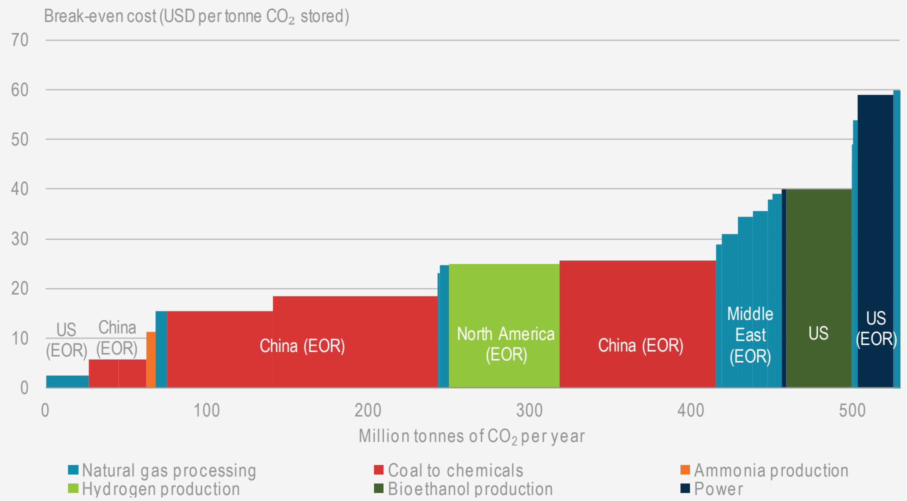
A significant near-term opportunity for governments to trigger investment in low-cost CCUS opportunities is in providing incentives to use or store CO_2. In many case, the mitigation costs of these options are in line with those of other low-cost clean energy technologies. Globally, this report estimates that there are over 450 Mt of CO_2 – equal to the global growth in emissions in 2017 – that could be captured and stored each year for under USD 50 per tonne in places where additional infrastructure needs are modest (Figure 3.20). If all these opportunities were exploited, the total amount of carbon captured and stored worldwide would increase 15 times, making a significant contribution to efforts to cut emissions. Larger reductions would necessitate parallel investment in CO_2 transport and storage infrastructure in other regions and continued R&D for technology improvement. This would require policies to reward private investment in CCUS in power generation, iron and steel and cement, where merit-order effects, technology risk and international competitiveness are significant barriers.

For individual projects, break-even costs will depend on the cost of financing, which reflects perceived risk. There are a range of risks which are unique to CCUS projects, primarily commercial risks stemming from a lack of experience with the technology, regulatory uncertainty and the commercial risks which arise from interaction among risks in each element of the CCUS chain (cross-chain, counterparty or integration risks). For example, damage to a pipeline could leave a storage operator without CO_2 supply, and therefore, revenue, forcing a carbon capture operator to vent CO_2. This would cause the operator to incur emissions charges or forgo CO_2 credits. Managing this counterparty risk has been a key challenge for projects with more than one equity sponsor. Liability for stored CO_2 can raise capital costs if storage operators face obligations and liabilities of unknown magnitude after storage operations cease. In some jurisdictions, requirements to continue active monitoring of storage sites last 10 to 50 years after closure and storage operators can be asked to post a financial security against the small chance of CO_2 leakage in decades to come based on the unknowable prevailing penalty for emissions at the time of leakage.

While these risks are generally lower for projects in the “low-hanging fruit” category, policy and regulatory design can help limit financing costs. Due to differences in business models and risks in different parts of the value chain, direct government involvement is usually needed, for example in ensuring that CO_2 transport and storage infrastructure and off-takers are available. To minimise risk, policy might ensure that factories are still allowed to operate without penalty if captured CO_2 cannot be stored for a period due to problems in the CCUS chain.

While CCUS projects to date have primarily been financed through equity – on project sponsors’ balance sheets or through joint ventures – projects should be able to include more debt in their capital structures as the technology matures. This can reduce the cost of capital. To this end, policy makers can ensure that the period of public support is well aligned to the commercial debt on offer to facilitate financing and refinancing. Governments can also help in assisting project developers to gain access to a wider range of financial instruments for first-of-a-kind early commercial projects, including loans and risk-sharing tools (EC, 2016). Alternative sources of finance include concessional financing from export credit agencies or multilateral development banks in some countries. Sustainable investment guidelines can ensure that financing of CCUS projects is possible through instruments such as green bonds. As companies and institutional investors are becoming more aware of their exposure to climate-related risks, both material and reputational, CCUS could come to be seen as a vital hedging technology for certain carbon-intensive industries. CCUS is given little attention in high-level discussions about investment in clean energy, but this may change as the technology is deployed more widely.

Figure 3.20 Low end of the CCUS supply curve



A commercial incentive as low as USD 50 per tonne of CO_2 sequestered could trigger investment in the capture, utilisation and storage of up to 500 million tonnes of CO_2 in the near term.

Notes: Costs include capture, transport and storage of CO_2. CO_2 sources are differentiated by proximity to CO_2 storage, including CO_2-EOR, quality of CO_2 storage resource and proximity to existing CO_2 transport infrastructure. The figure shows the potential for CCUS at relatively low break-even cost, encompassing the costs of capture from pure streams of CO_2 in regions which also have access to low-cost storage, often through EOR. The break-even cost is the all-in capital and operating costs of the project elements including the cost of financing. A range of costs and financing assumptions have been used reflecting the various regional conditions. For many of the regions where the IEA has found opportunities for CCUS but where there is no existing CO_2 transport infrastructure, this report has incorporated the cost of these transport links but recognises the importance of government leadership in developing them.
Sources: Inputs from National Energy Technology Laboratory (NETL, 2014), IEA GHG (2017).

References

ANL (Argonne National Laboratory) (2018), *BatPaC: A Lithium-Ion Battery Performance and Cost Model for Electric-Drive Vehicles*, web portal, Argonne National Laboratory, www.cse.anl.gov/batpac/index.html (accessed 4 July 2018).

ARB (Assessment Review Board) (2017), "Air Resources Board: Carbon capture and sequestration program", concept paper, Environmental Tribunals of Ontario, Ontario, www.arb.ca.gov/cc/ccs/documents/CCS_Concept_Paper_April_2017.pdf (accessed 4 July 2018).

Bloomberg LP (2018), Bloomberg Terminal (accessed 9 May 2018).

BNEF (Bloomberg New Energy Finance) (2018), *Manufacturing Plant Dataset*, BNEF, London (accessed 27 April 2018).

BNEF (2017), *Funds Committed* (database), BNEF, London, www.bnef.com/FundsCommitted/search (accessed 9 February 2018).

Buttler, A. and H. Spliethoff (2018), "Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: A review", *Renewable and Sustainable Energy Reviews*, Vol. 82, Part 3, pp. 2440-54.

Cleantech Group (2018), i3 database, (accessed 6 February 2018).

CoalSwarm (2018), *Global Coal Plant Tracker*, CoalSwarm, San Fransisco, http://coalswarm.org/trackers/india-coal-plant-tracker-map-and-table/.

Deutsche Bank (2016), *Market Research. EV battery makers*, 2 June 2016, Deutsche Bank, Hong Kong.

DIIS (Department of Industry, Innovation and Science) (2017), "Critical batter commodities", *Resources and Energy Quarterly*, 17 June, DIIS, Australian Government, Canberra, www.industry.gov.au/Office-of-the-Chief- https://industry.gov.au/Office-of-the-Chief-Economist/Publications/ResourcesandEnergyQuarterlyJune2017/documents/Resources-and-Energy-Quarterly-June-2017.pdf (accessed 6 June 2018).

ECO (Environmental Commissioner of Ontario) (2017), "Low-carbon procurement", in *Ontario's Climate Act from Plan to Progress: Annual Greenhouse Gas Progress Report 2017,* Ontario, http://docs.assets.eco.on.ca/reports/climate-change/2017/From-Plan-to-Progress-08.pdf (accessed 4 July 2018).

EU P2G (European Power to Gas) (2018), "Power-to-gas (demonstration) projects in Europe", (website), European Power to Gas Platform, Groningen, http://europeanpowertogas.com/projects-in-europe/.

FT (Financial Times) (2018), "BMW on verge of multiyear lithium and cobalt deal", 13 February 2018, *Financial Times*, London, www.ft.com/content/95ed34f0-10da-11e8-940e-08320fc2a277 (accessed 4 July 2018).

GCCSI (Global CCS Institute) (2018), *Large-scale Projects Database* (web portal), Global CCS Institute, Melbourne, www.globalccsinstitute.com/projects/large-scale-ccs-projects (accessed 4 July 2018).

Herron, S., A. Zoelle and W.M. Summers (2014), *Cost of Capturing CO_2 from Industrial Sources*, National Energy Technology Laboratory, U.S. Department of Energy, www.netl.doe.gov/energy-analyses/temp/CostofCapturingCO2fromIndustrialSources_011014.pdf (accessed 4 July 2018).

Hydrogen Council (2018), *Hydrogen: Scaling up – A Sustainable Pathway for the Global Energy Transition*, Hydrogen Council, http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf.

ICEF (Innovation for Cool Earth Forum) (2018), *Carbon Dioxide Utilization (CO2U): ICEF Roadmap 2.0*, Tokyo, www.icef-forum.org/platform/upload/CO2U_Roadmap_ICEF2017.pdf (accessed 4 July 2018).

ICF (2016), "Innovative financial instruments for first-of-a-kind, commercial-scale demonstration projects in the field of energy", European Commission, Brussels, http://ec.europa.eu/research/energy/pdf/innovative_financial_instruments_for_FOAK_in_the_field_of_Energy.pdf (accessed 4 July 2018).

IEA (International Energy Agency) (2018a), *Tracking Clean Energy Progress*, web portal (online publication only), OECD/IEA, Paris, www.iea.org/tcep/.

IEA (2018b), *Energy Technology RD&D Budget Database*, OECD/IEA, Paris, www.iea.org/statistics/rdd/ (accessed 11 June 2018).

IEA (2018c), *Global EV Outlook 2018*, OECD/IEA, Paris, https://webstore.iea.org/global-ev-outlook-2018.

IEA (2018d), *IEA Mobility Model*, 2018 version (database), OECD/IEA, Paris.

IEA (2018e), *World Energy Balances 2018*, www.iea.org/statistics/.

IEA (2018f), "Commentary: US budget bill may help carbon capture get back on track", OECD/IEA, Paris, www.iea.org/newsroom/news/2018/march/commentary-us-budget-bill-may-help-carbon-capture-get-back-on-track.html.

IEA (2017a), *Tracking Clean Energy Progress 2017*, OECD/IEA, Paris, www.iea.org/publications/freepublications/publication/TrackingCleanEnergyProgress2017.pdf.

IEA (2017b), *World Energy Outlook 2017*, OECD/IEA, Paris.

IEA (2017c), *Renewables 2017: Analysis and Forecasts to 2022*, OECD/IEA, Paris.

IEA (2016), "Ready for CCS retrofit: The potential for equipping China's existing coal fleet with carbon capture and storage", Insights Series 2016, OECD/IEA, Paris.

IEA (2011), *IEA Guide to Reporting Energy RD&D Budget/Expenditure Statistics*, OECD/IEA, Paris.

IEA GHG (IEA Greenhouse Gas R&D Programme) (2017), *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS,* OECD/IEA, Paris.

MI (Mission Innovation) (2018), "Mission Innovation country highlights", 3rd MI Ministerial 2018, http://mission-innovation.net/wp-content/uploads/2018/03/MI-Country-Highlights-2018-FINAL-Update-050618.pdf (accessed 18 June 2018).

MIT (Massachusetts Institute of Technology) (2018), *Carbon Capture and Sequestration Project* (database), MIT, Cambridge, MA, https://sequestration.mit.edu/contact/index.html (accessed 1 May 2018).

Nemaska Lithium (2018), "Nemaska Lithium and Northvolt announce signature of agreement in principle for supply of lithium hydroxide", press release, 27 April 2018, Quebec, www.nemaskalithium.com/en/investors/press-releases/2018/411eb855-075f-4922-a30d-f9bdfed1f3c7/ (accessed 6 June 2018).

OECD (Organisation for Economic Co-operation and Development) (2016a), *Effective Carbon Rates: Pricing CO_2 through Taxes and Emissions Trading Systems*, OECD Publishing, Paris, www.oecd.org/tax/effective-carbon-rates-9789264260115-en.htm (accessed 4 July 2018).

OECD (2016b), "Country case: Green public procurement in the Netherlands", Public Procurement Toolbox, OECD, Paris, www.oecd.org/governance/procurement/toolbox/search/green-public-procurement-netherlands.pdf (accessed 4 July 2018).

Platts (2018a), "Glencore to supply 42,800 mt of cobalt to China recycler GEM over 2018-2020", Platts Latest News, 15 March 2018, London, www.platts.com/latest-news/metals/hongkong/glencore-to-supply-42800-mt-of-cobalt-to-china-27926096 (accessed 6 June 2018).

Platts (2018b), *World Electric Power Plants Database*, Platts, Washington, D.C.

PNNL (Pacific Northwest National Laboratory) (2018), "Hydrogen delivery" (web page), *Hydrogen Tools* (web portal), Richland, WA, www.h2tools.org/hyarc/data/hydrogen-delivery (accessed 9 April 2018).

Sandalow, D. et al. (2017), *Carbon Dioxide Utilization (CO2U): ICEF Roadmap 2.0*, Innovation for Cool Earth Forum (ICEF), Tokyo, www.icef-forum.org/platform/upload/CO2U_Roadmap_ICEF2017.pdf (accessed 4 July 2018).

Schmidt, O. et al. (2017a), "The future cost of electrical energy storage based on experience curves", *Nature Energy*, Vol. 2, Article No. 17110, www.nature.com/articles/nenergy2017110 (accessed 4 July 2018).

Schmidt, O. et al. (2017b), “Future cost and performance of water electrolysis: An expert elicitation study”, *International Journal of Hydrogen Energy*, Vol. 42, No. 52, pp. 30470–30492, www.sciencedirect.com/science/article/pii/S0360319917339435 (accessed 4 July 2018).

Shedd, K. B., E. A. McCullough and D. I. Bleiwas (2017), “Global trends affecting the supply security of cobalt”, Mining Engineering (online), December 2017, Society for Mining, Metallurgy, and Exploration, Englewood, NJ, https://minerals.usgs.gov/minerals/pubs/commodity/cobalt/cobalt-supply-security.pdf (accessed 6 June 2018).

US DOE (US Department of Energy) (2018), “Alternative Fueling Station Locator” (web page), *Alternative Fuels Data Center* (web portal), Washington, D.C. www.afdc.energy.gov/stations/#/analyze (accessed 9 April 2018).

USGS (US Geological Survey) (2018a), “Cobalt”, US Department of Interior, Washington, D.C. https://minerals.usgs.gov/minerals/pubs/commodity/cobalt/mcs-2018-cobal.pdf (accessed 4 July 2018).

USGS (US Geological Survey) (2018b), “Lithium”, US Department of Interior, Washington, D.C. https://minerals.usgs.gov/minerals/pubs/commodity/lithium/mcs-2018-lithi.pdf (accessed 4 July 2018).

Lists of figures, tables and boxes

List of figures

List of tables

List of boxes

Abbreviations and acronyms

ABS	asset-backed security
AT&C	aggregate technical and commercial losses
BEV	battery-electric vehicle
capex	capital expenditure
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CfD	contract-for-difference
CO2	carbon dioxide
CO2-EOR	enhanced oil recovery
CSP	Concentrating solar power
CVC	corporate venture capital
DER	distributed energy resource
DRI	direct reduction of iron
DUC	drilled but uncompleted well
EAF	electric arc furnace
EBITDA	earnings before interest, taxes, depreciation and amortisation
ECA	export credit agency
EPC	energy performance contract
EPT	excess profits tax
ESCO	energy service company
ESI	energy savings insurance
EV	electric vehicle
FCEV	fuel-cell electric vehicle
FID	final investment decision
FiT	feed-in tariff
FSRU	floating storage regasification unit
GDP	gross domestic product
GHG	greenhouse gas
GST	goods and sales tax
HVAC	heating, ventilation and cooling, or
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
ICT	information and communication technology
IOU	investor-owned utility
IPO	initial public offering
IPP	independent power producer
IRR	internal rate of return
LCOE	levelised cost of energy
LDV	light-duty vehicle
LED	light-emitting diode
LFP	lithium iron phosphate
Li-ion	lithium-ion
LMO	lithium manganese oxide
LNG	liquefied natural gas
LPG	liquefied petroleum gas
M&A	mergers and acquisitions
MDB	multilateral development bank
NCA	nickel cobalt aluminium
NGL	natural gas liquids
NMC	nickel manganese cobalt
NOC	national oil company
NPA	non-performing asset
NPV	net present value
OCGT	open-cycle gas turbine
PACE	property-assessed clean energy
PCI	project of common interest
PEM	proton-exchange membrane (also called polymer electrolyte membrane)
PFI	public financial institution
PHEV	plug-in hybrid
PPA	power purchase agreement
PSM	payment security mechanism
PSP	pump-hydro storage power
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
ROE	return on equity
RoI	return on investment
RT&H	Renewable transport and heat
SOE	state-owned enterprise
SOEC	solid oxide electrolyser cell
T&D	transmission and distribution
TSOs	transmission system operators
UHVDC	ultra-high-voltage direct current
UICI	Upstream Investment Cost Index
USICI	Upstream Shale Investment Cost Index
VC	venture capital
VIU	vertically integrated utility
VRE	variable renewable energy

WLTP	Worldwide Harmonised Light Vehicles Test Procedure
WTI	West Texas Intermediate
YTD	year to date
YoY	year-on-year

Units of measurement

Energy

boe	barrels of oil equivalent
kboe/d	thousand barrels of oil equivalent per day
MBtu	million British thermal units
GJ	gigajoules
toe	tonne of oil equivalent
ktoe	thousand tonnes of oil equivalent
Mtoe	million tonnes of oil equivalent
kWh	kilowatt hours
MWh	megawatt hour
GWh	gigawatt hour
TWh	terawatt hour

Power

MW	megawatt
GW	gigawatt

Electricity

kV	kilovolt

Energy density

kWh/kg	kilowatt hours per kilogramme

Gas

bcm	billion cubic metres

Oil

kb/d	thousand barrels per day
mb/d	million barrels per day

Mass

kg	kilogramme
Mt	million tonnes
Bt	billion tonnes

Distance

km	kilometre

IEA/OECD possible corrigenda on: www.oecd.org/about/publishing/corrigenda.htm

IEA Publications
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/about/contact
Typeset in France by DESK - July 2018
Cover design: IEA; Photo credits: © GraphicObsession

World Energy Investment 2018

World Energy Investment 2018 provides a critical benchmark for decision making by governments, the energy industry, and financial institutions to set policy frameworks, implement business strategies, finance new projects, and develop new technologies. It highlights the ways in which investment decisions taken today are determining how energy supply and demand will unfold tomorrow.

The report looks at critical questions that have shaped the energy industry, including:

- Which countries and policies attracted the most energy investment in 2017, and what fuels and technologies are growing fastest?
- Is energy investment sufficient and targeted appropriately to realise the world's energy transition objectives?
- How are oil and gas companies responding to higher oil prices? Are they changing their strategy decisions in order to ensure adequate supplies while minimising long-term risks?
- How is the business model for US shale evolving? Is the rapid growth of production in 2018 still largely based on continuous overspending or is the industry finally moving towards financial sustainability?
- Are business models and financing approaches supporting a shift in power generation investments towards renewables? How are regulators around the world shaping enabling investments in power system networks and flexibility?
- What policy and market factors drive energy efficiency spending? What new approaches to financing are emerging for efficient goods and services?
- How are the sources of energy finance evolving? What roles are public financial institutions and utilities playing? How are decision makers addressing investment risks in India and other emerging economies?
- What are governments and the energy sector spending on energy research and development? What are the main considerations facing investors in batteries and the electric vehicle value chain; carbon capture, utilisation and storage; and hydrogen?