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World Energy Investment 2017

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

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- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
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Foreword

Investment made today in energy infrastructure will leave its mark for decades to come. For that reason, the energy sector presents exceptional opportunities but also challenges for investors and governments who must deliver capital at the right time and in the right place, while considering long time horizons. This is why good investment decisions require timely, accurate and reliable data and analysis. Governments rely on impartial information to craft the most appropriate policies needed to achieve the goals of energy security, environmental sustainability and economic growth. The energy and financial industries also need the best-possible information to make profitable investments.

The International Energy Agency provides authoritative, reliable and global data and analysis for decision-makers. We have been energy experts for more than four decades, first through our work on energy security and now through our comprehensive work across all fuels and all energy technologies. Since its first edition last year, I believe our *World Energy Investment* report has established itself as a must-read resource for government officials, investors and industry decision-makers who are shaping the energy system of the future.

The report provides a unique benchmark for measuring and assessing global investment trends across the entire energy sector, whether it is oil, gas and coal supplies, electricity generation and networks or spending on energy efficiency. This year, our analysis goes deeper by tracking the sources of financing, measuring spending by governments and companies in energy R&D and assessing how government policies are affecting energy investments, among other topics. While the focus is on investments made in 2016, we also reflect on what this means for meeting energy security and environmental goals ahead.

It is vital that we consider the global energy system in its entirety because it is deeply interlinked. For instance, decisions about LNG terminals in the United States or environmental policies in China can affect the prospects for other fuels on the other side of the world. Digitalization is making the energy world even more connected – the same way our personal lives have become dominated by smartphones and other connected devices. *WEI 2017* looks at how investment in digital technologies has been rising substantially. This trend, which the IEA is exploring in depth this year in a different report, is having profound impacts inside and outside the energy sector. It is re-shaping, but not replacing, investment in assets to be operated for decades to come.

The work of the IEA is to help governments, industries and citizens make good energy choices. We will keep providing the most relevant and timely data and analysis as well as policy solutions while keeping pace with a rapidly evolving and complex energy sector. Our goal is to ensure adequate investment for reliable, affordable and sustainable energy in a growing global economy.

Dr. Fatih Birol
Executive Director
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www.iea.org/investment.

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Executive summary

Total energy investment worldwide was around USD 1.7 trillion in 2016, 12% lower than 2015 in real terms and accounting for 2.2% of global gross domestic product (GDP). A 9% increase in spending on energy efficiency and a 6% increase in electricity networks were more than offset by a continuing drop in investment in upstream oil and gas, which fell by over a quarter, and power generation, down 5%. Falling unit capital costs, especially in upstream oil and gas, and solar photovoltaics (PV), was a key reason for lower investment, though reduced drilling and less fossil fuel-based power capacity also contributed.

The electricity sector edged ahead of the fossil fuel supply sector to become the largest recipient of energy investment in 2016 for the first time ever. Oil and gas represent two-fifths of global energy investment, despite a fall of 38% in capital spending in that sector between 2014 and 2016. As a result, the low-carbon components, including electricity networks, grew their share of total supply-side investment by twelve percentage points to 43% over the same period.

The People's Republic of China (hereafter, "China") remained the largest destination of energy investment, taking 21% of the global total. With a 25% decline in commissioning of new coal-fired power plants, energy investment in China is increasingly driven by low-carbon electricity supply and networks, and energy efficiency. Energy investment in India jumped 7%, cementing its position as the third-largest country behind the United States, owing to a strong government push to modernise and expand India's power system and enhance access to electricity supply. The rapidly growing economies of Southeast Asia together represent over 4% of global energy investment. Despite a sharp decline in oil and gas investment, the share of the United States in global energy investment rose to 16% – still higher than that of Europe, where investment declined 10% – mainly as a result of renewables.

Key trends in energy investment by sector

After a 44% plunge between 2014 and 2016, upstream oil and gas investment has rebounded modestly in 2017. A 53% upswing in US shale investment and resilient spending in large producing regions like the Middle East and the Russia Federation (hereafter, "Russia") has driven nominal upstream investment to bounce back by 6% in 2017 (a 3% increase in real terms). Spending is also rising in Mexico following a very successful offshore bid round in 2017. There are diverging trends for upstream capital costs: at a global level, costs are expected to decline for a third consecutive year in 2017, driven mainly by deflation in the offshore sector, although with only 3% decline, the pace of the plunge has slowed down significantly compared to 2015 and 2016. The rapid ramp up of US shale activities has triggered an increase of US shale costs of 16% in 2017 after having almost halved from 2014-16. The oil and gas industry is undertaking a major transformation in the way it operates, with an increased focus on activities delivering paybacks in a shorter period of time and the sanctioning of simplified and streamlined projects. The global cost curve has rebased, and a significant component of the cost reduction experienced over the last two years is likely to persist in the foreseeable future.

Global electricity investment edged down by just under 1% to USD 718 billion, with an increase in spending on networks partially offsetting a drop in power generation. Investment in new renewables-based power capacity, at USD 297 billion, remained the largest area of electricity spending, despite falling back by 3%. Renewables investment was 3% lower than five years ago, but capacity additions were 50% higher and expected output from this capacity about 35% higher, thanks to declines in unit costs and technology improvements in solar PV and wind. Investment in coal-fired plants fell sharply, with nearly 20 gigawatts (GW) less commissioned, reflecting concerns about local air pollution and the emergence of overcapacity in some markets, notably China, though investment grew in India. The investment decisions taken in 2016, totalling a mere 40 GW globally, signal a more dramatic slowdown ahead for coal power investment once the current wave of construction comes to an end. Gas-fired power investment remained steady in 2016, but nearly half of it was in North America, the Middle East and North Africa where gas resources are abundant. In Europe, although 4 GW of new capacity came online based on investment decisions made years ago, retirements of gas-power plants exceeded the amount of new capacity that was given the green light for construction. The 10 GW of nuclear power capacity that came on line in 2016 was the highest in over 15 years, but only 3 GW started construction, situated mostly in China, which was 60% lower than the average of the previous decade.

Spending on electricity networks and storage continued its steady rise of the past five years, reaching an all-time high of USD 277 billion in 2016, with 30% of the expansion driven by China's spending in the distribution system. China accounted for 30% of total networks spending. Another 15% went to India and Southeast Asia, where the grid is expanding briskly to accommodate growing demand. In the United States (17% of the total) and Europe (13%), a growing share is going to the replacement of ageing transmission and distribution assets. Overall, the grid is modernising and moving from a pure electricity delivery business to an integrated platform for data and services, enabled by rapid progress in digital information and communications technologies, which grew to over 10% of networks spending. Investment in grid-scale battery-based energy storage is ramping up quickly, having reached over USD 1 billion in 2016.

Investment in energy efficiency expanded once again, despite persistently low energy prices, reaching USD 231 billion in 2016. While Europe was the largest region for this type of spending in 2016, the fastest growth occurred in China, where a strengthening of energy efficiency policies is helping to reduce the energy intensity of the economy, alongside structural changes. Globally, most investment – USD 133 billion – has gone to the buildings sector, which accounts for one-third of total energy demand. While the energy performance standards of equipment and appliances in emerging economies are gradually tightening, there is still much room for improvement. For example, new air conditioners sold in 2016 will add up to 90 terawatt hours (TWh) of power demand globally and 10 TWh in India alone, exacerbating peak loads. This could have been 40% lower if the highest efficiency standards had been adopted in all countries. In 2016, the numbers of heat pumps sold grew 28% and electric vehicles grew 38%. These technologies improve overall efficiency and if co-ordinated with renewables deployment could help decarbonise space heating and mobility, though so far their impact on oil and gas demand is small. The 750 000 electric vehicles sold in 2016 are expected to reduce transport oil demand by around 0.02%.

Key trends in financing and funding energy investments

More than 90% of energy investment is financed from the balance sheets of investors, suggesting the importance of sustainable industry earnings, which are based on energy markets and policies, in funding the energy sector. This share has barely changed in recent years, though sources of finance are changing in some sectors. While the overall share of project finance, which depends on cash flows for a given asset, remains small, its use in power generation investment – especially renewables – has grown rapidly in the past five years, by 50%, reflecting lower project risk in some emerging economies and the maturation of certain technologies. Newer mechanisms for raising equity and debt, such as green bonds and project bonds, are enabling investors to tap into larger financing pools, especially for refinancing assets and funding investments in smaller-scale projects such as energy efficiency and distributed generation.

The role of state actors in energy investments remains elevated. While the share of public bodies in investment, including state-owned enterprises (SOEs), edged down slightly to 42% in 2016, the level was notably higher than 39% in 2011. This is largely due to the increased role of SOEs in electricity sector investment, notably in China. The share of public bodies in generation investment, at one-third in 2016, has recently begun to moderate while their share in networks investment, at nearly 70%, continues to rise. National oil companies are playing a larger role in upstream oil and gas spending, with their share rising to 44% in 2016 from below 40% before the recent downturn in oil prices. The costs of government energy efficiency programmes are equal to almost 15% of energy efficiency spending and, via loans and competitive mechanisms, directly generate private spending that is more than twice this level.

Government policies and new business models are having a profound impact on the way investment in electricity supply is funded. In 2016, 94% of global power generation investment was made by companies operating under fully regulated revenues or regulatory mechanisms to manage the revenue risk associated with variable wholesale market pricing. However, significant changes are occurring in some sectors and markets. Over 35% of utility-scale renewable investment took place in markets where prices for power purchase were set by auctions, contracts with corporate buyers and other competitive mechanisms, up from 28% in 2011. In wholesale markets, funding new thermal generation increasingly depends on capacity payments or other revenues beyond wholesale markets. While virtually all network investment has a regulated business model, unbundled grid companies accounted for only 40% of grid investment, with the large majority of this funded on the basis of regulated network tariffs, compared with 50% in 2011. Policies that help to reduce the cost of capital and improve the cost-reflectiveness of electricity pricing are especially important in countries such as India and Indonesia where electricity demand is growing rapidly and where utilities face financing constraints.

The downturn in oil prices did not significantly affect the funding of investments by oil and gas companies, though most of them increased leverage significantly**.** Despite investment cutbacks and better cost discipline, the oil majors increased debt by over USD 100 billion between late 2014 and early 2017. Independent US oil companies, which have a more leveraged business model, initially saw debt costs soar, but the availability and cost of bond financing has improved with a rebound of oil prices since early 2016 and their financial health has improved with efficiency gains. Increased interest in shale assets by large oil companies and financial pressures to reduce debt led to a series of asset sales by independents.

Energy innovation, digitalization and employment

We have tracked USD 65 billion of spending on energy research and development (R&D) worldwide in 2015, based on a bottom-up assessment of spending by public and private bodies. Despite growing recognition of the importance of energy innovation, spending on neither energy technology generally nor clean energy specifically has risen in the past four years. Europe and the United States are the largest spenders, each accounting for over 25% of the total, whereas China is the highest spender on energy R&D as a share of GDP, after overtaking Japan in 2014. Although public and private sources each represent around half of the R&D total, most private R&D is in the oil, gas and thermal power sectors, whereas most public R&D is devoted to clean energy technologies. Important carbon capture and storage projects, largely financed by companies, are starting operation in 2017, but current policies do not support a significant uptick of spending in this decade on these long lead-time projects, as evidenced by the lack of new projects entering construction.

The future role of digital technologies for generating, handling and communicating data has taken centre stage in energy discussions. We estimate that USD 47 billion was spent in 2016 on infrastructure and software directed towards digitalization of the electricity sector to facilitate more flexible network operation, demand management and integration of renewable resources. The oil and gas industry is scaling up its utilisation of digital technologies to improve performance of its operations while keeping costs under control.

It is difficult to justify major energy policy decisions on the basis of their employment impact alone. Our analysis suggests that, in general, technological progress is leading to lower labour intensity across the energy system. For example, a 30% drop in jobs in US oil and gas upstream from its peak level in 2014 to its 2016 trough was accompanied by only a marginal decrease in production. Productivity improvements are also unfolding for key renewable power generation technologies. A snapshot comparison of different power generation technologies suggests that renewables tend to create more upfront jobs in construction and manufacturing, whereas thermal generation requires more ongoing employment in operations and fuel supply. Combining these activities shows that the employment across the project life cycle resulting from the generation of a new unit of electricity is comparable across technologies. However, the impact on employment of investment in different power generation technologies is likely to be highly region-specific, partly because of the geographical mismatch between fossil fuel production and clean energy deployment as well as due to differences in the international competitiveness of relevant engineering and construction industries. Labour intensity also varies markedly across regions for the same technology. For example, the employment impact of both solar and coal-fired power can vary by 100% or more depending on local conditions.

Implications of energy investment

A 17% decline in global energy investment since 2014 has not yet raised major concerns about near-term energy supply adequacy, which have been eased by excess capacity in global fossil fuel supply and electricity generation in some markets, as well as cost deflation in many parts of the energy sector. But falling investment points to a risk of market tightness and undercapacity at some point down the line. A drop in upstream oil and gas activity and the recent slowdown in the sanctioning of conventional oil fields to its lowest level in more than 70 years may lead to tighter supply in the near future. Given depletion of existing fields, the pace of investment in conventional fields will need to rise to avoid a supply squeeze, even on optimistic assumptions about technology and the impact of climate policies on oil demand. The energy transition has barely begun in several key sectors, such as transport and industry, which will continue to rely heavily on oil, gas and coal for the foreseeable future.

In many cases, it is unclear whether the business models in place are conducive to encouraging adequate investment in flexible electricity assets, raising concerns about electricity security. Continuous investment in flexible assets to ensure system adequacy during periods of peak demand and to help integrate higher shares of wind and solar PV capacity into the system is essential. The bulk of the flexibility that has been introduced so far has come from existing assets, primarily dispatchable capacity (mainly gas-fired plants and hydropower) and transmission interconnections. In 2016, the amount of new flexible generation capacity plus grid-scale storage that was sanctioned worldwide fell to around 130 GW – its lowest level in over a decade, reflecting weaker price signals for investment stemming from ongoing regulatory uncertainty and flawed market designs. For the first time ever, this capacity was virtually matched by the 125 GW of variable renewables capacity (solar PV and wind) commissioned in 2016, whose construction times are generally a lot shorter. The 6% increase in electricity network investments in 2016, with a larger role for digital technologies, supports grid modernisation and the ongoing integration of variable renewables. However, new policies and regulatory reforms are needed to strengthen market signals for investment in all forms of flexibility.

Although carbon dioxide emissions stagnated in 2016 for the third consecutive year due to protracted investment in energy efficiency, coal-to-gas switching and the cumulative impact of new low carbon generation, the sanctioning of new low-carbon generation has stalled. Even though the contribution of new wind and solar PV to meeting demand has grown by around three-quarters over the past five years, the expected generation from this growth in wind and solar capacity is almost entirely offset by the slowdown in nuclear and hydropower investment decisions, which declined by over half over the same time frame. Investment in new low-carbon generation needs to increase just to keep pace with growth in electricity demand growth, and there is considerable scope for more clean energy innovation spending by governments and, in particular, by the private sector.

Introduction

This second 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 2017* describes how financing mechanisms and sources of funding for the energy sector are evolving.

The focus is on what happened in 2016 and how that compared with previous years. The report also highlights important trends in 2017 where reliable data are available. The *WEI* complements IEA projections and analysis in the annual *World Energy Outlook* and *Energy Technology Perspectives* and the series of annual market reports for the major energy 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 by companies, governments and individuals to acquire equipment that consumes less energy than that which they would otherwise have bought.

[1] The World Energy Investment Roundtable, held in February 2017, provided an opportunity for more than 40 senior officials from industry and finance to guide the IEA's 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.

1. Trends in energy investment

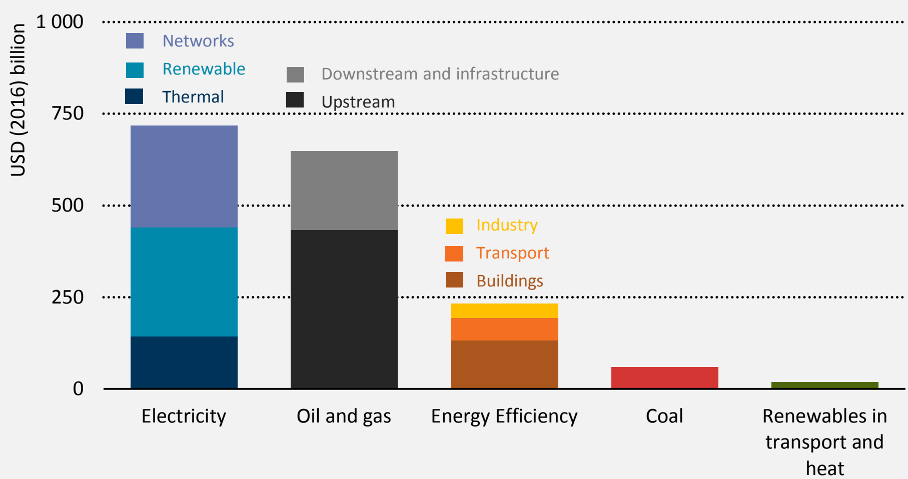
Highlights

- **Global energy investment amounted to USD 1.7 trillion in 2016, making up 2.2% of global gross domestic product.** For the second consecutive year, investment in real terms fell, by 12% compared with 2015, mainly due to a continued decline in oil and gas spending.
- **Lower costs are a major contributor to lower energy investment in some sectors.** Global upstream oil and gas costs fell 17% in 2016 and, with the exception of US shale, are expected to decline for a third consecutive year in 2017, albeit more slowly. Oil and gas companies have improved capital costs and operational efficiency to an extent that could herald a structural break with the past. Progress in technology and project management are driving down solar and wind costs, reflected in low generation contract prices. Solar PV unit capital costs fell 20% in 2016, partly offsetting a 50% rise in additions.
- **The People's Republic of China (hereafter, "China") remained the largest destination of energy investment, taking 21% of the global total.** With a 25% decline 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 in global investment rose to 16% – still higher than Europe, where investment declined 10% – thanks mainly to renewables. Energy investment in India jumped 7%, cementing its position as the third-largest country behind the United States.
- **Spending on energy efficiency jumped 9% to USD 231 billion – 13% of total investment – in 2016, bucking the trend of declining investment in other sectors.** Government policies continued to encourage the purchase of more energy-efficient equipment and appliances and refurbishment of buildings. The primary destination of energy efficiency spending in 2016 was the buildings sector, led by a robust construction market, tougher energy performance standards and other forms of government support.
- **Global electricity sector investment edged down by 1% to USD 718 billion,** with rising networks spending partly offsetting a drop in generation. Most of this decline was due to coal-fired power and renewables, partly from lower solar PV costs. Fewer final investment decisions in 2016 point to less spending ahead on large-scale dispatchable plants. Expected output from low-carbon generating capacity installed in 2016 is equal to 90% of the global electricity demand increase in that year. Renewables and networks made up 80% of investment, driven by measures to promote cleaner sources, replacement of ageing grids, rollout of "smart grid" technologies and grid extensions to new consumers.
- **Investment in the oil and gas sector plunged by 26% to USD 650 billion in 2016, and it lost its position as the largest recipient of investment to the electricity sector**. This was the result of lower upstream costs and reduced drilling, which makes up two-thirds of the sector's total investment. Upstream investment is set to rebound modestly, by 3% in real terms, in 2017 due to 53% upswing in US shale and resilient spending in Middle East and Russia. Investment in coal supply fell by 11% to USD 59 billion in 2016.

Total investment in the energy sector

Total energy investment worldwide in 2016 is estimated to have amounted to just over United States dollar (USD) 1.7 trillion, accounting for 2.2% of global gross domestic product (GDP) and 10% of global gross capital formation. Despite a drop of 36% in the two years to 2016, the oil and gas sector continues to represent two fifths of global energy investment, but the electricity sector moved ahead of it in 2016 to become the largest recipient of energy investment (Figure 1.1). In the electricity sector, 6% growth in investment in network assets, which represent around two-fifths of electricity investment, offset a 5% drop in investment in power generation. By comparison, oil and gas pipeline and infrastructure spending was much less robust and now makes up a lower share of oil and gas sector investment.

Figure 1.1 Global energy investment in 2016



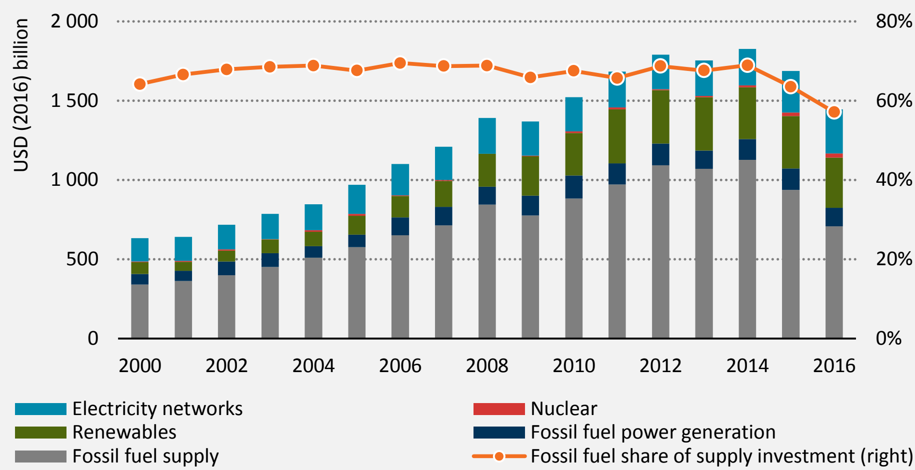
Global energy investment totalled USD 1.7 trillion in 2016, 12% down on 2015 due mainly to a fall of over one-quarter in oil and gas investment.

Overall energy investment fell 12% in real terms[1] in 2016. This is a more marked drop than in the previous year, showing that energy markets in general did not strengthen in 2016 and the only sector experiencing any significant growth was energy efficiency. The main cause of the overall decline was a fall of 26% in capital spending in upstream oil and gas resulting from lower oil prices and revenues since mid-2014 (Figure 1.2). However, the fortunes of the sector have since turned and a 4% rise in investment is foreseen in 2017.

[1] Unless otherwise stated, economic and investment numbers cited in this report are presented in real USD (2016), converted at market exchange rates.

China remained the largest destination of energy investment, representing 21% of the global total. Energy investment in India rose by 7%, cementing its position as the third largest country behind China and the United States on the back of a strong government push to augment India's power system and enhance access to affordable electricity.

Figure 1.2 Global investment in energy supply by fuel



Energy supply investment declined for the second year in a row in 2016 to USD 1.5 trillion – the same level as in 2010 – while the share of fossil fuels in total investment dropped below 60% for the first time.

In the electricity sector, investment in power generation worldwide fell 5% to USD 441 billion, largely due to the installation of 28 GW, or 17%, less fossil fuel and nuclear generation capacity than in 2015. Investment in renewables plant also fell, by 3%, due to fewer hydropower plants coming online. Depending on the region and technology, investment in large-scale, dispatchable plants was undermined by several factors, including an uncertain demand outlook, especially in China, robust solar photovoltaic (PV) and wind additions and, in the case of coal plants, policies to counter local air pollution. Further declines in investment in electricity generation are likely in the coming years based on recent investment decisions: less large-scale dispatchable generating capacity, including hydropower, was sanctioned in 2016 than in any year since 2002.

Lower unit costs made a big contribution to the fall in total investment in power generation – solar PV, in particular – and in oil and gas. In general, competition for capital and market share has become more intense in these sectors, exerting downward pressure on costs. This factor more than offset the effect of investment shifting to higher cost regions for some technologies. Investment in nuclear power increased by one fifth in 2016 even though capacity additions were broadly unchanged because the new capacity was added in high-cost regions.

Table 1.1 Energy investment by fuel and region (USD [2016] billion)

	Oil and gas		Coal	Power generation			Renewable transport & heat	Electricity networks	Total energy supply	Energy efficiency
	Upstream	Downstream/ infrastructure	Mining and infrastructure	Coal, gas and oil	Nuclear	Renewables				
OECD	**170**	**65**	**14**	**38**	**8**	**144**	**3**	**115**	**555**	**139**
Americas	116	36	4	12	5	60	1	58	292	49
United States	*81*	*28*	*3*	*8*	*5*	*53*	*1*	*48*	*227*	*41*
Europe	41	20	2	11	0	57	1	42	175	70
Asia Oceania	13	9	8	14	3	27	0	15	89	21
Japan	*0*	*4*	*1*	*4*	*0*	*22*	*0*	*6*	*36*	*n.a.*
Non-OECD	**264**	**130**	**41**	**79**	**18**	**153**	**16**	**162**	**865**	**92**
Europe/Eurasia	58	25	7	4	4	2	0	13	113	6
Russia	*42*	*20*	*5*	*2*	*4*	*0*	*0*	*7*	*81*	*n.a*
Non-OECD Asia	56	46	31	66	14	113	15	125	466	79
China	*29*	*19*	*21*	*34*	*10*	*90*	*14*	*77*	*294*	*63*
India	*4*	*16*	*7*	*21*	*3*	*10*	*0*	*20*	*81*	*7*
Southeast Asia	*24*	*12*	*2*	*9*	*0*	*7*	*1*	*20*	*74*	*n.a*
Middle East	75	47	0	6	0	1	0	8	137	2
Africa	35	4	2	2	0	10	0	7	61	2
Latin America	40	8	1	1	0	27	1	10	89	4
Brazil	*21*	*3*	*0*	*0*	*0*	*17*	*1*	*6*	*47*	*n.a*
World	**434**	**215**	**59**	**117**	**26**	**297**	**19**	**277**	**1 444**	**231**
European Union	*15*	*18*	*2*	*7*	*0*	*50*	*1*	*35*	*128*	*n.a.*

Note: Renewables for transport and heat include biofuels for transport and solar thermal heating installations.

Energy end-use and efficiency investment

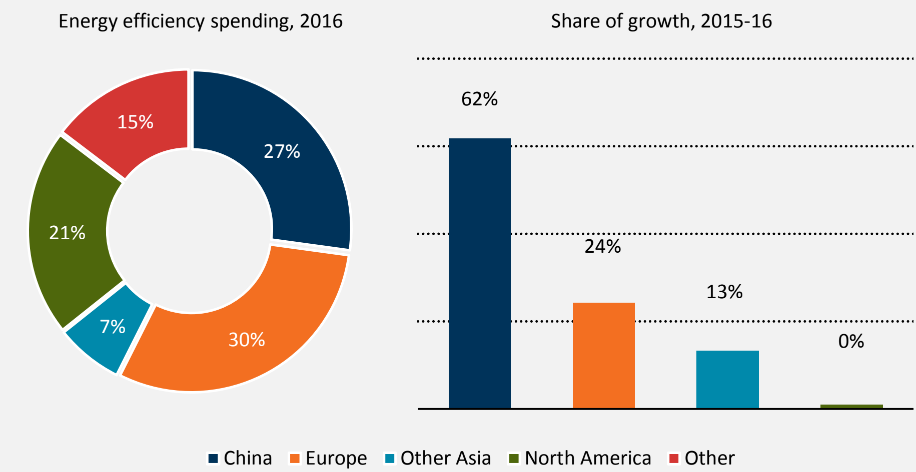
We estimate that USD 231 billion was invested worldwide by businesses, households and the public sector in improving energy efficiency in 2016, an increase of USD 19 billion, or 9%, compared with 2015. This expenditure corresponds to the incremental spending on equipment that consumes less energy than would have been used had the purchaser opted for a less efficient model or, in the case of building refurbishments, not undertaken the efficiency improvement (Box 1.1). Efficiency took a higher share of total energy investment than in 2015 as policies tilted markets towards more energy efficient goods, the construction industry expanded and people spent more on highly efficient vehicles. Europe maintained its position as the largest spender on energy efficiency (Figure 1.3) due to strong growth in spending in the buildings sector. While Europe was the largest region for energy efficiency expenditure in 2016, China saw the fastest growth, mostly in transport.

Box 1.1 Measuring investment in energy efficiency

As in *WEI 2016* and other recent IEA reports, we define an energy efficiency investment as the incremental spending on relatively efficient equipment or on building refurbishments that reduce energy use. The intention is to capture spending that leads to reduced energy consumption. Under conventional accounting, part of the spending would be categorised as consumption rather than investment. In the case of a car, it is assumed that the buyer of a relatively efficient car would have otherwise chosen a less efficient model of similar same 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. In the buildings sector, investment is the extra cost of erecting buildings that meet or exceed minimum performance standards or new regulations for energy efficiency compared with an older standard to which the market has already adapted. In this year's report, we have updated the US estimates to include the International Energy Conservation Codes (IECC) 2009 building codes. A methodological improvement this year has led to downward revision of the estimations for energy efficiency investment for freight transport compared with those published in *WEI 2016*. See www.iea.org/investment for more information about the methodology.

The **buildings sector** is not only the largest sector for energy efficiency investment, at USD 133 billion, but it also contributed most of the increase in overall energy efficiency investment worldwide in 2016. Incremental spending on more efficient building structures, including heating, ventilation and cooling (HVAC), insulation, walls, roofs and windows and jumped by USD 7 billion, or 9%, to USD 92 billion – 40% of total efficiency investment – with appliances and lighting making up the rest of the building sector total. In Europe, spending on buildings was bolstered by policy measures such as the increase in concessional energy efficiency lending by the German KfW Bank, from USD 10 billion to USD 16 billion (often accompanied by government grants). Europe accounted for around two-fifths of total sales of efficient appliances and lighting worldwide, reflecting tighter standards and higher consumer energy prices than in most other regions. Overall, incremental spending on more efficient consumer appliances grew faster than the market as a whole. In the United States, a notable contributor to this growth was a 6% increase in construction activity, concentrated in states that have adopted the 2015 International Energy Conservation Codes, which reduce commercial energy consumption on average by 11% compared with the previous set of building codes introduced in 2012. The new codes alone generated USD 1.5 billion of additional efficiency expenditure compared with 2015. From a low base, spending on efficient buildings grew 20% in developing Asia and Latin America, where a drive to tighten buildings codes is underway with support from multilateral development banks and local governments.

Figure 1.3 Energy efficiency investment by region and sector, 2016



Global spending on energy efficiency rose 9% to USD 231 billion in 2016, led by a surge in construction activity and government policies to improve efficiency standards in the buildings sector.

Total spending on energy efficiency in the **transport sector** grew by USD 3 billion to USD 61 billion. China accounted for most of the 5% growth in global sales of LDVs and sales of new cars in the most efficient categories. Electric vehicle (EV) sales also made a major contribution to worldwide energy efficiency spending.[1] Without growth in spending on efficient LDVs in China and global spending on EVs, transport efficiency

[1] EVs include battery EVs (BEVs), plug-in hybrid EVs (PHEVs) and fuel cell EVs (FCEVs). In this report we refer primarily to passenger EVs. 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.

spending would have been broadly flat in 2016. The underlying trend in most all countries is an increase in the average size of new vehicles, reflecting consumer preferences and lower fuel prices since mid-2014. Our measurement of energy efficiency spending takes account of these preferences and considers the incremental price of more efficient vehicles per size and power class.[2]

In North America there was no appreciable rise in total LDV sales while sales in Japan continued to decline modestly, leading to a slight decrease in efficiency spending. In the European Union, the improvement in overall new car efficiency was the smallest since 2006 (EEA, 2017). The effect of lower international oil prices on demand for more efficient vehicles was more pronounced in the United States, where fuel tax rates are low and pump prices have fallen significantly, making it less financially attractive to buy highly efficient cars. Since 2014, the sales-weighted fuel economy of new LDV sales has been relatively flat (UMTRI, 2017); fuel economy had been improving at a rate of about 2.3% per year between 2010 and 2014 as a result of fuel economy standards and high oil prices. In Japan, where consumer preference has traditionally been for small cars due to high fuel taxes and cultural factors, demand is shifting to medium-sized cars rather than sports utility vehicles (SUVs), as tax incentives for small car purchases are unwound. In China, where the passenger car market expanded by 15%, or 3 million cars, total expenditure on efficient LDVs increased by around USD 3 billion. The most efficient SUVs are significantly more expensive than less efficient vehicles in this category and the market share of SUVs and light trucks in China jumped by seven percentage points in 2016. If this trend continues, average fuel economy could deteriorate markedly without more hybridisation, electrification or much higher fuel economy in other vehicle categories.

A jump in sales of EVs, which use at least 30% less energy than conventional vehicles, accounted for over one-third of the growth in spending on transport sector energy efficiency in 2016. We estimate the global weighted average price premium for a BEV to be around USD 8 000 before subsidies compared with a conventional internal combustion engine car of equivalent size and power. Consequently, the 141 000 more BEVs sold in 2016 than 2015 represent an efficiency expenditure of around USD 1.1 billion. Road freight accounted for only a small fraction of the increase in total spending on efficient vehicles. Although sales of road freight vehicles are rising globally and there is huge potential for greater efficiency (Box 1.2), the average efficiency of the fleet is improving only slowly.

Total investment in energy efficiency in **industry** grew by 5% in 2016 in line with rising industrial production and brisk spending on industrial energy management systems, including software, especially in non-OECD countries. In the energy-intensive petrochemical sector, new projects, including upgrades that will lead to higher efficiency, worth around USD 80 billion have been announced in the last three years, twice as many as have been

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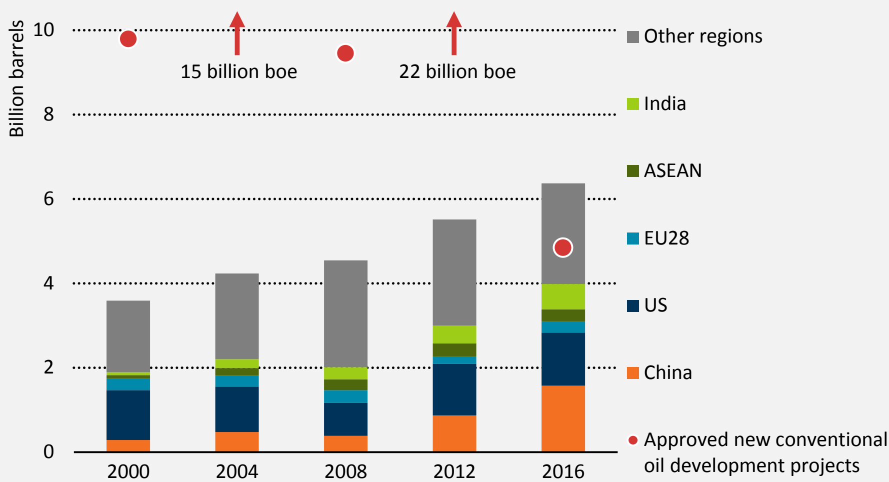
[2] The investment trend and the trend in the overall efficiency of the vehicle fleet may not always move together but, in general, it has been found that consumers globally are currently paying a price premium of around USD 100 for each percentage point of fuel economy improvement (GFEI, 2016).

delayed or cancelled as integrated oil and gas companies cut back spending (HPI, 2017). This uptick in spending in the sector reflects the lower feedstock price environment, especially gas in the United States but also oil in Asia and Europe. While expansion of global petrochemicals production will increase total energy demand, the amount of energy used per unit of chemical products will strongly depend on the feedstocks associated with new investments. In the United States, the almost 10 million tonnes per year of ethylene capacity due to start up by 2020 will use natural gas liquids, whereas in China, capacity using unconventional feedstocks, mostly derived from coal, could grow by around 3 million tonnes per year to 2018 and is more energy intensive than oil or gas-based capacity.

Box 1.2 Opportunities for investment in road freight energy efficiency

Road freight vehicles account for a big chunk of global oil demand. At 16 million barrels of oil per day (mb/d), road freight oil use is almost as big as that of the entire industrial sector and about two-thirds of that used by passenger vehicles. It is responsible for 7% of global CO_2 emissions. Demand for oil-based fuels for road freight is projected to increase by 66% by 2050 in one IEA baseline scenario (IEA, 2017a). Road freight activity remains closely linked to GDP, so improving fuel efficiency will be crucial to curbing oil consumption in that sector

Figure 1.4 Estimated lifetime oil consumption of new heavy-duty vehicles by year of sale and oil supply from conventional oil projects in year of approval



New trucks sold in 2016 will consume 78% more oil over their lifetimes than trucks sold in 2000 and more than the potential supplies from new conventional oil projects approved in 2026. The growth in sales more than outweighs the modest efficiency gains over that period.

Notes: Conventional oil projects do not include light tight oil or oil sands. All quantities converted to primary crude oil equivalence.

Sources: Marklines (2017) "Automotive industry platform vehicle sales data"; IEA (2017a), *Energy Technology Perspectives 2017*; IEA (2017b), "Mobility model March 2017 version".

Global sales of new heavy-duty trucks have grown by around 75% since the turn of the century, from about 2.3 million in 2000 to around 4 million in 2016 and now represent a market of over USD 200 billion (IEA, 2017b). China is responsible for nearly 30% of global truck sales, and the Chinese truck market picked up in 2016. Outside China, sales of new trucks have been growing steadily since the financial crisis, led by North America. The lifetime consumption of new heavy-duty trucks taking to the road worldwide in 2016 rose to 6.4 billion barrels of oil, more than the potential supplies from all newly approved conventional oil projects in 2016 (Figure 1.4). If all these trucks had been equipped with a suite of efficiency technologies, all with a payback time of less than three years, this demand could have been reduced by 0.25 mb/d, or almost 25%.

Commercial incentives for road hauliers to invest in efficient trucks appear to be strong. Fuel represents 20% to 30% of total road freight operating costs in the United Kingdom and up to 50% in China (CAI Asia, 2010; FTA, 2017). However, a range of factors discourage or prevent such investment, sometimes even when the payback is less than a year. These include a lack of information about technology performance, financial constraints for many small haulage companies with just a few trucks and competing demands on available capital. For these reasons, the average efficiency of new heavy-duty trucks is not improving as fast as that of new LDVs. Only four countries – the United States, Canada, China and Japan – have mandatory fuel economy regulations in place to reduce the fuel consumption of trucks. The European Union is considering introducing such standards. In some other countries, including some emerging markets that have older fleets, scrappage schemes have been introduced to encourage hauliers to invest in more efficient new trucks. Programmes such as SmartWay in the United States have helped fleet operators to adopt more efficient and more profitable practices. But more efforts are required to introduce more ambitious performance standards and enhance access to finance.

Direct public spending on energy efficiency, together with other policies such as energy performance standards, can have a significant effect in leveraging private spending on energy efficiency. By compiling government energy efficiency programmes around the world, we estimate that the public cost of energy efficiency policies is around USD 33 billion, mostly direct grants and tax exemptions.[3] This is equivalent 14% of all energy efficiency investment. The value is considerably lower than the USD 325 billion spent on fossil fuel consumption subsidies or USD 150 billion spent on renewables subsidies in 2015 (IEA, 2016a). If energy efficiency investments in publicly-owned assets, the full amounts of concessional loans, which are ultimately paid back by private entities, and energy savings obligations, such as those placed on electricity and gas utilities, are

[3] Included in this total are grants, tax exemptions, debt financing, administrative costs, public procurement and equity and risk financing for buildings, industry and transport programmes in 39 countries. For the European Union, preliminary results from a study funded by the European Commission have been used (EC, 2017). This estimate takes into account the net costs of concessional interest rate loans compared to market rates where available but it does not account for all costs, for example from risk guarantees or policy-implementation by public financial institutions, or policies of all sub-national entities. While not all programmes explicitly cover only the incremental costs of energy efficiency measures, policy rationales are generally based on the need to overcome the additional upfront costs and barriers that consumers face in comparison with alternative, less-energy efficient options.

included, the estimate rises to USD 74 billion, or 39%. This level of public sector involvement is not higher than in other energy sectors. Governments and state-owned enterprises (SOEs) are responsible for 15% of the investments into non-hydro renewables worldwide, more than half of the investments into all other types of power plants and two-thirds of the investments in electricity networks. Due to the significant role of national oil companies in the oil and gas sector, governments and SOEs are directly responsible for 44% of upstream oil and gas investment globally.

Air conditioning and cooling

Electricity demand for cooling is one of the fastest-growing segments of energy use in buildings, both in hot countries that have rising incomes and cooler OECD countries where consumer expectations of thermal comfort are increasing (IEA, 2017a). According to the latest *World Energy Outlook*, electricity demand for cooling worldwide is projected to rise by 60% by 2030, or 1 200 TWh – equivalent to the total power output of Latin America today (IEA, 2016a). Demand for space cooling is largely met by air conditioners, though other approaches, including improving the thermal performance of building envelopes or use of district cooling systems can equally provide thermal comfort. This section takes a look at spending on air conditioners and the energy impact.

The environmental consequences of the growing use of air conditioners came to global attention in 2016. Air conditioners, as well as refrigeration equipment, often make use of hydrofluorocarbons (HFCs) – a family of gases that contribute to climate change. In October 2016, the 197 parties to the Montreal Protocol signed the Kigali Amendment to phase out the use of those gases around the world. The Amendment takes effect in different counties between 2019 and 2028, depending on national levels of development. It also seeks to improve the efficiency of cooling equipment; improving the energy efficiency of air conditioners could double the impact of phasing out HFCs on curbing global warming, as well as reducing significantly peak electricity load in hot climates (LBNL, 2015).

The air conditioning market is shifting geographically

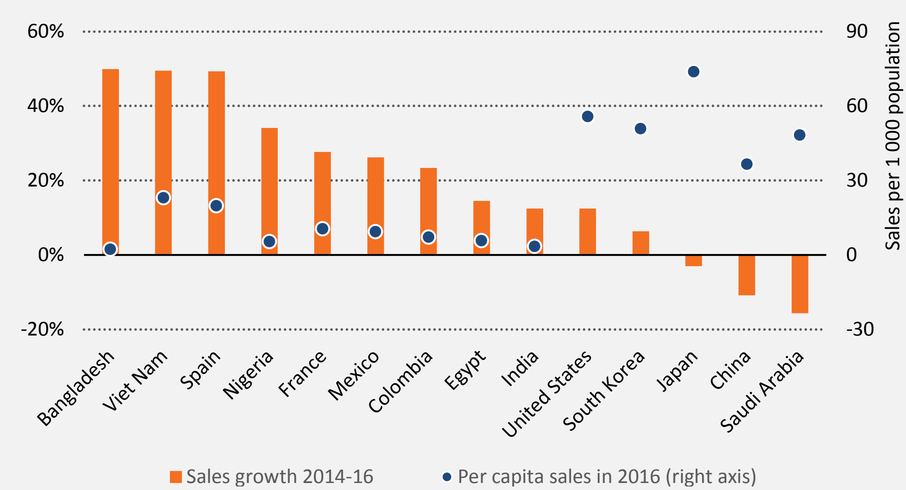
Around 125 million air conditioners worth USD 93 billion were sold worldwide for residential and commercial purposes in 2016 (BSRIA, 2017a).[4] Around 40% of this market and over half of all the units sold are in countries where the penetration of residential and commercial air conditioning is below 50% and where demand is growing rapidly due to climatic conditions and rising incomes. The global stock of air conditioners is rising quickly and may pass the 1 billion mark by 2018 – twice that of 2005.

Growing electricity demand for space cooling presents a challenge to power systems. As well as increasing overall demand on the network, it often coincides with times of peak load for other uses, making the peak more severe. This increases the overall need for

[4] Including individual window units, large chillers and packaged building systems. Our estimate of investment in energy efficiency includes only the incremental cost of more efficient air conditioning.

generating capacity or flexible resources on the system, raising the total cost of electricity supply. This is especially true in countries with growing electricity demand and expanding power generation capacity. More efficient air conditioners can reduce electricity costs for individual users and for the system as a whole. In Indonesia, for example, it has been estimated that adopting cost-effective measures to boost the energy efficiency of air conditioners could reduce peak load by 13% by 2030 compared to business as usual (Karali et al., 2015). In California, around 45% of the total value of improved cooling efficiency is estimated to derive from the reduction in peak load and the consequent avoidance of the costs of low-load factor generating plants (SEAD, 2015).

Figure 1.5 Air conditioner sales growth and per capita sales in selected



Sales of air conditioners are growing strongly in countries with low rates of market penetration, while sales are falling in the major markets China and Saudi Arabia, due to market saturation.

Source: BSRIA (2017a), World Air Conditioning Overview 2016

Countries with the fastest sales growth in the past two years tend to have low sales per capita, indicating considerable growth potential (Figure 1.5). In China, sales have been in decline following rapid growth in the preceding years, reaching 57 million units in 2014. The decline partly reflects the economic slowdown, saturation of demand among some consumer groups and the scaling back since 2013 of a subsidy scheme for efficient air conditioners. In absolute terms, sales growth in the United States since 2014 has been larger than in any other country; construction has picked up and the market for replacement air conditioners is strong, with penetration as high as 80% of all buildings.

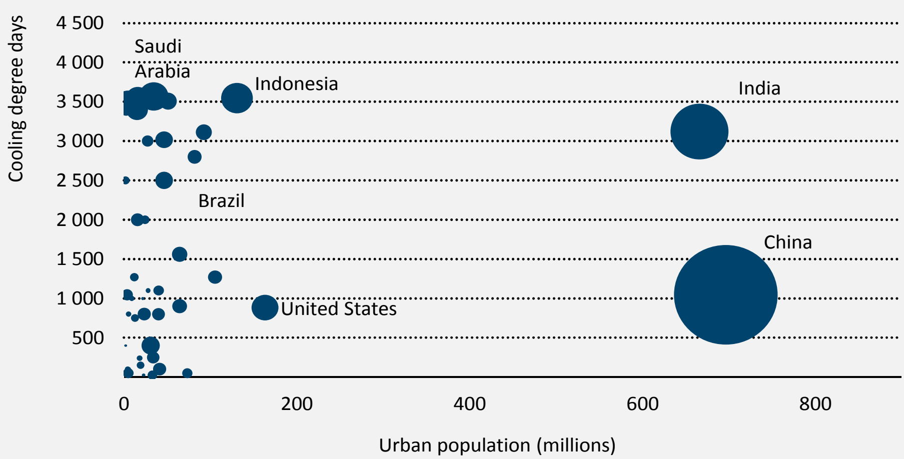
Cooling accounts for 15% of total electricity use in US buildings – up from 12% in 2000 (EIA, 2017). In fact, over 35% more electricity is used for that purpose alone in the United

States than in all buildings on the African continent. As Africa and other emerging regions become richer over the coming decades, global demand for cooling is likely to rise faster than for heating. In several Asian countries, as well as certain markets in Africa and Latin America, sales are rising very strongly in line with robust economic growth with considerable remaining potential for growth (see Box 1.3 on India). Viet Nam's air conditioning market has expanded by 50% over the last two years with rising incomes and unusually hot summers. Local manufacturing capacity is expanding rapidly, often helped by favourable customs tariffs between countries across the region.

Box 1.3 The challenge of managing new cooling loads in India

India's hot climate, the sheer size of its population and the enormous scope for raising living standards mean that the potential for new cooling demand is vast. Consequently, the efficiency of air conditioning will have a major impact on electricity investment needs in the coming decades (Figure 1.6). In the IEA New Policy Scenario, electricity demand for cooling in India's residential sector is projected to grow on average by 8% per year to 2040 as it becomes more affordable in urban areas with rising incomes (IEA, 2016a).

Figure 1.6 Cooling degree days and urban population in selected countries 2016



India, which is set to overtake China in the coming years as the world's largest market for air conditioners, is characterised by a large urban population and big potential demand for cooling.

Note: Bubble size is proportional to electricity demand added from air conditioners sold in 2016. Cooling degree days is the difference between the outside air temperature and an indoor temperature of 21°C multiplied by the number of days for which that difference is positive.

Air conditioner sales in India have been growing at around 6% per year over the last decade. Most sales in 2016 have gone to new uses rather than replacements, boosting electricity demand by more than 10 TWh per year. For commercial applications in particular, this demand is well matched to the timing of solar energy output, which is growing rapidly in India. Satisfying as much cooling demand as possible using solar electricity would help to curb the growth of carbon dioxide (CO_2) emissions. However, demand from additional air conditioner sales in 2016 was around twice as large the output of new solar PV units; the growth in PV capacity is not expected to catch up with that of cooling demand in the foreseeable future.

Moreover, cooling demand is highly correlated with evening peak electricity load in Mumbai and, to a lesser extent, Delhi, when solar output is low. The rapid growth in the number of air conditioners is exacerbating peak load and raising the total capacity requirement for the system, which is currently heavily dependent on fossil fuel-fired generating plant. Air conditioning will have a major impact on electricity investment needs in the coming decades (Figure 1.8). In the IEA New Policy Scenario, electricity demand for cooling in India's residential sector is projected to grow on average by 8% per year to 2040 as it becomes more affordable in urban areas with rising incomes (IEA, 2016a).

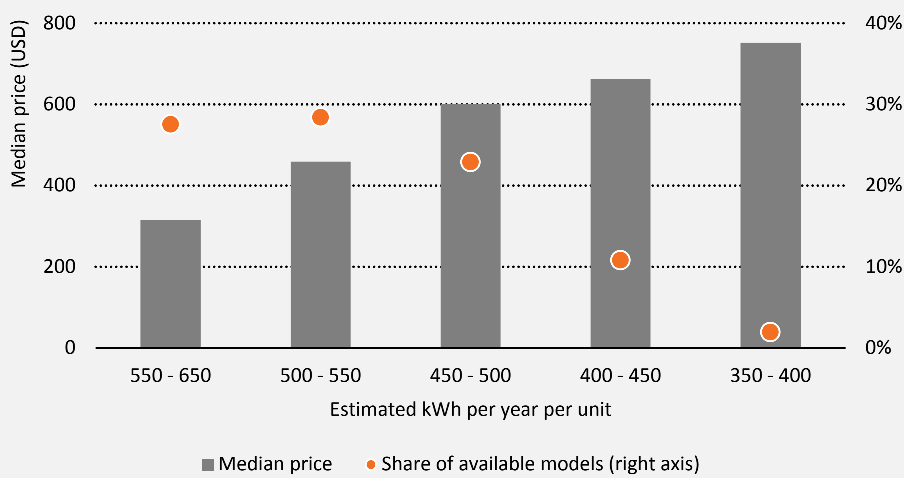
India's efficiency standards for air conditioners have been tightening since 2008 and will further rise in 2018 from a minimum EER (ratio of output to input energy) of 2.7 in 2016 to 3.1, adjusted to Indian climatic conditions. This has been accompanied by labelling and information efforts that have raised awareness among consumers. The increasing policy focus on air conditioners, including a proposed expansion of mandatory coverage of standards, is improving the energy performance of cooling. However, standards remain more lenient than those in other major markets. In addition, test procedures in India may overestimate efficiencies (CSE, 2016). Even after the revisions of standards, 2-3 million room air conditioners with efficiencies of around 3 EER could be sold per year. An increase to 4 EER, in line with the United States but lower than Japan and the European Union, would avoid over 2 TWh of demand and 1-2 GW of peak load being added to the system per year.

Air conditioners are getting cheaper in most regions despite the introduction of energy performance standards (LBNL, 2016a). The average price decline for a minisplit air conditioner across a sample of 47 countries was 16% in real terms between 2011 and 2016, mainly due to the greater economies of scale from mass production and competition among manufacturers. These factors have so far more than offset the negative impact of more energy-efficient designs on the cost of production. While higher-priced air conditioners tend have higher efficiencies in a given year and market, reflecting not only better energy performance but also additional features in many cases, their prices have generally fallen in line with the market average. The most efficient units in China can be twice as expensive as those at the level of the minimum energy performance standard (Figure 1.7), requiring more than ten years to pay back the additional cost purely based on electricity bill savings at current prices.

However, because models in the two lowest efficiency categories – those around the minimum performance standard – represent more than half of the available models, they benefit from economies of scale and the fiercest pricing competition. When standards tighten, these benefits transfer to higher efficiency categories that then become the market leaders, reducing their price.

While at least 85% of air conditioning sales in 2016 worldwide were covered by minimum energy efficiency performance standards of some kind, there is wide variation in the levels of the standards across countries and even greater variation in the efficiencies of the conditioners on the market (IEA, 2017c). The 125 million units sold in 2016 will consume around 200 to 250 TWh of electricity each year, of which as much as 90 TWh is to meet new cooling demand (the rest is consumed by replacement units). Sales in 2016 will add additional electricity demand equal to over 15% of the annual demand growth in India and the Middle East, but also in China, Europe and Latin America. If all air conditioners sold globally in 2016 had met the minimum energy performance standard of Japan (METI, 2015), the additional load would have been just 50 TWh per year – over 40% less per year. Standards are under review in many countries, including in Viet Nam, where the minimum standards currently stand at half the level of those in Japan (ASEAN-SHINE, 2016) and where household electricity prices are subsidised.

Figure 1.7 Median price and shares of air conditioners by consumption in China



More expensive air conditioners are generally more energy efficient, but most models available are at the lower end of the efficiency range.

Note: Based on a sample of 563 split air conditioners of 5 kW output or lower available in China in 2016. Electricity demand based on the advertised energy efficiency ratio (EER) of output to input energy on a Watt per Watt basis, or seasonal energy efficiency ratio (SEER) for variable-speed units, and 600 equivalent full-load hours per year.
Source: Based on data from Gerke (2016).

Heat pumps

Space heating accounts for around 10% of total global final energy demand. Heat pumps are a highly efficient electrical alternative to existing fossil fuel heating technologies. They are expected to gain market share, raising total energy efficiency spending in the building sector and contributing to the decarbonisation of the energy system to the extent they consume low-carbon electricity. Heat pumps are not new and the technology has long been used in cooling applications, but the market for heat pumps for space heating has grown significantly in recent years as governments in a number of countries have introduced incentives to exploit their potential for improving overall energy efficiency and decarbonising the fuel mix.

Consumers worldwide spent over USD 4 billion on heat pumps in 2016, with sales jumping by 28% to over 3 million units (BSRIA, 2017b). China accounted for 95% of the sales growth in 2016, boosted by city-level policies to replace coal-fired heating in order to reduce local pollution. These policies, introduced in different municipalities since 2014, led to the installation of 160 000 heat pumps in Beijing alone in 2016. Outside China, sales are concentrated in Europe and Japan. Europe, with only 60% as many sales as Japan in 2010, now has an equal 16% share of the global market. Residential applications and air source heat pumps dominate total sales. In Europe and China, around two-thirds of the market is associated with new buildings and the rest is for replacements and refurbishments. In Japan it is the reverse, reflecting the greater maturity of the Japanese market.

Heat pumps typically have efficiencies that convert one unit of electrical energy into two to four units of heat energy, depending on climate conditions. This is several times more efficient than the most efficient gas boilers, even when taking the efficiency of electricity generation by a combined-cycle gas turbine plant (CCGT) into account. We estimate that the heat pumps sold around the world in 2016 reduce global gas consumption by 0.75 bcm per year, assuming that highly efficient gas boilers would have been installed instead. However, heat pump deployment will need to accelerate to displace gas from residential buildings as it would take 90 years to reduce current residential gas demand to zero in Europe at the current growth rate. To raise this rate, heat pumps will need to be installed in more existing buildings and heat demand reduced through other efficiency measures.

Although cheaper than ground-source heat pumps, the higher upfront costs of air-source heat pumps limit their competitiveness against efficient gas-fired boilers, especially if hot water supply is also required. In real terms, the prices of heat pumps have not fallen in Europe or China in the past two years and have actually risen in several countries. As with other building energy equipment, such as solar hot water, a major cost component of heat pumps is the installation. Globally, installation costs represent around 15-20% of total costs, a share that appears to have declined modestly in 2016 and further declines can be expected for an industry that is scaling up in many countries.

While they are not a universal solution in all climates or buildings,[5] heat pumps are currently one of the most cost-effective ways to increase the share of low-carbon energy in space heating, if implemented alongside measures to decarbonise electricity supply. Heat

[5] In dense urban environments with old building stock or in colder climates, air and ground source heat pumps may not be appropriate and district heating can be a more suitable alternative.

pumps may also facilitate decarbonisation by playing a role in demand response in electricity markets (see Chapter 3) and large heat pumps can be used in district heating and cooling networks, while high-temperature heat pumps have some industrial applications.

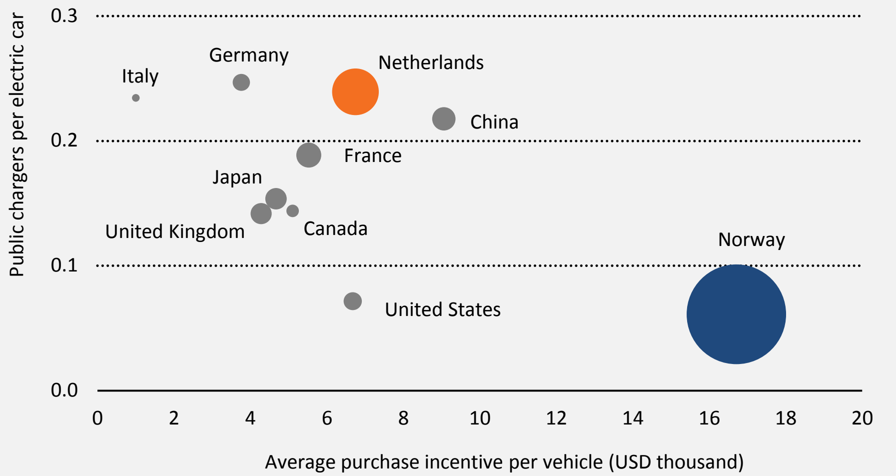
Electric vehicles

The market for EVs[6] continued to grow strongly in 2016. Global sales grew by 38%, reaching 750 000 units. Of these sales, 340 000 occurred in China, which is now home to more EVs than any other country (IEA, 2017d). While passenger-car registrations as a whole shrank in several key markets, including North America and Japan, all regions saw record EV sales, pushing up the total number of EVs on the road worldwide to just over 2 million. The share of EVs in total car sales worldwide rose to 1.1%, double that of 2014. However, the EV share of the total car stock remains much lower, at just 0.2%. Consequently, their impact on oil and electricity demand remains modest for now: EVs sold in 2016 will reduce global oil demand by around 10 thousand barrels per day (kb/d) and increase electricity demand by around 1 TWh. To meet the level of EV deployment under the IEA 2-degree climate change mitigation scenario, it will be necessary to maintain sales growth at its 2016 level to 2025 with a corresponding expansion in EV charging infrastructure and electricity supply would need to be steadily decarbonised. Globally, around USD 6 billion was invested in over 880 000 charging points installed in 2016, 42% more than in 2015 (see section on investment in electricity networks, below).

Policy continues to underpin the EV market, with fiscal incentives provided in almost all countries where EVs were sold in 2016 (IEA, 2017d). These incentives are encouraging motorists to buy EVs and car and battery manufacturers to invest in their development and commercialisation. In 2016, we estimate that governments spent around USD 6 billion on incentives for EVs. These include fiscal incentives, such as grants, tax credits and tax exemptions, and spending on public charging infrastructure. Strong purchase incentives have driven the rapid take-up of EVs in Norway, the country with the highest share of EVs in new car sales, while heavy public investment in chargers is supporting rapid deployment in the Netherlands, which has the second-largest share (Figure 1.8). Other measures include privileged access to certain areas and lanes of the road network and parking spots. These measures are of particular importance in China, where EVs are also exempt from certain licensing restrictions.

[6] This section focuses on passenger car EVs.

Figure 1.8 EV purchase incentives, public charging facilities and EV sales in selected countries, 2016



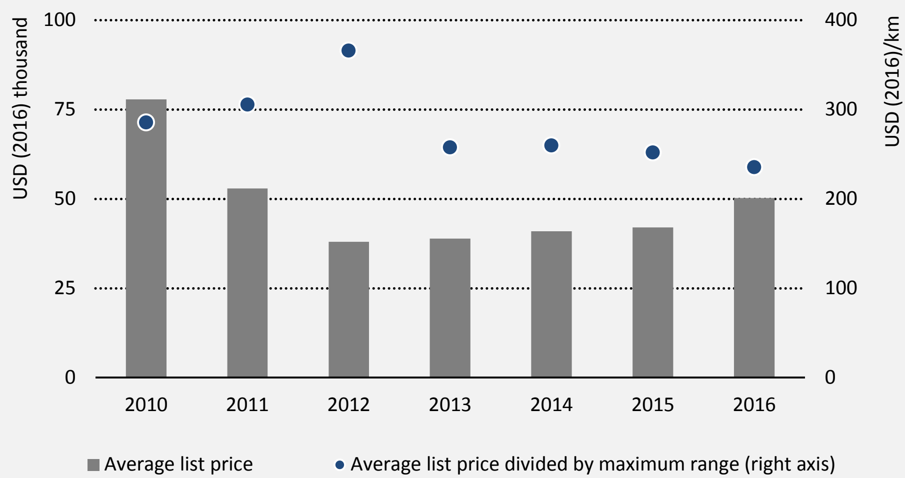
The share of EVs in overall LDV sales is highest in countries with the biggest EV purchase incentives and the most extensive network of public chargers.

Notes: Bubble area is proportional to EV share of all new car sales (e.g. 30% in Norway and 7% in the Netherlands). Incentives based on tax exemptions are estimated from average sales prices.

Sources: BNEF (2017), "EV policies dataset"; MarkLines (2017), "Automotive industry platform vehicle sales data"; IEA (2017d), *Global EV Outlook 2017.*

Improvements in operational performance are also increasing the attractiveness of EVs. The average price of EVs rose again in 2016 (Figure 1.9), but this reflects faster growth in more expensive models, such as the Tesla Model X and does not take account of increases in driving range through battery improvements. For now, reductions in battery costs are translating into longer ranges rather than lower vehicle prices: the average price per kilometre of driving range declined by 6% in 2016. As more cars with ranges of over 300 km of battery capacity become available within the price range of comparable conventional vehicles, declines in EV prices may accelerate as economies of scale rise. In the United States, sales of the Chevy Bolt, 5 000 of which have been registered since it was launched in late 2016, and the Tesla Model 3, production of which is due to start in mid-2017, are expected to push down the average price over the coming year. Elsewhere, prices may fall even faster where range expectations are lower. In China, the weighted average range of BEVs sold in 2016 was 200 km, compared with 290 km in the United States.

Figure 1.9 Average EV price and driving range



The average prices of the leading battery EVs rose in 2016 reflecting sales of more luxurious cars, but motorists are getting more driving range for their money.

Note: The arithmetic average of US prices for the five best-selling BEVs sold in the United States that are available globally.

Automakers' ambitions have risen to target over 10 million sales per year next decade

There are clear signs that automakers' commitment to EVs is strengthening. Over the last year, a number of leading manufacturers have announced bold sales targets for mainstream EVs, reflecting their faith in continuing reductions in production costs and government policies to sustain market expansion into the next decade (Table 1.2). Automakers are now moving away from viewing EVs as niche products and are starting to see them as direct competitors with conventional internal combustion engine vehicles. Volkswagen plans to treble its investment in making EVs to USD 10 billion over the next five years, almost as much as it will spend on raising the fuel economy of conventional vehicles, while Daimler has announced USD 11 billion of investment in EV development. Chinese firm BYD has announced factory projects worth around USD 3.5 billion in five different countries since November 2016.

Since 2015, Chinese car manufacturers are the world leaders in EV production (Figure 1.10). Ten of the top 20 selling EVs in 2016 were made by Chinese manufacturers. Chinese manufacturers have a market share of EV sales that is 60% higher than their market share of the rest of the global car market. The EV market is highly regional and domestic manufacturers are dominant in each of the four main regions.

Table 1.2	EV sales targets of selected carmakers		
Company	**Stated target**	**2016 sales (thousands)**	**Required annual growth rate**
BMW	0.1 million EVs sold per year by 2020	55	8%
Daimler	0.1 million EVs sold per year by 2020	18	53%
Ford	40% of models available in 2020 will be EVs	25	-
Honda	40% of sales in 2030 will be EVs	<1	>100%
Renault-Nissan	1.5 million EVs sold by 2020	100	45%
Tesla	0.5 million EVs sold per year by 2018	65	180%
Volvo	1 million EVs sold by 2025	45	17%
VW	2-3 million plug-in cars sold per year by2025	55	49%
Chinese OEMs	4.5 million EVs sold per year by 2020	350	89%

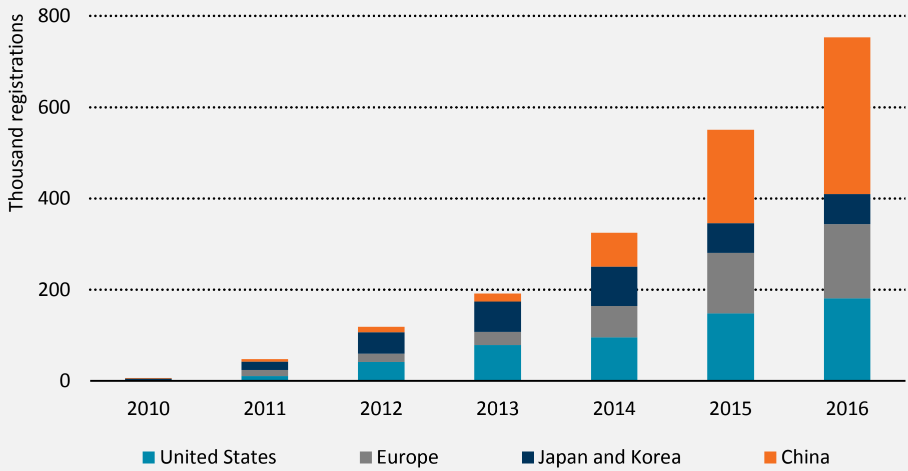
Notes: Sales figures to nearest 5 000. "Chinese OEMs" = 26 China-based original equipment manufacturers. Sources: IEA (2017d), *Global EV Outlook 2017*; BNEF (2017), *EV policies dataset.*

China leads the way in EV sales

China further established itself as the biggest EV market in the world in 2016, accounting for 45% of global new EV registrations. Sales fell dramatically in early 2017 following a sudden change in incentive policy,[7] but overall sales in the first quarter of 2017 were nonetheless up 45% year-on-year. Growth could be boosted by a plan for Beijing and 27 other cities to replace their taxi fleets with EVs and the possibility of high EV quotas for manufacturers in the next few years. It should be noted, however, that based on the current fuel mix in power generation in China, greenhouse-gas emissions from BEVs are higher than those from hybrids and diesels on a full fuel-cycle basis, but they contribute much less to local air pollution. In addition to cars, China reported sales of 116 000 electric buses – 95% of the global market – in 2016, a rise of 30% (Ofweek, 2017). These buses, assuming they replaced diesel engines, could displace twice as much oil demand per year as all the electric cars sold globally in 2016. Sales of electric two-wheelers (not included in our definition of EVs) in China are also substantial. Although data are patchy, their annual sales are thought to be similar to those of all new cars in China, around 25 million in 2016.

[7] The 20% reduction in the subsidy level, a cap on regional subsidies at 50% of the national subsidy and raised battery standards are aimed at guiding the market away from the small, low-speed EVs that have proliferated in Chinese cities and to tackle fraud in the subsidy system. The introduction of penalties for manufacturers not selling a prescribed quota of EVs from 2018 is under discussion.

Figure 1.10 Share of EV market by nationality of manufacturer

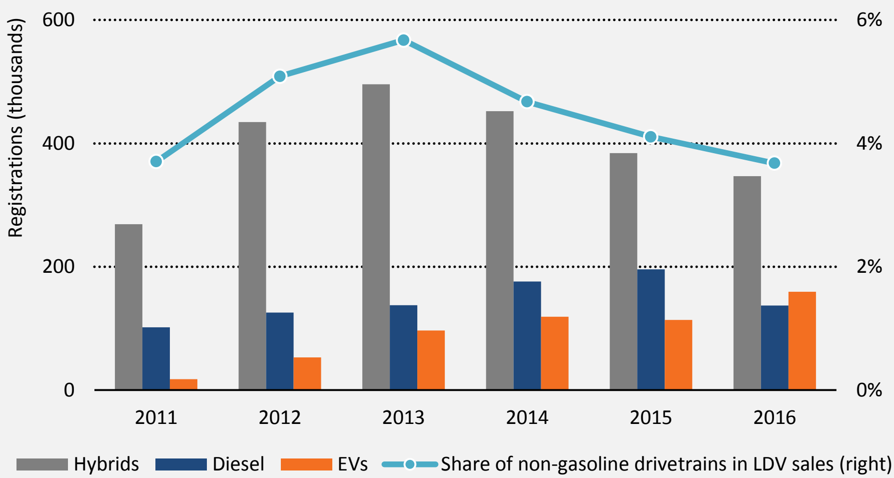


Chinese automakers overtook US companies as the largest manufacturer of EVs in 2015, with Chinese EVs accounting for almost half of all EVs sold worldwide in 2016.

Note: Renault-Nissan sales are allocated 50:50 to Europe and Japan.
Sources: MarkLines (2017), "Automotive industry platform vehicle sales data"; IEA (2017d), *Global EV Outlook 2017*.

EV sales in the United States jumped 40% in 2016, buoyed by the launch of the Tesla Model X BEV, after declining slightly in 2015. However, prospects are clouded by uncertainty over government incentives. Alongside federal tax credits, state incentives also play a significant role and six out of 21 states with purchase incentives have reduced or removed them since mid-2015, while 20 states have raised or plan to raise fees for EV owners, to compensate for lower fuel tax revenue. The future of Corporate Average Fuel Economy (CAFE) standards, which compel automakers to increase EV sales to compensate for sales of larger conventional vehicles, and the federal tax credit programme is also unclear. Unless legislators extend the federal tax credit programme, the largest EV makers may reach the limit of 200 000 vehicle tax credits claimed in 2017, after which the value they can claim per vehicle falls stepwise over a year. On the other hand, 30 cities have stated their willingness to buy 114 000 electric cars and trucks and there is evidence of strong consumer demand for the new longer-range BEVs that are arriving on the market in 2017, especially among wealthier buyers – a key first-mover market segment. The rise in EV sales compensated to some degree for declines in the sale of both conventional hybrids and diesel cars as a result of lower fuel prices (which make fuel economy a less important factor for car buyers) and revelations of cheating over diesel emission tests (Figure 1.11).

Figure 1.11 Sales of diesel cars, hybrids and EVs in the United States



Sales of EVs overtook those of diesel cars in 2016, as the latter suffered from the negative publicity associated with the scandal over diesel emission tests.

Sources: IEA (2017d), *Global EV Outlook 2017* and HybridCars (2017), "Market dashboard".

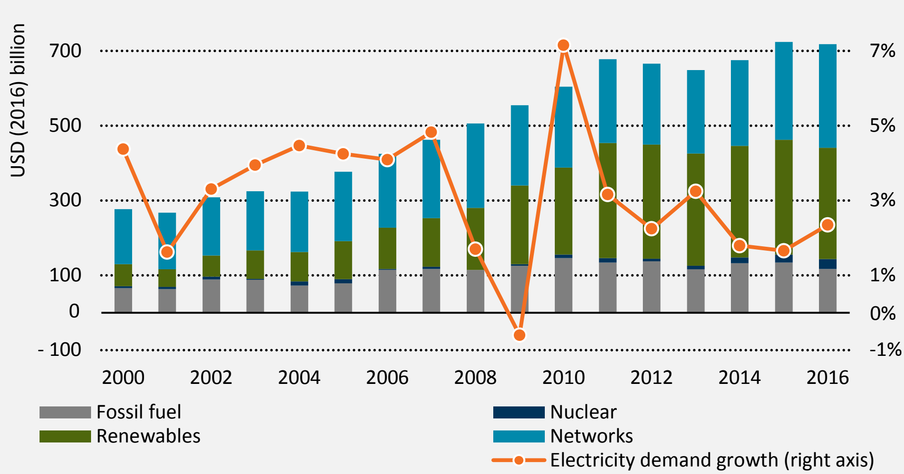
Europe's absolute sales grew by around 25 thousand, the lowest since 2012, dragged down by a dip in sales in the Netherlands related to changes in tax incentives. A few countries introduced policies to boost sales in 2016 pointing to a more positive outlook in the coming years. The Polish government announced in February 2017 a plan to invest in a domestic EV manufacturer, offer discounted night-time electricity for charging and a target to put 1 million EVs on the road by 2025. Germany introduced a USD 3 000-4 000 purchase incentive, though only 9 000 buyers took up the offer – well below the target of 300 000 by 2019. In fact, the rate of growth in German EV sales was lower than in the four previous years. Austria committed to uniting electric charging points into a national network of 2 000 public chargers by the end of 2017. In the United Kingdom, public support was provided for a factory to build 20 000 PHEV taxis per year in order to meet the requirement for all new taxis to be electrified by 2018. A UK purchase incentive of USD 9 000 per vehicle is available, compared with USD 3 500 for other EVs. Norway remained the region's leader in absolute EV sales and as a share of LDV sales, reaching a new high of 29% in 2016.

In Japan there was little change in total EV sales in 2016 and the number of publicly accessible chargers grew less than in all other major markets after subsidies were reduced. There was a notable shift to a higher share of BEVs as the new Nissan Leaf hit the market. Sales in Japan will need to double each year to meet its target of one million EVs on the road in 2020. In 2016, South Korea announced a new target for EVs of 30% of total car sales by 2020, compared with 0.3% in 2016. The country has generous national subsidies of USD 11 000 for BEVs, in addition to city-level incentives and tax breaks that can be equally generous. However, deployment continues to be hindered by charging concerns. In India, 2016 sales were low at under 1 000, reflecting the absence of publicly accessible chargers and affordable EVs for the middle class (the current purchase subsidy, at around USD 2 000 is low compared to other countries). Cheaper electric two-wheelers remain more attractive for now, with sales amounting to around 25 000 in 2016.

Electricity and renewables investment

Global electricity sector investment fell by nearly 1% in real terms to under USD 720 billion in 2016, with higher spending on electricity networks, particularly transmission, only partly offsetting weaker generation spending (Figure 1.12). Most of the fall was due to lower spending on coal-fired plants, investment in which appears to have reached its peak in the 2015-17 period, and less renewable investment – the result of a slowdown in wind and hydropower capacity additions and a continued drop in the average unit cost of solar PV. The decline also reflects an upward revision in our estimate of investment in power generation in 2015. The fall in spending on coal plants reflects several years of weakening electricity demand growth and the emergence of overcapacity in some markets, notably China, though investment remained strong in India. Renewable power and networks accounted for 80% of total electricity sector investment, driven by a continued shift towards cleaner sources, replacement of ageing networks assets, investment in digital technologies to enhance system adequacy and flexibility, and expanded access to new consumers.

Figure 1.12 Global power sector investment and electricity demand growth



Global electricity sector investment edged downward by nearly 1% to under USD 720 billion in 2016, with a decline in generation investment more than offsetting a rise in spending on networks.

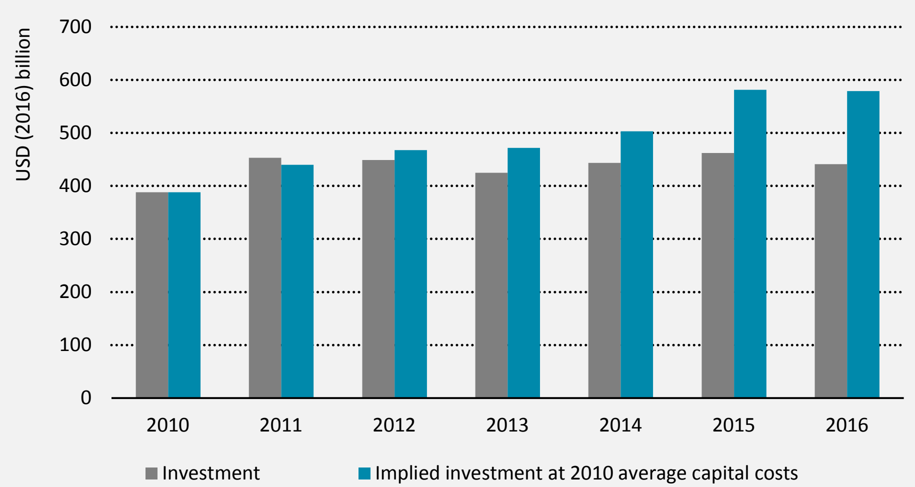
Note: 2016 electricity demand growth is estimated, from IEA (2017e) *World Energy Outlook 2017*, forthcoming.

The expected annual output from the low-carbon generating capacity (renewables and nuclear) installed in 2016 was around 90% of the increase in global electricity demand in that year. In 2015, that output exceeded the increase in demand. With a pick-up in the global economy, electricity use rose by an estimated 2.3% in 2016 compared with about 1.7% the year before. At the same time, plant retirements remained elevated, at over 40 GW, and final investment decisions for new large-scale dispatchable generation, both fossil fuel and low carbon, slowed. These trends imply that the scale and types of investment in power generation may not be on track in some regions to deliver energy security and sustainability goals in the years ahead (see Chapter 4).

Investment in power generation

Worldwide investment in power generation investment fell by nearly 5% to USD 440 billion in 2016 – its lowest level since 2013. A major reason for the fall in investment and recent annual fluctuations is changes in the unit capital cost of the various generating technologies. On a cost-adjusted basis, using 2010 as the starting point, power generation investment declined by only around 0.5% in 2016 and remained near five-year highs (Figure 1.13). With a continued decline in the costs of renewable technologies, partly offset by a somewhat more expensive geographic distribution of new fossil fuel plants, the capacity associated with investment in 2016 required around 30% less spending than if unit costs had remained at the average level of 2010.[8]

Figure 1.13 Global investment in power generation

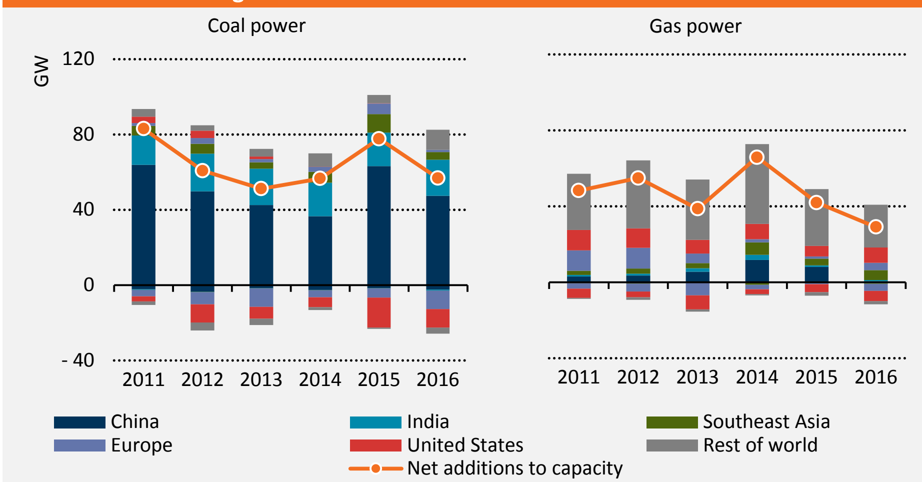


The capacity associated with investment in 2016 required around 30% less spending than if unit costs had remained at the level of 2010.

[8] This analysis does not account of the amount of energy that this capacity is expected to produce nor does it reflect on the electricity and investment needs of different regions.

Investment in fossil fuel-based power generation dropped by 12% to USD 117 billion in 2016. This fall was mostly due to a steep slowdown in the commissioning of coal plants (Figure 1.14). China accounted for most of the decline in coal-plant additions, with Southeast Asia and Europe also seeing a decline, offsetting a rise in investment in India. Nonetheless, at nearly USD 80 billion, coal was the third-largest recipient of generation investment, after solar PV and wind. The extent of the decline in 2016, combined with the relatively young age of the coal power fleet (nearly 60% of capacity is less than 20 years old) and a sharp drop in final investment decisions for new plants in 2016 to historical lows, suggests that investment may have reached its all-time peak in the 2015-17 period. Measures taken by Chinese authorities are slowing development and construction of new plants there (see discussion below). In Europe, the electricity sector industry association recently announced an intention not to invest in new-build coal-fired power plants after 2020 (Eurelectric, 2017). Meanwhile, investment in relatively inefficient and polluting, but cheaper, subcritical plants, largely concentrated in India and Southeast Asia, fell by almost one-quarter – a faster rate than that for overall coal-fired power plant.

Figure 1.14 **Additions and retirements of coal- and gas-fired generation by region**



The fall in investment in fossil fuel-based generating plant was mostly due to a steep drop in coal additions in China.

Source: Calculations based on Platts (2017), *World Electric Power Plants Database.*

Investment in gas-fired generation dipped slightly to USD 34 billion in 2016, its lowest level in a decade. Slowing investment in China and the Middle East offset an increase of capacity in the United States, Europe, Southeast Asia and Japan. Investment of under USD 4 billion in oil-fired plants, its lowest level in a decade, remained largely confined to the Middle East, Africa and Latin America. Taking account of plant retirements, which reached a three-year high of over 40 GW, the net additions to fossil fuel power capacity stood at only 90 GW. Aside from 2013, when a large amount of oil-fired generation was retired in Europe and the United States, the net increase was the lowest since 2004.

Investment in the nuclear power capacity that came on line in 2016 reached over USD 25 billion, mainly driven by China.[9] The nuclear power additions reached their highest level in over 25 years. The United States, which saw the commissioning of its first nuclear plant in 20 years, also contributed. This global investment represented 10 GW of new capacity, similar to 2015, but investment was over one-fifth higher due to greater commissioning of capacity in countries with higher overnight capital costs, such as the United States, compared with China.

Investment in new renewables power capacity, at USD 297 billion, remained the largest source of electricity spending despite declining by 3%.[10] In inflation-adjusted terms, investment was 3% lower than in 2011, but capacity additions were 50% higher and expected output from this capacity about 35% higher, thanks to lower unit costs associated mainly with technological progress. The expected annualised output from renewables plants commissioned in 2016 was equivalent to around 75% of global electricity demand growth in that year. While this report focuses on the investment associated with projects that came online in 2016, it is worth noting that asset financing data,[11] which is typically more volatile, showed a steeper decline. In 2016, asset financing for new renewables, excluding large hydropower, fell by over 15% (CEP, 2017). Nevertheless, this transaction data does not give a full picture of how evolving costs and capacity additions may affect investment in the future.

There were contrasting trends in investment in solar PV and onshore wind in 2016 (Figure 1.15). In the case of solar PV, investment rose by over 20%, led by a surge in utility-scale plants. Yet capacity additions increased to a record 73 GW, or over 50% higher than in 2015, thanks to a big decline in unit capital costs. China accounted for the bulk of the increase, where additions more than doubled, but deployment also rose in the United States and India. By contrast, the average cost of installing onshore wind farms was broadly stable, with slower deployment explaining the entire 20% decline in investment in that sector. Again, China was the main contributor to this

[9] Nuclear capacity additions are measured as the gross electrical size of the plants that were connected to the grid. Investment estimates are based on cost assumptions from IEA/NEA (2010) and IEA/NEA (2015), adjusted to reflect an average construction lead time of around five years. Investment data do not include upgrades and lifetime extensions at existing plants, which are very difficult to measure.

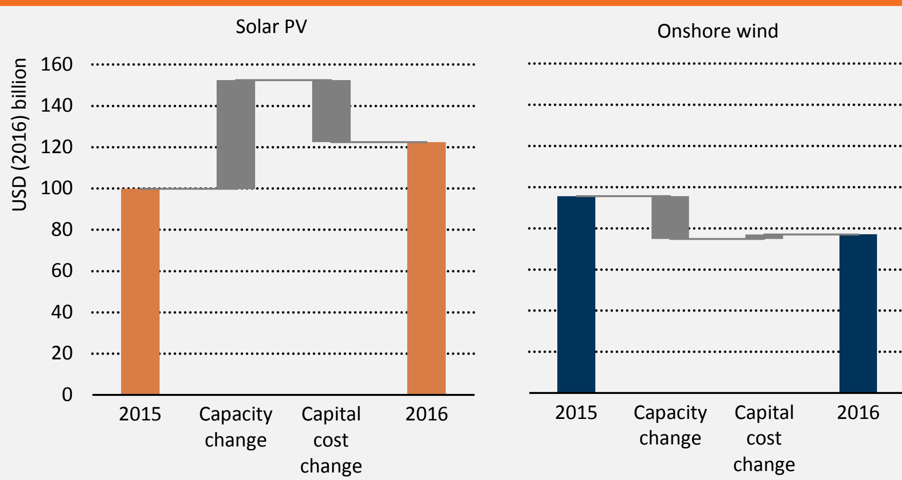
[10] Total investment in renewables, including biofuels for transport and solar thermal heating installations, amounted to USD 316 billion in 2016.

[11] Asset financing, which is not adjusted for general inflation, refers to the commitment of debt and equity capital for new projects. This discussion of recent trends in asset financing is intended to complement the investment estimates. The data on asset financing cover new projects and are expressed in nominal dollar terms. They exclude hydropower above 50 MW. Asset financing is a forward-looking indicator as it represents the potential value of renewable power that is expected to be commissioned one to four years after financing has been arranged rather than actual capacity additions.

trend, with elevated rates of curtailment[12] and changes to incentive schemes resulting in a 40% slowdown in capacity additions there compared with 2015.

Offshore wind and hydropower also saw declines in investment. In Europe, offshore wind investment fell by half from its record level in 2015, reflecting a pause in the commissioning of long lead-time projects. Nevertheless, final investment decisions for new projects grew strongly in 2016, hitting a record level of over USD 20 billion and representing capacity of 5 GW. While in monetary terms final investment decisions for new offshore wind farms increased by nearly 40% in Europe, new capacity financed rose by two-thirds compared with 2015, reflecting cost reductions and technological progress in the sector; in other words, the industry is financing more capacity for less (WindEurope, 2017). The slowdown in hydropower investment is in line with the long-term trend as opportunities for new large-scale projects diminish and local environmental obstacles hamper new developments. Though this decline was most pronounced in North America, Europe and Asia, investment in emerging economies in Africa and Latin America, which made up nearly 40% of the global total, almost tripled in 2016 compared with 2015 due to the start of commissioning of several large projects.

Figure 1.15 Factors behind changes in solar PV and onshore wind investment, 2016



Annual capital cost declines in solar PV offset over 55% of the investment boost provided by record capacity additions, while the decline in onshore wind investment reflects slower deployment.

Sources: Calculations for capital cost changes based on IRENA (2017), *IRENA Renewable Costing Alliance*, dataset.

[12] The rejection by the system operator of part or all of the output of a power plant.

A further slowdown in large-scale dispatchable power capacity additions is imminent

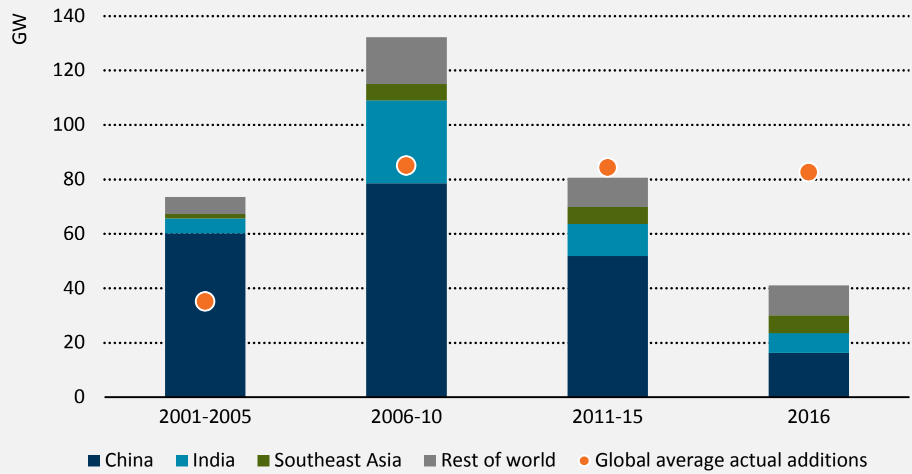
The *WEI* has begun tracking major equipment awards and construction starts as proxies for final investment decisions for long lead-time large-scale thermal generation and hydropower projects – the traditional recipients of power-generation investment. Orders of new power-generation turbines indicate the potential capacity of power assets expected to be commissioned several years after financing has been arranged, rather than actual capacity additions. Final investment decisions, combined with other indicators, provide reliable signals of the scale and types of investment over the coming years. Our analysis of global developments in 2016 and early 2017 points to the following outcomes:

- Coal power under construction amounts to around 250 GW in early 2017 (or three times that commissioned in 2016), 55% of which is in China (CoalSwarm, 2017). This suggests that coal investment may remain elevated in the near term. However, in China, this construction pipeline may not lead to any significant increase in coal-fired generation due to overcapacity in generation, concerns about local air pollution and new government measures to slow new plant development and the construction of some projects already in progress.
- The investment decisions taken in 2016, totalling a mere 40 GW, signal a dramatic slowdown in investment in coal-fired power once the current wave of construction comes to an end – mainly in China, but also in India (Figure 1.16). Depending on the rate of retirements, which reached a record 25 GW in 2016, net coal-based capacity additions may continue to decline.
- The capacity associated with investment decisions for gas-fired generation, which plays an important role in power-system flexibility, surpassed that for coal for only the second time during the past decade. Over half of this is in the United States, Middle East and North Africa – regions with good pipeline infrastructure. China, with a large expansion of gas power seen under the 13th Five-Year Plan, accounts for 10%. Only a small amount is in Europe.
- Investment decisions related to large-scale dispatchable low-carbon generation point to a slowdown in capacity additions in the next few years. Hydropower capacity in the construction pipeline in 2016, including plant refurbishments, amounted to 12 GW – the lowest level since 2001. Three nuclear reactors – in China and Pakistan – began construction in 2016, with a combined capacity of just over 3 GW, while retirements of existing plants in the same year amounted to 1.5 GW.

Overall, the amount of large-scale dispatchable[13] power generation capacity plus grid-scale storage (batteries plus pumped hydro storage) given the green light in 2016 totalled around 130 GW – its lowest level in over a decade. For the first time ever, this capacity was virtually matched by the 125 GW of variable renewables capacity (solar PV and wind) commissioned in 2016, whose construction times are generally shorter (see Figure 1.17).

[13] The ability to flexibly dispatch power varies by system, plant and generating technology.

Figure 1.16 Annual average coal power capacity additions by year of final investment decision compared with actual additions

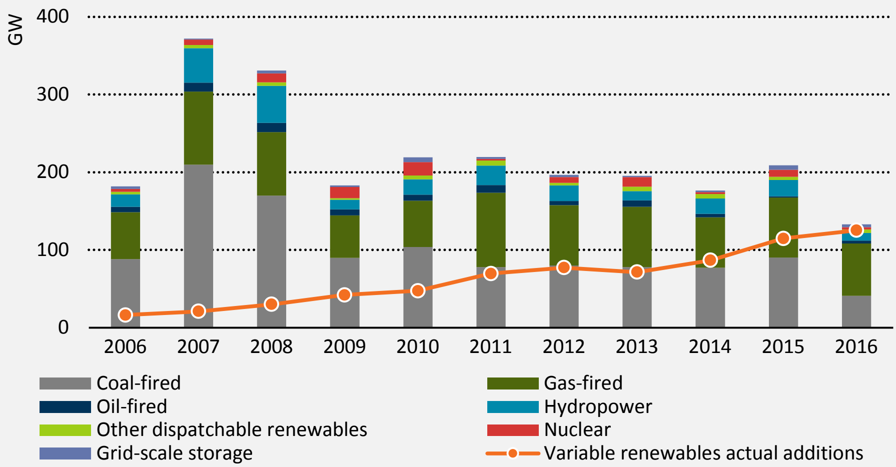


In 2016 newly sanctioned coal power fell to the lowest level in nearly 15 years, reflecting air quality concerns and overcapacity in some markets, notably China.

Note: Final investment decisions are estimated on the basis of awarded equipment contracts; data may not include projects below 5 MW.
Source: Calculations based on McCoy Power Reports (2017), dataset, and Platts (2017), *World Electric Power Plants Database*.

In other words, the electricity sector invested in variable power at almost the same rate, in capacity terms, as it sanctioned future large-scale dispatchable generation and storage in 2016. This increases the importance of ensuring system flexibility through the efficient use of existing thermal generation, robust grids and demand-side response to enable the long-term integration of solar PV and wind. These trends also raise question marks about the pace of decarbonisation of the power-generation fuel mix. Hydropower and nuclear that were commissioned in 2016 together accounted for 45% of the expected new generation from all low-carbon investment that year. Given their importance to decarbonisation of the energy mix, the decline in the amount of new capacity from these sources sanctioned in 2016 would need to be offset by a rebound in future years or a sharp increase in investment in variable renewables if global CO_2 emissions, which stagnated for the third year in a row in 2016, are to be held down (see Chapter 4).

Figure 1.17 **Global large-scale dispatchable power capacity and grid-scale storage additions by year of final investment decision and additions of variable renewables by year of commissioning**



The electricity sector is now investing in variable power at almost the same rate, in capacity terms, as it is sanctioning large-scale dispatchable generation and storage to be built in the years ahead.

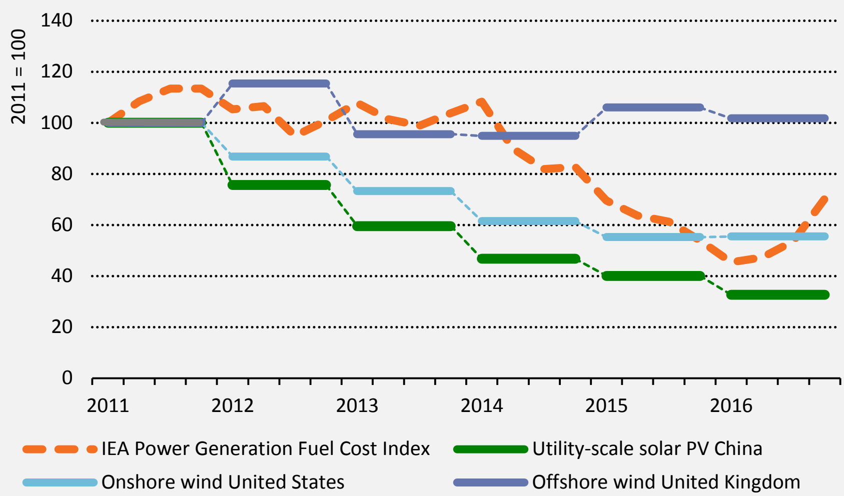
Notes: Final investment decisions are estimated on the basis of awarded equipment contracts (coal, gas and hydropower) and reported construction starts (nuclear). For dispatchable plants, data may not include projects below 5 MW (below 10 MW for hydropower).
Sources: Calculations for investment decisions based on IAEA (2017), P*ower Reactor Information Systems* (PRIS), and McCoy Power Reports (2017), dataset; variable renewables capacity additions from IEA (2017f), *Medium-Term Renewable Energy Market Report 2017*.

Trends in power generation costs

Capital costs of power generation plant generally remained stable in 2016, with the exception of some renewable technologies – notably solar PV. The unit cost of building new coal plants has not changed much in recent years, though local differences persist. For example, in Southeast Asia, coal stations built by Chinese companies are often cheaper than those installations made by other contractors. Nevertheless, a shift in investment towards more efficient technology raised the average unit cost of coal plants globally around 5% compared with 2015. Costs for new gas power plants have also been relatively stable, though improved supply-chain efficiencies in equipment manufacturing appear to be putting downward pressure on turbine pricing. Due to a lower level of local inputs to plant development compared with coal power, exchange-rate movements may also be affecting purchasing power for new plants, which are usually priced in dollars. But it remains difficult to generalise about the financial impact of changes in exchange rates. As with coal, investment in gas-fired plant has shifted towards more efficient CCGTs, whose capital costs are higher than open-cycle gas turbines. In some cases, CCGTs are increasingly being built and run as peaking plants, but the economic attractiveness of such investments, compared with gas turbines, varies considerably across regions according to local costs, utilisation rates and gas and carbon prices.

The economics of new power-generating plants based on fossil fuels changed significantly in some regions in 2016. Although the IEA *Power Generation Fuel Cost Index* – a composite index of global fuel prices – fell by 6% on average in 2016 to the lowest level for several years, the index rose by 55% between the first and fourth quarters, mirroring the decline that occurred from late-2014 through to the end of 2015 (Figure 1.18). This mostly stemmed from a steep rebound in coal prices in China and a moderate increase in regional gas and liquefied natural gas (LNG) prices in the second half of the year. The recent price increases have reduced operating margins for Chinese coal plants and stimulated a large shift from coal to gas in power generation in Europe. The longer-term effects on investment remain more difficult to gauge (see Chapter 4).

Figure 1.18 Levelised cost of electricity for renewables by year of commissioning in select markets and fossil fuel prices



A decline in generation fuel prices that began in 2014 reversed in the second half of 2016, while technical advances and improved project management continued to drive down the cost of solar PV and wind.

Notes: The IEA Power Generation Fuel Cost Index is based on a basket of nominal regional coal and natural gas prices by quarter, weighted as follows: 40% Qinhuangdao coal, 10% Amsterdam-Rotterdam-Antwerp (ARA) coal, 20% Henry Hub gas, 15% Japan spot LNG, 15% Title Transfer Facility (TTF) gas. LCOEs, expressed in real terms, correspond to the annual average for new plants commissioned in a given year. Capacity factors are held constant across solar PV project vintages, but those associated with wind projects are estimated based on DOE (2016), *2016 Wind Technologies Market Report*, for the United States and Energy Numbers (2017) for the United Kingdom.

In the case of renewables, the capacity-weighted average capital cost of new solar PV projects fell by 20%, consistent with declines in 2015, but faster than the average of the past five years. The fastest reductions for utility-scale projects, which made up 75% of global solar PV capacity additions, occurred in China, India and the United States, which together accounted for 80% of new plants, but smaller markets, notably France and Australia, also saw cost declines. A large part of the explanation for these cost reductions relates to lower average selling prices for modules, which fell 15% in 2016 – the fastest decline in three years.[14] Continuing improvements in module efficiency gains have also enabled the downsizing of panels and equipment related to the balance of plant. In China, the largest single solar PV market, these factors contributed to a two-thirds fall in the levelised cost of energy (LCOE)[15] of new utility-scale plants in the past five years.

While technology progress has remained important in lowering generating costs, other factors, such as robust module supply, improved cost discipline, standardised project documentation, better project management and more efficient supply chains, continued to drive down price bids in auctions for generation contracts in a number of countries. Over the past 18 months, Argentina, Chile, France, India, Mexico, Peru, Turkey, United Arab Emirates and Zambia awarded power purchase agreements (PPAs) for utility-scale solar PV to be delivered in the next few years at less than USD 70/MWh on average, with projects in the best sites, often accompanied by measures to lower financing risks, achieving much lower prices. These trends should be treated with caution. Auction results can be subject to aggressive pricing strategies to gain market share with developers often anticipating reductions in equipment prices. The pricing of modules tends to fluctuate according to cyclical factors and shifting pricing strategies; it remains to be seen how sustainable current prices levels are given low manufacturing margins (SPV Market Research, 2017). Furthermore, not all major markets experienced cost declines in 2016. In Japan, where deployment is slowing and high land costs and difficulties in integrating new capacity continue to constrain market growth, utility-scale PV costs were relatively stable.

In contrast with solar PV, the weighted average installed cost of onshore wind increased slightly in 2016, reflecting the significantly reduced share of projects in China, which have among the lowest costs in the world. Over the past five years, average investment costs have fallen by less than 15% in total. However, technology improvements, including larger turbines, increased rotor diameters, higher hub heights and the increased use of advanced turbines to unlock low speed wind sites have boosted generation even more. In the United States, for example, these factors resulted in a reduction of around 45% in the levelised cost of generation for new plants during the same period (Figure 1.19). Over the

[14] A rolling two-year average of prices is used here given the time lags between module price shipment quotes and installations, as well as volatility in annual module pricing. Calculations are based on SPV Market Research (2017).

[15] The present value of the sum of discounted costs of building and operating a power-generating asset over its lifetime divided by the total energy output of the asset over that lifetime. The LCOE describes the electricity tariff with which an investor would precisely break even, after paying debt and equity investors.

past 18 months, auctions in Argentina, Australia, Germany, India, Italy, Mexico and Peru all awarded onshore wind contracts at around USD 70/MWh or less.

Offshore wind capital costs, including grid connections, have also fallen over the past five years with technological advances, better project management and more efficient supply chains, though much more gradually than for onshore wind and solar PV. Significant cost reductions have already materialised in projects that took investment decision in 2015 and 2016 due to economies of scale, including larger turbines and industrialisation. Judging by recent contract prices below USD 60/MWh in auctions in Denmark, Germany and the Netherlands for projects coming online from 2019 and further improvements in technology, large cost reductions in offshore wind are still likely (IEA, 2016a). These price levels also partly reflect regulatory frameworks that allocate the cost of grid connections to the system. Lower administrative burdens and long-term visibility over tendered volumes have allowed the industry to mature and accelerate its technological learning. In addition, revenue stability for operators for offshore wind farms has enabled the reduction of financing costs and diversification of the sources of financing (see Chapter 2).

Investment in electricity networks and storage

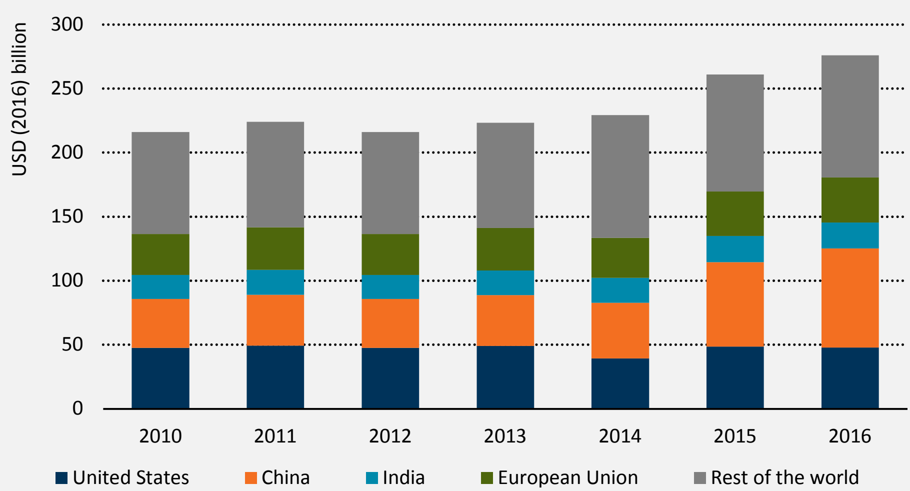
Investment in transmission and distribution infrastructure is critical to ensuring the reliability, resiliency and security of the entire electricity system. Spending on the grid is typically directed at the replacement of ageing assets, the integration of new power plants, especially remotely located renewables, reducing congestion, adjusting to local shifts in energy demand and improving system flexibility. Electricity networks and storage spending – including power lines and equipment, metering devices and grid-scale batteries[16] – have risen steadily over the last five years, reaching USD 277 billion in 2016. The share of electricity transmission in total network spending rose to 28% from 22% in 2015. Annual growth of networks and storage spending slowed to 6% in 2016, largely due to a slowdown in Chinese investment in distribution networks, which accounts for well over 70% of its network investment over the past two years (Figure 1.19).

China, India, the United States and Europe alone accounted for nearly two-thirds of the global electricity networks and storage investment in 2016. Globally, 11% of network investment went to integrating variable renewables. About 45% of spending went to expanding the grid to accommodate new generation assets and expand access to new consumers. However, a growing share is now going to replace existing transmission and distribution assets as they reach the end of their useful life in many countries. Delays in

[16] Pumped hydro storage is included in hydropower investment and thermal storage is included in the solar thermal electricity investment numbers of this report. Storage investment numbers do not include spending on behind-the-meter applications. Additionally, networks and storage investment does not include an estimated USD 25 billion of spending by end-users on reliability improvements. Such spending would include some USD 6 billion invested in the United States by commercial businesses, industry and households, mostly in back-up generators and short-term behind-the-meter storage, as well as a USD 4 billion annual market in lead-acid batteries in India alone; the rest is in small-scale diesel and gas generators.

replacing ageing assets are causing interruptions in electricity supply in some countries, incurring huge economic costs. In the United States, for example, the cost of annual interruptions has been valued at USD 110 billion, equal to 40% of global investment in networks (LBNL, 2016b). The replacement of old infrastructure with new technology can also enable the detection of system failures, making the system more resilient and improving security.

Figure 1.19 Investment in electricity networks and storage by region



Investment in electricity networks and storage has grown steadily in the last five years, driven by the need to integrate new renewables-based generation, improve system reliability and replace ageing assets.

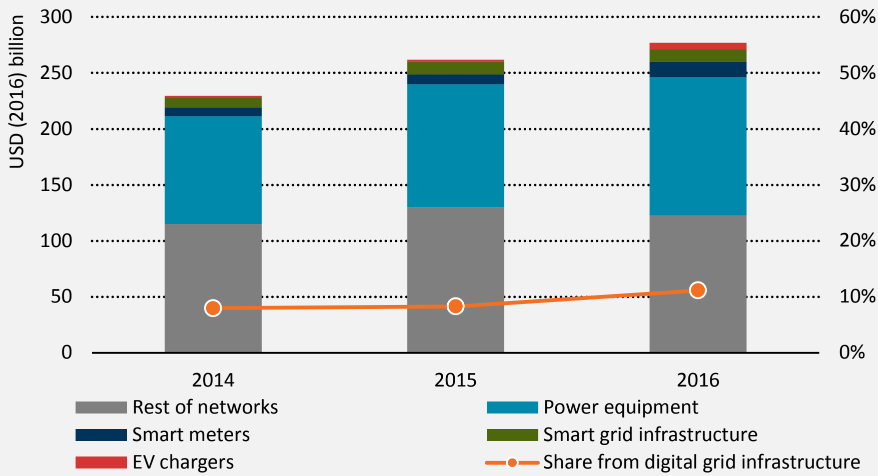
Sources: Calculations based on NRG Expert (2016), *Electricity Transmission and Distribution Database*.

Spending on grid-scale battery storage and EV charging facilities connected to the distribution system are attracting a lot of attention but represented little more than 3% of total spending in 2016, with USD 1.2 billion going to battery storage and USD 6 billion to charging infrastructure (see section on EVs above).

Spending on modernising and "smartening" the grid is on the rise

Spending on the grid comprises both investments in the physical infrastructure as well as the deployment of new digital technologies to the electricity network. Overall spending on standard equipment such as cables, transformers, switchgear and other equipment used in substations accounts for the vast majority of total network investment (Figure 1.20).

Figure 1.20 Share of spending on electricity network equipment by type



On average, spending on standard equipment such as cables, transformers, switchgear and other equipment used in substations accounts for more than 80% of total network investment.

Sources: Calculations based on NRG Expert (2016), *Electricity Transmission and Distribution Database*.

The share of traditional investment has remained broadly constant over the past five years. However, the grid is currently undergoing extensive modernisation and a transition from a pure electricity-delivery business to an integrated platform for data and other services, enabled by rapid progress in information and communication technologies. As a result, investment in digital grid infrastructure grew to over 10% of networks spending in 2016.[17]

Utilities worldwide are increasingly investing in "smart-grid technologies" – a term that covers a wide range of new digital-based technologies aimed at improving operating efficiency and preparing the system for the growing penetration of distributed generating sources, such as rooftop solar, battery storage, demand response and EVs, and associated new business models. The ability to leverage large amounts of data to reduce unplanned outages and to better forecast the availability and cost 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.

Worldwide spending on smart grids reached over USD 30 billion in 2016. The latest control and management systems improve utilisation of the latent analytical capabilities of smart metering, digital communications systems and control devices to reduce outages and

[17] This investment does not include spending on software, platforms and services to integrate this infrastructure into their system operations, which is often treated as an operational expenditure. Further analysis on this spending and that for digital technologies used more widely in the energy sector can be found in Chapter 3 as well as in a new IEA report on digitalization and energy to be published in late 2017.

increase efficiency. New transmission technologies allow operators to use rights-of-way more efficiently and better monitor the status and health of the grid. In general, this investment comprises primarily technologies to automate the monitoring and management of the grid, and to improve data metering in electricity distribution networks that allow communication between consumers and utilities in real time, such as distribution management systems, communication, sensors and energy storage. Advanced metering programmes bring a number of benefits to utilities and consumers, including reduced operating costs (as less labour and fewer journeys to fix problems or read meters are needed), more accurate billing and better customer support, notably through greater consumer awareness of their electricity consumption.

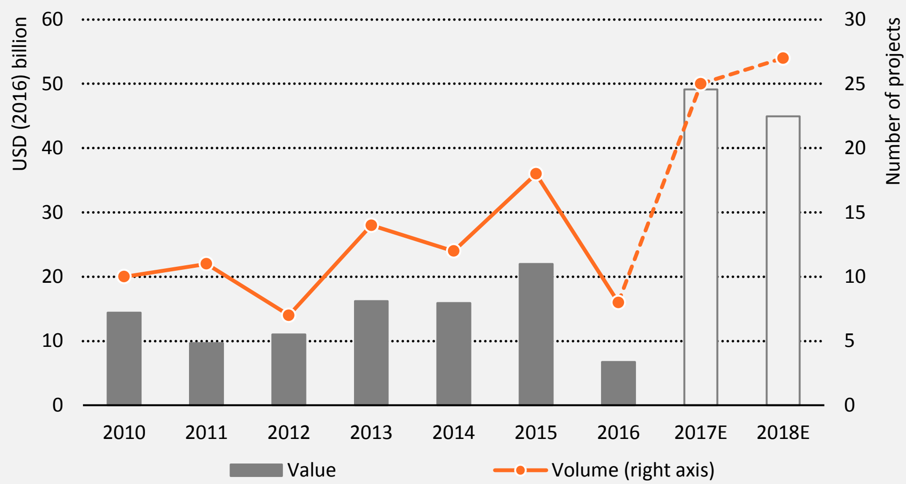
A number of programmes to support grid modernisation have been announced. However, the regulation for grid modernisation and digitalization still needs to progressively adapt. The *PowerForward* programme recently launched by the Public Utilities Commission of Ohio, New York state´s *Reforming the Energy Vision* and California´s *Distribution Resources Plan* have attracted significant attention and progress towards the necessary enhancements for a flexible and efficient grid. Similarly, 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 electricity meters with smart devices by 2020. Reforming the regulatory framework to incentivise spending on digital grid infrastructure remains a key factor. 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.

Investment in large-scale transmission projects is close to a step change

Large-scale transmission projects, involving long-distance large-capacity lines and interconnectors, are playing a critical role in the implementation of national energy-transition plans, as they are instrumental to increase flexibility of the electricity system by supporting the integration of variable renewable energy sources and to 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.

In 2016, eight large-scale projects, including cross-border interconnectors and domestic lines above 800 kV with a total capacity of 18 GW were completed globally. At USD 7 billion (or roughly 10% of total world investment in transmission lines), the investment associated with those projects was 70% lower than in 2015. But this is a temporary dip, as over 50 new lines are expected to be commissioned between 2017 and 2019. Together with other planned lines, a total of 230 GW of capacity is due to come on line in the next two years mostly in China (Figure 1.21).

Figure 1.21 World investment in large-scale electricity transmission projects



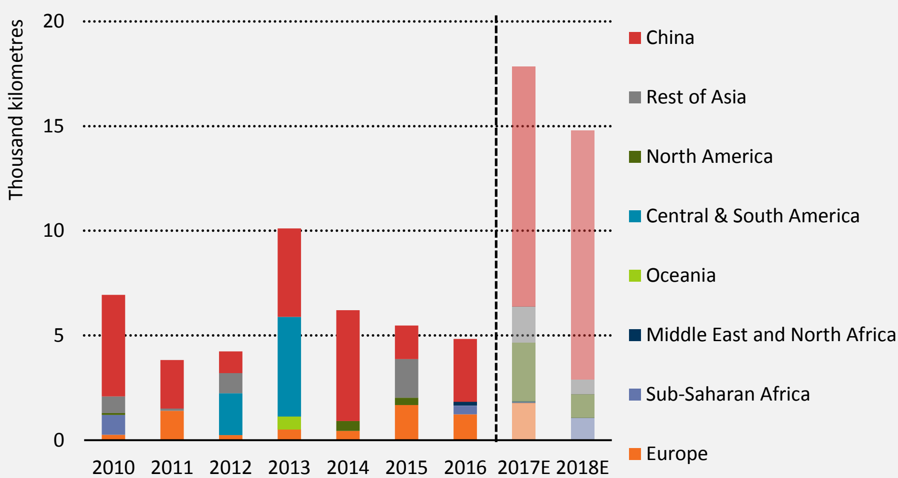
Only eight large-scale transmission projects were completed in 2016 – involving 70% less spending than in 2015 – but a raft of new projects are expected to be commissioned in the next two years.

Note: E= expected. Sources: Calculations based on corporate reports, IEEE (2013), dataset, and BNEF (2016), *Interconnector Dataset*.

In China, the expected ramp up in large-scale transmission infrastructure is aimed at integrating large-scale power generation with demand centres near the coast. These efforts are particularly important for wind and solar PV installations located in resource-rich interior provinces, where electricity demand is relatively low and evacuation infrastructure is insufficient both within and between provinces. Such constraints have contributed to elevated levels of curtailment, reaching over 17% for wind and around 10% for solar PV in 2016. Nevertheless, regulatory factors related to the administrative dispatch of power plants remain a challenge to integrating this output even with an expanded transmission grid. Local authorities often guarantee annual operating hours for coal-fired power plants and there are insufficient price signals for less efficient plants to stand down during times of adequate supply or to more flexibly operate as peaking plants. China is undertaking renewable policy changes and reforms to its electricity system, with a goal of reducing curtailment to 5% by 2020 as part of its 13th Five Year Power Development Plan. The institution of a proposed renewable quota on generators and grid companies would help improve integration. Nevertheless, reforms to date have been focused more on long-term markets for contracting power and have yet to spawn complementary short-term markets, which would pave the way for more efficient dispatch (see Chapter 2).

Globally, out of the total number of projects commissioned in the last five years, over half were built to transmit low-cost electricity over large distances, connecting remote large-scale generation resources, including hydropower, to major networks; 15% were specifically commissioned to connect asynchronous grids and 13% were used to tap into variable renewables-based electricity, both onshore and offshore. The length of the lines varies depending on the geography and the type of project. China was the leading region for such projects in 2016, with 3 000 km of lines completed (Figure 1.22). Outside Asia, Europe represents the leading region for the combined length of interconnectors. In North America, most projects have focused on interconnecting asynchronous grids through back-to-back installations with both AC/DC converters in the same area to keep the length of the direct current (DC) line as short as possible (Box 1.4).

Figure 1.22 Worldwide length of large-scale transmission projects by region



The length of transmission projects varies depending on the geography and type of project. China deployed over 3 000 km of large scale projects in 2016. The length of large scale transmission projects is expected to ramp up with more than 30 thousand km expected to come online in the next two years.

Note: E= expected.

Sources: Calculations based on corporate reports, IEEE (2013), dataset, and BNEF (2016), *Interconnector Dataset*.

Investment in interconnection projects does not differ technologically or from a cost structure standpoint from other types of transmission infrastructure, but the multiple jurisdictions involved usually add an additional layer of complexity. Barriers to completing such projects include the need to deal with several policy and regulatory bodies and the higher level of public scrutiny to large visible infrastructure and consultation that typically accompanies them. Financing can also be harder. For these reasons, central government support is therefore essential. In order to achieve a fully functioning and connected internal energy market, the European Council has set a target of electricity interconnection capacity in 2020 for member states equivalent at least to the 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. To this end, the Commission estimates that spending of

EUR 40 billion in those interconnections that have qualified for support under Project of Common Interest (PCI) status will be needed.[18] Electricity interconnectors represent 45% of the projects of the current PCI list. In Europe, only 12 countries exported more than 10% of their annual national generation to neighbouring countries in 2016 and only 14 countries imported more than 10% of their annual internal consumption needs in 2016.

Due to differences in taxes and transmission costs applied to generators in the respective EU member states, electricity is not always transmitted from the lowest to the highest cost producers and congestion may occur. Worldwide, some of these projects are built under merchant (or partially regulated) schemes funded by private investors, although most schemes involve transmission system operators with the costs covered by regulated tariffs. There are other schemes that have attracted significant investment, such as the 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 timeframes. This allows interconnector owners to earn returns within pre-determined price boundaries. Thanks to this regime, six projects connecting the United Kingdom with Belgium, Norway, France and Denmark involving total capacity of 6.3 GW are expected to become operational between 2019 and 2022.

Box 1.4 Large-scale transmission-line technology

Over the last decade, advances in power-transmission technology have paved the way for increases in capacity and operating voltage levels, as well as improvements in network reliability and flexibility. This has expanded the options for the delivery and modernisation of interconnected power grids.

Table 1.3 Significant large-scale electricity transmission projects outside China

Project name	Geo-graphy	Technology	Length (km)	Voltage (kV)	Status
Champa	India	UHVDC	1 365	800	Commissioned
North-East Agra	India	UHVDC	1 728	800	Under construction
Rio Madeira	Brazil	HVDC	2 375	600	Commissioned
Nordic Europe Projects connecting to mainland[19]	Europe	HVDC	1598	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 development

[18] List of key infrastructure projects drawn up by European Commission for completing European internal energy market and for meeting EU energy policy objectives.

[19] Includes the projects of NordBalt, SwePol, NordNed, Skagerrak and Baltic Cable.

In this report, high voltage (HV) large transmission technologies refer to technologies that support lines operating at more than 200 kV in AC or 500 kV in DC form. Ultra-high voltage (UHV) refers to lines operating at more than 1000 kV for AC or 800 kV for DC. When compared with traditional HVAC transmission, UHV AC power lines allow higher transmission capacity over longer distances depending on the voltage level, higher operational flexibility by sharing resources over a much wider geographic area, much lower losses and a smaller transmission corridor. HVDC on the other hand can be used to deliver large quantity of electric power to load centres over hundreds and thousands of kilometres in a point-to-point manner. HVDC becomes cost-competitive with HVAC for long distance transmission using overhead lines above 600-800 km. Additionally, thanks to the versatile nature of the technology, HVDC lines or cables can be used to interconnect two asynchronous grids that operate at the same or different frequencies, or form a hybrid AC/DC interconnection line.

HVDC remains the predominant technology for long-distance transmission, accounting for four-fifths of the lines completed in 2016, since the cost per unit length of line is lowest. HVDC is also favoured on long-length applications due to the lower level of electrical losses as well as AC´s length limit due to the reactive power flow associated with the large conductor capacitance. HVDC is also more practical for subsea lines, which are common in northern Europe, as well as for onshore cables, as the DC avoids heavy currents required to charge and discharge the cable. HVDC projects might also have an advantage in terms of permitting, which is one the key barriers for big transmission projects, due to the less space required and the possibility to use cables instead of overhead lines. Even for short distances, where the cost of the DC conversion equipment could represent an obstacle at first sight, HVDC has a number of advantages with respect to system stability, thanks to the ability to connect unsynchronized AC systems. Investment in HVDC technology totalled USD 4 billion in 2016; an additional USD 13 billion is being invested in projects currently under construction. Ultra-High Voltage is also ramping up, especially thanks to the use of the technology in the so called electricity highways in China, where they are primarily used to connect remote renewable generation sites in the west of the country, and in India, where the first multi-terminal transmission line will deliver hydropower from the northeast region to the city of Agra.

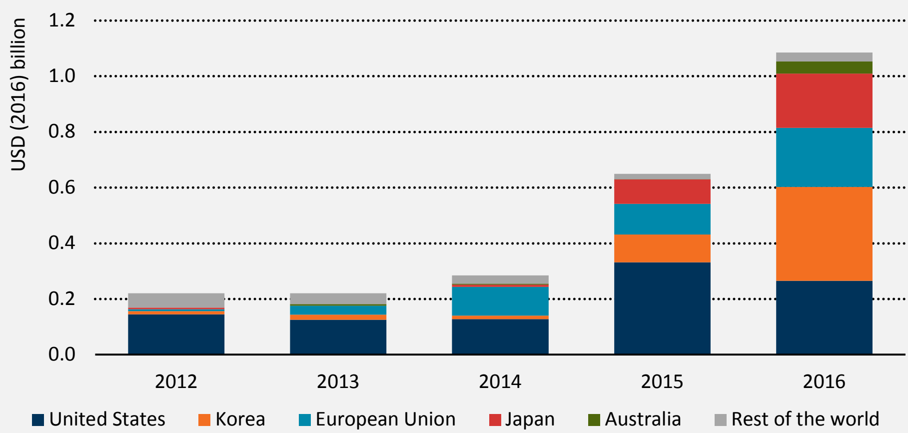
Electricity storage investments marked by rapid growth in batteries

Investment in grid-scale battery-based energy storage is ramping up quickly, reaching over USD 1 billion in 2016 (Figure 1.23).[20] Batteries can bring significant value to system operators, utilities and final customers, by lowering costs and enhancing the quality and reliability of supply. Costs have proved an obstacle in the past, but they have been falling steeply in the last few years; on average, the cost per MW stored dropped by 19% per year over the last five years and could fall by almost another third by 2020 to reach a level of around 200 USD/kWh (IEA, 2016b). This trend is expected to continue with the removal of barriers to the deployment of batteries, notably the way batteries are regulated, rules

[20] Electricity storage investment and installed capacity is dominated globally by pump-hydro projects (PSP). In this report, this investment is included in hydropower. At the end of 2016, 85% of the 7 GW total storage capacity installed during the year was PSP. China led the deployment last year with over 60% of the PSP capacity installed in the period.

limiting wholesale-market participation and especially the constrained capability to transfer system benefits to developers to allow them to achieve a return on their investment. Once again, the role of policies and programmes to allow the efficient installation and operation of storage facilities will be critical to their financial prospects. Similarly, structural changes to electricity markets that allow storage to earn a commercially attractive return will be key to continued growth in investment (see Chapter 2).

Figure 1.23 Investment in battery storage by region



Spending on battery storage is surging around the world as costs fall, though it remains small compared to other forms of network spending.

Source: Calculations based on US DOE (2017), *Global Energy Storage Database*.

In total, over 570 MW of battery storage was commissioned during 2016 and another 610 MW has been announced and is expected to be operating in the first half of 2017. The United States used to be the leading region, but has been overtaken by Korea, followed by Europe and Japan. In the United Kingdom, major contracts have been awarded for frequency regulation and peaking capacity which will enable the potential deployment of 500 MW by 2020. Asia saw the biggest increase in capacity in 2016, but a weakening of policy support and delayed tenders in China, India, Korea and Japan are set to limit growth in 2017. In the United States, policy drivers of different states are driving stronger activity than just two years ago. California continues to lead the way, with just under 70 MW coming on line in 2016. The state has set a target of 1.8 GW of storage by 2020, an approach adopted by some other states, including Oregon and Massachusetts. In Australia, there has been an increase in grid-scale installations mostly associated with large-scale solar PV plants; 10 MW was installed in 2016 and plans for at least 100 MW more have been announced.

Oil, gas and coal investment

Upstream oil and gas spending

Upstream oil and gas investment continued to tumble in 2016, falling by 26% in nominal terms to USD 434 billion – close to the rate of decline in 2015. Investment in 2016 was little more than half the peak level of 2014, when oil prices started to fall sharply. The fall in investment in 2015 and 2016 totalled USD 345 billion (in nominal terms) – an unprecedented contraction. The pace of the decline in upstream spending varies considerably by region, companies and type of asset. Most of the decline can be explained by lower unit costs, but a significant share of the contraction is due to reduced drilling activity (see Upstream Costs section). The vast majority of the companies that have released their investment plans for 2017 anticipate an increase in their budgets, indicating that spending may have bottomed out. However, with oil prices falling below USD 45 per barrel in mid-June 2017, there is a real possibility that companies may not be willing to fully implement these investment plans.

The contraction in upstream spending has affected all types of assets

North America experienced the largest decline in upstream spending over the two years to 2016, falling by nearly USD 180 billion, or 60%, led by a slump in shale drilling, which typically has a shorter investment cycle and can adapt more quickly to changed market conditions than conventional production.[21] By contrast, investment remained resilient in the Middle East and in the Russian Federation (hereafter, "Russia"), thanks to their lower finding and development costs, the prevailing fiscal regimes and, especially in the case of Russia, a well-developed local upstream service industry and exchange-rate effects.

Among companies, medium and small size operators with assets mainly in the United States reduced their spending most rapidly. Several companies, including Apache, Chesapeake and Marathon Oil, cut their spending by over 60% between 2014 and 2016, as lower oil prices dampened their financial capacity to continue sustaining the investment needed to compensate for the rapid output decline typical of tight oil fields. The major oil companies, or majors,[22] after a contraction of 17% in 2015, slashed their upstream capital spending by an additional 26% in 2016,[23] in response to sharply lower operating cash flows and their commitment to maintaining dividend payments. The strategies of national oil companies (NOCs) have varied. In the Middle East and Russia, NOCs largely maintained their spending plans as witnessed by rig activity, which remained close to record levels

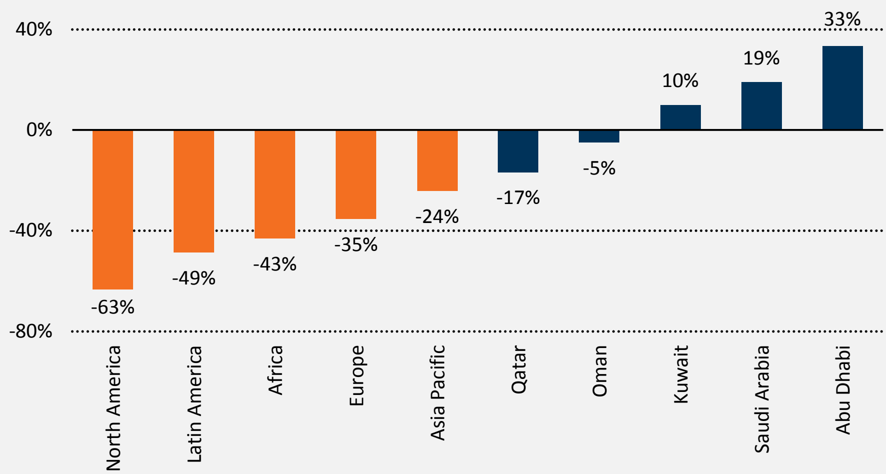
[21] The magnitude of the decline has been partially offset by increased spending by non-integrated oil and gas companies focused on exploration and production ("Independents") in the last quarter of 2016 when oil prices rebounded.

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

[23] For comparison, following the takeover from Shell, BG is included in the majors' aggregate spending in 2014 and 2015.

throughout 2016 (Figure 1.24). The top three Chinese NOCs reduced their spending by a combined USD 12 billion, or 26%, in 2016, following a 39% contraction in 2015.

Figure 1.24 Change in drilling activity in selected key regions (July 2014–December 2016)

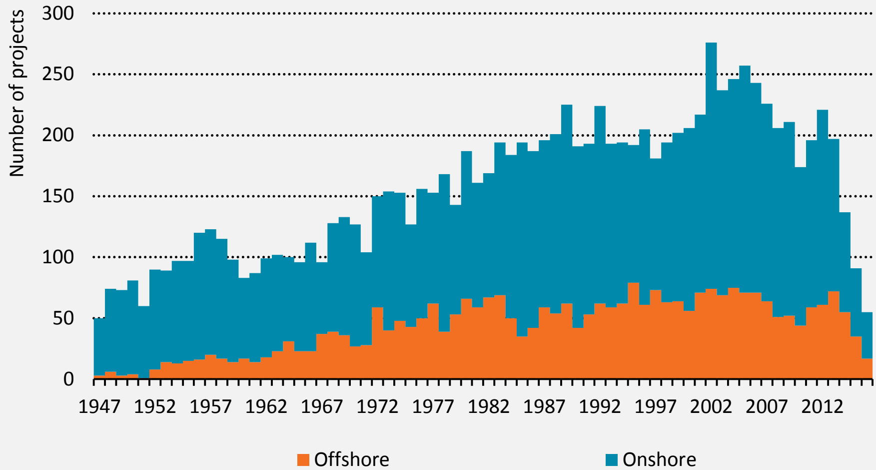


Drilling has held up in the Middle East over the last two years. The biggest decline since 2014 occurred in North America.

Source: IEA analysis of Baker Hughes data.

All types of investments have seen reduced spending, with the largest declines occurring in shale oil and gas basins. By 2016, investment there had dropped to less than one-third of levels reached in 2014. Oil sands saw a similar trend. Capital investment in conventional onshore and offshore projects showed greater resilience to the oil price collapse but drivers were fundamentally different. Onshore projects benefited from continued spending in regions like Russia and Middle East as well as the strategies of several companies, which focused on maximising output from already producing assets rather than developing new projects. Investment in offshore projects, which have longer lead times, was supported by continuing spending in already sanctioned projects. The magnitude of the drop in dollar spending on conventional crude oil resources – which have historically provided the bulk of global oil supply – is nonetheless unprecedented. The number of projects that obtained final investment decision for development in 2016 was down by over 70% compared with 2013, to little more than 50. For offshore projects, the decline is even more pronounced since only 17 projects were sanctioned in 2016 compared with over 70 just three years earlier (Figure 1.25).

Figure 1.25 Final investment decisions for conventional crude oil projects



The number of sanctioned crude oil projects in 2016 reached the lowest level since before 1950.

Source: IEA analysis of Rystad Energy data.

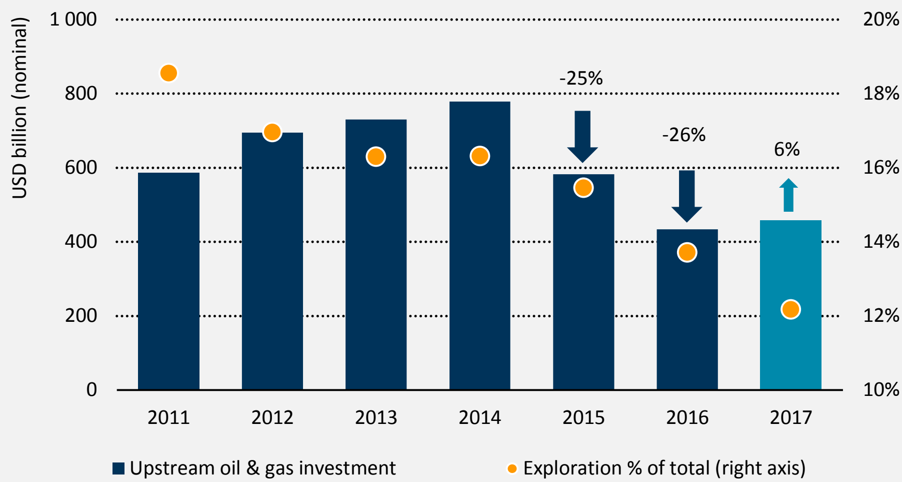
Light at the end of the tunnel for upstream investment?

In addition to slashing its capital spending, the oil and gas industry has reacted to a lower price environment since 2014 by making enormous efforts to tighten financial discipline, enhance operational efficiency and realise cost savings. This has led to a significant improvement in the industry's financial health, though it had still not achieved positive free cash flow by the end of 2016. Financial results for the first- quarter results of 2017 show a significant improvement in free-cash flow positions for most of largest oil and gas companies.

Most independent companies have increased significantly their debt exposure and/or raised equity (see Chapter 2). However, since the last quarter of 2016, following the decision by the Organisation of Petroleum Exporting Countries (OPEC) to cut production levels, market sentiment has shifted, with most upstream companies stepping up their capital investment or declaring their intention to do so in the expectation of higher prices and stronger demand.

On the basis of company announcements, we estimate that global oil and gas upstream investment in 2017 is set to increase by almost 6% to just less than USD 460 billion in nominal terms (a 3% increase in real terms). The trend varies by regions and by type of project and company (Figure 1.26). Many of the largest oil and gas companies are still implementing a cautious approach in scaling up their spending plans and have signalled their intentions to revise down their anticipated investment plans should oil prices not remain above USD 50/barrel.

Figure 1.26 World upstream oil and gas investment



Upstream investment continued to fall heavily in 2016, reaching USD 434 billion – 44% down on the peak year of 2014 – but there are signs of a modest rebound in 2017.

Source: IEA analysis based on announced company spending plans and guidance as of June 2017.

The largest planned increase in upstream spending in 2017 in percentage terms is in the United States, in particular in shale assets that have benefited from a reduction in breakeven prices as a result of a combination of improvement in costs and efficiency gains (see cost section below). On the basis of detailed analysis of investment announced by companies, spending in US shale activities is expected to increase by 53% in 2017 compared with 2016. In Mexico, upstream investment will get a boost from its first offshore licensing round which successfully attracted bids from several international operators. Chinese NOCs have all announced a significant rise in their investment after two years of sharply reduced spending, while the anticipated rise in Russia's upstream spending is subject to downside risks. While companies appear to be pushing ahead with new oil and gas projects to take advantage of tax breaks introduced by the government, the extension of oil production cuts agreed with OPEC in May 2017 and the appreciation of the ruble might slow activities (IEA, 2017g).

By contrast with other types of companies, the majors – with the exception of ExxonMobil and ConocoPhillips – plan further significant cuts in 2017 and have in some cases already indicated lower spending in the following years. Upstream spending by the majors in aggregate is expected to contract by 10% in 2017 based on current plans.[24] This means that their combined spending, at just more than USD 90 billion in 2017, will be barely half the level of 2014.

[24] In the first quarter of 2017, their spending was 28% lower than the same quarter in 2016.

The offshore sector enters a transitional phase

Capital spending in the offshore sector is expected to remain depressed in 2017, though some signs of a revival are emerging. Over the last two years, investment in that sector has been primarily focused on projects that had been sanctioned before the oil price downturn. The only new projects that are expected to go ahead in 2017 are those where costs have been cut sharply. They include projects in the North Sea and Gulf of Mexico, such as Statoil's Johan Castberg and BP's Mad Dog II, both of which have seen cost reductions and have benefited from simplification and standardisation (see the section on costs below). Brazil's offshore is another area where offshore activities are expected to continue due to the combination of favourable factors including quality of reservoirs, recent cost reductions and the entrance of experienced offshore operators such as Total and Statoil. In mid-2017, Hess and ExxonMobil announced final investment decision to proceed with the development of phase I of the deepwater field located offshore Guyana.

On the other hand, projects in Angola and Nigeria – the two largest oil provinces in West Africa – are still suffering from high costs, exacerbated by local content requirements and unfavourable fiscal terms. Similarly, activities in Southeast Asia are not expected to rebound quickly due to regulatory uncertainties and a resource base that is more gas-oriented and less economically attractive due to oversupply in regional markets and competition from large LNG supply facilities in Australia.[25]

The offshore sector, especially deepwater, seems likely to remain in a transition phase. There are several important changes taking place that are encouraging a wait-and-see approach on the part of many operators. These changes include:

- A scaling down of the size of new projects, standardisation of facilities and equipment, fewer wells, optimisation of project design and enhanced efficiencies from industry level collaboration. As of June 2017, only seven offshore projects had been sanctioned in 2017, six of which are very small and in some cases represent tie-backs to producing fields (the only exception is Israel's Leviathan I).
- Significant scope for cost reductions in the offshore sector, as multi-year contracts come to an end and opportunities for negotiating lower costs with suppliers increase in the face of reduced market activity, while oversupply in the offshore equipment markets persists (see the section on costs below).
- The continuing consolidation of the services sector. Mergers and acquisitions have accelerated, notably the mergers of Schlumberger and Cameron, Technip and FMC, and the proposed merger between GE Oil and Gas and Baker Hughes (see Chapter 2).

Some offshore companies are also betting on the future recovery of the sector by acquiring selected assets. Examples include Statoil's acquisition of Petrobras's Carcara field,

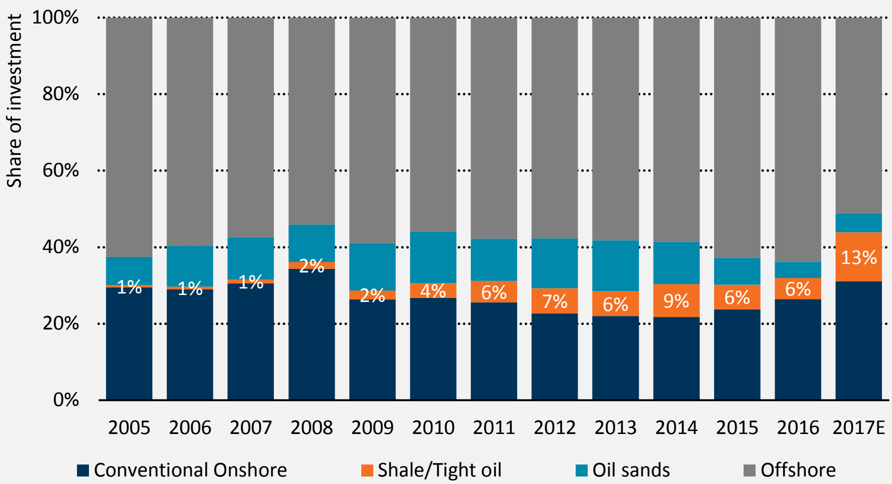
[25] In January 2017, the decision of Indonesia's government to move away from traditional production sharing contracts (PSC) and adopt a new model based on the split of gross production between the state and contractors might further delay new upstream investment.

Anadarko's acquisition of Freeport's assets in the Gulf of Mexico and Woodside buying a ConocoPhillips field in Senegal. Among the majors, deepwater remains a focus of upstream spending, though their 2017 investment plans mark a shift towards shorter-cycle investments (Box 1.5)

Box 1.5 The majors shifting towards shorter cycle investment

The severe downturn in oil prices since mid-2014 has both reduced the investments of the majors and forced a partial rethinking of their strategy and priorities in the wake of their changed financial conditions. A dual strategy is observable: more selective investments in complex projects where they are seen to have a comparative advantage and a greater share of investment in shorter-cycle projects (Figure 1.27).[26]

Figure 1.27 Upstream oil investment by majors adjusted by cost inflation by type of project



The majors are reviving their investments in short-term shale and conventional onshore projects, while cutting back on lumpy, longer-term offshore developments that are more exposed financially to oil-price fluctuations.

Sources: IEA analysis of Rystad Energy data.

The majors traditionally focus on large and complex projects where they have the necessary financial and technical capabilities, in particular in deepwater fields. Their access to these resources is also less limited by competition with NOCs, who are often the primary operators of conventional fields. Complex projects have long lead times and predictable levels of production but require huge capital outlays. While deepwater remains a crucial component

[26] For the purpose of this report we consider "shorter-term cycle" those projects aimed at reaching first oil production in a limited amount of time (maximum three years). Those include: tight oil projects, brownfield expansions and significant shortening of the time-to-market of conventional oil fields.

of their portfolios, the majors have become much more selective about embarking on multi-billion dollar projects and have focused on operational assets where much of the total spending is already committed. Many new projects have been deferred, reflected in the very few final investment decisions in 2015 and 2016. Those that are proceeding are often in diminished form. There is a general trend to limit the spending on infrastructures associated with new field developments, for example by postponing additional pipelines or processing capacity that might be required in the event of future expansions.

The other strategic change involves channelling investment to assets with shorter payback times. Divestment and spending plans announced in early 2017 show more capital being allocated to shale and onshore projects, and less spending on oil sands and deepwater projects.

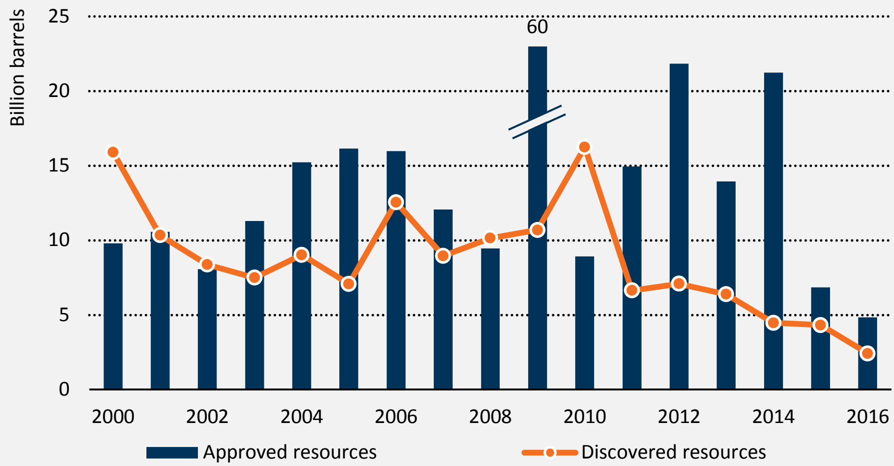
As an example of this trend, ExxonMobil announced in March 2017 that over one-third of its 2017 capital spending will go for short-cycle projects, primarily Permian and Bakken unconventional plays and short-cycle conventional programmes. Chevron is also targeting most of its investment at shorter-payback projects, following completion of some of the most complex and costly LNG projects, notably the USD 50 billion Gorgon development. Other companies that are less active in the tight oil area, have announced divestments or reduced focus on long-term projects such as oil sands where the bulk of new investment is undertaken by Canadian companies and generally redirected towards smaller-scale brownfield expansions. Shell has sold most of its oil sands interests in Canada, retaining just a 10% interest in the Athabasca Oil Sands Upgrader. ConocoPhillips sold the majority of its oil sands assets for over USD 13 billion in early 2017 but continues to retain a 50% interest in the Surmont joint venture with Total. Eni and BP are examples of companies that have succeeded in bringing new facilities into production ahead of schedule.

Is the industry investing enough to meet future supply needs?

Investment in exploration has fallen more heavily than that in developing existing reserves since oil prices started to collapse in mid-2014, raising question marks about whether sufficient reserves will be available in the coming years to meet rising demand (IEA, 2016c). Exploration spending had already halved in 2016 to around USD 60 billion compared with its historic peak in 2014. A further contraction of 7% is expected in 2017, bucking the overall trend in the upstream sector. The share of exploration in total upstream spending is set to reach around 12% in 2017 – the lowest level for more than a decade.

While the recent fall in nominal investment numbers is largely due to cost deflation (mainly affecting seismic surveys and drilling of appraisal wells), the contraction in activity has already translated into a sizeable decline of resources discovered. In 2016, total discoveries of conventional crude oil fell by half to just 2.4 billion barrels. This decline is all the more dramatic considering that 2015 saw the lowest level of discoveries since 1952. Furthermore, the total amount of conventional crude oil resources that were approved in 2016 reached just 4.7 billion barrels – a 30% decline compared with 2015, in which approvals were already very low (Figure 1.28). Three projects alone – Statoil's Johan Sverdrup, Shell's Appomattox and Kazakhstan's Tengiz – accounted for more than 40% of all the resources sanctioned in 2015 and 2016 combined.

Figure 1.28 World conventional crude oil resources discoveries and sanctioned reserves



As a result of continuing spending cuts, global oil discoveries and the number of conventional oil projects that were sanctioned in 2016 fell to historical lows.

Note: The peak in resources sanctioned in 2009 is due to Iraq's supergiant fields. The peak of discovered resources in 2010 is due mainly to offshore fields in Brazil and Johan Sverdrup fields in the North Sea.

Upstream oil and gas cost trends

Reduced costs are both a large part of the reason for, and a consequence of, the sharp decline in upstream spending in the last two years or so. According to the IEA Upstream Investment Cost Index (UICI),[27] average upstream costs worldwide have fallen over the last two years by about 30% to levels of more than a decade ago. The trend has been even more pronounced in the US shale industry, where the different nature of projects allowed operators to react faster and achieve even bigger cost reductions. Unit costs in the shale industry almost halved between 2014 and 2016. In last year's edition of *World Energy Investment*, we estimated that cost deflation accounted for around two-thirds of the overall USD 345 billion decline (in nominal terms) in total upstream investment between 2014 and 2016, with reduced activity accounting for the rest. Operators have renegotiated and terminated contracts, deferred, cancelled or reduced the scope of projects and retendered new contracts. The key question emerging for industry is to what extent the cost reductions achieved so far can be maintained in the coming years, especially if oil prices and/or drilling activity pick up again (Box 1.6).

[27] A full methodology document can be found at www.iea.org/investment.

Box 1.6 To what extent are recent upstream cost reductions structural or cyclical?

The dramatic reduction of costs seen between 2014 and 2016 has been crucial for most companies in surviving the steep decline of revenues and operating cash flow driven by lower prices. As markets appear to be rebalancing and several operators looking again at growth opportunities, the fundamental question is to what extent the cost reductions that have been achieved could be sustained in the future.

There is significant variability in the cost reductions achieved, by company types, assets and regions as well as categories of spending. Furthermore, the very limited number of new projects sanctioned over the last two years represents a major obstacle to assessing precisely the nature of each component that contributed to the overall cost reduction.[28] In recognition of this, we have undertaken a series of detailed interviews with most of the largest oil and gas operators, service companies and financial institutions to capture views about insights into the likelihood of cost reductions being structural, i.e. that they may persist over the longer term, or cyclical, i.e. that costs will rebound once/if activity and oil prices recover. On the basis of the responses we received, supplemented by additional information from company releases and internal analysis, we have identified the main factors driving costs and categorised them as structural or cyclical.

Upstream companies generally claim to have lowered costs mainly through improved efficiency in drilling, logging and completion activities, as well as by redesigning supply-chain strategies. Faster penetration of technology, such as advanced services like intelligent completions, logging while drilling, 3D and 4D seismic acquisition and processing or advanced rotary steerable systems for directional drilling, has helped improve well designs. Real-time data collection for reservoir management and analytics has increased the efficiency of drilling.

Table 1.4 Key upstream costs by category

Structural	Cyclical
Field layout	Raw materials prices
Efficiency in drilling and completion	Service costs
Standardisation of equipment	Labour costs
Improved designs	High grading assets
Corporate efficiency	
Integrated approach in supply chain	
Increasing use of digital technologies	

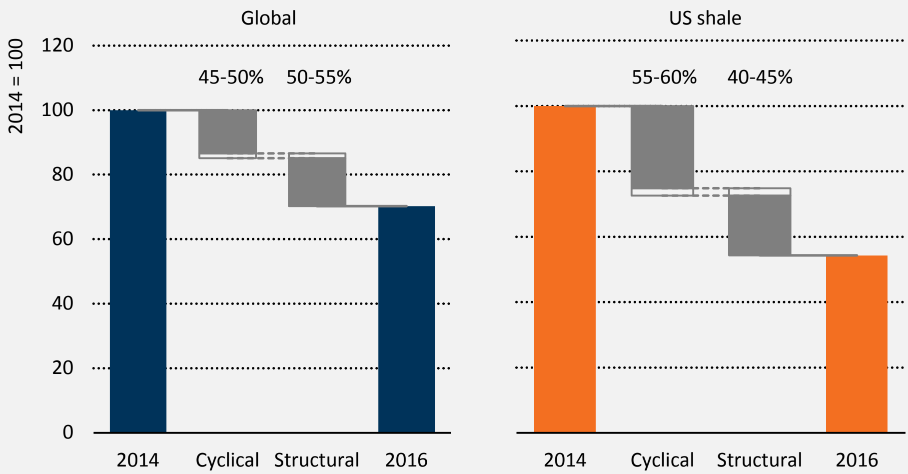
Financial constraints have encouraged operators to shift their focus to efficiency improvements rather than simply output growth, which was the primary goal during the period of high oil prices up to 2014. As a way of reducing unit costs, companies have targeted

[28] It has also to be noted that some projects have been simplified, limiting the development of infrastructure for future expansions which might result in subsequent phases being more expensive.

standardisation of equipment and processes, consolidation of the pool of suppliers, and the increased use of master framework agreements. Redesigning of equipment and modifying specifications has also helped operators and service companies to remove inefficiencies and further improve manufacturing and procurement strategies.

On the basis of information collected for the upstream sector as a whole (excluding the US shale industry), we estimate that about 50-55% of the cost reductions since 2014 can be characterised primarily as structural, with the remaining being more cyclical in nature and expected to evolve more in line with the trend in activities and evolution of markets (Figure 1.31). For the US shale industry, the structural component of cost deflation appears to be smaller at around 40-45%, as the nature of operations is more heavily influenced by short-term market factors.

Figure 1.29 The contribution of structural and cyclical factors to cost deflation



The global oil cost structure appears to have rebased with important savings expected to remain and improve economics of future projects.

Further efforts to cut shale costs focused on drilling activities and transportation. Drilling efficiency has already increased significantly, reducing the number of days it takes to drill a well by one-fifth in the last two years. For proppants, although much of the cost deflation experienced over recent years has a strong cyclical component, some structural logistics gains may remain in the medium to longer term. These include sand – since it has started to be obtained locally, avoiding associated transportation costs – and water supply as some operators have built water pipelines to Permian basin in order to ensure supply availability as well as reduce costs and fuel consumption.

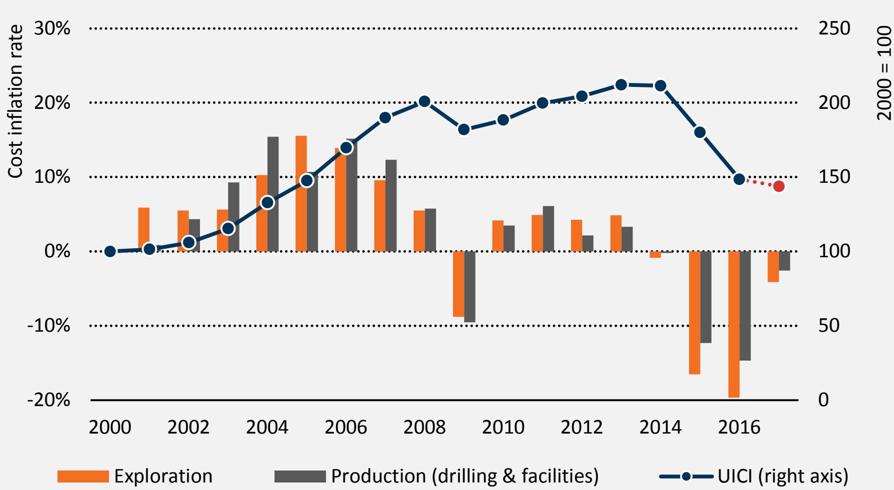
Another key factor set to affect the cost structure of the US shale industry concerns the progressive exploitation of the most prolific resources and the natural shift towards less prolific assets. During 2015 and 2016, the collapse of oil prices forced the US shale industry to concentrate its activities in “sweet spots” (or the so-called “high-grading assets” – acreage with the best geology and returning the highest level of production). As those resources will be progressively depleted, activity will inevitably shift to less prolific areas of each basin. As a result, the US shale industry might experience inflation pressure if it is to maintain its production levels.

The overall picture emerging is that industry has been able to implement improvements in its cost structure that will be very likely captured in future projects. However, a large component of costs will remain cyclical by nature. Commodities and raw material prices which have fallen, as well as exchange rates for labour and engineering costs, have only had a temporary effect on costs and might provide upward pressure in the future. In addition, service companies have reduced their capacity substantially over the last two years and so a recovery in activity might erode price concessions, as the sector fights to improve its margins. However, there are growing signs that oil companies are bypassing major service providers through internalisation of key operations or signing contracts directly with sub-contractors.

Prospects for global upstream costs in 2017

The unit costs of upstream exploration and development are set to decline further in 2017, but only by around 3% – a far smaller decline than in the previous two years (Figure 1.29). This results from diverging trends by regions and sectors, with offshore activities seen as the key contributor to continuing cost decline. Steel and raw material prices have rebounded significantly from the historical lows reached in early 2016, though prices remain depressed compared with past decades with persistent overcapacity in the international steel market (OECD, 2017). Similarly, the increasing activity triggered by higher oil prices is expected to lead a degree of inflation in some areas, notably in the services sector for onshore activities.

Figure 1.30 IEA Upstream Investment Cost Index

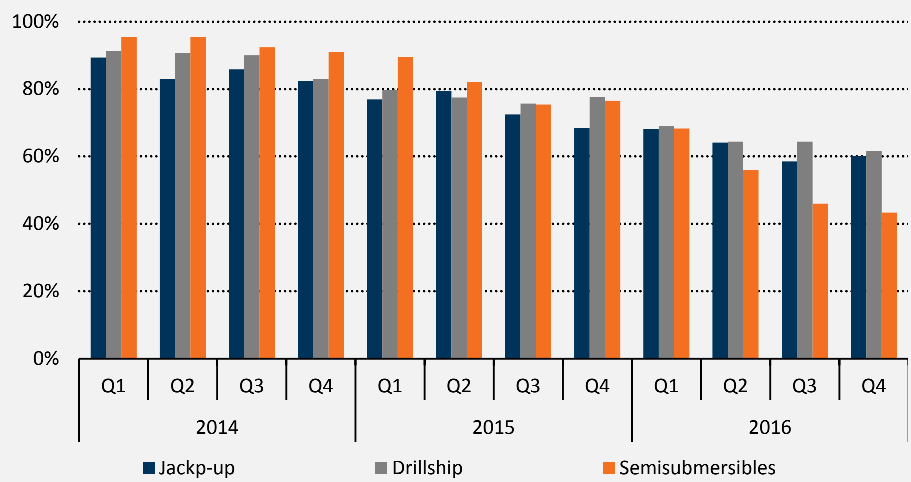


Global upstream costs are expected to decline for a third year in a row in 2017, though the magnitude of the fall is much less than in 2015-16.

Onshore drilling, one of the most important components of the upstream sector saw a sharp contraction in the period 2014-16, resulting in a large number of units being idled around the world. While a large portion of these rigs is not expected to come back onto the market due to increasing competition from newer and more advanced equipment, their utilisation rate – estimated at 70% at the end of 2016 – remains low in comparison with the period before 2014, when it averaged well above 90%. Day rates in 2017 are still expected to reflect the rebalancing of the available capacity and are estimated to continue declining, although the fall – in the order of 5% – is significantly smaller than experienced in 2016, when day rates plunged on average by 19%.

The offshore sector is less likely to rebound in the near future given the steep plunge in activity and the cost reductions negotiated during the last year, despite a probable small recovery in activity in 2017. Indeed, costs are expected to come down further during 2017, as several offshore rigs currently under contract, a legacy of pre-downturn multi-year agreements, are still above market rates.

Figure 1.31 Offshore drilling rig utilisation rates



A steep decline in activity and an oversupplied market have led to much lower utilisation rates of offshore drilling rigs.

Source: IEA analysis of Rigzone data accessed through Bloomberg terminal.

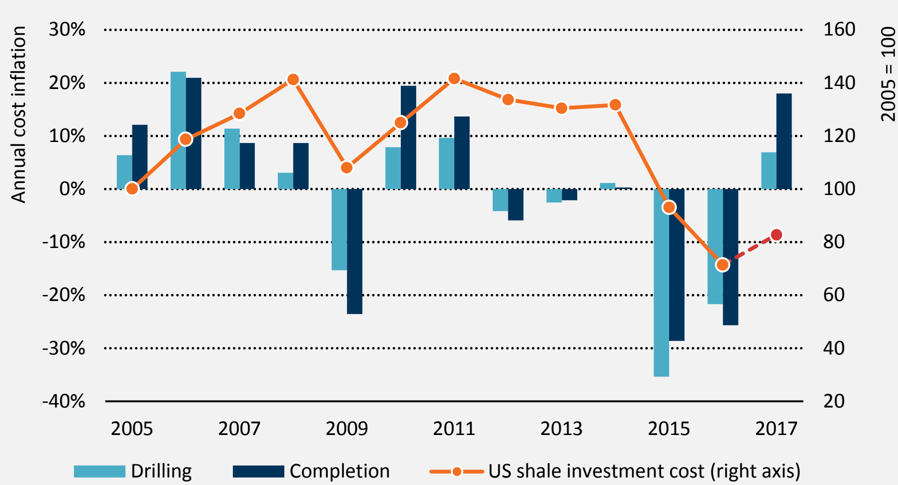
There are several factors helping to keep offshore costs down. Those include the introduction of standardisation in contracting, improved project designs through simplification that reduce the number of wells required, as well as the size of the facilities and the need for subsea equipment. Furthermore, there is an increasing reluctance among operators to embark on large, complex projects, and their preference for smaller assets that reduce the amount of capital needed, as well as shortening the time to bring production into the market.

Market sources report that the daily rate of a drillship has dropped by up to two-thirds (from about USD 0.6 million per day in 2014 to the current level of around USD 0.2 million); the trend is similar for jack-up rig rates. The offshore installation sector is experiencing depressed pricing with day rates being in the order of 30-35% lower than two years ago. There remains significant oversupply in offshore equipment, a legacy of investment decisions taken at the beginning of this decade when high prices and strong expectations encouraged the construction of several drillships and a number of semi-submersible and jack-up rigs. Oversupply in this market, combined with 30 new offshore units that were delivered in 2016 (already down from an average of 49 deliveries per year in the previous five years) have contributed further to declining utilisation rates (Figure 1.30).

US shale costs are already rebounding

The US shale upstream industry reacted very quickly to the changed market conditions since mid-2014 and shale operators, while continuing to outspend the cash flow generated, are generally in much better financial shape than in 2015. This is mostly thanks to an impressive increase in efficiency, improved technology and cost reductions. This has translated into a significant reduction of the oil price at which companies are able to break even; for key basins the breakeven price has fallen on average by over 40% compared to 2014.

Figure 1.32 IEA US Shale Investment Cost Index

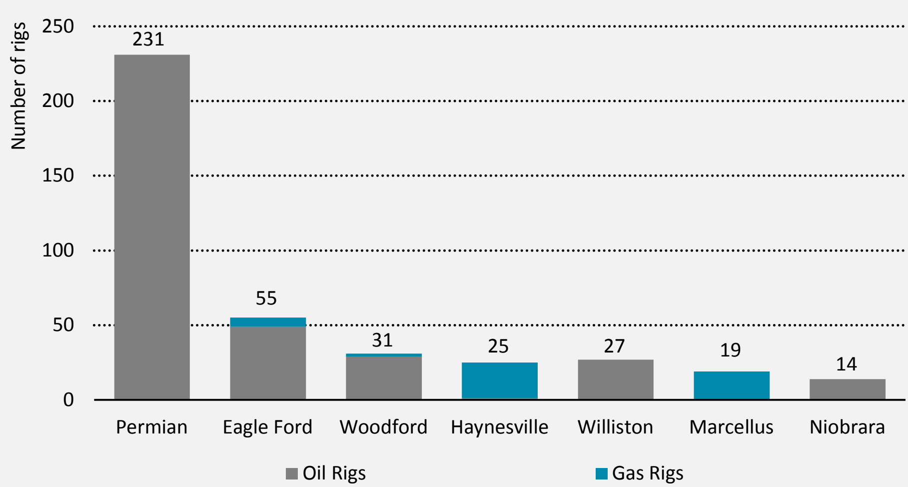


US shale capital costs are set to rise on average by 16% in 2017, reversing the sharp downward trend of the previous two years, though costs will still be almost 40% below 2014 levels.

US shale industry operates in a highly dynamic and competitive environment with a very flexible and well-developed service sector, which tends to adapt to market conditions very quickly. There are already signs that the sector is experiencing some renewed cost inflation – a trend that might accelerate in the second half of 2017, should oil prices remain at current levels (around USD 50 per barrel) or rise. We estimate that average costs for US shale activities will increase on average by 16% in 2017 (Figure 1.32). This figure should discount the fact that – while most of the items driving cost inflation are common among basins –activity has been ramping up at different speeds in different places.

Oil and gas rig counts in the shale sector have increased continuously since mid-2016 (Figure 1.33), especially for the most productive horizontal rigs which now represent 85% of the rigs in use. This effect is more visible in the Permian basin, which currently attracts much of the activity and where the vast majority of additional rigs have been added over the last year. Permian basin currently accounts for more than 35% of the total number of oil and gas rigs operating in the US market, a share that was only 15% just six years ago. This strong recovery in activity has not entirely translated into increasing inflation pressure due to the highly oversupplied rig market in the US shale industry and thanks to the widespread increase in rig operational efficiency. However, new crews need to be hired, after the massive labour decrease in the industry over the last 24 months, and less technologically advanced rigs will return to service, thus increasing costs for operators.[29]

Figure 1.33 Oil and gas rig count growth by key basins, May 2016 – Jun 2017



The rebound in drilling has been led by oil, with an increasing focus on drilling in the Permian basin.

Source: IEA analysis of Baker Hughes data.

[29] Labour availability emerging as one of the most immediate concerns in the US shale industry. Companies have indicated that is very hard to persuade former employees to return to the industry, despite attractive financial packages being offered.

A continuing shift towards more complex wells is likely to contribute to higher shale costs in the future. Wells today are 26% longer on average than they were in mid-2014. Consequently, current production techniques use more proppants to conduct hydraulic fracturing; the average amount of proppant used per horizontal well increased by about 45% in the period 2014-16. Demand for proppants, typically sand, resins and ceramic, which represent around 10% of the cost of a well, is increasing steeply and is expected to surpass 2014 levels before the end of 2017. Despite the strong cyclical component of these cost items, operators have started to acquire their own sand mines to avoid the effect of potential bottlenecks in supply.

The cost of pressure-pumping services, which are widely used in hydraulic fracturing and cementing of shale wells, remained broadly stable during 2016, because of an oversupplied market with a significant proportion of capacity idled at the beginning of the year. However, demand is growing again and is now starting to draw on the spare capacity as utilisation levels are now reaching 70% – above the average observed levels of the past 36 months. This also brings an increased need for labour. In addition, the extensive of pressure pumping equipment requires continuous investment for maintenance and replacement. As a result, new contracts are suffering pricing pressure as service providers try to benefit from recovery in oil prices and rising activity driving costs up by around one-fifth compared with 2016.

Trends in operating costs

The collapse of oil prices in the second half of 2014 led not only to a reduction in capital investment but also forced companies to rationalise operating expenditures. These costs are not included in our estimates of investment, but they do affect investment through their impact on the expected profitability of new projects.

Prior to the collapse in oil prices, companies prioritised production growth by embarking on new projects rather than focussing on keeping their operational costs under control. As a consequence, production operating costs, also called lifting costs,[30] increased by half between 2010 and 2013 (71% in the case of the majors, as their activities are more concentrated on complex projects), suggesting that there was unexploited potential for improving operational efficiency. Since 2014, companies have focused on capturing operational efficiency with the result that costs have fallen by an average of 29% over the last two years (Figure 1.34). This has been achieved in several ways:

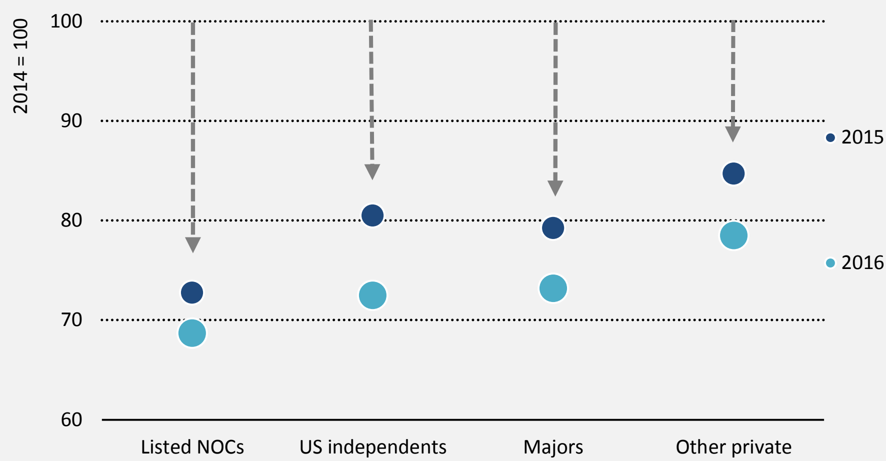
- Increased scrutiny of costs for expensive non-recurrent items and optimisation of the utilisation of equipment and logistics.
- Standardisation on the operational side to benefit from systematised processes and solutions that generate economies of scale. Standardisation helps in scaling-up supply

[30] Lifting cost is the total production cost of operating and maintaining a well divided by the total production. This typically refers to the cost of producing oil and gas after drilling is complete, including: transportation costs, labour costs, supplies, costs of operating the pumps and electricity used.

chains for volume discounts, developing long-term partnerships between operators and service companies and improved decision-making processes that produce savings both in time and costs.

- Leveraging the use of new technologies to benefit from increased worker productivity, better asset management thanks to the enhanced analytics capability and reduced IT infrastructure associated with the proliferation of cloud computing solutions.
- Changing corporate culture and streamlining organisational structures. Operators are reducing interfaces with projects, management layers, functional overlaps between regional centres and assets to reduce the duplication of roles and overheads across the portfolio of projects.

Figure 1.34 Weighted average lifting cost by type of company



Upstream oil companies have slashed their operating costs as well as their capital costs since 2014.

Notes: The weighted average lifting cost is total production costs divided by total production for each company type. Listed NOCs include PetroChina, CNOOC, Sinopec, Ecopetrol, Sasol, Statoil, YPF, Gazpromneft, Rosneft, ONGC and Petrobras. US Independents include approximately 50 US shale operators with more than 80% of their revenues from shale activities representing over 60% of US tight oil and shale gas production. Other private includes the top 14 private companies by market capitalisation (aside from the majors) that discloses relevant information.
Sources: IEA analysis of companies' financial statements; Bloomberg (2017), *Bloomberg Terminal*.

The reductions in operating expenditures since 2014 may be sustained for several years. While after the 1999 and 2009 crises, capital spending rebounded rapidly, operating expenditures tended to remain under control for a prolonged period, with a much more modest rate of increases. This results from the natural tendency of companies to maintain longer the operational efficiencies that have been stimulated by less favourable market conditions.

Investments in the LNG value chain

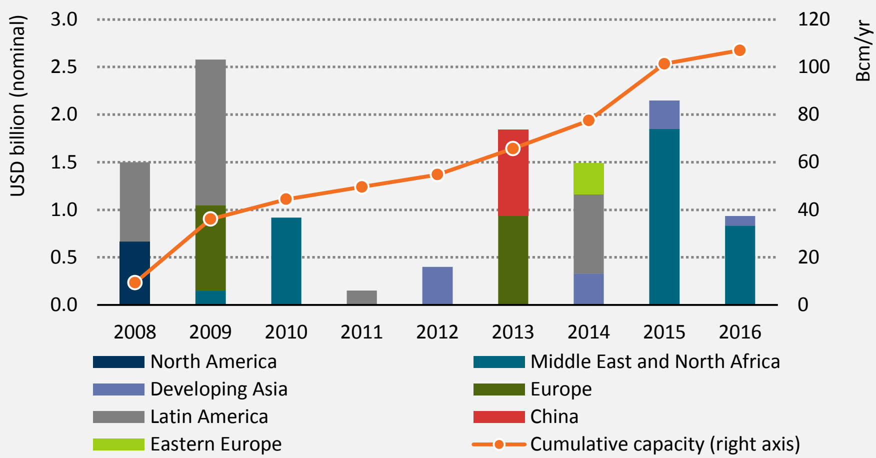
Investment in LNG production facilities peaked in 2014 and 2015 at about USD 35 billion per year, and fell to about USD 25 billion in 2016. Global trade in liquefied natural gas (LNG) increased around 10% in 2016, reaching a new record high of 353 billion cubic metres, driven in particularly by rising imports of China and India. Yet the climate for investment in new facilities has deteriorated over the last 12 months. Following the wave of new plants and conversion of existing regasification facilities commissioned in the first part of the decade, respectively in Australia and the United States, investment in new liquefaction facilities has slowed down dramatically. At the time of writing, since the announced expansion of Indonesia’s Tangghu LNG facility from BP in July 2016, only two projects (Elba Island LNG on US Atlantic Coast and Coral’s Floating LNG terminal offshore Mozambique) have been sanctioned. With ample supply availability and new forms of gas pricing and mechanisms gaining ground, LNG buyers and producers have adopted a wait-and-see approach to new supplies.

On the regasification side, global capacity has continued to rise reaching almost 1 120 bcm as of end of 2016. The number of countries with LNG import infrastructure has tripled since the beginning of the century, reaching 39 in 2016, thanks to the addition of Jamaica and Colombia. The vast majority of regasification terminals are traditional onshore facilities, but over the last few years there has been a notable shift towards the adoption of Floating Storage and Regasification Units (FSRU) which are either purpose built vessels designed to operate offshore, or conversions of conventional LNG vessels.

There are different factors incentivising the increasing utilisation of FSRU technology: upfront capital spending is significantly lower than that needed for onshore terminals, since floating terminals do not require the development of complex and expensive infrastructure, and they have a capacity smaller than the typical size of onshore projects. Furthermore, FSRU vessels have a greater degree of flexibility, better suited to serve highly seasonal markets as well as to be moved to a different location if needed. They also offer quicker access to natural gas supplies to countries lacking regasification infrastructure, or where demand is insufficient to sustain the large investment needed to develop the entire gas transportation supply chain.

Since 2008, about 80% of total capital investment (almost USD 10 billion) for FSRUs has been in facilities intended to serve non-OECD markets (Figure 1.35), including countries entering the club of LNG importers for the first time such as Egypt, Pakistan and Jordan. The overall regasification capacity of operating FSRUs now exceeds 100 bcm per year, representing about 11% of global capacity.

Figure 1.35 Investment in floating storage regasification units by major region and cumulative global capacity



Over the last ten years, increasing adoption of FSRU technology has helped unlock gas needs especially in emerging countries.

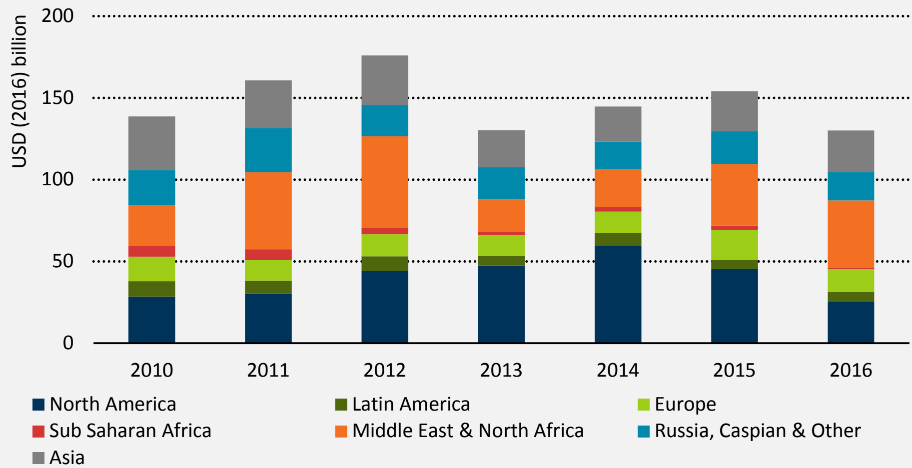
Source: IEA analysis of IGU data.

Oil and gas pipeline investment

Worldwide investment in oil and gas pipelines – including transmission and distribution – totalled around USD 130 billion in 2016, 15% less than in 2015 (Figure 1.36).

The fall in spending resulted from reduced activity in upstream oil and gas operations, which lowered the need for pipelines to connect new production facilities. Investment in 2015 was more resilient due to the long lead times for this type of project, which generally involves several years of construction, as well as the large share of gas, the price of which has been less volatile, in overall pipeline projects. Spending on onshore pipelines has been more resilient than offshore ones, reflecting projects in regions like the Middle East and Russia, as well as interconnection projects in Asia, Europe and between the United States and Mexico. Offshore pipeline construction has been more severely affected by the steep reduction in new upstream projects.

Figure 1.36 **Global investment in oil and gas transportation and distribution infrastructure by region**



Global investment in oil and gas pipelines fell by 15% in 2016 as lower upstream activities reduced scope for midstream infrastructure expansion.

Pipeline networks in China, Russia and the Middle East continue to expand

Investment in China's oil pipeline network remained robust in 2016, while gas pipeline construction activity slowed. In the case of oil, additional pipelines were built to alleviate key infrastructure bottlenecks. This included imports from Kazakhstan, Myanmar and Russia connecting the western, northeastern and Bohai Bay Rim regions with refineries in the midwest and Yangtze regions and easing congestion in the Qingdao Port area, which is home to most independent refineries and accounts for around 30% of China's crude oil imports. Although pipeline capacity continues to expand, the 13th Five-Year-Plan indicates that the ambitious plan to build oil storage capacity to cover 90 days of net crude imports may be postponed until after 2020. In 2016, two projects with a combined 50 million barrels of storage capacity were under construction by CNPC and CNOOC.

Natural gas pipeline activity in China has slowed down significantly since 2014 in line with a slowdown in domestic gas demand growth and regulatory uncertainty. Most companies have postponed projects in response to uncertainty about the planned unbundling of the gas sector and only one long-distance, inter-provincial pipeline – the West-East Gas Pipeline (Phase III) – has been sanctioned since 2015. Those gas pipeline pipelines that did move ahead in 2016 were mostly short intra-provincial gas grids aimed at improving access to natural gas in urban areas.

Spending on oil pipelines in Russia totalled almost USD 5 billion in 2016 as the country focused on diversifying export outlets. The main areas of investment in recent years have been the connection of new oil supplies from the Tyumen and Krasnoyarsk regions and the expansion of the Eastern Siberia-Pacific Ocean Pipeline System (ESPO) for the export of oil to China and other Asia-Pacific countries. Significant investment has also been directed at export capacity for oil products, especially diesel to Europe, for example, the 6 million tonne per year Yug and 15 million tonne per year Sever projects. Gas pipeline networks also continue to expand in Russia, in part to allow rising exports. Between 2010 and 2016, Gazprom commissioned almost 12 000 km of pipelines in Russia, including in 2016 the 1 200 km Bovanenkovo-Ukhta 2 pipeline that forms part of a new export route from Yamal to Germany (Gazprom, 2017). In addition, Russia and Turkey signed an agreement in 2016 to build the 30 bcm per year Turkstream gas pipeline under the Black Sea at an estimated cost of USD 15 billion.

In the Middle East, around USD 40 billion was invested in pipelines in 2016 and over 14 000 km are also planned or under development (P&GJ, 2017). Notable project completions in 2016 include phases 20 and 21 of the South Pars field on the Iranian side of the Iran-Qatar border, which is estimated to hold over 20% of global gas reserves. Other projects are aimed at connecting LNG import facilities, as in the 1 100 km pipeline between Karachi and Lahore, or replacing old lines, such as the Bahrain-Saudi Arabia interconnector.

Focus on United States pipeline infrastructure

The pipeline sector in the United States has largely benefited from the shale oil and gas revolution that began at the end of the previous decade. With new areas of production emerging, the infrastructure system has required large inflows of investment to transport growing volumes of oil and gas to refineries, processing plants and consumption centres. In the case of natural gas, the increasing contribution coming from shale basins has led to the reversal of most previous internal gas flows (usually going from southern regions – also due to imports – to demand centres in the north) and the development of several new inter-state gas transmission lines. This trend was largely triggered by the rapid increase of natural gas production from the Appalachian Basin,[31] which accounts for almost 80% of total growth in natural gas production in the United States since 2011. This has had far-reaching effects on operations in traditional producing regions in the western United States and the Gulf Coast. Overall, investment in oil and gas pipelines rose steadily to a peak in 2014 of about USD 50 billion. The collapse of oil and gas prices in 2014 led to a downturn in investment as the need for new capacity fell. Moreover, the market downturn put increasing financial strain on midstream companies as some fee-based contracts were renegotiated and some US independent upstream operators went bankrupt.

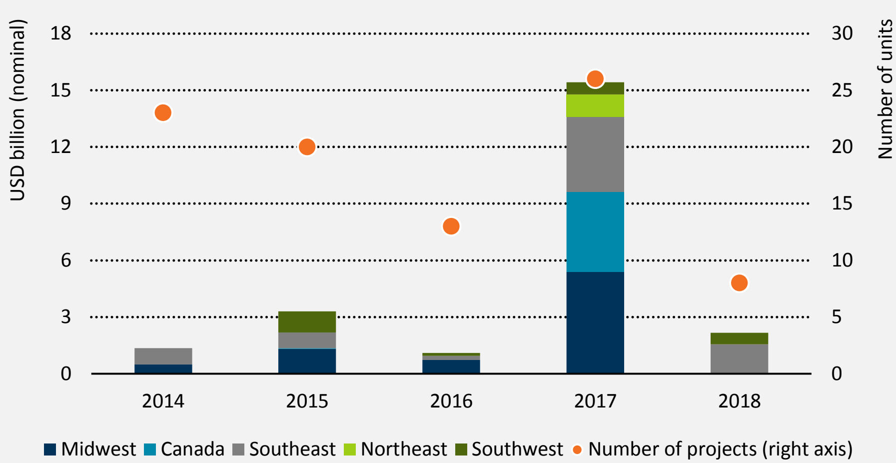
The new US Administration, entered in office in January 2017, has put among its priorities the development of internal infrastructures, including pipelines, as a way to stimulate the economy and contribute to jobs creation. During the first month of the new US president's

[31] The Appalachian Basin includes the Marcellus and Utica formations in West Pennsylvania, Ohio and West Virginia.

mandate, a series of executive orders, including those allowing the construction of the Dakota Access Pipeline (DAP) and the Keystone XL (KXL) pipeline, were signed.[32]

Several projects have been completed or are under construction to accommodate new direction of flows and rising demand. In 2016, the US Federal Energy Regulatory Commission (FERC), which regulates the interstate transmission of natural gas, approved 29 new gas pipeline projects with a combined transfer capacity of about 150 bcm per year. The Appalachian basin has progressively emerged as one key area for investment in interconnection capacity, with the aim to linking rising production (or expanding existing pipelines) from Marcellus and Utica formations with the gas consuming regions. In 2017, more than 25 projects from this basin are scheduled to be completed costing around USD 15 billion (Figure 1.37).

Figure 1.37 US investment in FERC-approved gas transmission infrastructure from the Appalachian basin by destination and commissioning date



Rising output from the Marcellus and Utica formations is spurring a wave of investment in gas pipelines .

Source: IEA analysis based on FERC data.

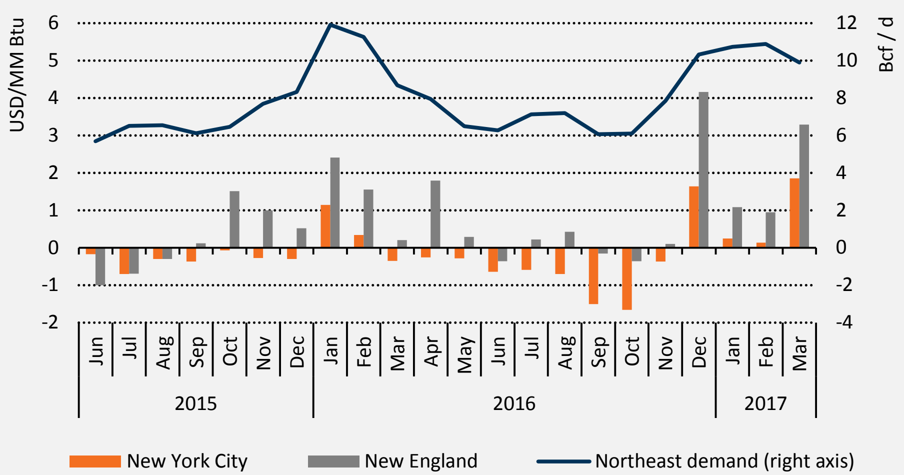
The Northeast region of United States has benefited from increasing shale gas production from the Marcellus and Utica formations over the last few years, reducing the need to transport gas from the more distant Gulf of Mexico or import LNG. However, New England and New York City, despite their proximity to Pennsylvania, lack adequate pipeline capacity to meet peak demand. As a result, the New England area experiences the highest natural

[32] The DAP is a 1 900 km oil pipeline to connect the Bakken shale basin with Illinois, scheduled for completion in 2017 and costing over USD 3.5 billion to date. The USD 8 billion KXL oil pipeline is over 1 500 km and intended to connect the Western Canadian Sedimentary Basin with the Gulf of Mexico.

gas prices in the country – roughly two times higher than those in Louisiana and 1.6 times higher than in the Mid-Atlantic region highlighting the need for additional pipeline capacity (Figure 1.38). Several new pipeline projects have been approved or are under construction to increase gas supply to the region, for an overall capacity in the order of 25 bcm per year, but environmental and permitting resistance at the local level is slowing down the development of these projects.

Cross-border pipelines to Mexico have been expanded considerably to meet demand from the Mexican power sector, as the country seeks to replace oil-fired generation with gas. Investment in these pipelines exceeded USD 2 billion in 2016 and will remain high in 2017 as the 25 bcm per year combined capacities of the Trans-Pecos and Comanche Trail projects are expected to come online. A further USD 2 billion is being invested in the Roadrunner (Phase II), Valley Crossing and Nueva Era projects.

Figure 1.38 Northeast vs. Henry Hub natural gas monthly average spot price



Bottlenecks in pipeline capacity between the Appalachia basin and New England are a major cause of very high regional gas prices during peak demand.

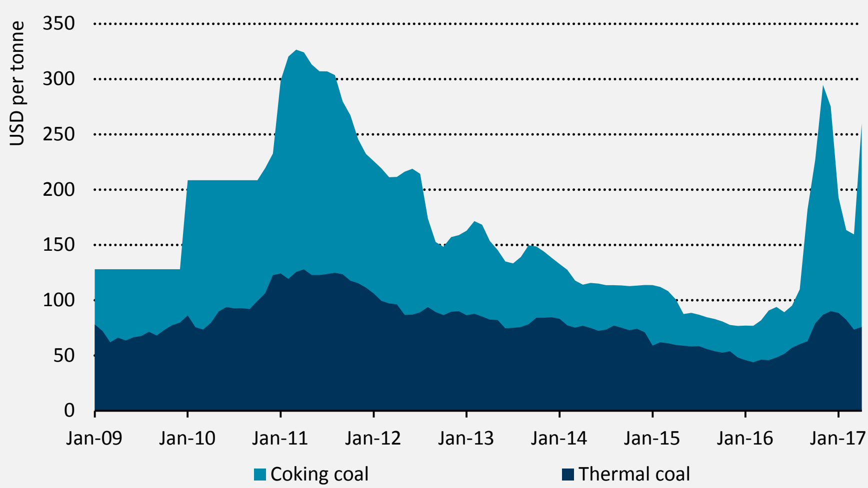
Coal

Global trends in coal-mining investment are dominated by China, which accounts for almost half of world production and more than two-thirds of production growth in the last decade. Chinese coal investment has been falling steadily since peaking in 2012. In 2016, it amounted to USD 13 billion, 20% lower than in 2015. Despite the reported overcapacity, we observe that investment in coal mining in China to expand production is still significant, as less than USD 9 billion 2016 was needed to sustain production. The continuing level of investment partly reflects the need to offset production from unsafe and unproductive mines that are going to be shut down, the long lead-times of new coal mines that had already been sanctioned before coal demand slowed as well as incentives to stimulate economic growth and employment in specific regions of the country. Preliminary data points to a continuation of this trend in the first quarter of 2017, with spending falling 16% compared with the same quarter a year earlier, as the need for new capacity declines with the stagnation and possibly a fall in coal demand in the coming years.

In India, coal investment in 2016 increased by over 10% to USD 3.7 billion, the result of the government's strategy, dating from 2014, of expanding coal generation while reducing thermal coal imports. India became the second-largest coal producer in the world in 2016, and persistent coal shortages have largely disappeared.

Despite the recovery in international thermal and coking coal prices in the second half of 2016 and early 2017 (Figure 1.39), there are few signs of a rebound in investment in coal mining. It is becoming clear that Chinese coal demand has peaked, and for the outlook for imports in India and other countries is uncertain.

Figure 1.39 Monthly coal prices, 2009-17



Policy changes aimed at restricting coal supply in China and regional disruptions in Queensland Australia drove the rapid increase of coal prices in 2016-17 but this is not expected to spur a new wave of investment and merger and acquisition deals as happened following the 2011 coal price spike.

Note: Prices for thermal coal refer to North West Europe thermal coal, and coking coal is Australian prime hard coking coal.

Cheaper gas in North America, rapid declines in the cost of renewable-based power technologies, and stronger climate policies are undermining the prospects for thermal coal demand. As a result, given the high debt exposure of producers, and low coal prices,[33] most companies are focused on reducing their leverage and maintaining dividend payments. Any capital that is allocated to investment is largely aimed at maintaining rather than expanding production. This is especially the case in the United States where most of the big coal producers went through bankruptcy protection due to a combination of lower than expected cash flows from the shrinking domestic market and the accumulation of large amounts of debt from acquisition of metallurgical coal assets.[34] Elsewhere, the industry has seen a wave of sales of non-strategic coal assets. For example, the Australian mining company, Rio Tinto, sold off some of its Australian mines and its share in the PWCS terminal in Newcastle to Yancoa, while Anglo American is selling its Eskom-tied coal mines in South Africa to Seriti Resources.[35]

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[33] Many of the coal producers are diversified resources companies, but the price cycle has been similar for most commodities, and hence, what is reported here for coal producers is generally true for most commodity producers.

[34] This approach was confirmed by three of the largest US companies: Peabody Energy bought McArthur, Arch Coal bought International Coal Group and Alpha Natural Resources bought Massey Energy, for a combined value over USD 15 billion.

[35] At the time of writing (June 2017), Glencore has offered USD 2.5 billion to acquire Rio Tinto's Australian coal assets.

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2. Trends in energy financing and funding

Highlights

- **More than 90% of energy investment is financed from investor balance sheets.** Though the overall share of project finance remains small, its importance in power-generation investment – especially renewables – has been growing rapidly. Newer mechanisms for raising debt and equity are enabling investors to tap into larger financing pools, especially for smaller-scale assets such as energy efficiency and distributed generation.
- **The role of state actors in energy investments remains elevated.** While the share of public bodies, including state-owned enterprises (SOEs), in investment edged down slightly to 42% in 2016, the level was notably higher than 39% in 2011. This is largely thanks to the increased role of SOEs in electricity sector investment, notably in China. National oil companies (NOCs) are playing a larger role in upstream oil and gas spending, with their share rising to 44% in 2016 from 39% in 2011.
- **The oil price downturn did not significantly affect the funding mechanisms for investments by oil and gas companies, though most of them increased leverage significantly.** For the majors, cash flow remained the main source of finance though net debt increased by over USD 100 billion between mid-2014 and early 2017. US independents, with a more leveraged business model, initially saw debt costs soar, but their financial health has improved thanks to efficiency gains and the lower cost of debt. They continue to rely heavily on asset sales and external equity financing.
- **Mergers and acquisitions (M&A) in the upstream oil and gas and electricity sectors, at USD 340 billion in 2016, are helping transform these industries.** In North America, most activity involves oilfield service firms, smaller operators, private equity and purchases by electricity utilities of regulated assets. M&A by Chinese companies is rising, with slowing domestic market growth and a growing interest in investing abroad.
- **Government policies and business models are having a profound impact on the way investment in electricity supply is funded**. In 2016, 94% of global power-generation investment was made with regulated revenues or mechanisms to manage the revenue risk associated with wholesale markets. Over 35% of utility-scale renewable investment benefited from power purchase prices set by auctions, contracts with corporate buyers and other competitive mechanisms, up from 28% in 2011. While virtually all network investment is based on a regulated business model, unbundled grid companies accounted for only 40%, mostly funded by regulated network tariffs, compared with 50% in 2011.
- **India and Indonesia, which are seen contributing nearly 20% of power-demand growth in the next decade, seek to enhance electricity reliability and flexibility with more private investment.** High cost of capital and prices that do not cover the cost of supply hamper investment, but policy reforms and new financing measures aim to reduce risks.

Overview

The first section of this chapter looks at trends in the sources of finance – the structure of financing arrangements, the types of financial instruments used to directly finance assets and their geographic location – for the energy sector investments presented in Chapter 1 (Box 2.1). We also analyse the type of ownership, or providers, of capital, using the financial sponsorship of projects as a proxy for the initial ownership of the investment (ownership of an energy asset can change over time through mergers and acquisitions, asset sales and restructuring of assets into new entities, such as joint ventures). All of these trends are linked to the cost and availability of capital, which remain key to any investment. Our analysis is based on reported data on financial transactions. 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.

Box 2.1 Principal sources of finance for energy investment

WEI 2017 broadly categorises the sources of finance for new energy assets into balance-sheet financing and project financing:

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 the capital markets. It measures the degree to which a company self-finances its assets. In our analysis, balance-sheet financing includes household spending with savings and loans; public financing with tax revenues and bonds; and investments made by holding companies, such as yieldcos, master limited partnership (MLP) and real estate investment trusts (REIT).[1] The funds available from this type of financing depend on the business performance and creditworthiness of an entire entity rather than on an individual energy project.

Project financing involves external lenders – including commercial banks, development banks and infrastructure funds – that share risks with the sponsor of the project. It can also involve fundraising from the debt capital markets with asset-backed project bonds. In practice, the use of project finance can indicate the maturity of the technology, the sheer size of the investment and the presence of well-understood policy underpinning the business model. These structures are generally more complex than investments made on balance sheet. They 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 parent companies of the project.

The first section looks at overall trends in financing for the energy sector as a whole. The remaining sections assess trends in financing and ownership of capital in the upstream oil and gas industry, the electricity sector and renewable generation. The analysis highlights how business models are evolving and how that is affecting the availability of capital

[1] See the section on renewables financing below for an explanation of these types of company.

(funding of investment) in the electricity sector, and how policies are influencing capital allocation in selected countries and regions. The chapter also examines trends in financial transactions, such as mergers and acquisitions and refinancing activity that occur after investments are made.

While trends in energy financing are driven by sector-specific factors, macroeconomic conditions, economic policies in general and wider developments in financial services can have an important impact. For example, financial innovation and low interest rates have played an important role in facilitating investment in oil and gas and renewables in recent years. A particular topic of interest right now is the sustainability of debt-financing models in the face of the rising leverage of some energy companies and the stricter lending requirements of many banks. In line with the recent improvement in prospects for economic growth, the risk of resurgence in inflation and higher interest rates is emerging in some countries for the first time since the 2008 financial crisis. Yet the availability of credit generally remains strong. Faced with slower domestic economic growth, China, in particular, has become a leading source of capital for direct foreign investment, especially in emerging economies with underdeveloped lending markets. But uncertainty about financial factors and the direction of macroeconomic policy adds an element of risk for investment decisions. As always, this risk is particularly pronounced in energy, given the highly capital-intensive nature of the industry and the inherent volatility of energy markets.

Global trends in energy financing

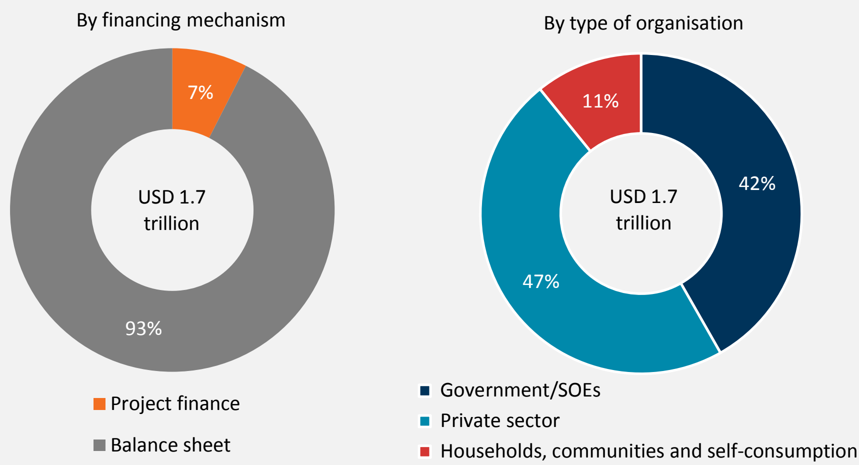
Sources of finance for new investments

In general, energy investments are self-financed by capital incorporated into a company's balance sheet or from private individuals' own assets, whether from borrowing, equity, cash flow or savings. In 2016, balance sheets accounted for over 90% of the USD 1.7 trillion invested globally in energy (including energy efficiency), with the rest coming from project finance – a pattern similar to that of five years ago (Figure 2.1).[2] In the fossil fuel supply sector, 95% of investment, around USD 700 billion, was financed by company balance sheets in 2016, primarily through operating cash flows supplemented by debt, equity and asset sales. 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 capability 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. Energy-efficiency investments in building, transport and industry are nearly all financed by corporate, government and

[2] To estimate the total transaction values of project finance and match them to IEA investment data, reported project-level, primary financing data is combined with reported operational dates or is adjusted using assumptions about construction times. For example, in the absence of a reported commissioning date, an onshore wind-power project, for which a primary financing transaction occurred in 2014, is counted as investment in 2016, based on an assumption of a two-year construction time. Balance sheet financing is estimated as the residual of the total investment less the contribution from project finance.

household balance sheets (though these entities obtain some funding from bond issues), with investments on the balance sheets of specialised energy service companies (ESCOs) playing an important role. Efforts are underway to increase the third-party financing in energy efficiency projects, but are at an early stage in some key sectors (Box 2.2). The electricity sector remains the largest destination for investment based on project finance structures, even though over 85% of total financing is provided by balance sheets.

Figure 2.1 Sources of finance by financing mechanism and type of organisation



While energy investment is largely financed by the balance sheets of corporations or individuals, the role of project finance is increasing in some sectors. Overall, state actors are playing a larger role in the ownership of energy capital.

Sources: Calculations based on IJGlobal (2017), IJ Global Transaction Database, Platts (2017), World Electric Power Plants Database, Bloomberg LP (2017), *Bloomberg Terminal* and BNEF (2017a), Renewable Energy Projects.

Despite this ostensibly stable picture in the aggregate sources of finance, three trends characterise an underlying shift in the financing landscape. First, though the role of project finance has increased only marginally in the past five years for the energy sector as a whole, it is growing in importance in power generation, with lower risk in some emerging economies and the increased maturity of newer renewables-based technologies. Second, the state and other public sector actors are playing a larger role in the ownership of the capital invested in energy projects. Third, the sources of finance for energy assets are also diversifying beyond traditional corporate balance sheets and lending from the banking sector, with innovative debt and equity vehicles allowing assets to tap into larger financing pools from the capital markets. Such instruments are seen as important enablers for investments in smaller-scale assets, particularly energy efficiency and distributed generation.

Box 2.2 Slow progress in attracting finance in energy efficiency

There is huge potential for reducing energy demand and costs through investment in energy efficiency. However, despite sometimes negative interest rates, attracting third-party finance for such investment remains difficult in many cases. Common barriers include the small sizes and heterogeneous nature of projects, raising aggregation costs; difficulties in guaranteeing energy savings, especially if consumer behaviour is uncertain; an absence of tangible assets to be used as collateral or to discourage borrowers from defaulting on their loans; a lack of sufficiently motivated counterparties; and a lack of familiarity about efficiency projects on the part of financers.

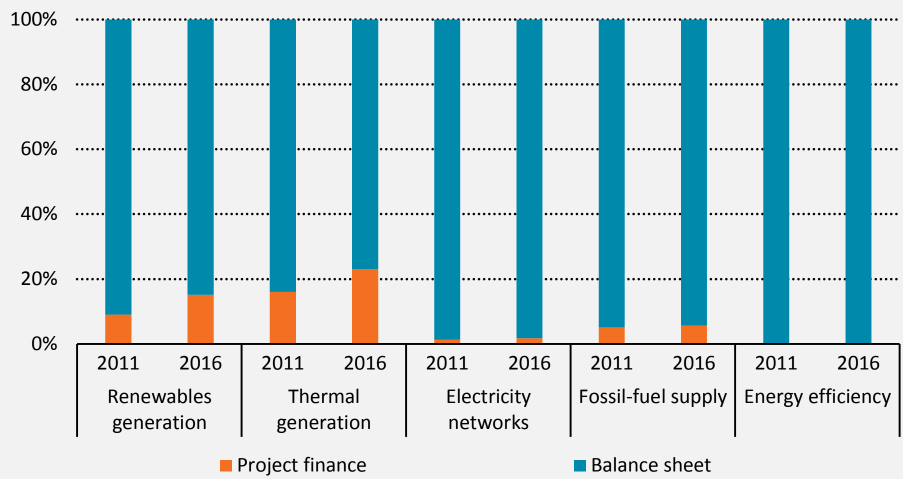
A range of stakeholders, including investors and obligated energy suppliers, are trying to attract more third-party finance to efficiency projects. The aim is to stimulate sustainable long-term demand for projects with a dependable yield. Pay-for-performance is often targeted as the best long-term approach, whereby asset owners or tenants share the savings in energy costs with the project developer for the duration of the loan, which is sometimes paid back via energy bills. However, with exception of projects to replace older lightbulbs with light-emitting diodes (LEDs), determining the value of future savings can be hard. This is starting to change, as smart metering and better data make it easier to estimate savings and in some cases sell them to electricity systems operators as quantified alternative resources to new supplies.

In the United States, the story of energy efficiency financing in 2016 was again dominated by the Property Assessed Clean Energy (PACE) programme, under which there were deals worth USD 1.7 billion, compared with USD 2 billion over the previous six years (PACENation, 2017). PACE ties efficiency and renewable energy costs, which are repaid through tax bills over a maximum of 20 years, to the value of the property. PACE finance, including loans and public bonds, enjoys priority of repayment and bonds, which bundle tens of thousands of projects, yield a return of around 4%. The standardisation of the system has attracted interest from mutual funds and insurers, as well as households; over 90% of the projects involve residential building upgrades. The US financial system and the specifics of its tax code lend themselves to this type of novel financing.

Europe is also exploring options for increasing third-party financing for energy efficiency. In late 2016, the European Commission announced, as part of its energy-policy package, the Smart Finance for Smart Buildings Initiative. Among the aims is the stimulation of a sector that can develop projects, aggregate them for investment and track performance, including through publication of project outcomes in order to address the risk perception of investors (EC, 2016). In Denmark, an energy efficiency investment scheme has been launched by the pension fund PKA with an initial sum of USD 45 million invested via a project developer for building refurbishments. Starting in 2016, the developer, Sustain Solutions, is guaranteeing the performance of the installed equipment – rather than the absolute energy savings – and receives a monthly payment from the building owner (part of which goes to PKA). The scheme is expected to demonstrate yields that are commercially attractive to PKA.

In India, where Energy Efficiency Services Ltd (EESL) has received government and MDB finance to pioneer a model for on-bill repayment of LEDs, an initiative has been launched to extend this approach to procurement and sales of efficient air conditioners (see Chapter 1).

Figure 2.2 Sources of finance for energy investment by sector



The sources of finance and recent trends vary markedly by sector, with project finance gaining ground in the renewables and thermal generation sectors.

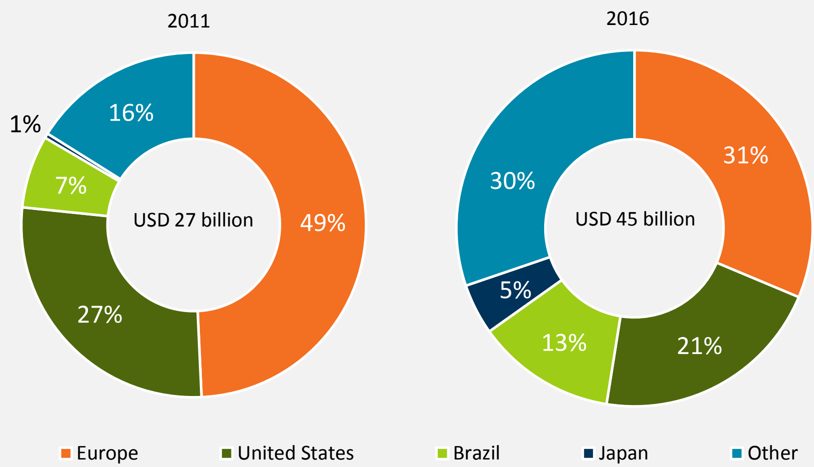
Notes: Fossil fuel supply includes oil and gas upstream, liquefied natural gas, oil refining, oil and gas transportation and distribution, and coal mining and infrastructure. Project finance is measured by reported primary financing for assets that became operational in 2011 and 2016.
Sources: Calculations based on IJGlobal (2017), IJ Global Transaction Database, Platts (2017), World Electric Power Plants Database, Bloomberg LP (2017), Bloomberg Terminal and BNEF (2017a), Renewable Energy Projects.

Project finance is growing only in power generation

Although the value of project-finance transactions corresponding to the 2016 energy investments totalled only USD 125 billion, this amount is around one-fifth higher than in 2011 and masks more dynamic and divergent changes at the sectoral level (Figure 2.2). In the past five years, investment under project-finance structures in fossil fuel supply has declined by nearly 20%, in large part due to the slowdown in investment in upstream oil and gas. Of the USD 42 billion of fossil fuel supply investment stemming from project finance in 2016, LNG facilities accounted for one-third. Project finance is often used to cover at least part of the large upfront investment for integrated LNG projects, which typically cost tens of billions of dollars. For example, Yamal, Ichthys and Cameron LNG projects are among those that were project financed in 2016. Most of the rest of project finance for hydrocarbon supply was in oil refining, though balance-sheet financing accounted for a vast majority of investment in these activities.

While project finance has long been used for large-scale power projects, particularly those based on fossil fuels and hydropower, its overall role in the electricity generation sector has grown only in recent years. At USD 78 billion in 2016, it accounted for nearly one-fifth of generation investment. Since 2011, this amount has grown by 50% and the share has increased by over 50% due to improved market and technology risk factors. Public financial institutions can often play a role in financing such transactions (Box 2.3).

Figure 2.3 Project finance for renewable electricity investment by region



Project finance for renewable electricity generation increased by 60% in the five years to 2016 as government policies enable access to financing notably in the United States, Japan and Brazil.

Note: Project finance is measured by reported primary financing for projects that became operational in 2011 and 2016.
Source: Calculations based on IJGlobal (2017), IJGlobal Transaction Database, Platts (2017), World Electric Power Plants Database, and BNEF (2017a), Renewable Energy Projects.

Thermal generation investments, especially those based on fossil fuels, witnessed a 40% increase in investment based on project finance in the past five years, while balance-sheet financing for such projects declined by 10%. In 2016, project finance accounted for around one quarter of the total investment in the sector, up from around 15% in 2011. Most of this growth occurred in Asia, in particular India and Southeast Asia, where such transactions doubled to USD 15 billion in 2016 and represented 46% of the total project finance in thermal-generation investment. The boom in investment in coal-fired power generation in China over the past decade was fuelled by generation companies' balance sheets leveraged with corporate borrowings from local banks. But this model is proving less viable in other parts of Asia. The attractiveness of project finance is growing in Indonesia, Viet Nam, the Philippines and other emerging Asian economies, as they seek to facilitate investment by independent power producers (IPPs), who often rely on external funding, rather than state-owned vertically integrated utilities (VIUs), whose balance sheets are often too weak to support significant new capital spending (see discussion on Indonesia later in Chapter 2).

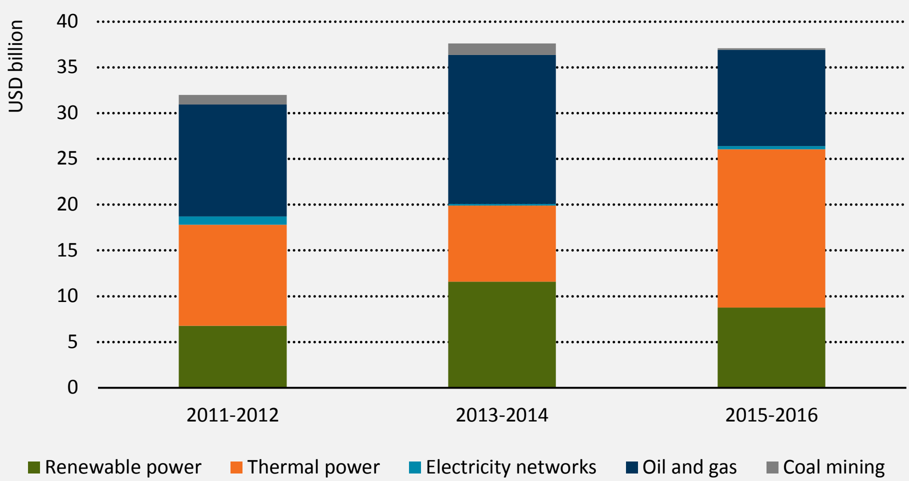
Project finance is also growing for thermal generation in the United States. Whereas overall investment in thermal power has shrunk considerably in recent years in most mature markets, investment in gas-fired power capacity remains strong in the United States.

Around 40% of new US gas-fired generation capacity was financed by project finance structures in 2016, up from 15% in 2011. Project financing is most prevalent in states that have deregulated their electricity sector, typically taking the form of joint ventures of IPPs, private-equity firms and foreign companies in the merchant generation business.

Box 2.3 Are public financial institutions heading in a cleaner direction?

Public financial institutions play an important role, not only providing funding *per se*, but also facilitating external private capital flows. Over 2015 and 2016, public financial institutions – including development banks, development financial institutions and export credit agencies – committed at least USD 35 billion annually to energy-supply investments compared with an average of USD 32 billion between 2011 and 2015 (Figure 2.4).[3] These figures take into account funds committed under project-finance structures that reached financial closure in a given year and should be regarded as indicative relative to the IEA investment data.

Figure 2.4 Public financial institution average annual commitments to energy investments based on project-finance structures by year of financial closure



Public financial institutions continue to play an important role in providing direct funding and leverage private funding for energy projects.

Sources: Calculations based on IJGlobal (2017), IJ Global Transaction Database

Other data sources and qualitative information provide a further indication of sectoral financing trends by such institutions. A number of public financial institutions continue to play a strong role in energy-related climate finance. In 2015, multilateral development banks

[3] The estimates include financial commitments in all sectors of energy supply and are based on IJGlobal (2017), which includes transactions by over 200 public financial institutions and governments.

(MDBs)[4] committed just over USD 10 billion to activities in energy-related sectors, which accounted for more than half of their financing for climate mitigation activities. Of this, USD 6 billion was invested in renewable energy and measures to facilitate integration of renewable electricity, such as smart grids and storage. Another USD 3 billion went to energy efficiency and USD 1.5 billion to the upgrading of transmission and distribution systems and to improving the efficiency of thermal power plants. Climate-related energy finance represents around half of the total energy finance commitments and over 15% commitments for total infrastructure from the MDBs[5] (OECD, 2017). Although this financing fell from 2014 to 2015, these institutions continue to support overall financing of clean energy through co-financing and other activities. Direct financing by the MDBs is estimated to have mobilised more than twice as much climate finance from other sources by enhancing the viability of projects (MDB Joint Reporting, 2016).

Some newer activities by development banks include structuring lending packages around Nationally Determined Contributions (NDCs) under the Paris Agreement and providing advisory and financing packages that aim to de-risk investments in newer markets, such as the World Bank Group's Scaling Solar Program. The Development Bank of Japan recently created a wind power development fund to refinance existing projects with capital from institutional investors. Meanwhile, such institutions also play a crucial role in lending for electricity networks that enhance power system flexibility and integration of variable renewables. In 2016 and the first half of 2017, the European Investment Bank committed to lend over USD 1 billion for transmission projects to connect offshore wind and support the first interconnection between Norway and Germany.

Financing by public financial institutions of fossil fuel-based power generation has been mixed. As the World Bank and public financial institutions in Europe have slowed their own financing of coal-fired plants, global transactions for coal-fired plants benefiting from public finance have remained relatively steady over the past five years, driven by public financial institutions in emerging markets and Japan (IJGlobal, 2017). Chinese banks have been actively involved in coal-fired projects in other Asian countries such as the Philippines, Indonesia, Viet Nam and Pakistan as Chinese engineering, procurement and construction companies seek overseas markets for business opportunities with a slowing domestic market. Chinese public financial institutions have emerged as the largest lender for coal-related projects in the past few years (NRDC and OCI, 2016). By contrast, the Asian Infrastructure Investment Bank, a Chinese-backed multilateral development bank founded in 2016, is not involved in coal-fired power projects. The energy strategy that the bank is currently drafting suggests it would focus on projects in electricity networks, energy efficiency and renewable energy sectors and would consider financing coal-fired power plants only under limited circumstances (AIIB, 2017).

It is important to note that the sectoral activities described above represent only part of the impact of public financing activity in the energy sector, which includes lending to corporate entities by public financial institutions and facilitation of capital from the private sector. In this light, the role of Chinese and other Asian banks is noteworthy. In 2016, the top ten energy projects with a public finance component reaching financial closure were worth a total of over USD 90 billion, and eight involved development banks and export credit

[4] The African Development Bank (AfDB), the Asian Development Bank (ADB), the European Bank for Reconstruction and Development (EBRD), the European Investment Bank (EIB), the Inter-American Development Bank Group (IDBG), and the World Bank Group (WBG).

[5] The six MDBs and the Islamic Development Bank.

agencies in China, Japan and Korea. The project type of such transactions varies from a coal-fired power plant in Indonesia, to large-scale power projects, based on gas and nuclear, in the Middle East. The largest transaction by value in 2016 was the Yamal LNG project in Russia which took up loans from Chinese and Japanese public financial institutions as well as domestic banks.

In renewable generation, investment via project financing worldwide increased by over 60% to USD 45 billion between 2011 and 2016, while overall renewable investment was 3% lower (Figure 2.3). This trend largely reflects the fact that financing solar PV and wind projects has become commonplace, with a better understanding of risk profiles and predictable cash flows under long-term contracts. Project finance has been particularly important in scaling up financing in what is a relatively new industry, where smaller developers with constrained earnings find it harder to finance assets from their balance sheets. This trend is set to continue: project finance transactions for renewables investments were around USD 90 billion in 2016 for projects due to come online over the next few years.

Over half of the increase in project finance for renewables investment has occurred in the United States, Japan, Brazil, Chile and Mexico. Policy support and the availability of long-term contracts for renewables has attracted a range of project developers, from utilities to non-utilities to the market using project finance, whereby they can leverage limited available capital to generate healthy returns on investment (a more detailed discussion on renewables business models is presented later in the chapter). In the United States, a mature market for power purchase agreements (PPAs) whose pricing is enhanced by federal tax credits, has facilitated access to financing. Auction schemes in Brazil, Chile and Mexico and the feed-in tariff scheme in Japan helped attract more external funding in addition to balance sheet financing, by providing predictable cash flows over the long-term. The role of project finance in renewables in China, the world's largest renewables investor, remains negligible, as Chinese commercial banks remain reluctant to lend in such a way.

Europe has seen a modest increase in project finance for renewables investment, while its share has declined dramatically. In 2016 over 60% of the total went to wind projects as government policies to support other renewables technologies have weakened. In recent years, offshore wind has seen more project financing. On average, project finance has accounted for 45% of total investment in offshore wind in the past five years. But this is changing: project finance was used for only one-third of new offshore wind projects that received a final investment decision in 2016, down from 45% the year before, due to an increased role of balance sheet financing by developers. Competitive pressures across the value chain are also changing the landscape for offshore wind financing. Developers are carrying projects on their balance sheets through the development phase and refinancing them with project finance at a later stage. Refinancing activities or the sale of project minority stakes are now incorporated early in the financial arrangements of projects (WindEurope, 2017). This trend is helping to reduce perceived technical risks borne by lenders and can reduce overall financial costs.

Project finance outside the fossil fuel supply and electricity generation sectors remains minimal. A mere USD 5 billion of electricity-networks investment was project financed in 2016, most of going to strategically important large-scale transmission assets (see Chapter 1). In the energy efficiency sector, this report has not tracked any investments based on explicit project finance structures. However, it is important to note that certain public infrastructure projects (e.g. schools and hospitals) that have a large energy efficiency component can be and have been structured and financed by project finance.

The role of state actors in energy investments remains elevated

While comprehensively tracking the sources of finance in terms of their equity and debt contributions to energy investment remains a challenge, analysing the type of organisations providing funds for energy investments, using the initial ownership of the investment, gives an indication of the evolving split of public versus private sources of energy capital. On this basis, we estimate that the share of public sector bodies, including state-owned enterprises (SOEs) in total energy, investment rose from 39% in 2011 to 43% in 2015, and remained elevated at 42% in 2016. That of the private energy businesses fell from 49% in 2011 to 47% in 2016 (Figure 2.1). Nevertheless, the absolute investment level associated with state entities was about 3% lower than in 2011, with the increased share occurring as the total level of investment declined at a faster rate.

The elevated share of state actors is largely thanks to the increased role of SOEs in electricity sector investment, notably in China. Their role in networks investment, at nearly 70%, is rising both in share and absolute investment levels, reflecting growing spending by state-owned grid companies in a number of emerging markets. The share of public bodies in generation investment, at one-third in 2016, has recently begun to moderate, in large part due to lower 2016 investment by Chinese SOEs in coal, wind and nuclear power generation. In all, Chinese SOEs were responsible for 21% of all the investment in the electricity sector in 2016, up from 15% in 2011, but down from over 25% in 2015.

In upstream oil and gas, the share of national oil companies (NOCs) rose to 44% in 2016 from 42% in 2015 thanks to resilient spending in the Middle East and the Russian Federation (hereafter, "Russia"), where NOCs dominate. The share has remained elevated as private oil and gas companies cut back spending more sharply as a reaction to lower oil prices. In addition, the overall reduction in absolute levels of upstream oil and gas spending played a role in boosting the NOC share which was below 40% before the downturn (see section investment by type of oil and gas company).

The share of investment owned by households, communities and commercial and industrial consumers was 11% in 2016, down slightly from 12% in 2011. Their spending in absolute terms was 20% lower than the 2011 level, in large part due to the lower unit capital costs of residential and commercial-scale solar PV, which was not fully offset by an increase in household spending on energy efficiency. [6]

A growing role for capital markets in asset finance

Within both balance-sheet and project-finance structures, energy investments can be financed by debt instruments and listed equity vehicles that are bought and sold on publicly traded capital markets as a means of cost-effectively tapping into much larger capital pools. Capital markets most often take an *indirect* role in funding energy investments through corporate financing activities. Debt instruments and equity vehicles are playing a small, but growing role in *direct* financing of energy assets. In 2016, they accounted for only 4% of financing for new energy investments, but this share is four times higher than in 2011.[7] Listed equity vehicles – such as master limited partnerships (MLP), real estate investment trusts (REITs) and yield companies, or yieldcos, which make investments on their balance sheets – accounted for USD 25 billion of new investment in 2016.[8] Project bonds, a form of project finance where bonds are issued against the cash flows of the underlying asset, represented USD 10 billion of direct investment in 2016 mainly in the fossil fuel supply and power generation sectors, such as the project bond issued for the construction of the Tanjung Bin supercritical coal-fired power plant in Malaysia, which came online in 2016. Relative to the overall issuance of these debt and equity instruments, the direct financing use of these instruments remains small. Nevertheless, their more prevalent usage in corporate finance, where they are often earmarked to investments, and to refinance existing assets, can often have a positive indirect impact on opening up markets to new investors and funding new assets.

Focus on green bonds

Green bonds[9] have gained recognition from policy makers and financiers due to their fast growth and their aim of connecting debt capital markets to companies and projects in energy and other sectors that have environmental benefits. The proceeds from green

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[6] Chapter 1 has an overview of the role of government-funded programmes in energy efficiency spending.

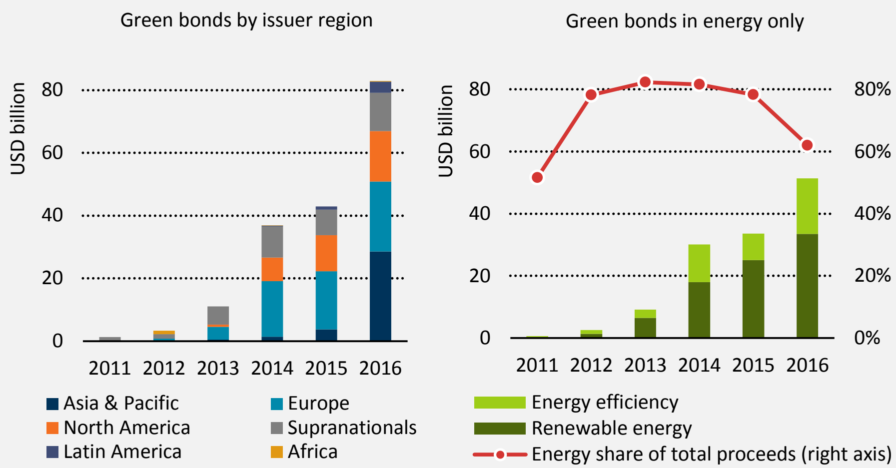
[7] In our estimates of investment financing, this report only includes new capital spending and excludes spending used to refinance existing assets.

[8] Overall, MLPs, REITs and yieldcos are essentially holding companies that are designed to pass through income to shareholders. As such, they are treated more as capital market instruments for the purposes of this analysis rather than traditional corporations investing on balance sheet. MLPs are a partnership arrangement that is publicly traded, combining the tax benefits of a standard limited partnership with the liquidity of publicly traded securities – is mainly used to raise funding for oil and gas pipelines and financing investments on balance sheet, primarily in the United States. REITs are companies that own and finance income-producing real estate-related assets, including energy infrastructure. Yieldcos are companies that distribute a stable dividend stream to investors tied to renewable energy assets with long-term contracted assets and predictable cash flows.

[9] Green bonds cover: corporate bonds, asset-back securities, supranational, sub-sovereign and agency (SSA) bonds, municipal bonds, project bonds, sovereign bonds and financial sector bonds. In this report, only labelled green bonds are discussed; unlabeled climate-aligned bonds are excluded.

bonds are used to fund investments made on balance sheets and in project finance structures and, as such, do not represent a new or additional form of financing. They can, however, 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.

Figure 2.5 Value of new green bonds by region and use of proceeds by energy sector



Growth in green bond issuance in China underpins increase in total green bonds as energy represents the majority of proceeds.

Note: Energy efficiency covers buildings, industry and road transport.
Source: Calculations based on Climate Bonds Initiative (2017), dataset.

The market for all labelled green bonds[10] increased 93% from USD 43 billion in 2015 to USD 83 billion in 2016 with energy as the largest share, despite growth in other sectors, such as climate adaption and water management (Figure 2.5). Green-bond issues in the energy sector alone amounted to over USD 51 billion in 2016, an increase of USD 18 billion, or over half, compared with 2015 and a sharp increase compared with the less than USD 1 billion issued in 2011. Renewable energy represented the largest share of the proceeds used by the energy sector, amounting to approximately USD 34 billion. Several transactions involved the refinancing of wind and solar assets. Energy efficiency accounted for almost USD 18 billion, or 35%, of total issued green bonds in the energy sector, which covers efficiency in industry, road transport and residential and commercial buildings.

[10] Labelled green bonds earmark proceeds for either financing new assets or refinancing existing assets that are linked to environmental/climate activities. The labelling process of green bonds is largely unregulated and can either be self-labelled by issuers or independent opinions can be provided by reviewers.

The geographical concentration of related projects in the energy sector is changing. The green bond market has continued to develop beyond the traditional and relatively-liquid debt markets in Europe and the United States. Asia, led by China, represented the largest source of issuance in 2016 with over USD 30 billion. The growth in China and India in late 2015 and early 2016 benefited from the introduction of national green-bond guidelines, procedures for issuance and recognised standards. Commercial banks drove the majority of issuances to fund loans for projects across a number of sectors issuing financial sector bonds,[11] including renewable energy and energy efficiency.

Both private and public institutions are making increasing use of these innovative sources of finance to either finance new energy assets or refinance existing assets. For example, in 2014, ENGIE issued a EUR 2.5 billion green bond, to date one of the largest issuances by a corporation, with proceeds funding renewable and energy efficiency projects. In 2016, Electricité de France issued a EUR 1.75 billion green bond to raise funds for new renewables assets and NTPC, India's largest power utility, issued a USD 300 million green bond towards wind and solar projects and the associated transmission infrastructure. However, proceeds can provide a means for issuers to refinance existing assets, such as Iberdrola's three issuances (totalling USD 2.7 billion) earmarked for the refinancing of existing renewable energy, transmission and smart-grid assets during the year.

The nature of the green bond market has changed significantly in recent years. Prior to 2013, green bonds were mainly issued by supranational institutions or multilateral financial institutions which helped to establish the market. However, since then, the role of the private sector has increased significantly, with more offerings from corporations and commercial and investment banks in the energy sector. Utilities, which typically benefit from strong capacity to raise capital at competitive rates, high credit ratings and a long history of issuing bonds, made up over half of green bond issuance by energy sector companies in 2016. Green bonds from non-energy issuers with a use of proceeds in the energy sector is growing too; for example, Apple issued a USD 1.5 billion green bond in 2016 and a USD 1 billion green bond in June 2017, with proceeds going towards renewable energy, green buildings, energy storage and energy efficiency projects. The shift from public to private issuance can be attributed to the development of a market-governance structure for the labelling, disclosure of use of proceeds and verification requirements of green bonds. This has reduced transaction costs for investors and alleviated concerns about the environmental integrity of projects and perceived investment risk, while enabling issuers to meet demand from investors with environmental objectives.

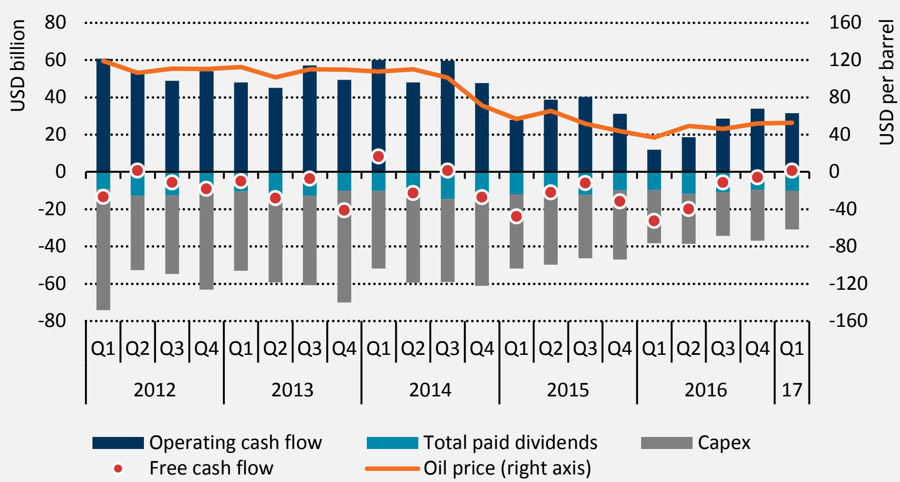
[11] Financial sector bonds are typically issued to finance "on-balance-sheet lending", whereas corporate bonds can provide companies the ability to refinance existing on-balance-sheet assets to free up capital or finance new assets.

Key financial indicators for the upstream oil and gas sector

Sources of finance

The decline in oil prices between 2014 and 2016, while undermining the finances of upstream oil and gas companies, has not structurally changed the way the sector funds its operations. For the seven major international oil companies,[12] operating cash flow remains the main source (Figure 2.6), while the Independents are still largely reliant on external sources of capital, mainly by raising equity and debt. Despite the sector's poor financial performance and the observed loss in stock market value since mid-2014, it remains capable of attracting capital inflows. During the period from mid-2014 to 2016, the sector's finances were stretched to their limits, prompting a number of changes, which by early 2017 had led to a big improvement in the sector's financial performance.

Figure 2.6 Free cash flow of the major oil companies



The majors benefited from internal cost reduction activities and an improved oil price environment towards the end of 2016 and the early 2017.

Notes: FCF = Free Cash Flow. The majors = BP, Chevron, ConocoPhillips, Eni, ExxonMobil, Shell and Total.
Source: Calculations based on company disclosures and Bloomberg LP (2017), *Bloomberg Terminal*.

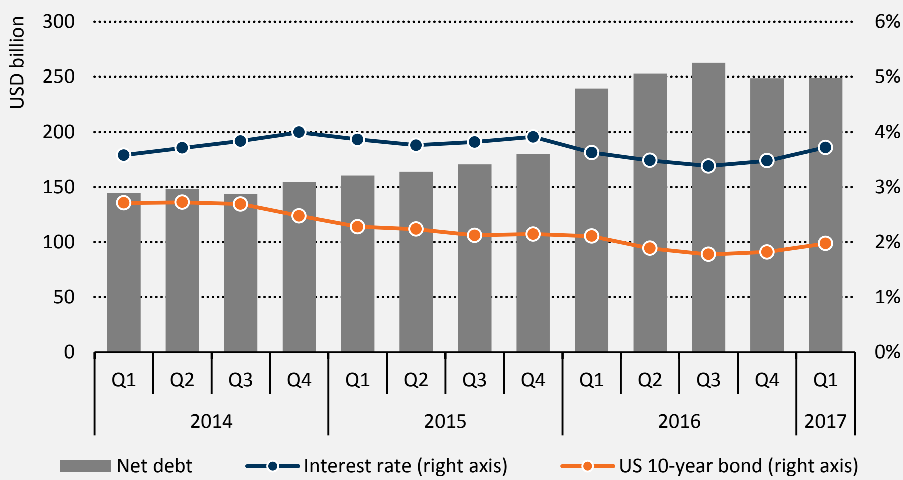
The majors begin to see an improvement in their financial health

The majors' commitment to maintain their dividend policies was a major factor behind the need to issue more debt (Figure 2.7). In 2016, their dividend yields averaged 4%, compared

[12] BP, Chevron, ConocoPhillips, Eni, ExxonMobil, Shell and Total.

with global equity dividend yields around 2.6%, providing an incentive for investors to maintain or expand further their positions in these companies. The success of this policy is reflected in the positive changes in shareholding positions of the top 20 institutional investors in majors that made up 28% of total equity of these companies at the end of 2016, increasing from 23% in 2014 (an increase in nominal shares of 35%) (Figure 2.8). In the wake of the Paris Agreement in December 2015, these trends suggest that large institutional investors still see financial value in maintaining exposure to the oil and gas sector.

Figure 2.7 Net debt of the major oil companies and the average interest rate of corporate debt

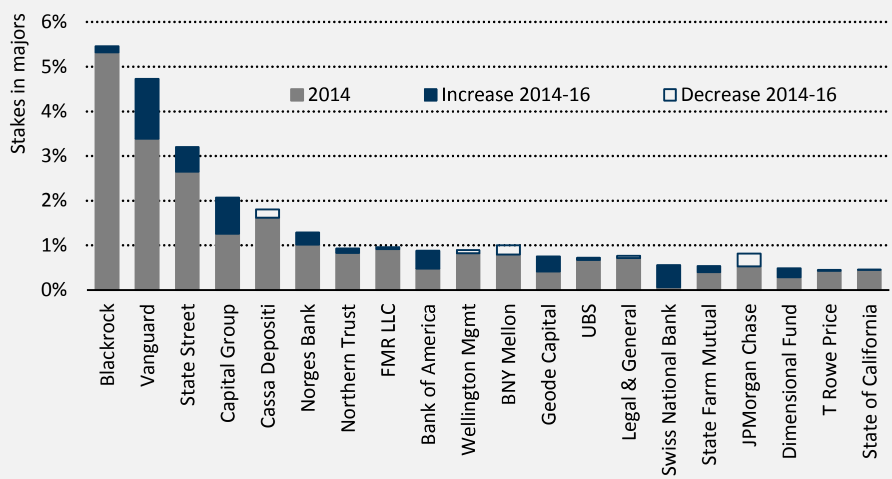


During the oil price downturn, the majors were able to continue to borrow in order to fund their capital spending and maintain dividends.

Notes: The corporate debt interest rate was calculated using the average trailing interest expense of the last four quarters shown on companies' income statements. The majors are BP, Chevron, ConocoPhillips, Eni, ExxonMobil, Shell and Total.
Source: Calculations based on company disclosures and Bloomberg LP (2017), *Bloomberg Terminal*.

While the majors as a whole plan to cut capital expenditures further in 2017, dividend yields have been retained and even increased in the case of Chevron, Exxon, Total and ConocoPhillips. It remains to be seen whether the overall strategy towards stable dividends, combined with low levels of upstream spending, is sustainable given that their financial conditions still largely benefit from cash flow generated by projects sanctioned before 2014. However, in line with cost discipline implemented since the oil price downturn, the majors have partially shifted away from capital-intensive, large-scale projects with long payback periods, to smaller and more flexible projects with shorter investment cycles, which may reshape the profile of cash flows in the future (see Chapter 1).

Figure 2.8 Shareholdings in major oil companies of the top 20 investors



The leading institutional investors have increased their equity stakes in the majors substantially since the oil-price downturn in 2014-2015.

Source: Calculations based on Bloomberg LP (2017), *Bloomberg Terminal*.

Independent US shale producers increase their reliance on equity financing

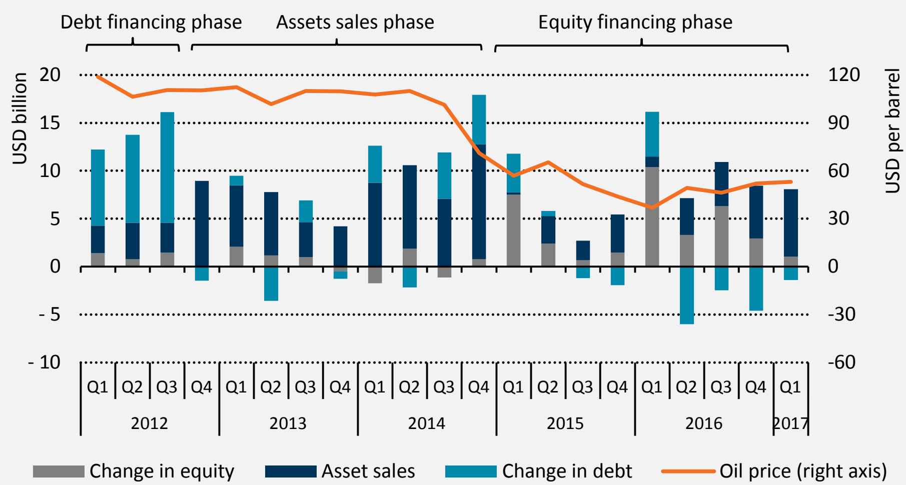
For medium and small companies operating in the US shale industry, the financing model is fundamentally different compared with the large oil and gas companies. US Independents rely on a combination of short-cycle investments, high levels of gearing and hedging[13] production to provide a buffer against commodity price fluctuations. They can initiate new projects in a matter of months, as developments are smaller on average with ramping-up and decline rates much faster than for conventional wells. Maintaining a constant level of production requires continuous investment to compensate for the decline of producing fields.

Expectations of a significant scale-up of production encouraged a rapid increase of investment in the shale industry in the first half of the decade. Our analysis of fifty US independents suggests that their aggregate spending has exceeded cash flow from operations by over 50% since 2012. Since 2013, the Independents have found it difficult to increase leverage further, due to stricter lending requirements by banks and the increased cost of capital. As a result, these companies sold assets to finance ongoing operations and capital expenditures. However, cash inflows from these transactions fell heavily in 2015 as the collapse in oil prices reduced asset valuations. This further undermined their ability to

[13] Companies can hedge their output on the futures market, by fixing a price for future production.

borrow. US Independents have turned to more costly equity issues[14] since 2015 to strengthen operations and finance capital expenditures, with equity investors showing a strong appetite to provide funding for the strongest players.

Figure 2.9 Sources of financing for US shale independents



Independent US shale producers increased their reliance on external sources of financing and, thanks to higher oil prices and lower costs, reduced their net debt position in 2016.

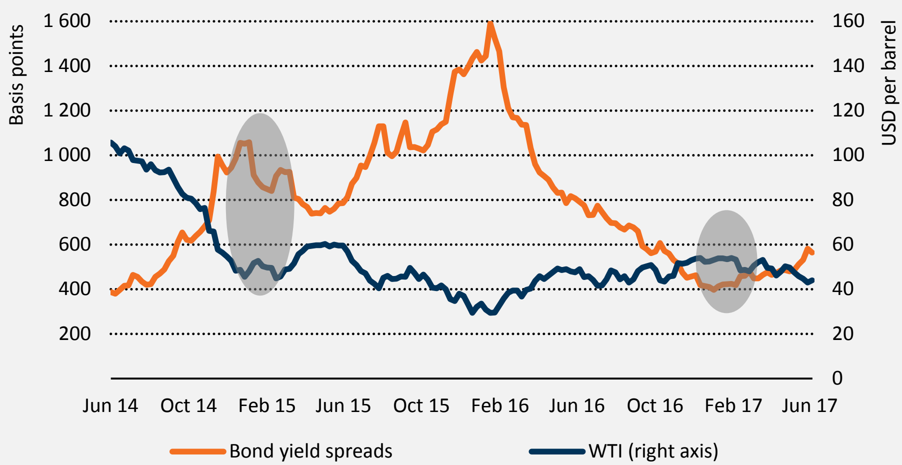
Note: This analysis covers approximately 50 US shale operators, which have more than 80% of their revenues from shale activities, and represents over 60% of US tight oil and shale gas production.
Sources: Calculations based on company disclosures and Bloomberg LP (2017), *Bloomberg Terminal*.

Despite the deterioration of finances during the oil-price downturn, US Independents managed to maintain access to funding (Figure 2.9). Throughout this period, companies have implemented substantial efficiency improvements, reduced headcounts and rationalised their portfolios. These measures allowed them to achieve a better free cash flow than during the period when prices were above USD 100 per barrel, though they still remain highly leveraged. The rise of oil and US gas prices during the second half of 2016 also contributed to a shift in market sentiment, with several operators shifting from survival to growth mentality looking to expand production once again rather than simply survive. The combination of the recovery in oil prices and the results of cost-cutting activities enabled more nimble producers to increase asset acquisitions in productive basins and to deleverage their balance sheets.

[14] Equity is considered more expensive than debt as investors have limited claim to a business and assume more risk.

Investment in shale activities started to ramp up again from the fourth quarter of 2016. The majority of companies, particularly those focussing their activities in the Permian basin, anticipate increasing their capital spending in 2017 at double-digit rates (see Chapter 1). Companies have dramatically reduced the breakeven price of their operations, reduced drilling times and maximised production per well. The improved conditions have also translated into a better market perception, as shown by the reduced bond premiums that US Independents have to pay in order to finance their operations. As of March 2017, yields on high-yield corporate bonds of energy companies, which are representative of the US shale sector, have narrowed significantly – 400 basis points[15] – compared with yields for US government bonds, at roughly the same oil price level as two years prior (Figure 2.10). This suggests that the market has been factoring in the cost deflation and productivity gains that the US shale industry has been able to implement.

Figure 2.10 US Independent bond spreads and the crude oil price



Yield spreads for corporate bonds of US Independents have narrowed significantly since the oil price downturn, compared with early 2015 when the price was at the same USD 50 per bbl level.

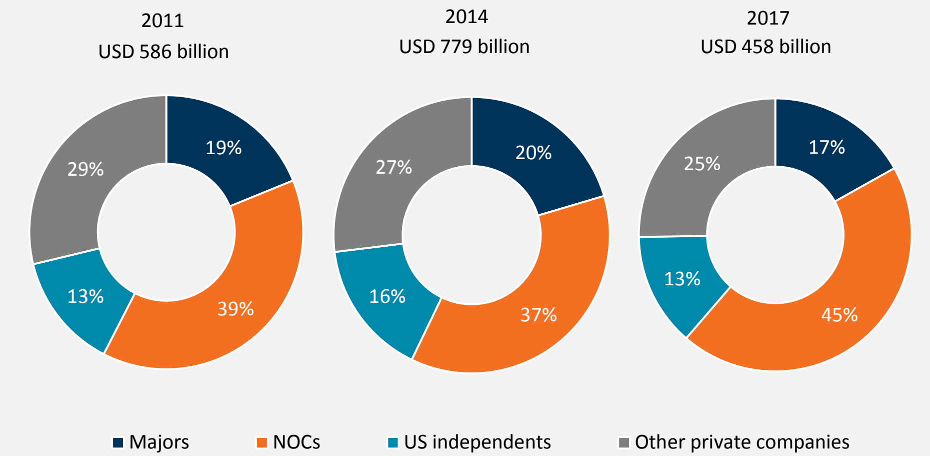
Notes: The bond spreads are the difference between the weighted average of corporate bond yields by market capitalisation and the US government Spot Rate Treasury Curve. The graph shows yield spreads for USD denominated corporate bonds of energy companies with a credit rating below investment grade.
Source: Calculations based on Bloomberg LP (2017), *Bloomberg Terminal*.

[15] One basis point represents one hundredth of one percentage point.

Investment by type of oil and gas company

The ownership of investment in upstream assets has changed substantially in the last few years, reflecting market upheavals, the shifting geography of oil production and differences in the financial health of different operators. The share of NOCs in total upstream capital spending worldwide rose to a record 44% in 2016 and is expected to reach 45% in 2017, largely as a result of continued reduced spending by private oil and gas companies (Figure 2.11).

Figure 2.11 World upstream oil and gas investment by company type



The share of NOCs in global upstream investment is expected to hit a new record high of 45% in 2017 as the major oil companies continue to cut spending.

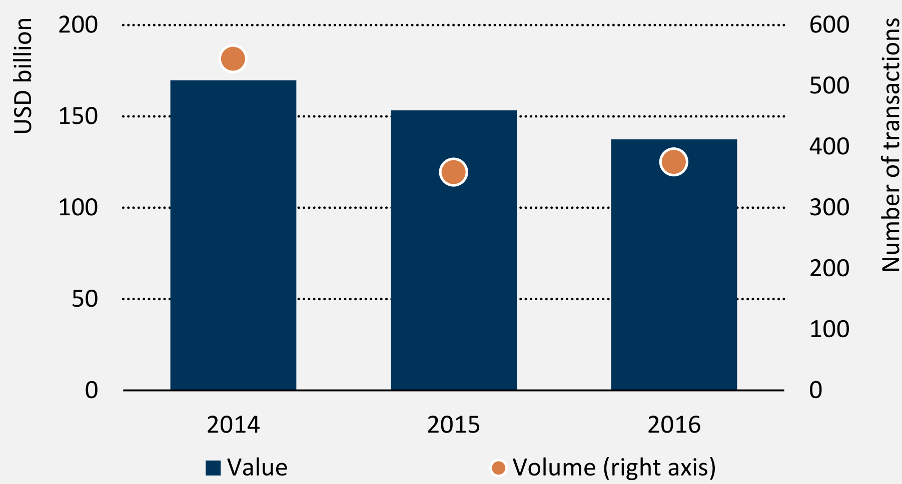
Note: Total investment values are in nominal terms.
Source: Calculated based on Rystad Energy data (2017), *UCube*.

Capital spending held up most among Middle Eastern NOCs led by the Saudi Arabian Oil Company (Saudi Aramco) and the Abu Dhabi National Oil Company in 2016 who have been able to retain access to international debt markets to raise funding in the lower oil price environment. In 2017, Chinese and Russian NOCs will drive the share of the NOCs, supported in many cases by the robust cash flows (e.g. PetroChina, CNOOC, Sinopec and Gazprom) and continued access to debt markets (e.g. Rosneft). The increase in spending by Russian NOCs in USD is in part explained by the appreciation of the ruble compared to very low levels reached in the 2015 and first part of 2016. In the Middle East, equity raising is emerging as a new source of financing. Following Saudi Arabia's announcement of Saudi Aramco's initial public offering (IPO) plan, the Omani government has announced that it is seeking an IPO of Oman Oil, one of its NOCs, in need of external funding to finance investments given the squeezed fiscal balance of the government. Private companies in the region are also looking at this option, with Kuwait Energy announcing an IPO.

Mergers and acquisitions in the oil and gas sector

Since the downturn in oil prices towards the end of 2014, there has been a marked decrease in mergers and acquisitions (M&A) activity across the upstream sector – the consequence of the reduced availability of financing. During the first half of 2016, most operators chose to wait until confidence in the sector returned, as well as a narrowing of bid-to-ask spreads in asset values between counterparties. Towards the end of 2016, evidence of an acceleration in activity emerged as oil prices firmed up.

Figure 2.12 Number and value of global upstream M&A transactions



The total value of upstream M&A transactions dipped in 2016, despite a rise in the number of deals in North America in the second half of the year.

Note: Includes announced and completed deals in which the transaction values were disclosed.
Source: Calculations based on company announcements and Bloomberg LP (2017), *Bloomberg Terminal*.

Total upstream M&A activity fell by almost 10% from over USD 150 billion in 2015 to under USD 140 billion in 2016, despite a 5% increase in the number of transactions (Figure 2.12). Most of the deals involved asset sales rather than company takeovers, as companies sought to optimise asset portfolios and raise capital to fund operations in the face of lower oil prices. Activity was concentrated in North America, driven by small-size operators and private equity where asset values and transaction volumes have risen most in the Permian basin (mainly oil) and Marcellus basin (shale gas) – the result of the particular characteristics of the geology that has favoured efficiency gains, high well productivity and lower costs. Interest from financial institutions as buyers increased to 22% of total upstream M&A transactions by value in 2016, compared to 12% in 2015. The Permian and Eagle Ford basins attracted particular attention from well-capitalised private equity, as traditional operators were capital constrained. Notable deals included RSP Permian's acquisition of Silver Hill Energy Partners, which increased exposure to the Permian basin and Alta Resource's acquisition of Marcellus gas assets, which are both private-equity backed.

While M&A activity in North America was dominated by the Independents in 2016, in the rest of the world, the majors and NOCs accounted for the lion's share of deals, with NOCs being net sellers of assets. Two large deals were closed in Russia, due to the start of large-scale privatisation process initiated by the government that put on sale the majority of Bashneft (acquired by Rosneft) and a 19.5% stake of Rosneft taken by Glencore and Qatar Investment Authority. The disposal programme launched by Petrobras also raised appetite among majors, with both Statoil and Total acquiring stakes in the prolific pre-salt offshore basins. The picture emerging is that the largest corporations have now started to look at specific high-quality assets – such as the USD 6.6 billion acquisition by ExxonMobil of 250 thousand acres in the Permian basin – in order to capture long-term growth opportunities that have been reduced by a low level of investment spending.

M&A activity in the upstream services sector was strong in 2016 as a reaction to reduced activity and significantly contraction of margins, following pricing concessions to operators. Two large transactions – the mergers of the companies Technip and FMC Technologies, and the proposed one between GE Oil & Gas and Baker Hughes – made up the bulk of total M&A transaction value, suggesting that the model adopted by companies targets vertical integration and service differentiation. There are also indications of new operating approaches emerging with increasing risk sharing between operators and service companies.

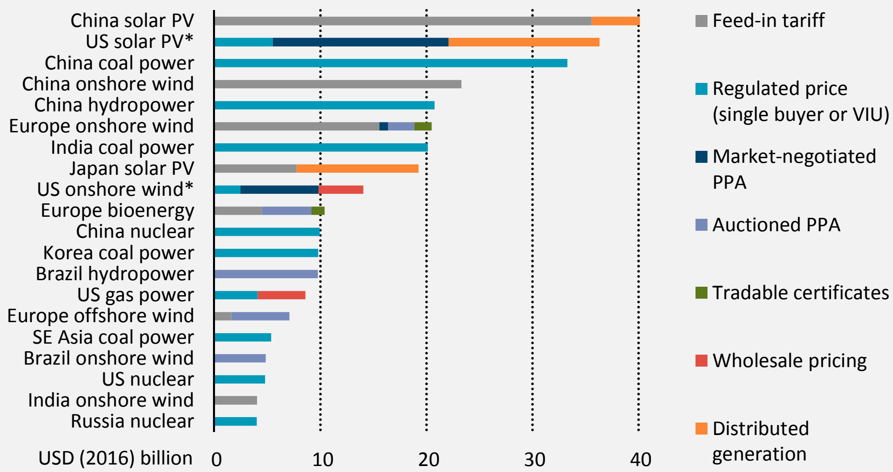
In 2016, three large M&A deals were seen in the North America midstream sector, for an overall value of USD 110 billion (Sunoco Logistics' announced acquisition of Energy Transfer Partners, Enbridge's announced acquisition of Spectra Energy and TransCanada's closed acquisition of Columbia Pipeline Group). Companies involved sought to optimise cost savings, diversify asset bases and cut borrowing costs, given the extended period of pressure on profit margins.

Financing and funding of electricity supply investment

The impact of policy and new business models on funding

Government policies and business models are having a profound impact on the way investment in electricity supply is funded, i.e. how capital is made available for investment. In 2016, 94% of global power-generation investment was made by companies operating under fully regulated revenues or mechanisms to manage the revenue risk associated with variable wholesale market pricing; in 2011 the share was 92%. The top twenty destinations, in terms of market and technology, for power-generation investment, which accounted for two-thirds of the world total in 2016, mostly have contracted pricing that allows for long-term cost recovery of assets or, in the case of the US gas power, wholesale market pricing (Figure 2.13).[16] These mechanisms have played a strong role in enabling the sector to fund the 50% increase in installed power capacity worldwide over the past decade and will continue to do so in the coming years, given that the bulk of final investment decisions on new projects taken in 2016 were in regulated segments and single-buyer markets whereby independent power producers (IPPs) sell their output at regulated or contracted prices to the company that owns and operates all grid assets.

Figure 2.13 Investment in the top-20 power-generation sectors by main business model, 2016



The top-20 destinations for power-generation investment, which accounted for two-thirds of the world total in 2016, mostly have contracted pricing that allows for long-term cost recovery of assets.

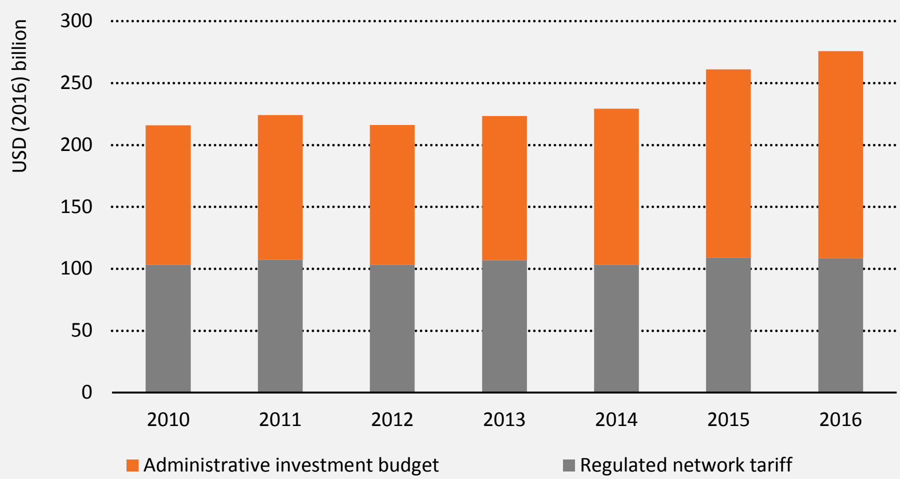
*Renewables in the United States benefit as well from federal tax credits and market-negotiated PPAs are often struck to satisfy utility purchase obligations.
Note: Distributed generation breakdowns are only available for solar PV; VIU = vertically integrated utility; PPA = power purchase agreement.

While virtually all network investment occurs in highly regulated markets, the sources of funding for grid investments have evolved. Five years ago, the sources of funding for investments in electricity networks were roughly split between those largely reliant on regulated network tariffs – in the case of many unbundled markets where independent network operators undertake the large majority of investment – and those made under the

[16] Business models for distributed generation are largely determined by the design of retail electricity tariffs.

administrative investment budget, which is often approved by a government entity, of monopoly grid companies in single-buyer markets (Figure 2.14). Investment by unbundled grid companies has remained stable in absolute terms, reflecting continued needs to modernise the grid and replace ageing assets, and in 2016 represented 40% of total networks investment. In 2016, over 60% of grid investments were made on the basis of the administrative investment budgets of grid companies in single-buyer markets, up from 50% in 2011, reflecting the increased share of China, India and Southeast Asia countries in total networks spending. Merchant network investment represents a small portion of the total, and the analysis does not account for the role that public private partnerships (PPPs) can sometimes play in transmission investments.

Figure 2.14 Sources of funding for investment in electricity networks



While virtually all network investment occurs in regulated markets, over 60% of grid investments in 2016 were made on the basis of the administratively determined budgets of grid companies in single-buyer markets, compared with 50% five years prior.

Overall, significant changes continue to unfold in power generation and in the distribution sector of some countries. Electricity market reforms in several key economies are creating new investment opportunities, notably for private actors. Innovation in policy design for renewables increasingly seeks to balance managing revenue risks faced by investors with meeting policy goals of making electricity affordable and integrating new renewables into the system in a cost-effective way. In countries with established wholesale markets, policies are increasingly focused on securing the adequacy of supply in the face of weak price signals from energy-only markets for investment, including through capacity mechanisms, but this is making business models more complex.

Market reforms in emerging economies are changing investment opportunities

In 2016, nearly two-thirds of global investment in power generation and networks investment took place in countries with single-buyer or vertically integrated systems. This share is set to change in the near future, with China, Japan, Mexico and Korea, which together contribute nearly 40% of global investment, moving towards more open wholesale markets and retail price competition, creating opportunities for new players (Table 2.1). These reforms will have far-reaching effects on financing arrangements.

Reforms in **China**, initiated in 2015, seek to open the electricity market in three ways:[17]

- The buying and selling of electricity will increasingly occur in an independent long-term electricity market consisting of direct sales between IPPs and large consumers – direct power purchases, or DPPs (which has been possible since 2006) – and, since the reforms, via independent electricity sales companies. In 2016, such market-based electricity sales accounted for around 30% of total power generation. In Guandong, the most populous Chinese province, DPPs accounted for about 60% of market sales with the rest transacted by electricity sales companies. In general, negotiated market prices are lower than regulated tariffs, with the largest difference to date registered around USD 30/MWh (CNY 0.189/kWh).18 However, reforms have yet to spawn complementary short-term markets, which would facilitate more efficient dispatch.19
- While traditional grid operators remain the owners of and investors in transmission infrastructure, they are moving towards establishing transparent, fixed pricing for transmission of third-party electricity, which would facilitate the direct sales model.
- The role of private participants in the distribution sector is also growing, with the establishment of about 100 private retail pilot programmes, all of which interact with the centralised grid company.

The long-term impact of electricity reforms is complex, particularly in system operations, but they are already encouraging private participation in selling power. They should also be viewed in the context of additional policy and regulatory measures that seek to slow new coal power development, introduce more competitive mechanisms for funding renewable projects and build out the grid; these dynamics are discussed throughout this report.

Japan introduced full liberalisation of the retail market in 2016, which eliminates boundaries for vertically integrated, regional electricity companies (EPCOs) and opens their markets to new entrants. In 2020, the networks segment of the EPCOs will be unbundled. Reforms, in addition to renewable policies, have started to result in a shift in investment

[17] The forthcoming *World Energy Outlook 2017* will feature detailed analysis on China's power sector reforms.

[18] Electric Power Planning & Engineering Institute, personal correspondence, 2017.

[19] A competitive electricity market that gives incentives for optimal dispatch and investment and that allows market participants to manage the risks related to operation and investment is based on a liquid short-term market and a liquid market for long-term financial contracts (IEA, 2016a).

from EPCOs and reduce their market power in their traditional service areas. In 2016, over 5% of customers switched retail supplier. These trends, coupled with weak demand, are putting financial pressure on the EPCOs. The government will probably need to continue encouraging investment in renewables technologies to meet low-carbon goals, as these can be more difficult to finance when based on revenues from competitive markets (IEA, 2016a). As yet, reforms have not boosted regional interconnections, which remain underdeveloped.

Mexico initiated a restructuring of Comision Federal de Electricidad, the state-owned vertically integrated utility (VIU), unbundling its generation and networks and spreading its assets among new companies. A wholesale market for energy and ancillary services was introduced, but trading remains nascent. Finally, an auction system offering long-term contracts for energy, capacity and clean energy certificates was introduced to attract investment from new players, with locational prices that signal where technologies would bring the greatest value to the power system. Two auctions took place in 2016, awarding nearly USD 7 billion of generation coming online from 2018 – 60% more than the investment in generation that came online in 2016.

Table 2.1 Electricity market reforms and investment in key markets in 2016

	Investment (USD2016)	% Δ vs 2015	Progress of reforms in 2016
China	134 bn (G)	-13%	Expansion of direct sales through provincial wholesale pilots.
	77 bn (N)	+17%	Allow private distribution businesses, initially through pilots.
Japan	25 bn (G)	-21%	Full liberalisation of the retail sector, allowing new entrants in the market for households and small businesses.
	5.7 bn (N)	-15%	
Mexico	4.0 bn (G)	+65%	Unbundling of state-owned VIU and introduction of short-term wholesale market.
	3.6 bn (N)	+55%	Two long-term auctions held for energy, capacity and clean energy certificates.
Korea	17 bn (G)	+120%	Announced restructuring of state-owned VIU and direct sales.
	6.4 bn (N)	-1%	

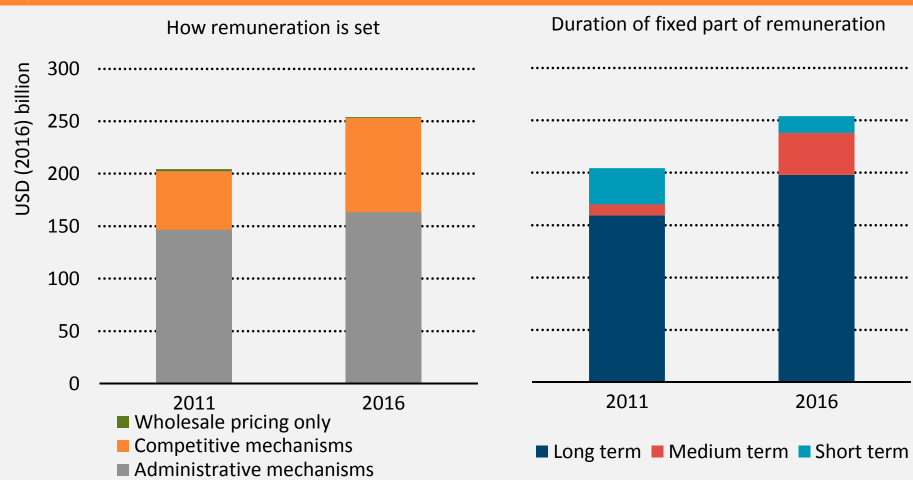
Note: G= generation; N = Electricity networks; VIU = vertically integrated utility.

Finally, electricity reforms are just starting in **Korea** where sales by KEPCO, the state-owned VIU, account for the vast majority of power. In 2016, the government announced that KEPCO would publicly list its generation subsidiaries and orient their investment strategies towards renewables, storage and grids. Reforms will also permit direct sales between IPPs and large consumers as well as address regulated consumer tariffs. Exactly how these reforms will be implemented remains unclear.

Renewables policies place more emphasis on competition and system value

The manner in which renewables-based power is being developed and traded is changing in many markets, which is having a major impact on financing. In some instances, new business models are increasing exposure of projects to market pricing, which can potentially mean higher risks to fully recover their cost, but they are also prompting developers to improve the efficiency of project management and utilise technologies, operations and locations that enhance the value of integrating renewables into the overall electricity system.

Figure 2.15 Utility-scale renewables investment by business model



Over 35% of utility-scale renewable investment now takes place under competitive remuneration-setting mechanisms, and projects largely benefit from fixed pricing over the majority of their lifetime.

Note: Duration = portion asset's economic lifetime covered by fixed remuneration, expressed as long term (≥75%), medium term (50-75%), short term (<50%).
Source: Calculations based on IEA/IRENA *Joint Policies and Measures Database*.

Utility-scale renewables accounted for 60% of power-generation investment in 2016, with policy support increasingly tied to competitive processes for determining the pricing of renewable generation. Remuneration set administratively, e.g. through feed-in tariffs set by the regulatory authorities, still drove the majority of this investment, but one-third was covered by contracts awarded by auctions and independently negotiated PPAs (bilaterally negotiated contracts between IPPs and utilities or corporate buyers), up from near 15% in 2011. Combined with tradable certificates and wholesale pricing, remuneration levels set by competitive mechanisms played a role in 36% of total utility-scale renewable investment, up from 28% in 2011 (Figure 2.15). Nevertheless, despite this role for competitive mechanisms, such business models largely continue to insulate generators from wholesale market pricing risks and can include support, such as tax credits in the United States, that influence price discovery.

This shift towards greater competition in determining the remuneration of renewables reflects the growing use of auctions. Examples include offshore wind in Denmark and the United Kingdom and solar PV and wind in Brazil, India, Mexico and South Africa. Such schemes have been instrumental in driving down costs while reducing investment risks with fixed price contracts. However, given their centralised nature in setting contracted volumes, it is important that these schemes adjust to changing supply and demand situations in the overall energy system (Box 2.4). Non-energy corporations are also emerging as an additional source of PPAs. These trends are likely to continue.[20] For example, China, where renewables investment has been based on feed-in tariffs, has announced plans to move towards more competitive mechanisms, including auctions and a proposed renewable quota on generators and grid companies with tradable certificates for setting remuneration, though developers would continue to face risks related to the grid integration of renewable output (see Chapter 1). Several European countries are introducing auctions, with EU state aid rules prescribing their use for awarding support to most new renewable generators from 2017 onwards.

The duration and predictability of renewable support remains important to reassure investors and attract financing. For this reason, many renewable contracts fix remuneration over a long-term horizon relative to a project's economic lifetime. Globally, over three-quarters of renewable investments in 2016 benefited from support that was predictable over at least 75% of their lifetime. In many emerging markets, power-purchase contracts for solar PV and wind are often set for 20-25 years as a way to reduce risks of revenues falling short of that required to recover the investment. This has been crucial to attracting private developers and raising debt finance in such markets, though does not necessarily address risks that may arise in the sale of power due to resource availability and system constraints.

Box 2.4 Brazil auctions to address changing power market fundamentals

Since 2005, Brazil's auction scheme has been a successful model for stimulating cost-effective investment in renewables. Now, regulators are adjusting the policy design to respond to a changing supply and demand situation. In the decade between 2005 and 2016, Brazil contracted almost 80 GW of new power generation capacity through its public auction system, which represented around USD 75 billion (BRL 260 billion). As a result of the current economic recession in Brazil, the country's electricity consumption has decreased by nearly 4% since 2014, and one reserve energy auction planned for 2016 was cancelled, due to the low demand. Given this situation, the project pipeline resulting from past auctions (including wind, thermal and hydropower projects) raises the potential of a situation of power system overcapacity in the coming years.

[20] The IEA *Market Report Series: Renewable Energy 2017* (forthcoming) analyses such forecast trends.

In response, by the end of August 2017, Brazil plans to hold decontracting auctions, which will award the right to withdraw from power purchase contracts awarded in previous reserve energy supply auctions. Bidders offering the highest payment will be freed of contractual obligations. The Ministry of Mines and Energy (MME) will set the maximum amount to be auctioned based on supply security studies by the National Planning Company (EPE). MME will also publish criteria to differentiate between different technologies – wind, solar and small hydropower – in the selection process.

The auction mechanism itself will award the right of contract annulation based on the sum of 1) the premium offered by the contractor (in BRL/MWh) and 2) the price per MWh (in BRL/MWh) of the project in question. This way the most expensive energy supply projects will have better chances of being cancelled. The mechanism offers an orderly and transparent method to adapt the overcapacity in the project pipeline to actual power generation needs, avoiding the respective additional cost for the power system and, ultimately, electricity consumer.

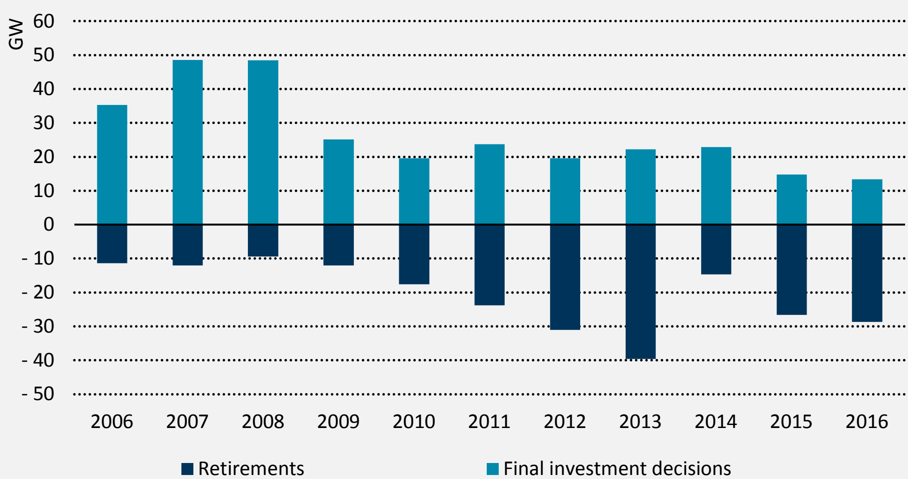
Finally, with some economic growth expected in Brazil over the next two years and the adoption of new auction rules for power generation contracting, including extending the construction and delivery periods for some auctions, the government foresees that auctions for new capacity could restart again in late 2017 or early 2018.

In mature markets, short-to-medium term contracts are playing a somewhat larger role. Greater scrutiny of the financial cost of policy support has led some European countries to offer fixed remuneration over a shorter duration; for example, 15-year contracts for UK offshore wind awarded under competitive processes. In the United States, the most common term for onshore wind PPAs with utilities is 20 years. However, developers are increasingly investing using other structures, such as contracts with corporate buyers, whose duration is typically shorter, and 10-12 year price hedges for projects selling in wholesale markets, when utility PPAs are unavailable (US DOE, 2016). In some cases, policy support is incorporating the exposure of investors to market prices to incentivise more system-friendly capacity. In Germany, though the average duration of PPAs remains long, onshore wind auctions are now awarding variable feed-in premiums, whereby generators receive additional payments in addition to the wholesale market price (giving them exposure to trading risks and imbalance, but limiting risk from movements in the underlying spot price). In its first offshore wind tender in 2017, several bidders secured awards based solely on the wholesale price. Nevertheless, the viability of this business model depends on an allowed long development time to 2024, enabling developers to take advantage of anticipated availability of larger, more advanced turbines, and the provision of the grid connection by the system operator, the cost of which is recovered through electricity tariffs.

In wholesale markets, an increasing focus on reliability and supply adequacy

In countries with established competitive wholesale power markets, such as Europe, the United States and Australia, government policies are increasingly focused on ensuring system reliability and the adequacy of supply in the face of weak price signals from energy-only markets for investment. With growing renewables and often stagnant demand, governments face the challenge of managing the transition for incumbent generation, maintaining the adequacy of supply in the face of planned retirements, facilitating business models that stimulate investment in capacity and flexible assets and ensuring affordable electricity for consumers. Investment in large-scale dispatchable generation plus grid-scale storage in wholesale markets was around USD 20 billion in 2016; in 2011 it was over USD 35 billion. The amount of large-scale dispatchable power (thermal and hydropower capacity) that took final investment decision in 2016, to come online in the coming years, totalled only around 13 GW compared with 23 GW in 2011 and was outpaced by the retirement of existing plants for the fourth time in the past five years (Figure 2.16).

Figure 2.16 Sanctioned large-scale dispatchable generating capacity and retirements in established wholesale markets



In established competitive wholesale power markets, the sanctioning of new large-scale dispatchable power capacity has been outpaced by retirements of existing plants in four of the past five years.

Note: Includes established wholesale markets in North America (Canada, United States), OECD Europe and European Union, and Australia and New Zealand; final investment decisions are estimated on the basis of awarded equipment contracts (coal, gas, hydropower, other dispatchable fossil fuel and renewable generation) and reported construction starts (nuclear). Data may not include projects below 5 MW (below 10 MW for hydropower). Retirements include only fossil fuel and nuclear capacity.
Sources: Calculations for investment decisions based on IAEA (2017), P*ower Reactor Information Systems* (PRIS), and McCoy Power Reports (2017), dataset; retirements based on Platts (2017), *World Electric Power Plants Database*.

The weakness of wholesale prices in a number of these markets, due to overcapacity in some areas, is making it harder for the operators of conventional power plants to recover their investment costs with energy revenues alone, in contrast to low-marginal cost renewables that are typically covered by business models largely based on regulated and contracted remuneration. In some cases, this has prompted the more efficient operation of older, depreciated plants – when consistent with environmental goals – but has also led to asset sales and write-downs.[21] In Europe, with anticipated retirements of over 25 GW of thermal power during 2017-19, and only 0.5 GW of new gas plants sanctioned in 2016, questions persist over whether current market designs can deliver sufficient investment to ensure adequacy even with more renewables capacity, growing demand side participation and improvements in energy efficiency in electricity end uses (see Chapter 4). To this end, some markets, including the Electric Reliability Council of Texas and the Nordic power market are working to enhance price formation in the spot energy markets to ensure that reliability (and flexibility) is adequately rewarded.

Nevertheless, industry sources indicate that obtaining finance for power generation in countries with wholesale markets, whether for new projects or for the acquisition of existing assets, increasingly depends on mechanisms that provide incremental revenue streams. These mechanisms include:

- Contracts for electricity, as well as delivery of heat, steam and compressed air, enabled by district heating networks and local integrated energy networks for industry.
- Tolling agreements (i.e. exchange of energy output for energy input).
- Capacity mechanisms, involving payments for making capacity available to deliver electricity at specific periods.
- Provision of grid and ancillary services.

Options for reliability and supply adequacy: capacity mechanisms and storage

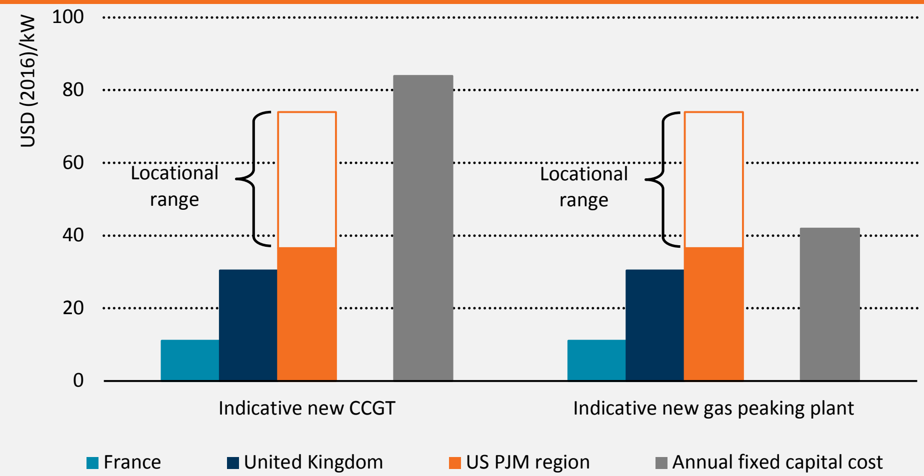
Capacity mechanisms have attracted attention from regulators as a means – in addition to the signal provided by pricing in energy-only markets – of assuring supply adequacy during scarcity periods, but they are generally uncoordinated across markets and can also impact upon efficient price discovery in the wholesale market itself. They remunerate generators, and often demand side response (DSR), by

- Targeted payments for strategic reserves to be used in tight supply situations. They are most common in Europe; for example, Belgium and Sweden.
- Market-wide payments auctioned by a central buyer; for example in the United Kingdom and the US PJM Interconnection (an independent system operator [ISO]).
- Market-wide capacity obligation on suppliers, who can purchase certificates; for example, France.
- Reliability options whereby capacity providers receive a fixed payment in exchange for giving up peak prices during periods of scarcity; for example the US ISO New England.

[21] Operating economics are also determined by relative fuel and carbon prices. In Europe, these factors supported a shift from coal to gas power in 2016 even as total output from these sources grew modestly.

Three market-wide auctions in 2016, which awarded contracts to around 10 GW of new-build and refurbishing capacity for delivery in future years, illustrate the range of price signals that capacity markets provide (Figure 2.17). However, their effectiveness in staying the retirement of efficient generation for economic reasons or stimulating investment in new capacity can be difficult to judge in all cases.

Figure 2.17 Awarded annual capacity payment levels compared with indicative new gas power plant costs in selected markets, 2016



Capacity mechanisms are playing a role in stimulating investment in cases where long-term capacity payment levels are attractive relative to annual fixed capital costs for new plants.

Note: CCGT = combined cycle gas turbine; the PJM Interconnection is a regional transmission organisation that co-ordinates the movement of wholesale electricity in all or parts of 13 states in the eastern US; the range for capacity payments in PJM reflects clearing prices that are determined on a locational basis within the market.

Sources: Calculations based on National Grid (2016), *Final Auction Results T4 Capacity Market Auction for 2020/21*, PJM (2016), *2019/2020 RPM Base Residual Auction Results*, and EPEX SPOT (2016), "EPEX Spot successfully launches first auction of French capacity market".

The third UK Capacity Market Auction awarded capacity agreements to over 4 GW of new-build and refurbishing capacity, double that of the 2015 auction, to be delivered in 2020-21. Investment would consist of mostly gas generation, but also battery storage and DSR, and 60% of agreements for new and refurbishing plants benefit from a 15-year duration. While changes to the mechanism reduced incentives for distributed generation, mostly gas and diesel engines, which were 45% of new-build awards in the 2015 auction, the clearing price (around USD 30/kW/year) tended to support lower cost, but less efficient generators. The average size of awarded generation was around 25 MW, while those that exited the auction at higher prices averaged more than four times larger. Existing assets continued to account for around 90% of awards, and the clearing price supported only a quarter of the new capacity that participated in the auction.

The well-established capacity market in the US PJM region, where total electricity generation is more than twice that of the United Kingdom, saw the award of over 5.5 GW of new generating capacity in 2016. The awards are set by location; the resulting price range would remunerate a significant portion of annual fixed capital costs for a new CCGT to be delivered in 2019-20. In the past five years, PJM has awarded capacity obligations to over 25 GW of new generation, mainly CCGTs (equivalent to 45% of all gas-fired power capacity sanctioned across the United States). Although new assets remain a small part (<5%) of total awarded capacity, 85% of new generators have been successful in receiving payments since 2011. DSR and energy efficiency represent almost 10% of the total. Overall, the PJM capacity market allowed for the timely retirement of over 20 GW of coal power and their replacement by gas power as market participants reacted to anticipated tightening of federal air quality standards on power plant emissions (PJM, 2017).

Another example is France, which held its first capacity auction in 2016. While awarded new capacities were not reported, the clearing price levels and short delivery period (2017) suggest this mechanism is currently not stimulating significant investment in new generation assets, though it may help prevent the closure of existing generation or enhancing the attractiveness of distributed generation and DSR.

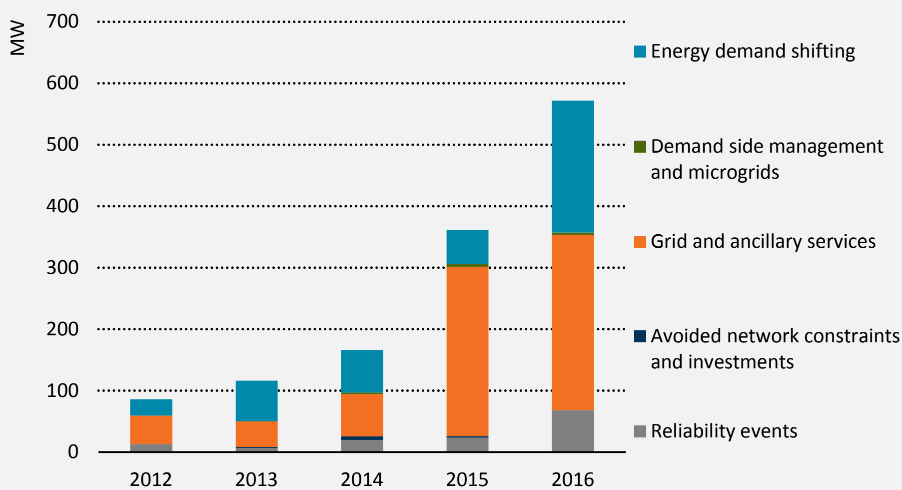
The effectiveness of capacity mechanisms in the future will depend on a number of market and policy developments. For example, the European Commission is considering a rule limiting capacity market participation to generators emitting less than 550g CO_2/kWh, which could affect the role of existing coal-fired power plants in capacity markets. From a broader perspective, improved locational pricing signals and balancing incentives; best practice for system operation; the development of effective instruments to allow trading and risk management over longer timeframes; and investments in electricity networks that facilitate more integrated regional wholesale markets could temper the need for national capacity mechanisms. Market participation by a portfolio of technologies, including storage, DSR and cross-border generation can also address concerns over reliability and enhance system functioning without impeding efficient price formation.

To this end, grid-scale storage is seen as an important potential source for reliability and flexibility and batteries have received a lot of attention due to their modularity and recent rapid technology development.[22] Storage investments rely on a combination of business models that can provide diverse revenues for a project corresponding to the multiple services that they can provide to electricity systems (Figure 2.18). Although its investment was equivalent to only 0.4% of networks investment in 2016, battery storage has been

[22] Storage systems allow utilities to address local needs in terms of demand, reliability conditions, and renewable integration when deployed at the substation level. They can also reduce peak demand, capacity and transmission costs and serve a means to hedge energy prices. Storage at the transmission level can provide frequency regulation and other ancillary services, and help to integrate variable power sources.

growing rapidly with decreasing costs (see Chapter 1). This trend has benefited from changes in the regulatory framework in many instances, including changes to rules that limited wholesale market participation, and improved capability of developers to monetise system services. In the last five years, around 65% of such investment has taken place in established wholesale markets. The main use of this storage is to provide grid and ancillary services, such as frequency regulation, with demand shifting – storing energy during lower demand periods and discharging it during peak times – also an important driver.

Figure 2.18 Main applications of world battery storage investment



The expansion of grid-scale batteries, which are used mainly for frequency regulation and demand shifting, will hinge on policies to reward additional capacity, flexibility and avoided grid cost services.

Source: Calculations based on DOE (2017) *Global Energy Storage Database.*

In many instances, regulators are still trying to work out the best way of stimulating more investment in battery storage. For example, the 15-year contracts awarded to 0.5 GW of battery storage in the United Kingdom and capacity contracts available in US states such as California and Massachusetts have helped finance this new, capital-intensive technology. The UK approach allocates payments based on a centralised competitive auction, while California has enacted utility procurement obligations. In some cases, storage has emerged as a rapid way of addressing energy security concerns – in 2016 California regulators held an emergency tender, which resulted in the commissioning of 70 MW of grid-scale batteries in less than six months, to alleviate severe supply constraints created by the Aliso Canyon gas storage leak. In March 2017, in response to local supply pressures, South Australia unveiled an energy plan which includes direct funding of 100 MW of battery storage and a 250 MW gas-fired plant, among other measures. The state is also home to the development of a 330 MW solar PV plant and a 100 MW/400 MWh battery storage facility that, once operational, will become the largest hybrid plant of its kind.

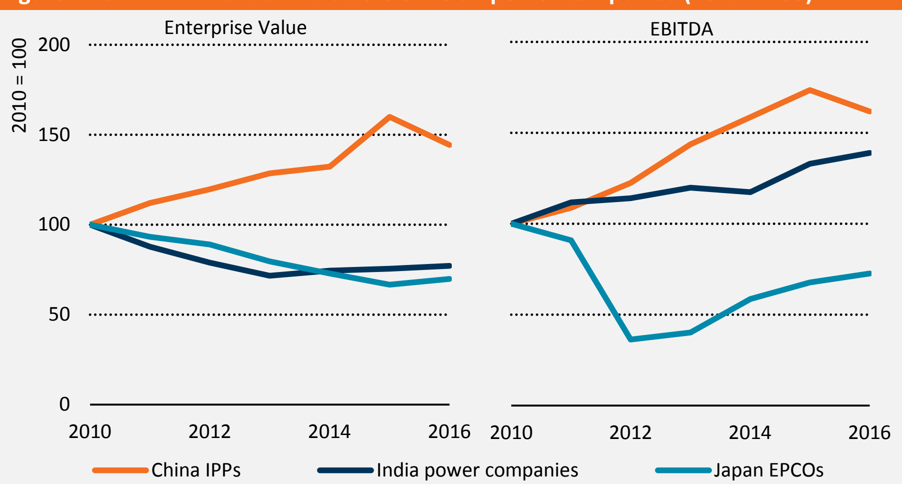
Utility strategies to mobilise finance

The impact of changes in business models and government policy on the financial performance of electricity companies varies across countries and regions. In Asia, revenues for some power companies are becoming less predictable with increased financial stress on incumbent utilities. In Europe and the United States, electricity companies continue to adjust to low wholesale prices and weak demand growth. A number of companies have taken advantage of the low interest rates to transform themselves into more financially sustainable businesses, including through M&A and joint ventures, but no one-size-fits-all model has emerged.

Asian utilities seek out new investment opportunities

In China, where listed electricity companies are largely state-owned IPPs investing in both thermal generation and renewables, generator valuations have been pressured mainly by declining operating hours for coal-fired power, as well as elevated renewable curtailment and greater competition under newer business models (Figure 2.19).

Figure 2.19 Financial indicators of Asian power companies (2010 = 100)



Changing market conditions are undermining the ability of power companies in Asia to invest in domestic markets, with some turning their strategies towards renewables, M&A and overseas opportunities.

Notes: Enterprise value is comprised of market capitalisation and net debt. EBITDA = Earnings before Interest, Taxes, Depreciation and Amortization.
Sources: Calculations based on Bloomberg LP, 2017, *Bloomberg Terminal*.

Additions to coal capacity, an important source of revenue growth until recently, have dramatically slowed, and industry earnings began to level off and decline in 2016. Nevertheless, power companies still benefit from strong cash positions and low levels of debt, thanks to several years of strong profitability for coal-based power with guaranteed hours and, in some cases, capital injections from state-owned parent companies. These conditions remain conducive to robust investment, but Chinese power generators are increasingly seeking out opportunities outside the domestic market.

The financial performance of Indian power companies reflects declining operating hours for coal power, but also risks of selling power to financially strained state distribution companies. Indian power companies increasingly seek to run existing coal plants more efficiently, but also to procure and invest in renewables, while the government is attempting to enhance the health of the distribution sector.

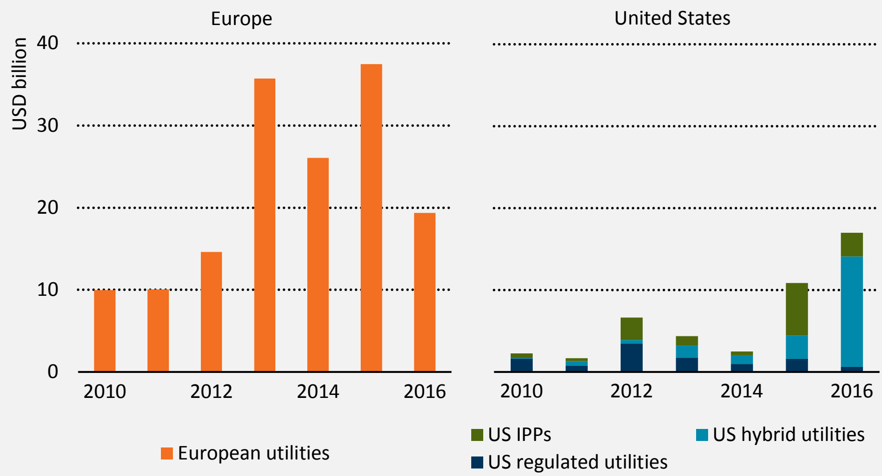
Retail competition reforms in Japan may bring new sources of capital to the power sector, but may also pressure the valuations of EPCOs, whose financial performance has been dominated by the country's nuclear situation since 2011, with a partial recovery in earnings. Some industrial consolidation has started, with a joint venture between Japan's largest (TEPCO) and third largest (Chubu) utilities by revenues.

European utilities are turning the corner

In Europe, utilities are pursuing different paths to ensure long-term financial health. Since 2011, they have written down over USD 130 billion of assets, reflecting unprofitable market conditions for thermal generation, which accounted for around half of the total losses. Companies with business models based on regulated and contracted network and renewables assets with stable cash flows mainly enjoy higher market valuations than those exposed more to wholesale-market risks. A recovery in power prices and margins for gas-fired power, particularly in the second half of the year, slowed the pace of write-downs to USD 20 billion in 2016, compared with a record of over USD 35 billion in 2015 (Figure 2.20). But low interest rates and reductions to regulated rates of return in some markets (Germany, for example), may pressure the financial performance of some network assets.

This financial backdrop, along with wider business model trends, has prompted the European industry to adopt new corporate strategies, including a shift towards contracted and regulated revenue sources, implement cost-reduction programmes and restructure itself. In 2016, the initial public offerings of new spinoff companies from the German utilities, RWE and E.ON, in response to severe financial constraints, created distinct businesses separating merchant generation from regulated networks and renewables assets. The equity listing of state-owned DONG Energy in Denmark raised its prominence as an international player focused on offshore wind with a long-term stated interest of divesting from oil and gas. In recent years, Spain's Iberdrola and Italy's Enel, who had previously spun off renewable businesses, ultimately found greater financial benefit from reintegration, with reduced exposure to businesses based on competitive markets. Several European electricity companies have invested in new digital technologies in networks, retail and power generation.

Figure 2.20 Asset write-downs by European and US power companies



Asset write-downs slowed in Europe in 2016 with the recovery in wholesale power prices, while they have grown in the United States over the past two years.

Note: Includes asset impairments on plant, property, equipment and intangible assets of global operations.
Source: Calculations based on Bloomberg LP, 2017, *Bloomberg Terminal*.

US utilities' strategies depend on different state policies

US power companies face some of the same competitive threats as in Europe. However, their financial performance and strategies reflect the diverse regulatory landscape across US electricity markets. For the utilities mainly operating in regulated markets, stock-market valuations have generally been more favourable, reflecting higher earnings expectations from regulated assets. Hybrid utilities operating in both regulated and competitive markets have generally seen strengthening valuations, reflecting their mix of income from contracted and wholesale pricing, though some have recently seen significant losses. IPPs with earnings largely derived from wholesale markets have seen more stagnant valuations with asset write-downs, mainly related to coal plants, on the rise in the past two years (Figure 2.19). Unlike in Europe, investment in new gas-fired power capacity remains significant.

Utility strategies remain diverse and depend on policies, focusing either on networks with regulated returns, renewables or acquiring smaller companies with such assets. Driven by demand from corporate consumers, regulated utilities are increasingly investing in renewables and offering renewable purchasing options through green tariffs, 13 of which have been proposed or approved across 10 states, up from zero just five years prior (WRI and WWF, 2017). Several hybrid utilities are also increasing retail-level activities, such as distributed solar PV, storage, demand side management and electric vehicle (EV) infrastructure. In early 2017, California's major investor-owned utilities sought regulatory approval for USD 1 billion in EV charging investments. Hybrid utility Nextera has been aggressive in developing renewables. Meanwhile, FirstEnergy announced in 2016 a full transition to regulated business, in the wake of large losses for coal and nuclear assets, which would convert existing thermal generation to regulated and contracted structures, sell unprofitable assets and focus on grid investments.

In early 2017, the federal government signalled a shift in national energy and climate policy, including a review of the Clean Power Plan. Nevertheless, the ten-year strategic focus of most utilities largely remains focused on increasing renewables, storage and gas generation, with any perceptions of improving coal prospects largely based on the expectation of being able to run existing coal plants longer (Utility Dive, 2017).

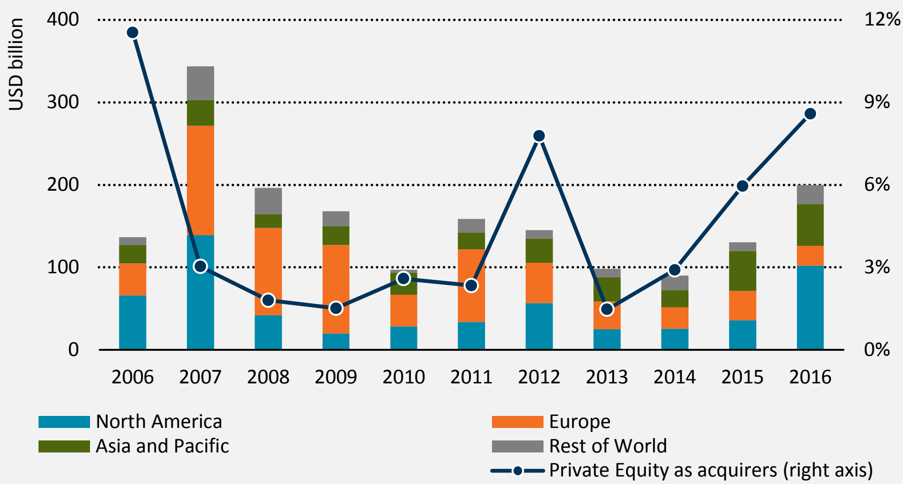
Global M&A activity booms with changing utility business models

M&A activity is one indicator of changing utility business models. At USD 200 billion in 2016, global M&A activity in the electricity sector was at its highest level in nearly a decade, equivalent in dollar terms to over a quarter of the investment in new electricity assets (Figure 2.21). The previous surge in M&A in 2007-09 was mainly due to the restructuring of the European electricity sector as utilities sold off transmission network assets in response to an increased regulatory burden and aims to enhance their competitive position in the new internal energy market.

While activity in Europe remained important in 2016, reflecting sales of some German utilities and the acquisition of several large renewables projects, almost 90% of the transactions involved targets in North America, Asia and newer regions such as Latin America.

This geographical shift in M&A activity reflects the relatively strong balance sheets of US companies, which accounted for 30% of asset purchases, and cross-cutting factors. Private equity and infrastructure funds, which have higher risk tolerance than power companies, have emerged as a growing source of refinancing and accounted for almost 10% of acquisitions, including some notable acquisitions of plants operating in US wholesale markets. Another important trend is the role of Chinese companies in M&A. In 2016, their acquisitions rose to over USD 25 billion, more double the level of 2011, with around 30% of the assets located outside China. This trend reflects declining profitability in the domestic electricity market and government encouragement to enterprises to invest abroad.

Figure 2.21 M&A in the electricity sector by region of targeted entity



Global M&A activity in the electricity sector rose to its highest level in nearly a decade in 2016, with almost 90% of the transactions in North America, Asia and newer regions such as Latin America.

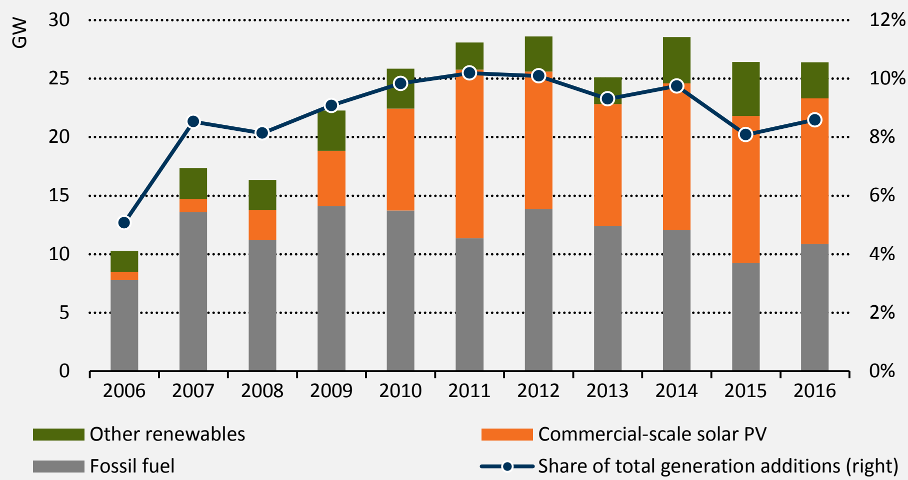
Note: Includes the value of reported completed transactions where an electricity sector company is the seller, acquirer or target entity; includes company spinoffs and joint ventures.
Source: Calculations based on Bloomberg LP (2017), *Bloomberg Terminal*.

The role of corporations in electricity sector investments

Companies other than the traditional utility and independent power generators (utilities and IPPs) are taking an increasing involvement in shaping their power supply options. Traditionally, large companies and public-sector organisations, such as universities and hospitals, purchased electricity under contracts with utilities or procured it directly from offsite IPPs or onsite generation. The two latter options based on direct procurement can be attractive for companies, such as those in heavy industry, with particular demand profiles, or located in places where grid-based power may be unreliable, e.g. in India. The gross additions of generating capacity of all types directly serving corporate commercial and industrial facilities, as well as public entities, is estimated to total over 25 GW in 2016 – nearly 10% of all global generation additions (Figure 2.22).23 This share has remained broadly consistent in recent years. Renewables, now 60% of new capacity in this segment, have grown in importance, largely due to commercial-scale solar PV, whose additions represented nearly half of the total.

[23] The total annual additions presented in Figure 2.22 are likely an underestimate given challenges in tracking small-scale diesel and gas generators or direct power purchase of fossil-fuel power from entities other than utilities. It is also important to note that not all onsite generating assets contribute to meeting self-consumption needs; for example, distributed solar PV may supply power exclusively to the grid under feed-in tariff schemes.

Figure 2.22 **Power generation capacity additions to directly serve commercial, industrial and public consumers**



Generation directly serving companies and public entities was 10% of all new additions in 2016; it can be attractive for consumers with particular demand profiles or in places where grid power is unreliable.

Source: Calculations based on Platts (2017) *World Electric Power Plants Database*.

Corporations, in particular, are pioneering new ways of procuring renewable electricity. Companies are now taking on greater roles in setting clean energy targets, independent of government plans, for their own consumption and in serving as credit-worthy off-takers for power supplies. While most of this procurement follows traditional form of purchasing and contracting, some companies are creating new models for energy procurement. These trends serve as a driver for renewable market development, in general, and provide developers of these assets with a new and additional remuneration mechanism, which can be important for investment as government support policies evolve. For the electricity system as a whole, the participation of a more diverse set of actors with a particular demand for renewables places greater emphasis on efficient grid operating and management.

Corporate PPAs present a new opportunity for renewables investment

The number of companies announcing targets to source renewable power has grown rapidly in recent years. At the beginning of 2017, nearly 90 corporations, with collective demand over 100 TWh (more than the consumption of the Netherlands or the United Arab Emirates) had committed, under the RE100 initiative, to matching 100% of their global electricity use with power produced from renewable sources; in 2015, only 15 companies had made such a commitment (The Climate Group, 2017). In 2016, 48% of the 500 largest US companies by revenue (The Fortune 500) had established a quantitative target to increase renewables consumption, energy efficiency or decrease greenhouse gas emissions, compared with 43% in 2014; those with renewable-specific targets rose to above 50 companies in 2016, compared with nearly 40 in 2014 (WWF et al., 2017).

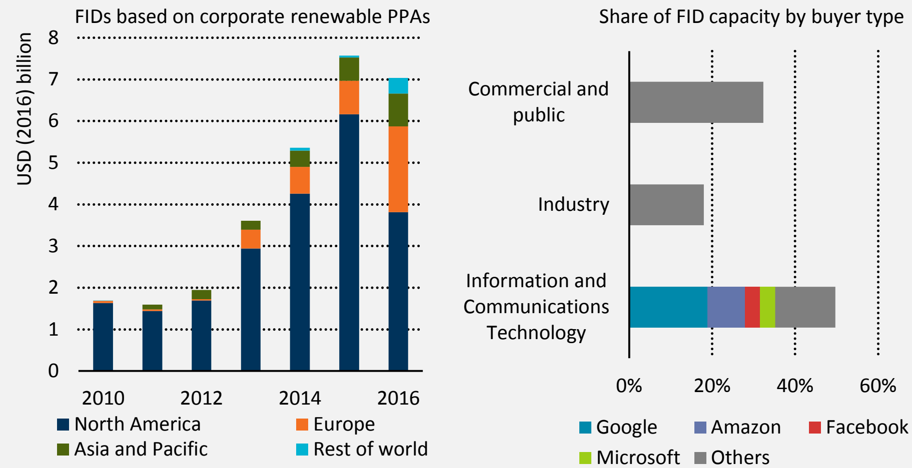
Companies look to procurement of renewables-based electricity for a variety of reasons: to protect themselves from the volatility of power prices (particularly in high power price environments), to diversify supply and to meet their own internal clean energy targets. For many, sourcing clean power to run their businesses is seen as responding to consumer demand and enhancing the value of their brand and their overall supply chain. Information, communications and technology (ICT) companies, who sometimes face double digit annual percentage increases in electricity demand and have data centres with relatively flat 24-hour demand profiles, have found particular value in renewables procurement. Of the top 50 ICT companies by revenue (roughly 40% of total ICT industry revenues), at least twenty have quantified renewable procurement goals and eight of them have pledged to source power based on 100% renewable electricity. For renewables project developers, these new customers can help facilitate debt and other finance in the absence of long-term financial incentives from governments.

To meet renewable purchase targets, companies have taken a variety of approaches, which involve financial transactions as well as physical delivery of power. For example, companies within the RE100 were reported to consume 60% of their 2015 renewable power through purchases of renewable certificates or guarantees of origin, which provide an accounting claim on power produced from a renewable facility, and another 35% through green electricity contracts or tariffs with utilities, where such products are linked to renewable projects and certificates (The Climate Group, 2017). However, these approaches, while attractive for their ease of transacting, do not always provide clear evidence of renewable investment (i.e. additionality of new renewable capacity), which is specifically linked to a given company's consumption, nor do they necessarily provide predictable pricing for the electricity consumed.

To capture these benefits, large companies are increasingly turning to new methods of procuring renewables. One option is to invest in renewable assets on their own premises, though the scale of such projects is often limited by space constraints and resource availability. Another option is investment into larger offsite projects, though this can often involve tying up capital outside of a core business area. As a result, newer structures in the form of corporate PPAs with large-scale renewable projects, in competitive markets, and green tariffs from utilities or direct access contracts with third parties, in regulated markets, that demonstrate clear additionality have emerged as a fast growing trend to satisfy this demand.[24]

[24] Such transactions in North America largely consist of *financial PPAs* (e.g. contract-for-difference) where the end-user buys power from the utility, the developer supplies power to the grid and the two parties settle the difference versus a strike price. In some cases, parties enter into a *physical PPA* where the end-user pays the developer for electricity and the utility or another third-party for balancing and delivering the physical supply. There is no one-size-fits-all model and most buyers combine different contract types, sizes, and locations to suit demand profiles and sustainability goals.

Figure 2.23 Final investment decisions based on corporate renewable PPAs by region and type of buyer



Corporate buying via PPAs has accounted for the sanctioning of over USD 30 billion of new utility-scale renewables over the past decade, led by technology firms looking to hedge power price volatility, diversify supply and meet in-house sustainability goals.

Note: Includes projects based on utility green tariffs in the United States, shares by buyer type are calculated based on contracted capacity.
Sources: Calculations based on RMI (2017), Business Renewables Center dataset; BNEF (2017b), *EMEA Corporate PPA Database*, Platts (2017), *World Electric Power Plants Database*.

Globally, the cumulative spending associated with large-scale renewable projects taking final investment decision based on a PPA with a corporation has totalled more than USD 30 billion in the decade through 2016, based on around 16 GW of new capacity, with two-thirds of this coming in the past three years (Figure 2.23).[25] Since 2011, over 10% of the top 100 US companies by revenue have signed such contracts; in Mexico, large industrial users have contracted a significant portion of new wind capacity using direct procurement methods. Interest is now growing in other regions. In 2016, corporate renewables PPAs supported the sanctioning of 3.8 GW of new renewable capacity in 2016 – slightly below the level of 2015, but six times higher than five years ago. In 2016, rapid growth in Europe, where contracting of offsite renewables nearly tripled, offset some of the US decline, due to uncertainty over the renewal of a tax credit at the end of 2015 and low power prices.

[25] This figure also includes capacity associated with green utility tariffs in US regulated markets, which represent a smaller but growing amount of contracting activity (around 0.2 GW in 2016).

Electricity policy and system considerations shape corporate renewable procurement

Corporate renewable procurement is shaped by a number of local policy and market factors (Table 2.2). Corporate buying based on PPAs, in particular, has sprouted in those places, such as the United States, with clear rules for contracting and reselling power and utilities who provide billing, balancing and physical delivery services. These arrangements are far more common in US states with organisational structures based on wholesale markets and retail competition, such as such as Texas and Illinois. The leaders in Europe are Norway and Sweden, where a joint green certificate scheme allows for separate power and certificate contracting, and the United Kingdom, where corporate PPAs offer an alternative fixed price for onshore wind and solar PV projects excluded from the Contract-for-Difference scheme. In other European markets, a transition from feed-in tariffs, which tend to crowd out corporate PPAs, to market premiums may boost future demand. Measures under the EU clean energy package, proposed in 2016, may further facilitate PPAs. Proposed access to renewable guarantees of origin and clear rules on their retirement will be particularly important for the development of renewable procurement in EU countries, and would enable corporations to have clear renewable claims, demonstrate progress against internal targets and avoid issues related to double counting.

There is a large potential for corporate procurement of renewables-based power in Asia. In China, market reforms to stimulate direct sales between IPPs and large consumers could offer a new market for renewables, as developers of onshore wind and solar PV face significant risks of curtailment and potential reductions in future incentives. Up to now, most direct sales have involved coal-fired power. Hydropower in Yunnan province and wind farms in Inner Mongolia are already participating in direct sales, though it is uncertain how much new investment these arrangements are stimulating.

The clarification of rules for third-party contracting of renewables and fees associated with "wheeling" power via the transmission and distribution grid by the grid operator, as well as institution of a proposed renewable quota with tradable certificates, applied to generators and grid companies with adequate design and implementation, could help spur development. India is another potentially large market for corporate renewables procurement, with over 45 GW of captive power for self-consumption, mostly coal power. Corporate renewable procurement is starting to play a larger role – for example, in 2017, the Delhi Metro Rail Corporation contracted for nearly a quarter of a 750 MW solar PV project tendered in Madhya Pradesh (see next section for further details). But expanding the direct purchasing of renewables hinges on the long-term modernisation of the distribution sector, the consistent allowance of third-party contracting and implementation of predictable grid charges.

Corporate renewables buying represents just a part of the investments consumers are making to shape their energy-supply options, including those aimed at enhancing energy efficiency, and transaction types are likely to evolve in the future. In some cases, rising renewables demand from large corporations is driving changes in utility tariff offerings for customers, in reaction to business locational decisions. To date, most corporate buying has been carried out by large enterprises rather than smaller corporations, due to the complexity of transactions. Two key barriers for smaller corporates to procure renewables through PPAs are the long-term tenor of the contracts and limited access to credit. Future transactions may include schemes based on community purchase, industrial consortia buying together and aggregation schemes to help distribute risks and lower transaction costs. In Europe, a newly sanctioned wind farm in the Netherlands in 2016 involved an innovative consortium of four different companies from diverse sectors.

Table 2.2 Market and policy drivers of corporate renewables-based power procurement in selected countries

Country	Ownership[1]	Third-party access[2]	Grid wheeling & banking[3]	Tracking and certification of renewable attributes[4]	Utility green tariff offering[5]
Brazil	🟢	🟡	🟡	🟡	🔴
China	🟢	🟡	🟢	🟡	🔴
India	🟢	🟡	🟡	🟡	🔴
Indonesia	🟡	🟡	🟡	🔴	🔴
France	🟢	🟢	🟡	🟡	🟢
Germany	🟢	🟢	🟡	🟡	🟢
Japan	🟢	🟢	🟡	🔴	🟡
Mexico	🟢	🟡	🟢	🟢	🔴
Norway/Sweden	🟢	🟢	🟢	🟢	🟡
United Kingdom	🟢	🟢	🟢	🟡	🟡
United States	🟢	🟡	🟡	🟢	🟡

🟢 Fully available 🟡 Partially available or available only in some states 🔴 Not available

[1]Regulatory environment allows corporations to own and operate generation on-site and off-site.
[2]Independent power producers may sell power to independent electricity sales companies and enter direct contracts with corporations.
[3]Grid wheeling & banking: Provision of transmission services that match the purchasing terms of electricity and allow for virtual accounting of electricity between a producer and supplier.
[4]Frameworks for renewable certificates or guarantees, which provide an accounting claim on power produced from a renewable facility.
[5]Utilities actively offering green tariffs.

Sources: Assessment based on *IEA/IRENA Joint Policies and Measures Database*, 21st Century Power Partnership (2017), *Policies for Enabling Corporate Sourcing of Renewable Energy Internationally* and WBCSD (2016), Corporate Renewable Power Purchase Agreements: Scaling up globally.

Finally, the potential for corporate demand for renewables to outpace that anticipated by the system planning of regulators and utilities could raise integration challenges. But there are also benefits: additional demand from data centres, for example, may actually improve the efficient use of wind power during night periods (IWEA, 2015) and such assets could, with appropriate market frameworks, provide services to the grid. The evolution of electricity tariffs, with appropriate allocation of network and balancing costs, a growing role for market aggregators – who combine and trade power from many assets – in some regions and the development of robust, flexible networks and adaptive renewable policies will all be important factors in shaping the future market.

Focus on financing electricity investment in India and Indonesia

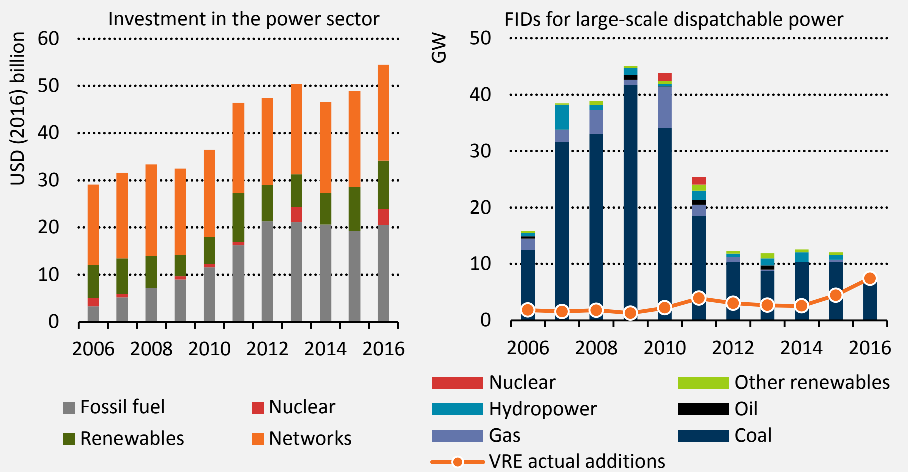
Both India and Indonesia are seeking to augment the reliability and flexibility of their power systems and enhance access to affordable electricity. The two markets accounted for 8% of power investment in 2016, but are seen in the *World Energy Outlook* as comprising nearly a fifth of global demand growth in the next decade (IEA, 2016b). Private investment with business models based on long-term contracts are expected to play a stronger role in meeting these goals, but under distinct regulatory structures and with varying roles for renewables integration. A high cost of capital and the poor cost-reflectiveness of electricity pricing remain important barriers in both countries.

India: financing a flexible system for the transition to low-carbon power

India is organised around a single-buyer model of state distribution companies. The government's energy strategy is focused on the cost-effective deployment and integration of large amounts of renewables to meet growing demand, diversify supplies and improve air quality. Peak electricity load grew nearly 13% over the past two years as demand from a growing middle class for new energy services, such as air conditioning, which place higher demands on the system, expands (see Chapter 1).

India has set a target of more than tripling the output of renewables-based power – mainly solar and wind, but also bioenergy and small hydropower – from 50 GW in 2016 to 175 GW in 2022. In addition, large hydropower capacity is planned to grow by around a quarter. To reach these goals, renewables in total would need to account for over 40% of India's power capacity. The energy strategy and measures that the government has put in place are already yielding some results. In 2016, total power sector investment rose by 5% to nearly USD 55 billion, with spending on both networks, which accounted for nearly 40%, and renewables (one-fifth) reaching record levels (Figure 2.24). Renewables investment, supported by long-term contracts, grew to USD 10 billion, with solar PV surpassing wind for the first time.

Figure 2.24 Electricity sector investment and final investment decisions in new generating capacity in India



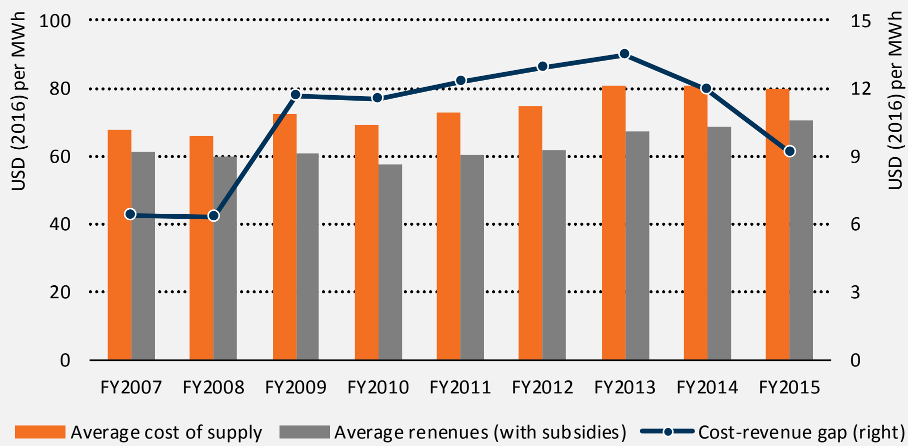
Power-generation investment in India reached nearly USD 55 billion in 2016, over half of which went to renewables and networks, with additions of variable renewables capacity equalling sanctioned new capacity of large-scale dispatchable plants for the first time.

Note: VRE = variable renewable energy (solar PV + wind); FIDs may not include plants <5 MW (below 10 MW for hydropower).
Source: Calculations for FIDs based on McCoy Power Reports (2017), dataset.

Although electricity demand is growing strongly in India, at nearly 7% in 2016, the electricity system has room to produce more power with existing assets and generation capacity has climbed to almost twice the level of peak demand. Coal plant utilisation rates fell to around 60% in 2016, the lowest level in two decades despite improved availability of relatively cheap domestic coal. Investment in coal-fired power plants coming online in 2016 remained strong at USD 20 billion. However, some initiatives are underway to improve the efficiency of the coal fleet and replace old, inefficient plants (IEF-IGU, 2016).

Nevertheless, in the absence of stronger market signals for flexibility, investment in future coal-fired power has grown more uncertain – sanctioned new plants to come online in the coming years fell to only around 7 GW in 2016, the lowest level since 2005. Investment in flexible gas-fired generation remains constrained by the relatively high price of LNG and a lack of import and pipeline infrastructure, while hydropower continues to face barriers. As a result, the total amount of large-scale dispatchable generating capacity reaching final investment decision in 2016 fell to its lowest level since 2002 and was equalled by additions from solar PV and wind for the first time (Figure 2.24).

Figure 2.25 **Average cost of supply and revenues of the state power distribution companies in India**



Low regulated power prices create a mismatch between revenue and costs, undermining the state companies' ability to invest in generation and the grid, though reforms are helping to reduce this gap.

Note: FY = fiscal year.
Source: Calculations based on Power Finance Corporation (2016), *Report on the Performance of State Power Utilities*.

Securing financing for renewables and flexible assets for integration will be a key challenge for India to meet its energy policy goals. Both renewables and coal power are financed partly on the balance sheets of large companies and partly via project finance structures, where the cost of financing remains crucial for project economics. Some companies, such as state-owned NTPC, India's largest power producer, have issued so-called masala bonds, which are denominated in rupees but are marketed internationally, to fund investments. Boosting the availability of low-cost, long-term debt is important to financing the necessary investment in the electricity system. Low regulated power prices and high network losses have contributed to a mismatch between realised revenue and costs for state distribution companies (Figure 2.25), which have been forced to increased short-term borrowing and become highly leveraged. As a result, they are increasingly reluctant to procure power to be sold at a loss, often leading to unreliable purchase and delayed payments to all generators, as well as to undertake fixed investments to expand and upgrade the grid. Investors see the unreliable offtake of power and insufficient grid infrastructure as two critical risk factors for new renewables projects (CEEW, 2016; CPI, 2016).

The government is introducing a number of reforms to enhance the funding position of the sector and help facilitate financing of investment in the electricity system:

- The government's Ujwal Discom Assurance Yojna (UDAY) scheme is trying to revive state distribution companies through debt restructuring and improving efficiency.

Already UDAY has issued 85% of the bonds intended to restructure 70% of the total debt held by participating entities. State distribution companies have made progress in metering and electrification and in reducing the cost-revenue gap. However, results are uneven and success will ultimately depend upon reforms to electricity tariffs and reducing high network losses in some areas.

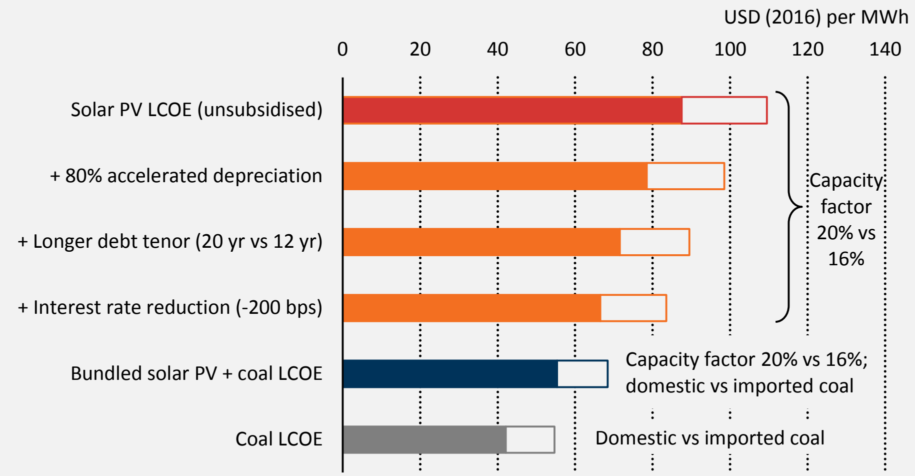
- Renewable policies are evolving to reduce risks for investors and enhance cost-effectiveness. A recent tender in Madhya Pradesh awarded 750 MW of solar PV at a price of USD 55/MWh, the cheapest in India and among the best worldwide – derisking mechanisms from the central and state governments and financing from the World Bank Group played key roles. Solar PV prices in auctions have decreased by half over the last three years in India and in some cases, contracted prices have fallen below pricing for some coal power plants. The most recent auction in May 2017 awarded 750 MW of solar PV at less than USD 40/MWh. The first wind auction in 2017 resulted in 1 GW awarded at just over USD 50/MWh.
- Other measures aim to reduce project risks. These include accelerated depreciation rates, guarantees for power purchases and attractive debt financing and infrastructure provisions, such as land and grid connections. Rate reductions by the State Bank of India have also improved the attractiveness of renewable debt finance (currently around 10-11% in nominal terms), but the current lending periods from banks remain relatively short, at 12-13 years, for long-lived assets.

A combination of measures that increase the tenor or reduce the cost of debt, in addition to technology cost reductions, can help to improve the financial attractiveness of renewables in India (Figure 2.26). Nevertheless, delivering electricity when it is most valued, including for meeting India's early evening peak demand, will require an increasingly flexible power system. One measure that is enhancing the attractiveness of renewables procurement by distribution companies is the bundling of contracted solar power with coal generation, as currently pursued by state-owned NTPC, India's largest power producer.

India's power system is adapting to the integration challenge, with existing thermal and hydropower assets operating more flexibly. A central government programme continues to finance the expansion of the transmission system, but interconnections between regions remain underdeveloped, and the distribution grid remains inadequate to meet the needs of the population. Pumped hydro storage investment has not materialised in line with proposed projects, though some companies are developing grid-scale battery storage.

The system will require increased investment in all forms of flexibility. Progress is needed to reform electricity tariffs to reflect the underlying cost of the system, to finance the build-out of the grid and stronger price signals for more efficient thermal generation. There is now an opportunity to upgrade the thermal power plant stock and retire some of the least efficient plants without compromising reliability. Integration would be enhanced by adding electricity storage and demand response from consumers themselves, supported by smart metering technology (IEA, 2016b). Distributed solutions, such as rooftop solar PV and microgrids, can help quickly scale supplies in underserved areas. The degree to which market-based or regulated price signals drive these investments remains a crucial question.

Figure 2.26 India levelised cost of generation of new solar PV and coal power, 2016



Financing with lower cost, long-term debt and attractive depreciation can reduce solar PV generation costs by a quarter and bundling with coal-fired power by half.

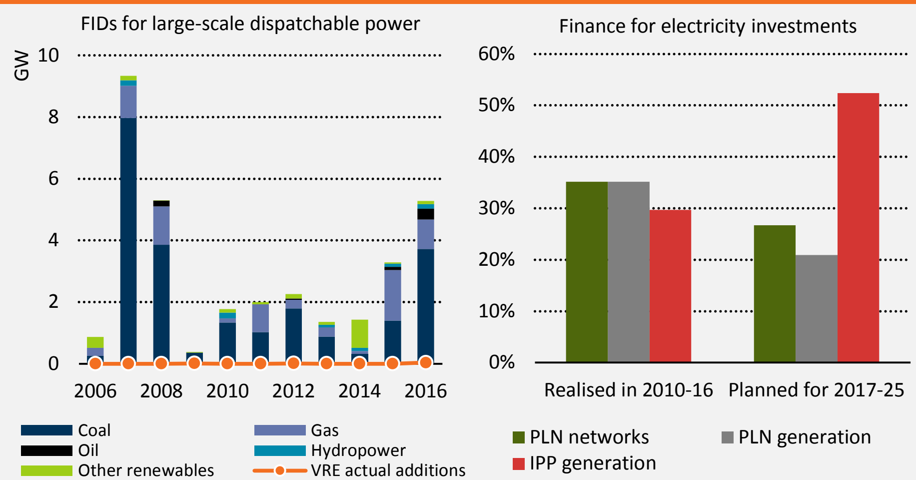
Notes: 8.4% real weighted average cost of capital (WACC) is used to calculate the levelised cost of energy based on the following assumptions: debt to equity ratio 70%:30%, interest rate on debt 5.25% in real terms (9.75% in nominal and 4.5% of inflation rate), and after-tax equity return (real) 15.6% (20.1% nominal, 4.5% inflation rate). In the bundled solar PV and coal, the ratio of the capacity is 2 (solar):1 (coal). The capacity factor of coal-fired generation is assumed to be 70%.

Indonesia: Financing greater access to affordable electricity

The modernisation and expansion of the electricity system is a major development goal in Indonesia. The government recently updated its ten-year plan for the sector and announced policies to augment supplies, expand the role of IPPs, incentivise investment in renewables and enhance the reliability of the electricity system. Indonesia's power system is dominated by the state-owned vertically integrated utility, Perusahaan Listrik Negara (PLN). Policy makers are targeting 100% electrification by 2024, from 91% in 2016. The plan calls for over USD 10 billion generation investment per year over 2016-25, largely in coal-fired power generation, with USD 4 billion per year in networks by PLN (MEMR, 2017). This would more than double power generation capacity from 2016 levels, with over 80 GW of new capacity by 2025, in part to meet rising peak demand and inadequate electricity supply in some areas. Policy makers see coal and gas best providing this increase for the western, more populous provinces (e.g. Java, Sumatra), while renewables are seen as more attractive on eastern islands, where diesel generation is currently more prevalent.

Investment in power generation totalled USD over 2 billion in 2016, down 40% on 2015, with fossil fuel power accounting for three-quarters of this. Investment in networks across the country has risen significantly in recent years, nearly USD 4 billion in 2016 – more than double that of just three years ago. However, capacity additions over the past decade have consistently fallen short of those planned due to challenging land acquisition issues, complex negotiation and procurement processes, onerous permitting and a need for financial guarantees. The amount of large-scale power generation sanctioned over the past two years has increased, but at around 5 GW in 2016 it remains well below the 8-10 GW per year targeted under the current plan (Figure 2.27). Large reserve margins are maintained in anticipation of project delays and in the case of higher-than-expected economic growth.

Figure 2.27 Final investment decisions for large-scale power-generation capacity and investment by type of company in Indonesia



New sources of finance would need to play a much larger role in order to meet Indonesia's sizeable power sector investment needs.

Note: VRE = variable renewable energy (solar PV + wind); FIDs may not include plants <5 MW (below 10 MW for hydropower).

Source: Calculations based on McCoy Power Reports (2017), dataset, for FIDs and MEMR (2017), *Indonesia's Policy on Power Sector*, for finance.

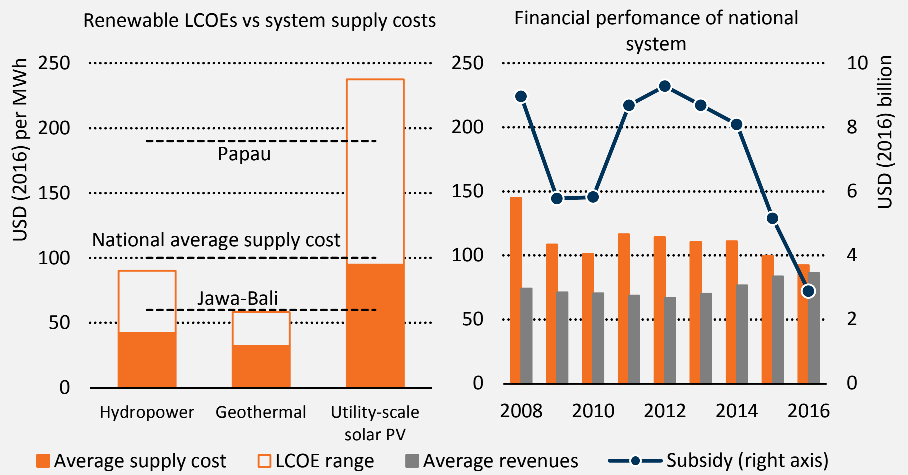
PLN has traditionally been the biggest investor in both generation and networks. The government sees IPPs, largely based on international project finance, accounting for a bigger share in the future. Over the next decade, their share of total investment is expected to rise to 50% and that of generation to 70%. This would take pressure off the stretched balance sheet of PLN, which often cannot fully recover its power-generation investments, in part due to subsidised electricity tariffs, and allow it to focus on investing in electricity networks. However, in most cases this financing shift would still require PLN to serve as a credit-worthy and reliable purchaser of power. The increased role of IPPs could also require increased regulatory and market co-ordination among public and private actors.

The impact of several recent policy changes, among others, will determine the ability of the power system to attract private finance on this unprecedented scale:

- PLN has more flexibility in contracting with the private sector. It can directly procure power from some projects with more simplified processes, and negotiation no longer requires government approval when done with published ceiling prices. This flexibility may also allocate additional risks onto developers of new coal-fired plants, which had previously enjoyed attractive 30-year take or pay contracts.
- From early 2017, a new renewable feed-in tariff scheme allows PLN to directly procure hydropower, bioenergy and geothermal, while solar PV and wind would be contracted under tenders, with a ceiling price that varies by location. This approach should augment PLN's willingness to procure renewables in areas with high electricity costs.
- Aside from selling to PLN, "private power utilities" are being encouraged to sell to large consumers in designated business areas. This could help improve the reliability of supply to industrial parks and expand access in remote locations. One source has estimated the annual cost of grid-supply outages for the manufacturing sector at over USD 400 million per year (PwC and GE, 2016). This is equivalent to the annualised capital costs for over 7 GW of new CCGTs.

A number of barriers to realising the investment needed for power sector goals remain: the ability of PLN to invest and the relatively high cost of renewables. PLN's financial position raises uncertainties over its own capital expenditures and its role as a reliable purchaser of power. With regulated revenues still not fully covering the cost of production, financing depends on government equity and external loans. The recent depreciation of the Rupiah has also caused some losses on loans held in foreign currency. The gap between revenues and costs of production narrowed in 2016 to its lowest level since 2007, benefiting from reduced fuel costs, increased revenues from new connected customers and efforts to reform electricity tariffs (Figure 2.28). But IPPs and lenders continue to require government guarantees to guard against power purchase risks. Projects traditionally require guarantees from international public finance as a further de-risking mechanism – in the past decade virtually all IPP coal power financings benefited from the participation of export credit agencies or development banks. In general, such sources have started limiting participation in new projects by some countries (IEA, 2016c). But Chinese firms, developing or furnishing equipment for around one-quarter of the coal-fired power capacity sanctioned in 2016, are often not bound by such financial constraints.

Figure 2.28 Levelised cost of renewables-based generation and electricity sector financial indicators in Indonesia



Renewables are attractive in a number of areas, but with stringent ceiling prices, solar PV is limited to high cost regions.

Source: Calculations based on MEMR (2017), *Indonesia's Policy on Power Sector*.

Increasing renewables procurement requires cost reductions and regulatory support to meet more stringent ceiling prices. While the national average production cost has varied around USD 100/MWh in the past three years, local costs range from USD 60/MWh (IDR 800/kWh) in Jawa-Bali to USD 190/MWh (IDR 2 500/kWh) in Papua. These values suggest that hydropower and geothermal can be attractive in a number of areas, but utility-scale solar PV, whose development is nascent, remains attractive in higher cost regions (Figure 2.28). Moreover, project bankability will rely on resolving land use issues and the availability of grid connections for remote projects. The regulatory framework does not yet take into account the time value of power or the speed of bringing assets to market, which could improve the attractiveness of more modular solutions, such as solar PV, for meeting growing air-conditioning demand and quickly scaling power supplies.

Meeting the government's objectives for the electricity sector requires further progress in improving grid operations and more investment in the electricity network as a whole. With the exception of Jawa-Bali, islands are not interconnected. In the past five years, network losses have declined somewhat, but remain elevated at just under 9% in 2016. Peak demand, which occurs in early evening, rose to near 46 GW in 2016 – 80% higher than five years ago. Some progress is being made to address these challenges. Grid investment is planned to almost double in the next five years. An interconnection under development between Sumatra and Java is key to triggering investment in 3 GW of new coal plants. Although investment in storage is limited, Indonesia's first pumped hydro storage plant, with a capacity of 1 GW, to help meet peak load in Java, is expected online before 2020.

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3. Innovation, digitalization and jobs

Highlights

- **We have tracked USD 65 billion of spending on energy research and development (R&D) worldwide in 2015, 3% lower than 2014**. Available data on corporate spending indicate a possible further decline in 2016. This fall in expenditure comes against a backdrop of consensus over the need to increase energy innovation spending to meet clean energy targets. Among companies, the share of clean-energy R&D has increased, reflecting not only more spending on renewable technologies but also less spending on oil and gas R&D.
- **Governments are directly responsible for around one-third of total energy R&D spending and two-thirds of clean-energy R&D**. Around two-thirds of all government funding for energy R&D comes from the United States, Japan, the People's Republic of China (hereafter, "China"), France, Germany and Korea. Taking state-owned enterprise spending into account in addition, China has recently and marginally overtaken Europe as the region with the highest public R&D spending. The share of public spending in total energy R&D has declined slightly over the past four years, and energy R&D spending by IEA member governments remains below that of 1980. Government-directed R&D is key to ensuring affordable, secure and sustainable energy.
- **Carbon capture and storage (CCS) projects coming on line in 2016 fell to a four-year low in terms of the money invested in them**, but this is set to rebound to a record high of around USD 10 billion in 2017. However, the lack of new projects entering construction indicates that current policies do not currently support further CCS investment.
- **The future role of digital technologies for generating, handling and communicating data has taken centre stage in energy discussions.** We estimate that USD 47 billion was spent in 2016 on infrastructure and software directed to digitalization of the electricity sector, more than that spent on gas-fired power generation. This spending, which has grown 50% since 2014, facilitates more efficient operation of generation and network assets, allows demand response in real time, and can reduce maintenance and capacity needs.
- **In general, technological progress is leading to lower labour intensity across the energy system.** For example, a 30% drop in jobs in US oil and gas upstream from its peak level in 2014 to its trough in 2016 was accompanied by only a small decrease in production. A comparison of different power generation technologies suggests that renewables tend to create more upfront jobs in construction and manufacturing whereas thermal generation requires more ongoing employment in operations and fuel supply. However, the impact of investment on employment is likely to be highly region-specific, partly due to the geographical mismatch between fossil fuel production and clean energy deployment and differences in the international competitiveness of relevant engineering and construction industries.

Overview

This chapter looks at three topical themes in the debate about energy sector trends and uncertainties: innovation, digitalization and jobs. Technological innovation has always been a key driver of change in the energy sector, yet information on the level of investment in research and development (R&D) activities related to energy technology is scarce.[1] One of the most exciting areas of energy innovation today is the integration of connectivity, data management and real-time responsiveness using digital technologies. Investment in digital resources – physical hardware, virtual resources and software – could have a profound impact on the way energy is supplied and consumed. The impact of specific decisions about energy supply on employment is also a much-debated and highly controversial question in policy circles. The methodologies for looking at the number of jobs created or destroyed in each of the different parts of the energy sector can be as variable as the quality of the underlying data itself, complicating the task of analysing the jobs impact of the transition to clean energy. This chapter brings together available data across these three themes to describe the key trends and assess their relationship with energy investment.

Investment in energy innovation

The importance of energy innovation will only increase as societies strive to provide all citizens with affordable, secure and sustainable energy systems (IEA, 2017). Innovation will be particularly crucial to tackling the environmental problems associated with energy use, notably climate change and air pollution. Rapid technological developments in unconventional oil production and the improving cost and performance of renewable electricity have already shaped the beginning of this century. But much more progress will be needed if the world is to succeed in meeting its energy needs almost entirely from low-carbon sources by the second half of the century. The profound transformation of the energy system that this will involve hinges on an acceleration of technological progress. The 22 country signatories to Mission Innovation, a landmark intergovernmental initiative launched in December 2015 to mobilise support for clean-energy technologies, in part through doubling public R&D funding over five years and encouraging greater levels of private-sector spending, have pledged their support for making this happen. Innovation 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.

This section focuses on spending on R&D – the first stage in the process of innovation. It examines the best available data on public and private energy R&D, highlighting the main trends. However, tracking and understanding the progress of innovation is a much broader

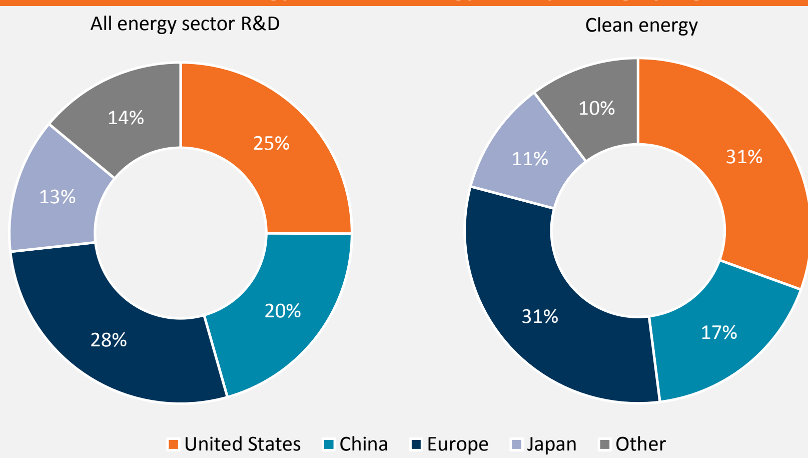
[1] R&D refers here to research, development and funding for demonstration projects that establish commercial or technology feasibility.

task 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, 2017). There is enormous potential for improvement in tracking progress.

Spending on energy research and development

Based on a bottom-up analysis of public and private data, we have tracked global energy R&D spending totalling USD 65 billion in 2015 (the latest year for which full data is available), equal to 4% of total energy investment.[2] Energy made up just 5% of total spending of USD 1.3 trillion on all types of R&D (UNESCO, 2017). This comparison does not by itself raise alarm about the adequacy of energy innovation; the need for innovation varies between sectors. For most fossil fuels, production technology is mature and the potential profitability of innovation may be more limited than for other consumer products.

Figure 3.1 World energy and clean energy R&D spending by region, 2015



The United States and Europe are the biggest spenders on both energy R&D generally and clean energy specifically.

Note: Corporate R&D spending is assigned to the country in which the company is domiciled. Sources: Bloomberg LP (2017), *Bloomberg Terminal*; IEA (2017),*Tracking Clean Energy Progress*; Cleantech Group (2017), i3 database; NBS (2013-17), *Statistics Yearbook on Science and Technology Activities of Industrial Enterprises 2012-2015*; government sources.

But overall energy R&D is not growing: in real terms, spending in 2015 was 3% lower than the previous year, largely due to a drop in spending by the oil and gas industry in

[2] R&D expenditure is not included in our total energy investment estimate. In practice, much of it is labour and other costs that are treated as operating expenditure.

response to the financial difficulties caused by the collapse in oil prices.[3] This drop has not been offset by rising spending on clean energy R&D, which has also been essentially flat at around USD 27 billion since 2012. This indicates that recent calls by governments and the private sector – through initiatives such as Mission Innovation and the Breakthrough Energy Coalition – to increase spending on energy innovation and facilitate the roll-out of novel technologies are welcome.

More is spent on energy sector R&D in the United States than in any other country. The country was also the lead spender on clean energy R&D in 2015 (Figure 3.1). Spending on energy R&D in all European countries is slightly higher than that of the United States and suffered a lower drop in 2015. The share of China in both total energy and clean energy R&D has reached one fifth, having risen by around 7% per year since 2012, and China is the highest spender per unit of gross domestic product (GDP), having overtaken Japan in 2014.

Private sector energy R&D spending fell in 2016

The private sector is the largest single source of energy R&D funding. Corporate spending, excluding SOEs, accounted for 44% of the total in 2015 and early stage venture capital for 3% (Figure 3.2). These figures, however, understate the importance of spending by the corporate sector because of difficulties in compiling company-level data across all technologies (Box 3.1). We estimate that more energy research is undertaken by companies on fossil fuel technologies than on renewable energy, electric mobility, storage and smart grids.

Publicly reported R&D spending by energy companies worldwide, including SOEs, has been falling, largely because of less oil industry spending. Spending fell by 4% in real terms in 2015 and 1% in 2016 (Figure 3.3). The 15% decline in R&D spending by oil and gas companies – including oil service companies – in 2015 and a further 5% fall in 2016 has not been fully offset by increased spending on clean energy R&D. While firms generally try to smooth their R&D spending over time, if possible, to retain key skills, R&D can be vulnerable to sharp changes in the total capital budgets of companies, especially in markets with highly volatile prices, like oil. R&D expenditure reported by companies active in clean energy sectors is growing: it reached USD 7.2 billion in 2016, USD 1.2 billion more than in 2012, and now represents 18% of all reported corporate energy sector R&D spending.

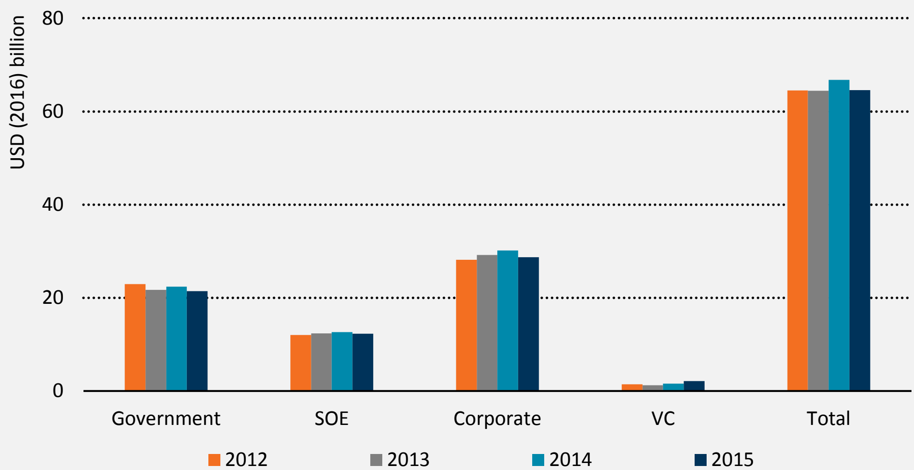
While oil and gas companies account for a sizeable chunk of corporate energy R&D, their R&D intensity (spending relative to total corporate revenue) is around 0.4% – a similar level to that of electricity utilities but low compared with other sectors. Manufacturers of thermal power-generation equipment and clean-energy companies spend around 3.5% of their revenue on R&D. In the latter case, this reflects the greater need for innovation in less mature markets.[4] For example, just the five largest corporate spenders on R&D in the IT

[3] Currency fluctuations also explain a small part of this trend.

[4] By comparison, the automobile manufacturing sector has an R&D intensity of around 4% on average.

sector have R&D budgets equivalent to all public and private energy sector R&D worldwide, while the top two IT companies in this regard have equivalent spending to all the clean energy R&D expenditure we have tracked.

Figure 3.2 World energy R&D spending by source of funding, 2012-15



Spending on energy R&D fell 3% in 2015, despite public and private calls to increase spending on innovation – particularly in the area of low-carbon energy.

Notes: SOE = State-owned enterprises (companies with government ownership of 50% or more). VC = early-stage venture capital funding. Corporate and SOE spending includes that of firms with revenue in all main energy sectors, including energy supply, energy equipment manufacturers and service companies.
Sources: Bloomberg LP (2017); IEA (2017); Cleantech Group (2017); NBS (2013-17); government sources.

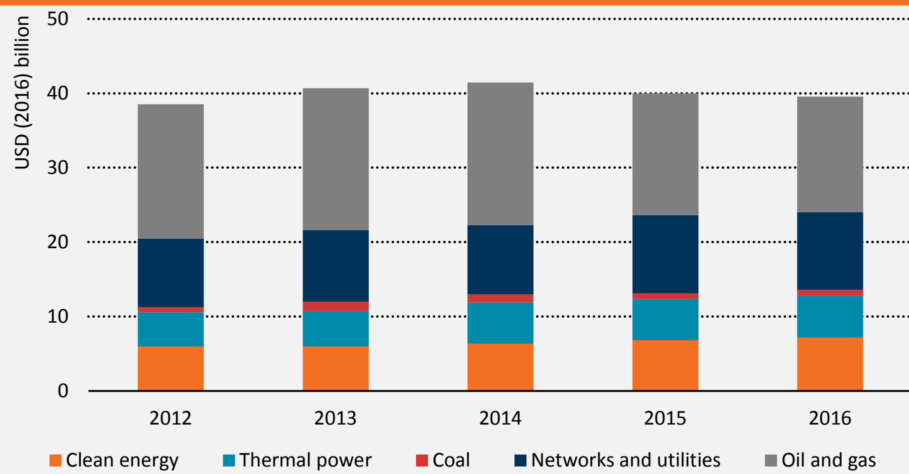
Early stage[5] venture capital (VC) funding of energy R&D is rising rapidly. VC funds invested a record USD 2 billion in energy, mostly clean-energy technologies (Cleantech Group, 2017). VC funds generally target early-stage firms that are aiming to commercialise an idea, usually after basic research and testing in public or industrial research laboratories. Since the first wave of "cleantech" VC crashed in 2012 as investors learned that the VC model was ill-suited to asset-intensive R&D, such as solar and bioenergy,[6] the role of VC in the energy sector has been reinvigorated. This has been led by the rise of digital technologies that lower the costs of learning about viability in a technology's early stages. Solar and wind together now receive less than 10% of energy VC funding compared to over one-third between 2007 and 2012, while clean-transport technologies excluding biofuels now

[5] Includes seed, series A and series B funding rounds, usually the first three steps in start-up financing.

[6] While governments signal the importance of energy innovation and in some cases specifically support VC activity, the two are often not well matched. The time to learn about the viability of energy projects can be too long, the capital requirements for technology demonstration too high, and the consumer value too low.

account for half of the total, up from 12%. In parallel, there has been a rise of corporate involvement in VC transactions, partly because venturing can involve a lower level of commitment to a technological solution than corporate R&D, which involves owning research facilities and training researchers. Half of clean energy VC activity now has at least one corporate investor, up from one-third in 2013.

Figure 3.3 Publicly reported energy R&D spending by companies



Publicly reported R&D spending by energy companies worldwide has fallen, largely because of oil industry cutbacks, though their spending on clean energy technologies has risen slightly.

Note: Sample includes some SOEs. Classifications are based on Bloomberg Industry Classification System. R&D is allocated according to shares of revenue per sector for companies active in multiple sectors. Clean energy includes renewable energy, electric mobility, electricity storage, nuclear, LEDs and smart grids. Thermal power includes original equipment manufacturers (OEMs) of power plant equipment for fossil-fired generators.
Source: Bloomberg LP (2017), *Bloomberg Terminal*; Company disclosures.

Box 3.1 Counting global R&D expenditure

There is as yet no centralised, reliable source of data on global energy R&D spending by the public or private sectors. The IEA is almost alone in collecting data on public R&D budgets; member countries report annually their spending for each technology category according to IEA guidelines. Some non-member countries publish budgets and expenditures, but they do not generally provide a breakdown of the data beyond broad classifications. In some countries, there is a large amount of public support for innovation that is not included in government budgets. In China, for example, a large share of research is funded and carried out directly by SOEs, but under governmental direction.

Compiling data on energy R&D is harder for the corporate sector, with many firms hesitant to report funding in any detail. Definitions of R&D and categories vary. Energy and non-energy

R&D spending are often difficult to distinguish for companies that are active across several sectors, such as automakers with extensive R&D programmes on biofuels. There is a great deal of scope for improving the quality and extent of public and private R&D expenditure reporting.

The data presented in this report comes from several sources. IEA member governments report their national R&D spending each year to the IEA secretariat. For other countries, the R&D budgets of the relevant ministries and agencies are aggregated. For China, the government's statistical records of public and private R&D spending by industrial enterprises are used for five energy-relevant sectors. In some cases, data for key SOEs is from other public sources. Corporate R&D spending is taken from the annual reports of over 1 000 companies active in energy sectors and allocated to specific energy activities according to the firms' share of revenue from that activity, or specific company-level breakdowns. It includes spending by manufacturers of energy supply equipment and service companies. Our estimate of R&D into clean energy technologies in the public sector includes energy efficiency, renewables, carbon capture and storage, nuclear, fuel cells, batteries and smart grids. For the corporate spending, it includes renewables, nuclear, electric mobility, LEDs and smart grids.

We acknowledge that this exercise is likely to underestimate considerably the true amount of spending worldwide on all types of energy R&D, because of information gaps. Corporate research into energy end-use efficiency (including transport and buildings) is particularly hard to separate from non-energy research and is only included in the private-sector data in some very specific sectors, such as electric vehicles (EVs). While the coverage of the corporate sector is generally good, there are many non-listed companies missing from the dataset and others do not report capitalised research expenditure as R&D spending. In addition, within the IEA's consistent data set of government spending, sub-national public spending is often not included. Some top-down estimates suggest higher spending. For example, a rough estimate of spending on low-carbon technologies based on patent counts, using EC methodology, yields a global total that is almost double our estimate for all energy (IEA, 2017).

Government energy R&D spending is still rising, but slowly

Governments play a major role in energy innovation, often funding basic and higher risk research as well as novel low-carbon technologies whose costs are high or whose market value is not yet large. Our dataset shows that half of total energy R&D is from public sources, if SOEs are included, a share that is unchanged in recent years. Excluding spending by SOEs, the share drops to 33%. The six leading countries for public energy R&D are the United States, Japan, China, France, Germany and Korea.[7] Spending by these six countries accounts for two-thirds of all public spending worldwide.

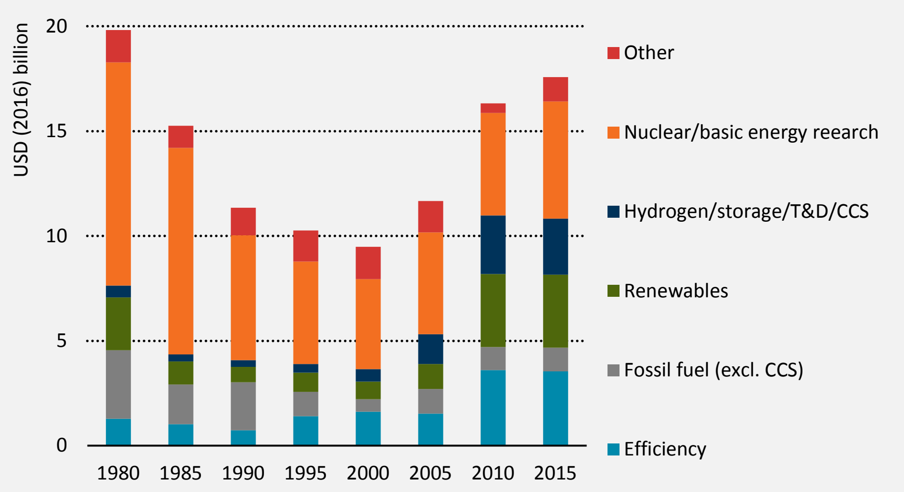
The governments of IEA member countries, for which the most complete dataset is available, spent almost USD 18 billion on energy-related R&D in 2015, or 5% of their total

[7] Note that France and Germany also contribute a significant amount to the energy R&D budget of the European Commission, which amounted to USD 1.5 billion in 2015.

spending on all types of R&D (which took up 0.1% of their total public spending). Spending doubled since 2000, but most of this increase took place in the first decade of the century; since 2010, it has increased at a rate of only 1% per year on average and its share of total R&D spending has declined. In fact, spending in 2015 was lower than in 2012 (Figure 3.4).[8] Preliminary data for 2016 shows no further increase. Spending on fossil fuel technologies declined over the five years to 2015 in real terms, but this was not fully offset by increased spending on clean energy, which has stagnated since 2010.

In addition to funding R&D, governments support a considerable amount of 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 new technologies to be developed and supporting existing technologies to be deployed, which will itself lead to innovation through learning-by-doing (IEA, 2017b). A combination of these two approaches delivers cost reductions and performance improvements that meet the needs of users and markets.

Figure 3.4 Energy R&D investment by IEA member governments since 1980



Energy R&D spending by IEA member governments has doubled since 2000, but has slowed since 2010 and is still not back to the level of 1980.

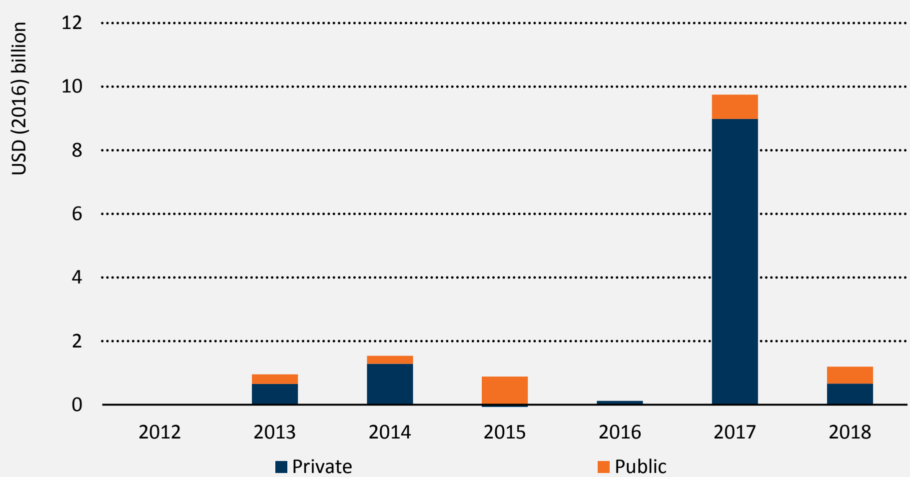
Note: T&D = electricity transmission and distribution; CCS = Carbon capture and storage.
Source: IEA RD&D Statistics (2016a).

[8] In fact, the peak year since 2000 was 2009, related to post-crisis stimulus packages such as the US American Recovery and Reinvestment Act of 2009.

Spotlight on carbon capture and storage

One technology that requires higher-risk financing for innovation is carbon capture and storage (CCS). Funding especially needs targeting at the latter stages of the R&D process, namely early-stage commercial projects that demonstrate technical and economic viability. Investment in CCS projects coming on line in 2016 was at a four-year low, but in 2017 will reach a record high of USD 10 billion (Figure 3.5).[9]

Figure 3.5 Global investment in CCS projects by start date



The value of new CCS projects coming online this decade will be at its highest in 2017, as no new projects reached the stage of a final investment decision in 2015 and 2016.

Sources: GCCSI (2017), Large scale CCS projects database; BNEF (2016a), *Clean Energy Investment Trends*; MIT (2016), Carbon capture and sequestration project database.

By comparison, cumulative investment in CCS projects over the previous four years was just USD 3.4 billion. The Petra Nova project in Texas commenced operation in early 2017, capturing 1.4 $MtCO_2$ per year from an existing coal-fired power plant and using the CO_2 for enhanced oil recovery nearby. Three more CCS projects expected to start up in 2017, capturing CO_2 from natural gas processing, power generation and bio-ethanol production.[10] Investment in 2017 is somewhat inflated by delays and cost overruns in the two largest of these projects. The overruns, totalling almost USD 5 billion, are mostly associated with construction of industrial facilities from which the CO_2 is captured – the power plant and gas production plant – rather than the CCS elements.

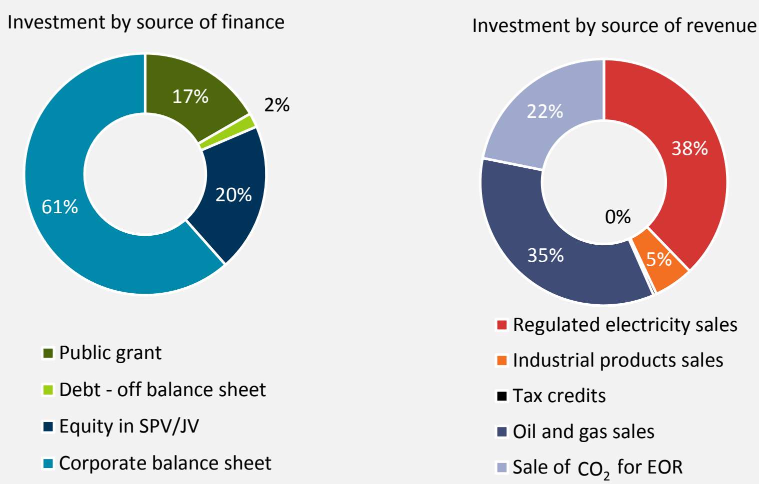
[9] While this is a key innovation investment, only a small share is counted as R&D spending.

[10] A 2017 commissioning date for CO_2 capture at the Kemper County Energy Facility is assumed, though this is uncertain at the time of going to press.

Following this investment peak in 2017, there is likely to be a significant lull in project start-ups, as no investment decisions for CCS projects were taken in 2015 and 2016 and there are few projects in the earlier stages of development (IEA, 2016b). There is broad consensus that CCS is a critically important technology for achieving the goal of the Paris Agreement on climate change, but there is considerable uncertainty about its commercial prospects.

Public support remains critical to commercial investment in CCS. Over the past five years, public spending in the form of grants and tax credits on the 12 CCS projects that have come on line has made up just 17% of total investment, but has helped to leverage the other 83%, or USD 11 billion, of private-sector investment (Figure 3.6).

Figure 3.6 World CCS investment, 2011-2018



Public grants represent just one-fifth of CCS financing, but have helped to leverage private investment.

Notes: Where plants have several revenue sources, investment has been allocated equally except where revenue shares are clearly stated. SPV = Special purpose vehicle. JV = Joint venture. EOR = enhanced oil recovery.

Sources: GCCSI (2017), Large scale CCS projects database; BNEF (2016a), *Clean Energy Investment Trends*; MIT (2016), Carbon capture and sequestration project database.

Most private investment has been financed through corporate balance sheets, while only one project has secured off-balance sheet debt financing, reflecting the commercial risks and the leading role of large utilities and energy companies in the sector. Equity investment in special purpose vehicles (SPVs) or joint ventures (JVs), usually by large project sponsors and operators, has been of the same magnitude as public grants over the same period.

None of the commercial-scale CCS plants in operation today are pure demonstration projects. The private investment has been made in the expectation that the revenues generated will secure an acceptable return on equity or debt. In the case of the 12 projects that have come on line since 2011, there are three main sources of revenue. Revenue from electricity generated by utilities in regulated markets is the largest single source, accounting for 38% of the cumulative total since 2011. More than half came from projects tied to oil and gas production: direct sales of oil and gas accounted for 35% and sales of CO_2 for enhanced oil recovery 22%. Thus, investment in CCS spending tends to be vulnerable to oil and gas investment cycles. Notably, despite expectations in Europe and Australia, no private investment has been supported by revenue from sales of electricity in liberalised markets or from CO_2 credits or carbon pricing schemes.

Investment in digital technologies in the electricity sector

Interest in the role of digital technologies that generate, handle and communicate data have recently taken centre stage in discussions about the future of energy. Although information and communication technology (ICT) hardware and software have been contributing to improving the technical and financial performance of the energy industry over many decades, recent years have seen a step-change in data processing capabilities and connectivity allowing the processing of much more information to facilitate the operation of physical supply-side and demand-related assets in real time. Declining costs of hardware and software have also been important enablers of this acceleration. Firms and governments are now investing in digital infrastructure in all parts of the energy system.

To highlight this trend, we have compiled some statistics on expenditure on physical infrastructure (such as sensors and control systems) and virtual architecture (such as cloud computing platforms and analytical software, which collect and analyse data) in the electricity sector to illustrate the growing importance of digitalization in energy.[11] Digital electricity infrastructure allows electricity suppliers and consumers to collect more accurate data on electricity use, communicate directly with one another, modify consumption patterns in response to real-time information and manage assets to optimise their costs and life spans. We estimate that total investment worldwide in smart-grid technologies, connected building and industrial control systems and EV charging infrastructure to have been USD 47 billion in 2016 (Figure 3.7).[12]

On top of this, around USD 2 billion was spent by electric utilities on software, platforms and services to integrate this infrastructure into their system operations. These items provide data analytics, smart grid management, predictive asset maintenance, billing systems and security. Spending on all these digital technologies has increased by 50% since 2014, overtaking the level of investment in gas-fired power

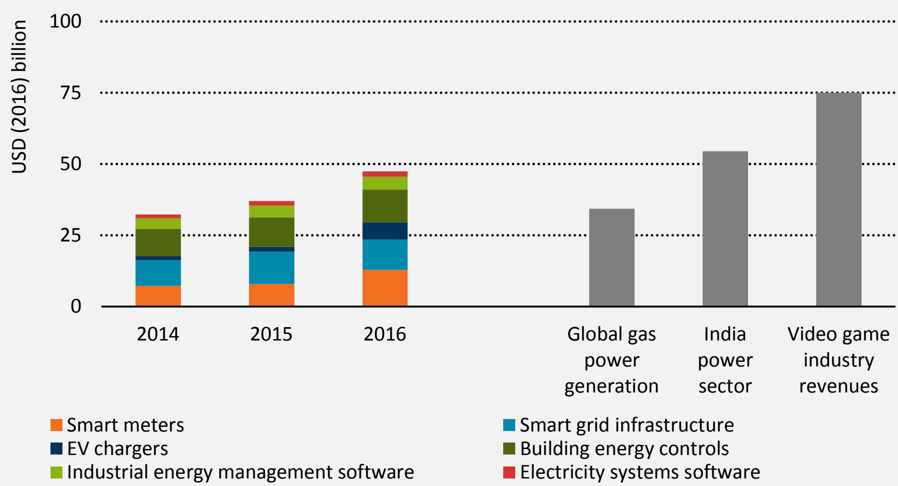
[11] The IEA will publish a new report on digitalization and energy in late 2017.

[12] Smart meter installations, smart grid infrastructure and EV chargers are included in the electricity networks investments and energy management systems are included in the efficiency spending presented in Chapter 1. Spending on software, which is often counted as an operational expenditure, is excluded from the overall investments presented in *WEI 2017*.

plants. However, to put it into perspective, this investment in digital technology is still equal to less than two-thirds of the revenues of the video-game industry.

Smart meters, at nearly USD 15 billion, became the largest category of digital electricity infrastructure investment in 2016, with notable increases in Japan and China. The two countries were responsible for almost half the global smart-meter market in 2016. As investment in smart meters tends to be driven by government policies and as they tend to be deployed in one go, growth rates in individual countries tend to be volatile: once the roll-out of a meter installation programme has been completed, investment drops away sharply. While North American spending on smart meters was more than double that of Europe in 2012, European spending was larger in 2016. Smart grid infrastructure spending to monitor and manage the grid was relatively stable at just over USD 10 billion.[13] World investment in publicly available fast EV chargers grew an impressive seven-fold in 2016. Through connectivity, chargers for EVs can increase the flexibility and digital management of electricity supply and demand.

Figure 3.7 World investment in digital infrastructure and software in the electricity sector by technology



Investment in digital electricity infrastructure and software grew by 50% between 2014 and 2016, overtaking the level of investment in gas-fired power plants and nearly reaching the investment in India's power sector, but is still far behind video game industry revenues.

Source: Calculations based on MarketsandMarkets (2016), *Internet of Things in Utility Market*; BNEF (2016b), *Digital Energy Market Outlook*.

[13] See section in Chapter 1 on spending on modernising and "smartening" the grid.

Electricity utilities' spending on software, platforms and services for integrating digital hardware rose nearly 20% in 2016, with the combined share of North America and Europe unchanged at two-thirds of the world total (MarketsandMarkets, 2016). More than half of this global spending was for operational controls and data analysis, with smart-grid management the third largest category, at around one-fifth. These three areas are vital if utilities are to integrate the newly available data from operations and consumers to better manage assets and improve market efficiency. The remaining expenditure went towards software for security, predictive asset maintenance and billing.

The attractiveness of investing in digital electricity technologies varies among different users. Operators of geographically dispersed assets – such as extensive remote solar farms, hundreds of wind turbines or thousands of individual load centres – can realise considerable cost savings by automating the monitoring of the system and detecting problems. Much of the current investment is targeted at avoiding costs of maintenance or replacement. With an appropriate regulatory framework, investments in grid-related technologies can provide utilities a rate of return on investment in a regulated part of the electricity sector (Chapter 2). This development would also serve larger electricity sector goals, such as the integration of variable renewables by reducing the total need for standby generators and enabling consumers to better manage their use of electricity and, by responding to differentiated pricing, more closely align it with patterns of electricity generation.

Putting these investments in context, expenditure on grid-related digital technologies, while growing, still makes up little more than 10% of total electricity-networks investment worldwide, with lines and substations, themselves increasingly automated, dominating spending in 2016 (see Chapter 1).[14] Similarly, spending on digital control technologies to make buildings more energy efficient is less than 10% of total energy-efficiency investment in the buildings sector. For the time being, maintaining electricity supply and reducing buildings electricity demand is mostly dependent on cables, insulation and other large hardware. However, the boundaries between digital technologies and traditional infrastructure will continue to become more blurred as ICT is increasingly embedded in energy investment. In a similar development, digital technology firms outside the energy sector are increasingly driving investment in renewable generation (see Chapter 2).

The impact of energy investment on employment

The impact of energy investment on employment is a complex and controversial topic. Many of the jobs associated with the energy system involve the manufacturing and operation of technical equipment to produce energy from various sources. Policy makers and the public at large are often concerned about creating and sustaining these types of

[14] Automated lines and substations do not wholly fall within the *advanced communications and control systems* category of network investment that is considered "digital" and are not included here among digital electricity investments as a result.

technically skilled middle-class "blue collar" jobs as employment continues to shift away from manufacturing and towards service sectors. The impact on employment of energy investment is invoked as an argument both in favour of and against policies to accelerate the transition to low-carbon energy.

Assessing the employment impact of energy investment is hampered by a lack of statistics in the different parts of the energy-supply chain, from manufacturing of equipment and construction of a plant to operation and maintenance of those assets. In most countries, labour statistics are based on the industry classification of individual companies, i.e. they count people who are employed by companies that produce and distribute energy and work on the site of the energy facility. Inherently, such figures underestimate the employment impact as they do not cover all the parts of the supply chain or the duration of employment. Amid these difficulties, empirical studies of energy employment variously measure employment effects in up to three categories.[15]

- Direct employment (construction workers and facility operators).
- Indirect employment (persons employed to produce inputs for the new facility, in manufacturing industry or service sectors).
- Induced employment (jobs generated by consumption as the wages earned in direct and indirect employment are spent). Measuring jobs in this category is very difficult.

While there is insufficient data to estimate the total employment in the global energy sector, we examine below the employment implications of investment in three energy sectors: power generation, upstream oil and gas, and the clean energy transition.

Power generation sector

The job needs of different generating technologies vary widely

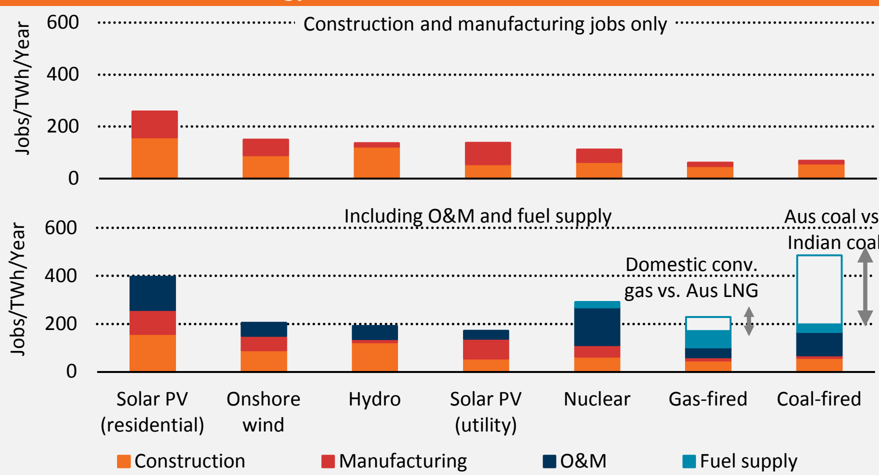
Our analysis on the job creation potential of new power generation (Box 3.2) shows that the most-labour intensive types of generating technology, measured as jobs per TWh of annual electricity output, are residential solar PV systems or coal-fired power plants, depending on the source of the fuel (Figure 3.8). Employment in power generation is generally concentrated in construction and the manufacturing of equipment, as relatively few jobs are involved in running and maintaining most types of power stations. This implies that to sustain jobs over time, continual capacity additions are needed.

Residential solar PV systems are highly labour-intensive because of the small unit size, the customised nature of installation work on rooftops and the low load factor that requires a large number of panels to produce 1 TWh of electricity, though the number of jobs involved differs among countries. Most residential solar PV related employment is construction and maintenance, which is inherently local. But there are significant regional differences.

[15] For example, IRENA (2017), Cameron and van der Zwaan (2015), Houser and Mohan (2014), Lemma et al. (2016), Wiser et al. (2016), Mills (2014) and Wei et al. (2010).

Installations in Germany are among the least labour-intensive, while projects in the United States are among the most intensive, illustrating the impacts that the local policy and functioning of a supply chain can have on project costs and jobs (Seel, Barbose and Wiser, 2013). Onshore wind, hydro and utility-scale solar PV are less labour-intensive than nuclear power, residential solar PV and fossil-fired plants depending on the location of the fuel supply. Gas-fired power plants are less labour-intensive than other types of conventional generation as construction periods are shorter and operations more streamlined. The employment impact of hydropower is concentrated in the construction of the plant, but this is strongly market- and site-specific.

Figure 3.8 Employment associated with 1 TWh of new generation in 2016 by technology



The employment impact from switching to low-carbon generation sources depends on the mix of clean technologies chosen and regional characteristics of fossil fuel supply.

Sources: IEA estimates derived from various data sources, for example, AWEA (2016), EWEA (2012), IRENA (2017), KPMG (2015), McKinsey Australia (2016), Navigant (2009), NEA/IAEA (2017), Solar Foundation (2017), Uria-Martinez, O'Connor and Johnson (2015), US DOE (2017) and US BLS (2017), as well as company disclosures and consultation with industry experts.

Other studies focused on renewable energy have produced similar results in terms of relative labour intensity, although estimates for absolute levels vary. For example, IRENA (2017) estimates that the renewable energy sector employed 9.8 million people directly or indirectly in 2016; solar PV is the largest employer with 3.1 million jobs, mainly in installation. The methodology used in the IRENA study involved collecting data from governments and relevant industry associations on the number of people engaged in the various activities across the sector in selected countries. Unlike our analysis, which is limited to renewables-based electricity technologies, it includes employment in the biofuels sector, including farming. In line with our analysis, the study finds employment to be highest for solar PV and somewhat lower for wind.

Box 3.2 Estimating the employment intensity of power-generation technologies

We have assessed the direct and indirect employment impact of investment in power generation on the basis of publicly available data sources and analysis, a broad industry consultation and in-house research. The analysis for nuclear power is based on NEA/IAEA (2017). Indirect jobs include employment in the supply chain (first-order indirect employment) and do not consider industries supplying products and services to this supply chain. The chosen metric, jobs per TWh per year, was calculated by estimating the number of employees and the number of years needed for one GW of capacity in each phase of the supply chain and then averaged over 25 years, assuming load factors representative for the given technology. We excluded induced employment from our scope of analysis because it is unlikely to vary by technology as it largely depends on the location of the deployment and its socio-economic situation. Given data limitations, the results should be interpreted with caution. See www.iea.org/investment for more information about the methodology.

In general, the impact on employment of equipment manufacturing is comparable to that of construction, though where those jobs are located depends on the structure of the industry and the degree of competition. For example, investment in a solar PV project obviously generates jobs in manufacturing, but not necessarily in the country where the panels are installed. Operation and maintenance account for a significant share of the employment related to coal-fired plants and nuclear power stations. These jobs are cyclical, as maintenance is usually periodic. Most jobs, either on or off site, are with the original equipment manufacturer and engineering company or, in the case of residential solar PV, the installer.

Due to the sheer capital intensity of power generation, even a big change in the pattern of investment and the generating mix would be expected to have a limited impact on overall employment at the global level compared with the effect of macroeconomic fluctuations or labour-market and tax policies. For example, in both Europe and the United States, the cyclical recovery from the financial crisis generated far more jobs in other economic sectors than the ramp up of wind and solar. In the entire economy of the United States, 15 million non-farm jobs were created from 2010 to 2016, while solar energy-related jobs have been estimated to have increased by nearly 170 000 during the same period (US BLS, 2017; Solar Foundation, 2017).

Solar PV and onshore wind are becoming less labour-intensive

Technological progress has been a key component of the improving competitiveness of renewables, partly by reducing labour intensity. With the rapid increase in the deployment of solar PV, the production of panels is benefiting from standardisation and mass manufacturing. Panel manufacturing is increasingly concentrated in Asia, although Europe and the United States retain a sizeable position in manufacturing inverters and specialised tools for panel manufacturing. These represent an increasing share of value added in the sector, given the declining price of the modules themselves: Germany has a trade surplus in solar-related manufactured goods, despite importing a large proportion of its panels from China. Rooftop solar PV systems are still a significant source of employment and installation is very difficult to automate. The cross-country differences in solar PV costs, which remain significant, are attributable to a number of factors, including legal, business development and marketing costs, some of which generate a significant number of jobs.

Onshore wind power, which is significantly less labour-intensive, has seen major improvements in labour productivity through technological advances. One of the most important factors behind the increased competitiveness of wind power is the increasing size and load factor of wind turbines, which have led to a disproportionately large increase in output per turbine. On the other hand, manufacturing larger capacity wind turbines does not need proportionally more workers. Similarly, the number of construction jobs is largely related to the number of towers erected rather than the average load factor of the turbine.

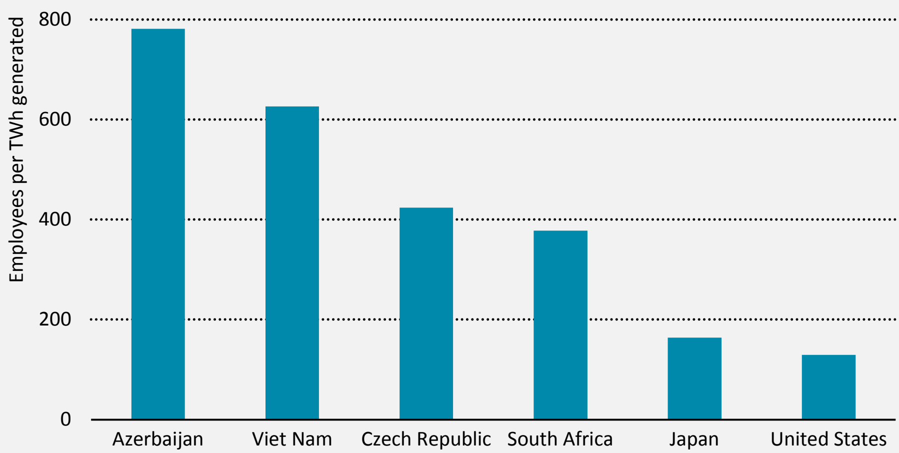
Technology is also reducing job needs for fossil fuel generation

For conventional power generation, the employment associated with the supply of the fuel is significant, though the location of those jobs depends on whether the fuel needs to be imported. The time profile of fuel-supply-related employment differs by project type. For large conventional gas fields and LNG, it is similar to power plants, as employment is largely concentrated in field development and construction, with a much lower need for people to maintain the facilities once they are installed. Shale gas and coal mining have a more stable employment time profile, with employment closely correlated with production.

The labour intensity of fuel supply varies enormously by fuel type and region of production. The labour productivity of coal mining varies widely across regions according to the extent to which advanced technology has been applied. Productivity varies by more than a factor of ten: typically large, mechanised open pit mines in Australia and the western United States are far more productive than deep-pit mining in the Appalachian regions of the United States or Poland. Around 200 Australian miners and supply-chain employees can support the fuel-supply needs of a modern 1 GW coal plant in Asia, whereas domestic mining in India would employ ten times more workers for the same output.[16] While coal mining in India is predominantly open pit, it is far less mechanised and so more labour-intensive. Similarly, the labour intensity of electric utilities and network operators also varies across regions, while utilities of similar labour intensity can perform very differently with respect to service quality, reliability and emissions (Figure 3.9).

[16] We assume 2.5 million tonnes of coal production per year to support a 1 GW coal plant.

Figure 3.9 Labour intensity of electricity utilities in selected countries, 2015



The labour intensity of electricity utilities varies across regions, while utilities of similar labour intensity can perform very differently with respect to service quality, reliability and emissions.

Notes: Azerbaijan indicates Azerenerji. Viet Nam indicates EVN. Czech Republic indicates CEZ. South Africa indicates Eskom. Japan includes Tokyo Electric, Chubu Electric, Kansai Electric and Kyushu Electric. US includes Duke Energy, Southern Company, Entergy, Dominion Resources and Xcel.
Source: Calculations based on company disclosures; Bloomberg LP, 2017, *Bloomberg Terminal*.

Employment in the upstream oil and gas sector

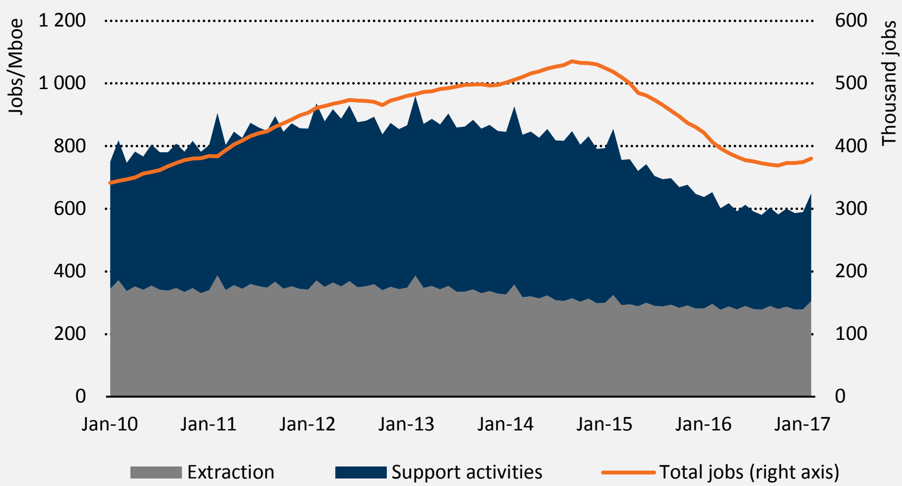
Drilling-related jobs in the United States did not fall as heavily as the oil price

The downturn in upstream investment triggered by the 2014 oil-price collapse did not lead to a proportional decline of employment in the United States. Whereas US upstream spending fell 60% from 2014 to 2016, jobs in US upstream production decreased by only 30% from its peak level in mid-2014 to its trough in October 2016. This reflects in part the significant proportion of jobs, especially in the conventional oil and gas sector that are associated with ongoing production and maintenance. In addition, it reflects a tendency for industries like oil and gas to try to maintain employment levels and institutional capabilities during a cyclical downturn so as to be better placed to profit from any subsequent upturn in business. At the same time, the industry has become less labour-intensive as a result of various efficiency measures and innovation, as evidenced by the decline in the number of jobs per unit of oil and gas production since the fall in oil prices in 2014 (Figure 3.10).

The relationship between upstream investment and employment is affected by other factors as well. In mature regions, such as the North Sea, decommissioning requires employment as well, so productivity measured as current production per employment automatically declines as production levels drop. This is one reason why employment in the

United Kingdom, at around 180 000 (Oil and Gas UK, 2016),[17] is similar to that in Norway (Statistics Norway, 2017), even though production in the latter is much higher. Another reason is the much lower average field size in the United Kingdom: the Troll field in Norway produces as much as the 25 biggest UK fields combined. A cluster of small fields requires widespread logistics and maintenance operations, increasing the labour intensity of production.

Figure 3.10 Employment per barrel equivalent of oil and gas produced in the United States upstream



Continuous efficiency improvements mitigate the labour demand in the US upstream oil and gas industry

Source: Calculations based on Baker Hughes (2017); US Bureau of Labor Statistics (2017), Labor statistics database.

National oil companies are often obliged to employ as many people as possible to reduce unemployment in the country and spread the benefits of local resource development. As a result, their labour productivity is generally significantly lower than that of international oil companies and independents. In addition, especially in remote locations, NOCs routinely provide a range of social services for employees that would normally be outsourced. For example, the Russian gas company, Gazprom, produces around six times more hydrocarbons than the privately owned Novatek, which operates in similar geographical locations, but employs 467 000 people compared with 7 500 at Novatek (Gazprom, 2017; Novatek, 2017). It is worth noting that Gazprom's employment includes activities that are outsourced by other companies, such as housing, medical and transport services.

[17] Includes direct and indirect employment.

Most upstream jobs are associated with initial field development

Much of the employment generated in the upstream industry is associated with the large material, equipment and engineering inputs required to develop oil and gas fields (though it is difficult, in practice, to separate out the portion of employment associated with ongoing operations). Considering shale development, which has a short development cycle that requires a constant inflow of engineering resources, we estimate[18] that a single shale rig in the United States requires on average over 10 pump trucks and over 100 heavy trucks for well completion and logistics services, typically provided by companies other than the owner of the rig. Operating the rig generates demand for over 3 000 tonnes of tubular goods (steel pipes) and up to 100 000 tonnes of fracking proppant and around USD 20 million worth of chemicals of various types every year.

Other branches of upstream oil and gas have similar employment intensities, though with a different composition; US shale typically has a higher proportion of construction industry type inputs while offshore inputs relying dominantly on mechanical engineering. Similar to electricity, the location of this indirect employment can be different from the field development depending on the competitiveness of local suppliers. A good example of this is the supplying of UK and Norwegian North Sea activities by Dutch offshore engineering service companies. Engineering, procurement and construction companies like France's Technip or Italy's Saipem also operate mainly outside their home countries. While field development is the most labour-intensive part of the lifecycle of a field, ongoing operation also requires significant numbers of people for well workovers, maintenance and periodic replacement of components like valves and compressors, often undertaken by the same employees and service contractors as for field development.

Declining oil prices have increased pressure on the industry to raise productivity

Some of the most promising innovations that have led to lower costs in the upstream have done so by raising productivity, which has had the effect of reducing employment. As a result, even with the recovery of investment in North America, overall employment in the upstream oil and gas industry worldwide may struggle to return to its 2014 level unless there is a big increase in production. The most important employment effects of innovation include:

- Advances in 3D seismic imaging that reduce drilling needs. The widespread use of 3D seismic analysis generates employment in ICT and data science, but these jobs require very different human capital and often in a different region than drilling operations.
- Faster drilling times in North American shale increase the number of wells drilled per rig, which cuts the employment/new well ratio, although less than proportionally as

[18] Our estimates are derived from data from various sources; for example, IHS (2014), American Petroleum Institute (2017), EOG Resources (2017), Chesapeake Energy (2017) and Nabors Industries (2017).

the new generation rigs are more complex. Drilling multiple wells from the same pad drilling, in particular, reduces the need to disassemble and move rigs, which is a labour-intensive process.

- Standardisation and modular design in offshore reduces the need for both the highly skilled design as well as the assembly and engineering related employment need.
- The increasing use of sensors, drones and automatisation in general reduces employment need while delivering efficiency and safety improvements.

Energy efficiency and employment

Some studies have indicated that energy efficiency investment can induce jobs by redirecting saved energy bills to spending or investing in the other part of the economy which has on average higher labour intensity than the energy sector (Bell, 2012; UKERC, 2014; Wei et al., 2010). Moreover, at the national level, government policies to promote energy efficiency can generate jobs in developing more efficient technologies and new manufacturing capacity. To the extent that they encourage more rapid turnover of the stock of energy-consuming equipment and appliances, they may also boost sales and employment in retailing and manufacturing.

Assessing the direct employment impact of energy efficiency faces similar methodological challenges to measuring energy efficiency investment in general. For some aspects of energy-efficiency investment, such as refurbishing buildings, the identification of direct employment is feasible. On the other hand, counting the proportion of a factory's employees that are dedicated to making a product, such as a hybrid car or low-energy lightbulb that is more efficient than standard alternatives is very difficult. The manufacturing of inefficient cars and refrigerators may involve just as many workers as producing efficient ones. A person building the hybrid drivetrain has a genuine efficiency job, whereas a person installing seat belts into the hybrid car arguably has a car industry job with no connection to energy efficiency. In addition, the transition to more efficient products can in some cases initiate manufacturing changes that reduce labour intensity. This is the case with light-emitting diode (LED) lightbulbs, which require fewer employees to produce bulbs that each last much longer.

One difference between the employment related to energy efficiency and that involved in energy supply is the almost entirely upfront nature of jobs in energy efficiency, i.e. there is usually no employment associated with the operation of the energy-efficient equipment in question once it is installed. An exception to this is the energy service company (ESCO) sector that is contracted to provide energy efficiency benefits to customers on a continuing basis. In China, it is estimated that there are over 5 000 ESCOs employing 607 000 people in 2015, six and three-and-a-half times more respectively than in 2010 (CERS, 2017).

Making buildings more energy-efficient can create a lot of jobs initially

In the buildings sector, many energy-efficiency jobs are associated with the labour-intensive process of refurbishing existing buildings. For new buildings, a smaller number of highly-skilled and well-remunerated jobs are also associated with the design of the building envelope and the heating, ventilation and air conditioning (HVAC) system. Previous studies in Europe and the United States suggest that a USD 1 million annual investment in building renovation and installation of equipment designed to improve the energy efficiency of the building would support 10-20 direct jobs and an additional 10-20 indirect jobs (Bell, 2012; Cambridge Econometrics, 2015, Cuchí and Sweatman, 2012; Janssen and Staniaszek, 2012; Pikas et al., 2015; Ürge-Vorsatz et al., 2012),[19] while retaining such jobs would require continuous investment. This job creation potential is comparable on an investment basis to that of power-generation technologies, which range from 5 to 20 job years per USD 1 million investment with residential solar PV the lowest and nuclear the highest.[20] However, 20-60% of the jobs in power generation can be attributed to operation and maintenance that continue over the operating life of a plant, while energy efficiency jobs in the building sector are mostly supported only for a short period of time. Applying these ranges to our estimate of USD 92 billion spent on more efficient building envelopes and HVAC in 2016 produces an estimate of around 1.5 million direct jobs and a similar number of indirect jobs worldwide, after accounting for the shares of investment in new and existing buildings. Among these, over 600 000 direct and indirect jobs combined would be in the United States, according to this simple methodology.[21]

In the car industry, empirical evidence suggests that fuel-economy standards have led to significant incremental investment in manufacturing capacity and design, both of which are associated with job creation. As mentioned above, developing and making components like hybrid drivetrains can more easily be defined as additional energy efficiency jobs. On the other hand, some others such as light weighting, lower aerodynamic drag, low resistance tyres and gasoline direct injection engines have manufacturing processes that appear comparable to those of cars without these efficiency features in terms of labour input.

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[19] In some studies the split between direct and indirect jobs is not clear.

[20] For comparison, we assume the construction period of energy efficiency measures is one year. The labour intensity estimates in job years per USD 1 million are based on the IEA's estimates for 2016 capital costs and our job estimates used in Figure 3.8. Jobs for fuel supply for coal and gas are excluded as the capital costs do not include such investment. This comparison is illustrative and does not take into account the jobs required per unit of energy produced or saved, which in the cased of electricity generation, is described in more detail above.

[21] This is broadly comparable to the estimate for US DOE (2017) of 540 000 direct energy efficiency jobs in the construction sector in "Traditional HVAC goods, control systems, and services" and "Advanced Building Materials/Insulation" and 884 000 direct and indirect jobs in the entire supply chain of these technologies. The difference largely arises from our estimate of incremental energy-efficiency investment only, i.e. the additional spending above the average or standard energy performance rather than all the spending (and therefore employment) associated with construction of energy-efficient buildings.

Two recent studies consider the employment impact of the corporate average fuel efficiency (CAFE) standards in the US automotive industry. They estimate that nearly 500 000 employees are working on component parts that increase the fuel economy of vehicles out of a total of 1.1 million workers in the component parts sector (US DOE, 2017) and that 288 000 employees are working with automotive components and technologies that contribute to improved fuel efficiency (NRDC and BGA, 2017). Both studies include all employees involved with efficient vehicles and components rather than the net incremental employment impact of raising fuel-economy standards.

While improvements to the fuel economy of internal combustion engine vehicles has so far had a more powerful impact on oil demand than EVs, employment in EV manufacturing is rising. However, as with other types of efficient products, it is challenging to separate out EV-related employment from total employment in car manufacturing, because many popular EVs, for example the Renault Zoe, share a manufacturing platform with internal combustion engine cars. Tesla and certain Chinese manufacturers that only produce EVs are exceptions. One study that has attempted to count the number of US workers involved in the production of EVs or EV components produced an estimate of 12 000 direct jobs (manufacturing jobs for motor vehicles and component parts) and 42 000 indirect jobs along the entire value chain (US DOE, 2017).

It seems likely that the main employment impact of a switch to EVs would be associated with the production and installation of the electric drivetrain, including the battery, compared to an internal combustion engine. Producing internal combustion engines involves complex supply chains and requires more engineering resources than making an electric motor, but this difference may be offset by higher employment in battery manufacturing. We estimate that current battery manufacturing employs 8-12 employees to produce 1 000 EV batteries per year, which is slightly higher than the employment of internal combustion engine manufacturing. How this comparison would change as EVs reach the same economies of scale and manufacturing maturity as internal combustion engine cars is unclear.

Jobs and the transition to a low-carbon energy system

Achieving climate stabilisation will require a major reallocation of capital in the energy sector, with far more going to energy efficiency and low-carbon production, and far less going to fossil fuel supply and transformation. The reallocation of capital will inevitably have a major impact on employment.

A modelling analysis suggests that climate mitigation policies would result in job increases in the energy efficiency and renewable energy sectors and declines in the fossil fuel and energy-intensive sectors (OECD, 2017). Assuming unchanged levels of overall national employment, it has been estimated that global job reallocation would represent 1.5% of the total labour force were the global temperature increase limited to two degrees in 2050 (OECD, 2017). The disparity between regions in economic structure and human capital composition, however, underscores the importance of government policies to support this reallocation of capital.

However, there is no obvious one-to-one relationship between the transition to a low-carbon system and a net change in the number of jobs related to the energy sector as a whole. Switching investment from fossil fuels to low-carbon energy sources and technologies may create or destroy employment on a net basis, depending on the mix of technologies and time period. Clearly, some regions are better placed to create jobs on a net basis than others. To the extent that governments are concerned with a corresponding "just transition" of the workforce, various programmes and policy measures can be taken at company, community and country levels to retain, redeploy and retrain the workforce as well as to support investment in low-carbon infrastructure (OECD, 2017).

In the transition to a low-carbon energy system, employment related to energy efficiency as well as manufacturing and construction of low-carbon supply infrastructure will unambiguously increase at an aggregate level with a significant expansion of investment. Ultimately, the much lower energy demand associated with achieving the goal of limiting the global temperature increase to two degrees will probably reduce overall employment in energy supply, which might not be fully compensated by employment associated with improving energy efficiency, depending on technology choices. The net impact will vary across sectors. In power generation, for example, even with slower demand growth, the substitution of fossil fuel technologies with solar PV and wind, which generally run at lower load factors, means that more generating capacity will be needed for a given level of demand. This might boost employment in the power sector on a net basis. An internal combustion engine car running on corn-based ethanol might generate more jobs than an EV running on wind-generated electricity, but the latter might bring several benefits from an electricity-system perspective. The impact of lower energy demand would also be expected to lead to a net increase in jobs outside the energy sector, with energy savings boosting consumer purchasing power and inducing employment in other part of the economy.

A number of studies show a positive impact of the energy transition for countries that are fossil fuel importers and exporters of low-carbon related technologies, such as Germany and Denmark (Ragwitz et al., 2009; Lehr et al., 2008; OECD, 2017). This is unsurprising considering that it would involve the replacement of imported fuels with domestic capital investment. The impact on jobs will be harder to manage in countries where fossil fuel production or manufacturing supply chain serving fossil fuel industries play a major role today.

Renewable energy, improved energy efficiency and a transition to EVs bring major environmental benefits, which make their large-scale deployment a welcome and positive development regardless of any long-term economic and social benefits that may also accrue. In some countries, especially net fossil fuel importers with sophisticated engineering industries and good human capital, investment in clean energy may result in a significant boost to economic activity, job creation and employment rates. But hopes that green jobs are the answer to the problem of unemployment and middle class stagnation around the world are likely to prove wide of the mark. Nevertheless, governments are right to pay attention to the socio-economic impacts of a shift in investment to low-carbon energy: mitigating the negative side effects and ensuring broad social and employment benefits from of the transition to clean energy is important to maintaining the momentum of climate policymaking.

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4. Implications of investment

Highlights

- **An 17% decline in global energy investment since 2014 has not yet raised near-term energy security concerns,** which have been eased by excess capacity in global fossil fuel supply and electricity generation in some markets as well as cost deflation in many parts of the energy sector. However, a drop in upstream oil and gas activity and fewer final investment decisions on flexible power generation point to potential risks in the years to come. A combination of government policies and market signals will need to trigger an upswing in investment that will be needed to meet projected demand.
- **The recent slowdown in the sanctioning of conventional oil fields to its lowest level in more than 70 years may lead to tighter supply in the near future**. Given depletion of existing fields, the pace of investment in conventional fields will need to rise to avoid a supply squeeze, even on optimistic assumptions about technology and the impact of climate policies on oil demand. The energy transition has barely begun in the transportation and industrial sectors, which will rely heavily on oil, gas and coal for the foreseeable future.
- **In many cases, it is unclear whether business models in place are conducive to encouraging adequate investment in flexible electricity-supply assets, raising concerns about electricity security.** In 2016, the amount of new flexible generation capacity and storage that was given the green light worldwide fell to its lowest level in over a decade, with the sanctioning of grid-scale storage facilities only around 3% of the total. The 6% increase in electricity network investments in 2016, with a larger role for digital technologies, supports grid modernisation and variable renewables integration. But new policies are needed to strengthen market signals for investment in all forms of flexibility.
- **Despite rising GDP and energy demand, global energy-related CO2 emissions stagnated in 2016 for the third consecutive year.** This was mainly the result of protracted investment in energy efficiency, coal-to-gas switching and the cumulative impact of new low carbon generation. US shale gas production, in particular, enabled more than 1% of global coal generation to be replaced by gas in 2016. Wind and solar photovoltaic (PV) capacity additions reached a record level at 125 GW.
- **However, other low carbon sources are losing investment momentum.** While the expected generation from newly sanctioned solar PV and wind capacity has grown by around three quarters over the past five years, that from final investment decisions for nuclear and hydropower declined by around 55% over the same time frame. As a result, the expected low-carbon generation from sanctioned new facilities is not keeping pace with demand growth, falling far short of what is needed for the low carbon transition.

Overview

Timely investment is critically important for maintaining energy security, expanding energy access and achieving greenhouse-gas emission-reduction targets. Simply maintaining the current energy system would require continuous capital investment due to the need to replace depleting fossil fuel production facilities and ageing power-generation and network assets. Meeting growing energy services with improved efficiency and transforming the capital stock so as to move rapidly to low-carbon energy supply adds an additional consideration for investment. Among low-carbon sources, the most rapid technological progress and the biggest increase in investment in recent years has come from wind and solar PV, which require accompanying investment to facilitate their integration into the power system. Without investment in network upgrades, flexible power-generation capacity or electricity storage and demand response, embracing digital technologies to improve the efficiency, reliability and security of system operation, continuing investment in wind and solar power will quite simply not be sustainable.

Concerns about the adequacy of investment in upstream oil and gas have intensified over the past year. Since the 2014 oil-price collapse, investment in developing fossil fuel resources in what are considered geopolitically secure regions, such as the North Sea, North America and Australia, has plunged. Given that the bulk of upstream oil and gas investment worldwide is needed just to make up for the depletion of existing fields rather than meet the growth in demand and the high lead times of conventional development, the adequacy of current levels of investment to ensure energy security remains a valid concern.

Impact of energy investment in 2016

Implications of investment for energy security

Oil and gas supply security

The recent spectacular decline in upstream oil and gas investment raises major concerns about the prospects for the adequacy of supply in the years to come. Oil remains the leading primary energy source and, after four decades of decline, its share in the global energy mix has actually been increasing since 2014. None of the factors that led to stagnating global CO_2 emissions had any measurable impact on global oil demand. There is no doubt that current upstream investment is not sufficient to cover the medium-term growth in oil demand given the outlook for macroeconomic factors and current government policies as highlighted in the IEA's latest *Market Report: Oil* (IEA, 2017). The continued growth of the light tight oil industry in the United States, which is capable of ramping up production rapidly if markets tighten, is undoubtedly a positive development for supply security. However, underinvestment in longer lead-time projects, such as in the offshore, is a concern. IEA analysis points to the potential emergence of a supply-demand gap in the longer term that exceeds the potential for increasing light tight oil production in the short-term. The longer the investment gap lasts, the more likely it is that a sharp boom-and-bust cycle, characterised by project-management bottlenecks, shortages of human capital and rampant cost inflation, will reoccur.

Climate policies would only make a minor contribution to alleviating oil-supply security concerns. Given that 85% of the investment need is associated with replacing declining production from currently producing fields rather than increasing demand, the demand reduction from a potentially stronger climate policy does not have a proportional impact on reducing upstream investment needs. In the *IEA World Energy Outlook 2016* 450 Scenario, which meets an ambitious climate mitigation goal, very strong policies and rapidly declining oil demand shape investment but annual field development in the 2020s is still around 14 billion barrels compared to almost 10 billion in 2016.[1]

The security of gas supply also requires continuous investment. Current low-carbon deployment has a far bigger impact on demand for gas than for oil: international gas markets are well-supplied largely because of recent gains in the efficiency of electricity end use and the increase in low-carbon electricity generation. However, implementation of the Paris Agreement and tackling of local air pollution concerns would likely lead to gas taking an important share of new electricity supply to compensate for less use of coal and to provide flexibility for renewables. As LNG projects have high lead times, the sharp deceleration of LNG investment in the past two years coupled with rising demand could potentially lead to market tightness and volatility.

It remains to be seen whether energy policies as they stand provide a sufficient institutional basis for developing new upstream resources. Even with abundant gas resources, energy security can be compromised if underinvestment in pipelines creates infrastructure bottlenecks. This is the case in the northeastern United States (in particular New England) and India. Given strong gas demand for heating buildings, both Europe and the People's Republic of China (hereafter, "China") will need to develop and maintain substantial amounts of gas-storage capacity. Nevertheless, in both regions, it is unclear how regulatory reforms will affect the attractiveness of investing in storage. Europe has witnessed the mothballing of storage capacity and the cancellation of several projects. Gas storage capacity in China is increasing, but at a considerably slower speed than winter heating demand. In Africa, a lack of investment in pipelines is preventing the reduction of gas flaring and the use of gas for power generation from already producing fields, which would help improve access to electricity for poor households. The status of nuclear power also has a major impact on gas supply security. For example, were the US nuclear fleet were to be phased out and replaced by gas turbines, the increase in gas use would be equivalent to over one-third of current US shale gas production a quantity comparable to the projected US and Australian exports at the end of the decade.[2]

[1] The amount of resources sanctioned in 2016 includes 4.7 billion barrels of conventional crude oil reserves and almost 5 billion barrels of tight oil.

[2] The energy-security implications of gas-market development will be investigated in detail in the *World Energy Outlook 2017* (IEA, 2017).

Electricity security will depend on a viable business model for flexibility

The ability of electricity systems to maintain supply security during a rapid technological transformation has become a policy priority.[3] In most cases, the bulk of the flexibility that has been provided to assure system adequacy during peak demand periods and, as they reach higher shares, to help integrate wind and solar capacity into the electricity systems is provided by existing assets, primarily internal dispatchable capacity (mainly gas-fired plants and hydropower) or external capacity through interconnections. New technological options, such as batteries and demand response, have potential, but still play only a minor role. In 2016, investment decisions for new hydropower and gas turbines declined by over 20 GW, whereas those for grid-scale batteries increased by only 0.8 GW.

The facilities that provide flexibility are often decades-old. Investing in new ones is not always viable under the current regulatory framework. While digital solutions could improve the flexibility contribution of both transmission and thermal plants, there are limits to such “asset-light” approaches. In parallel, concerted efforts to improve the efficiency of electricity end-uses, such as air conditioners, could reduce investment needs by cutting peak demand.

Practically all the wind and three-quarters of solar deployment that took place in 2016 went to large, utility-scale projects, which rely on a robust electricity network. Even for residential solar, the vast majority of households with panels remain connected to the grid. For a family with a full set of household appliances living in a temperate climate, a disconnected solar self-supply in most cases is not a practical option. Network investment remains robust for now, but worries have emerged in several regions about the prospect of a “utility death spiral” as the long-term economic viability of grid investments diminishes. The still widespread regulatory practice of remunerating fixed network assets on the basis of a variable per kWh charge is poorly suited for a power system with a large amount of decentralised solar PV and storage capacity. The failure of regulatory approaches to keep up with technological changes is a potential risk for the security of electricity supply and can enhance the potential for supply interruptions.

Batteries are unlikely to become a “one size fits all” single solution to electricity security and flexibility provision. While batteries are well-suited to frequency control and shifting hourly load, they cannot provide seasonal storage or substitute the full range of technical services that conventional plants provide to stabilise the system. In the absence of a major technological breakthrough, it is most likely that batteries will complement rather than substitute conventional means of providing system flexibility. While conventional plants continue to provide essential system services, their business model is increasingly being called into question in unbundled systems. The electricity commodity produced is increasingly a by-product and sold into wholesale markets, often at depressed or volatile prices. On the other hand, the valuation and remuneration of the services they provide to

[3] While this has been assessed in detail in other IEA publications, some investment-specific considerations are highlighted here.

the system are often not defined as a specific product and in most cases faces regulatory uncertainty as balancing arrangements can repeatedly change. Even if grid-scale batteries were perfect substitutes for conventional generating capacity, their expansion would need to be scaled up by at least a factor of seventy five from 2016 deployment to replace the slowdown in 2016 capacity growth from flexible gas power and hydropower.

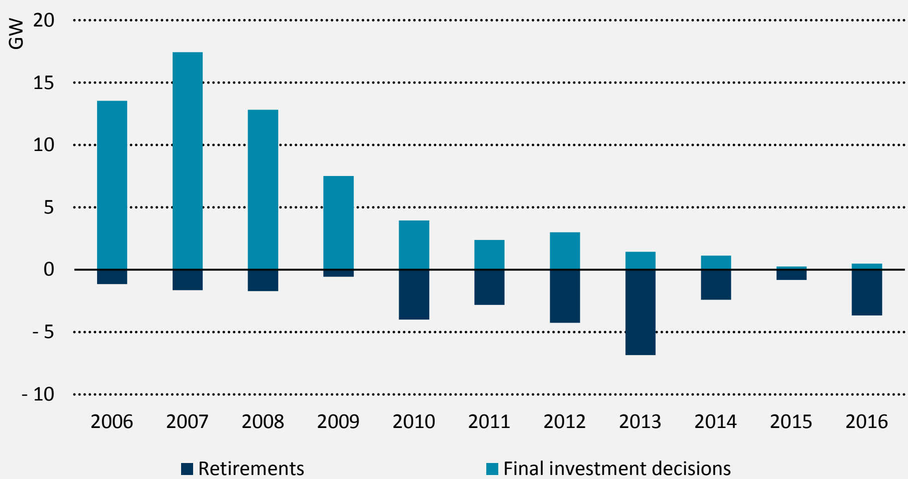
Both storage technologies and demand response face investment difficulties of their own, because electricity prices usually do not reflect the genuine system value of distributed resources in a location and time-specific fashion in providing peak power or bypassing network bottlenecks. Some regulators treat batteries as grid assets, while others treat them as power plants running on cheap electricity. The EU clean energy package, proposed in 2016, aims to clarify this by mandating system operators to procure flexibility rather than to own batteries. In the absence of such flexibility provision or a long-term power-purchase contract, storage assets might struggle to attract financing. In reality, batteries could be considered both grid assets and alternatives to generating plant and their value could come from multiple services. A comprehensive regulatory approach to enable sustained investment in flexible resources and infrastructure is an essential precondition both for the continued growth of renewables as well as the maintenance of electricity security.

Electricity security concerns differ across regions

In **Europe**, a sizeable increase in gas-fired capacity will be needed to provide system flexibility in view of the looming decommissioning of large amounts of baseload coal and nuclear capacity across the continent and the seasonal mismatch between winter peak demand and summer solar production. While capacity balance is adequate, ageing nuclear capacity and cold weather conditions can create periods of tightness such as January 2017. In the IEA *World Energy Outlook* 450 scenario, existing coal plants are not replaced by gas capacity on a one-to-one basis given expansion in the use of renewables, demand response and storage. Even so, the gas capacity needed to maintain system balance in Europe increases by over 40 GW by 2030 in that scenario. There are very real doubts about whether this will happen, given the collapse in investor confidence and the current lack of investment in gas capacity. Every year since the financial crisis, retirements of gas plants in the European Union exceeded final investment decisions for new plants (Figure 4.1).

In the **United States,** investment in gas-fired capacity remains strong. Moreover, some of the highest renewable shares are in states that have retained a regulated utility industry and thus organise network operation, balancing and the operation of conventional plants into a single company. The ability of these vertically integrated utilities to continue to invest is determined by regulatory decisions. Like in Europe, the decommissioning of nuclear and coal-fired plants will decrease baseload capacity with higher reliance on variable renewables and a flexible use of gas. Even with abundant shale gas resources, the nuclear and coal capacity of the northeastern United States has been indispensable to keeping the lights on during extreme weather conditions, such as the Polar Vortex of 2014. Transmission infrastructure investment is steady, but inter-regional interconnection capacity remains much lower compared with the size of the system than in Europe. This limits the benefits coming from the geographical dispersal of renewable production. Investor interest in interconnection is increasing. For example, Plains & Eastern – a major transmission line linking Oklahoma with Tennessee – cleared the regulatory process in 2016. On the other hand several other transmission projects face regulatory and licensing barriers.

Figure 4.1 Sanctioned gas-fired generating capacity and retirements in the European Union



Flexible gas-fired capacity in Europe is shrinking as new investment dry up and retirements accelerate, prompting concerns about system security as the penetration of variable renewables continues to grow.

Sources: Calculations based on Platts (2017); World Electric Power Plants Database, McCoy Power Reports (2017), dataset.

Australia experienced two significant electricity-supply security events in 2016 and 2017, triggering an intense debate about the role of renewables and highlighting the vital importance of policy decisions even in countries with abundant natural resources. Australia has one of the highest proportions of households with PV systems on their roof of any country in the world, and its electricity use in its National Electricity Market is spread out over a huge and weakly connected network. It appears that a series of accompanying investments and regulatory changes are needed to utilise Australia's abundant wind and solar potential: changing system operation methods and reliability procedures as well as investment into network capacity, flexible generation and storage.

In **China,** electricity security is being enhanced by continuing heavy investment in generating capacity and networks. However, utilities need to adapt to stagnating and, in some cases, declining thermal generation. The most attractive renewable resources are in remote regions and curtailment is emerging as a serious investment risk for renewable projects because of transmission bottlenecks. Market reforms are progressing and a proposed quota may enhance the procurement of renewables by generators and grid companies, but pricing still does not provide incentives for optimised dispatch and project location.

India has been very successful in ramping up investment in conventional generation and renewables, especially solar. Nevertheless, the governance and financial stability of the state distribution companies continues to impede the ability and willingness to invest in generation and networks. The country's fleet of thermal generating plants is made up of mainly inefficient and inflexible subcritical coal-fired stations. More flexible conventional capacity, including gas-fired plants, better connections with hydro resources and investment in battery storage will be needed to support continued growth in solar power.

Energy investment and CO_2 emissions

World energy-related CO_2 emissions stagnated in 2016 for the third year in a row, despite healthy global growth in gross domestic product (GDP). While this is undoubtedly a positive phenomenon, trends in energy investment in 2016 suggest the possibility that this could be a temporary pause rather than a structural peak in emissions.

A drop in energy intensity causes global CO_2 emissions to level off

The single most important component of the recent decoupling of emissions from GDP growth was a decline in energy intensity.[4] While a structural shift towards the service sector played an important role in some key countries, declining intensity also resulted from investments in energy efficiency. Nevertheless in China, electricity demand growth rose to around 4% with service sector demand expanding at a faster rate. Due to large investments in modern ultra-supercritical coal plants, the average thermal efficiency of coal plants in China has improved markedly, reducing CO_2 emissions by a total of around 25-30 million tonnes in 2016 compared with what would have been emitted had efficiency not improved. Despite strong power demand growth the overall energy intensity of the Chinese economy continued to improve, leading to lower coal use in industry. There are clear indications of improving energy efficiency in India as well, in part thanks to the roll-out of highly energy-efficient light-emitting diode (LED) lightbulbs.

In the transportation sector, the demand impact of low oil prices continues to hinder efficiency improvements and efforts to curb CO_2 emissions. Despite a surge in sales of electric cars (EVs) and shared transport, global gasoline consumption grew almost as fast as GDP. Jet fuel demand grew even faster than global GDP, indicating the powerful impact of a growing middle class in emerging economies on the demand for flying. If they all run on zero-carbon electricity, the EVs sold in 2016 would reduce emissions by over

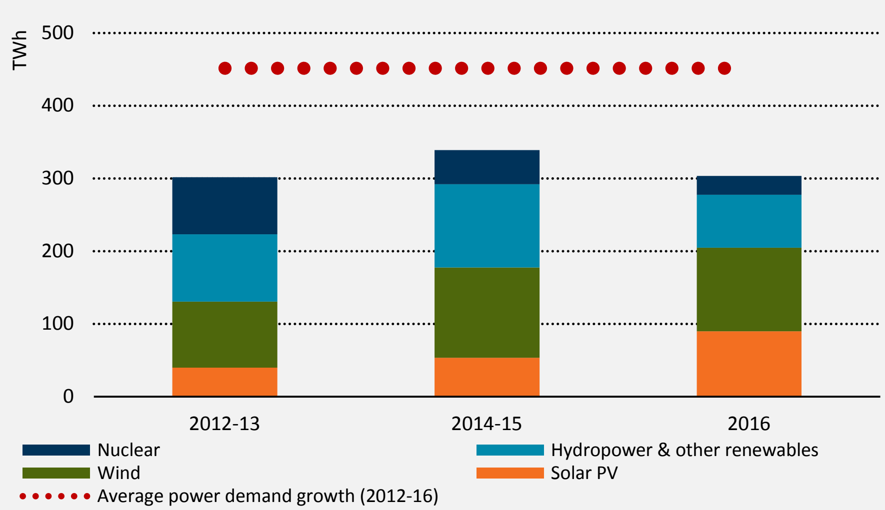
[4] Measured as primary energy consumption per dollar of GDP.

1 million tonnes, but that compares with an 80 million tonne increase from gasoline-fuelled cars. Low oil prices kept gasoline demand growth, at 2.4%, higher than the average over the previous five years. Overall, transportation sector emissions continued to rise.

Investment in low-carbon electricity is not keeping pace with demand

The large-scale deployment of low-carbon technologies and switching from coal to gas in both new and existing power plants largely offset the impact of rising electricity demand worldwide, leading to stagnation in global emissions from power generation in 2016. Overall, investment in renewable power dropped slightly in 2016, though total capacity additions continued to rise on the back of 50% stronger solar PV deployment. The wind turbines and solar panels alone that were installed in 2016 are expected to contribute around 1% of global power generation; in the past five years their annual contribution to new generation has increased by around three quarters (Figure 4.2). Switching to gas was a particularly important contributor to lower emissions in the United States, Europe and China. In 2016 global coal fired generation fell to 4% below its 2014 peak, compared to 3% annual growth from 2000 to 2014.

Figure 4.2 Expected annual average power generation from final investment decisions for new low-carbon generating capacities



The boost to low-carbon generation provided by wind and solar capacity additions in the past five years may be almost entirely offset in the future by lower hydro and nuclear investment, whose investment decisions plummeted in 2016.

Note: Generation is based on the expected annualised output of sanctioned gross additions to capacity in a given year. Nuclear plant FIDs are based on reported construction starts.
Source: Calculations for nuclear and hydropower FIDs based on IAEA (2017), Power Reactor Information System (PRIS) and McCoy Power Reports (2017), dataset.

Investment in other low carbon sources is slowing. Over the past five years, fewer final decisions have been taken on investing in nuclear and hydropower, the impact of which is expected to almost entirely offset the boost to low-carbon generation provided by wind and solar capacity additions. This means that the contribution of expected new low-carbon generation is not keeping pace with demand growth, which over the past five years has averaged near 450 TWh, or 50% higher than the expected new low-carbon generation sanctioned in 2016 (Figure 4.2). Expected annual generation from the low-carbon capacity that was brought online in 2016 was equal to only around 90% of the increase in demand in the same year. In 2015, expected annual generation from the new low-carbon capacity outpaced demand growth.

Climate policies help to drive down costs and boost new low-carbon technologies

At the request of the German Presidency of the G20, the IEA in co-operation with IRENA, has analysed the investment pathway that would be consistent meeting the limiting the global temperature increase to two degrees under the Paris agreement. The extent of transformation needed is profound. Average annual investment needs for the energy sector reach USD 3.5 trillion in 2050 compared with 1.7 trillion in 2016 (IEA and IRENA, 2017). The investment increase is primarily driven by the scaling up of energy-efficiency investment as well as a 150% increase in renewable investment. Fossil fuel investment needs decline. The risks of fossil fuel assets not fully recovering their investment costs are, nevertheless, manageable, provided that early and consistent policy action facilitates the transition. Delaying the implementation of low-carbon investment policies increases such risks in a non-linear fashion. The low-carbon investment pathway also has major additional benefits for local air quality, as SO_2, NO_x and PM emissions are significantly lower.

Investment in renewables is already clearly benefiting from the increased momentum of government climate policies: practically all countries have introduced measures to boost investment in renewables as part of their Nationally Determined Contributions following the Paris Agreement. Highly successful new renewable tenders took place in countries where the natural conditions are favourable but the current renewable share is still low, for example in Mexico and India. The increased use of various risk-mitigation schemes to reduce the cost of financing played an important role in several developing regions, notably in Africa. Declining costs – in large part the consequence of past policies – are boosting the attractiveness of investing in solar PV and wind and expanding the range of countries that are major renewable investors. In the case of large hydro and nuclear power, the other main types of low-carbon power generation, the capacities that came online in 2016 were the result of investment decisions taken several years before. For hydropower, global deployment declined by nearly 10% while new nuclear plant commissioning was relatively stable. In China, the growth in hydro and nuclear generation in 2016 each had a bigger impact on Chinese emissions than solar PV by a factor of four, despite China being by far the largest solar investor in the world. Hydropower production there also benefited from favourable weather conditions. In the United States, the growth of hydro production equalled the growth of solar production, despite stagnating hydro capacity and record high solar deployment as droughts eased.

The wave of investment in long lead-time large scale low-carbon generating capacities appears to be coming to an end. Both large hydropower and nuclear saw far fewer final investment decisions in 2016 than in previous years. Capacity additions for hydropower, currently the largest low-carbon generating technology in terms of electricity production, are slowing primarily in China, and there is as yet not enough of an increase in investment elsewhere to compensate.

The near-term prospects for nuclear power are also weak, at least outside China. In both Europe and North America, nuclear is still the largest low carbon source by a wide margin. The few ongoing nuclear projects in both regions are plagued by delays and cost overruns, triggering considerable degree of financial distress in the nuclear engineering industry. In the case of the French company, Areva, government intervention has been needed to stabilise the financial position of the company, while the US company Westinghouse declared bankruptcy in 2017. In the United Kingdom, the Hinkley Point plant was finally given the go-ahead to begin construction in 2016, representing the first Chinese equity investment in a nuclear project outside China. But several nuclear plants across Europe and North America were shut down, including some units that received regulatory approvals for lifetime extension, in the face of low wholesale prices caused by cheap gas and renewables with zero marginal costs. The impact is significant: since 2010, the expected lost production from capacity that has been decommissioned is equal to around 30% of the generation expected from new wind and solar PV in the two regions. Neither region has effective policies in place to prevent the premature decommissioning of existing nuclear plants. In Asia, India brought online a Russian-designed unit that started construction in 2001, but has not launched any new projects since 2011. The government announced an ambitious programme for 10 new reactors, but this is yet to result in any investment. Viet Nam has suspended its nuclear programme, while the future of the Japanese nuclear fleet is still uncertain. The construction of Barakah in the United Arab Emirates is progressing well, but none of the other projects in the Middle East or planned projects in South Africa and Egypt has reached the construction stage. Nuclear investment is increasingly concentrated in China and the Russian Federation (hereafter, “Russia”).

The immediate prospects for carbon capture and storage (CCS) have improved as four large-scale projects are set to start up in 2017, including the first major project in China. The opportunity to apply CCS to oil sands operations remains, but recent decisions by some oil majors to reduce oil sands activities make a repeat of Shell’s Quest CCS project unlikely in the coming years. Renewed policy attention around the world is needed to reinvigorate investment in early commercial CCS projects in industrial and power sector applications.

Coal to gas switching benefits from previous investment into LNG and gas capacity

The increased share of gas in power generation in 2016, largely at the expense of coal was an important contributor to holding down the growth in emissions in that sector. Only a small proportion of the increase in gas-fired generation came from new plants. Switching to gas was most pronounced in the United States. With a 3.5% jump, gas-based generation in the United States accounted for 40% of the reduction of total global coal-fired generation in 2016, reducing CO_2 emissions by around 85 million tonnes compared with what they would otherwise have been. The bulk of the fuel switching came from increased utilisation of existing gas plants to take advantage of favourable economics for gas compared with coal. Switching from coal to gas also contributed to emission reductions in Europe as well, almost entirely involving existing plants. Low gas prices thanks to strong supply from Russia and abundant LNG made gas a more attractive option for generators, despite carbon prices under the EU Emissions Trading Scheme remaining at a very low level. There is practically no new investment in gas-fired power generation capacity in Europe, because of depressed wholesale prices and low average utilisation rates that are expected to decline further over time. Several modern, high efficiency plants have been mothballed. There is a further scope for short-term switching from coal to gas in existing plants if carbon prices increase or the price of coal rises relative to that of gas. The European Electricity Association (Eurelectric) has also announced its commitment to not invest in new-build coal-fired power plants after 2020.

Switching from coal to gas in China and India also helps to hold down emissions

There was also a sizeable amount of switching from coal to gas in China in 2016. Gas increased its share in the country's primary energy mix from 5.8% in 2015 to 6.3%. Most of the switching occurred in heating of buildings and industry. Gas use also expanded in India primarily in industry. In both China and India, air-quality regulations together with low Asian LNG prices were the main drivers of the switch to gas. Nevertheless, domestic coal remains robustly competitive in both China and India even at the current LNG prices.

The competitiveness of gas benefited from both excess production capacity in Russia as well as LNG market developments. As a result of major Australian projects entering into production and US exports ramping up as well as persistent demand weakness in Japan and Korea LNG markets were characterized by abundant supply and low prices. Asian LNG prices averaged around USD 6 per Mbtu, well below even the most optimistic assumptions of the cost of developing new supply. Similarly, European prices covered the marginal cost of existing Russian production but not the cost of new developments. There was very little new investment into LNG capacity in 2016 and Russian production continued to rely on existing fields like Bovanenkovo that took investment decision in 2009. The ongoing debate on the long term role of gas has a noticeable impact on investor confidence especially for long lead time projects. A sustained period of underinvestment into new LNG supply might trigger a boom and bust market tightening and reverse the competitiveness gains of gas versus coal especially in Asia.

Low-carbon investments are not on track to meet climate change objectives

Our analysis of investment activity in 2016 suggests a cautious interpretation of the recent stagnation of global CO_2 emissions. Both the increased reliance on low-carbon energy sources and switching from coal to gas – the main reasons behind the levelling off of emissions – benefited largely from projects that were launched several years ago when market conditions were much more favourable than those of today. Collectively, investment in energy efficiency and low-carbon energy is not on track to meet the goal of limiting the global increase in temperature to under 2°C. While investment in solar PV and wind power is broadly consistent with the *IEA World Energy Outlook* 450 scenario, investment in other low-carbon technologies currently falls far short. If the shortfall were to be made up by even more solar PV and wind power, investment in these sources would need to scale up by more than a factor of three, requiring an extra wind turbine every eight minutes and 20 additional solar panels every second on top of the rate of investment observed in 2016. A broad diversified technology portfolio will be essential for the transition to a low-carbon system.

Technology change, regulation and energy investment

The impact of technological change and energy-policy developments on the structure and organisation of the energy industry is often seen as potentially leading to underinvestment in energy-supply infrastructure. This concern is especially prevalent in the electricity industry. For a century, electricity utilities have invested in power generation and grid, and purchased primary energy inputs to produce power and sell it by the kWh to their clients. Market reforms, involving the unbundling of the electricity-supply chain and the creation of a competitive wholesale market, have been introduced in a growing number of countries, but the basic model of buying primary energy and selling electrical energy remains.

The sustainability of this model is being questioned: decentralised solar PV, battery storage and charging EVs blur the distinction between consumers and producers, while demand-side response programs have the potential to provide flexibility in balancing supply and demand in real time at a lower cost than utility-owned generating capacity. In addition, digitalization is opening up opportunities for new entrants to the supply of energy services and is changing the interaction of consumers with the electricity system. A number of companies, both established utilities and new entrants, are experimenting with new, aggregation or service based business models. Regulatory frameworks will need to adapt to these models providing the appropriate arrangements to allow them to contribute to the overall efficiency and decarbonisation of the energy system. The implications of all these changes for future investment are still very unclear.

In the oil industry, the basic investment model is still broadly intact, but important changes are taking place in the allocation of capital. The prospect of oil demand peaking in the foreseeable future is being is being discussed by major investors and is starting to affect investment decisions. There is a marked shift in the types of projects being pursued: for nearly a century, investment tended to be directed at ever larger and more complex projects with long lead times. This changed abruptly with the emergence of the shale industry in the United States, pioneered by medium-sized independents. The past two years have witnessed a remarkable shift in the investment strategy of the majors, which are starting to abandon high-cost assets, such as in the Artic offshore and oil sands, or sell them off to specialist investors and reallocate spending to shale projects. Corporate finance is also changing. Traditionally, the low marginal cost of production of existing assets provided ample cash flow for investment from retained earnings and for paying dividends. This has changed with shale independents raising new capital for investment and lower oil prices compressing the cash flow of majors. Large oil companies have recently borrowed tens of billions of dollars in order to maintain dividends, triggering discussions about the sustainability of their finances.

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Abbreviations and acronyms

AC	alternate current
ADB	Asian Development Bank
AfDB	African Development Bank
ARA	Amsterdam-Rotterdam-Antwerp
BEV	battery-electric vehicle
BNEF	Bloomberg New Energy Finance
CAFE	corporate average fuel economy
CCGT	corporate average fuel economy
CCS	carbon capture and storage
CO_2	carbon dioxide
DC	direct current
DAP	Dakota Access Pipeline
EBRD	European Bank for Reconstruction and Development
ECA	export credit agencies
EESL	Energy Efficiency Services Ltd.
EIB	European Investment Bank
ESCO	energy service company
ESPO	Eastern Siberia-Pacific Ocean Pipeline System
EV	electric vehicle
FCF	free cash flow
FERC	Federal Energy Regulating Commission (US)
FID	final investment decision
FSRU	floating storage regasification unit
HFC	hydrofluoric carbon
HV	high voltage
HVAC	heating, ventilation and cooling
HVDC	high voltage direct current
ICT	information and communication technology
IDFC	International Development Finance Club
IDBG	Inter-American Development Bank Group
IDR	Indonesia rupee
IECC	International Energy Conservation Codes
IEA	International Energy Agency
IPO	initial public offering
IPP	independent power producer
IRENA	International Renewable Energy Agency
ISO	independent system operator
JV	joint venture
KXL	Keystone XL
LCE	levelised cost of electricity
LDV	light-duty vehicle
LED	light-emitting diode

LNG	liquefied natural gas
M&A	mergers and acquisitions
MDB	multilateral development banks
MLP	master limited partnership
NDC	nationally determined contributions
NDRC	National Development and Reform Commission (China)
NEA	Nuclear Energy Agency
NOC	national oil company
OECD	Organisation for Economic Co-operation and Development
OEM	original equipment manufacturer
OPEC	Organisation of Petroleum Exporting Countries
PACE	property-assessed clean energy
PCI	project of common interest
PLN	Perusahaan Listrik Negara
PPA	power purchase agreement
PSC	production sharing contracts
PSP	pump-hydro projects
PV	photovoltaic
R&D	research and development
REIT	real estate investment trust
SOE	state-owned enterprise
SPV	special purpose vehicle
SSA	sub-sovereign and agency
T&D	transmission and distribution
TTF	title transfer facility
UHV	ultra-high voltage
UICI	Upstream Investment Cost Index
USICI	Upstream Shale Investment Cost Index
VC	venture capital
VIU	vertically integrated utility
WACC	weighted average cost of capital
WBG	World Bank Group
WEI	World Energy Investment
WEO	World Energy Outlook

Units of measurement

Energy		
	Wh	watt hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Mass		
	g	gramme
	kg	kilogramme
	t	tonne
	Mt	million tonnes
	Gt	billion tonnes
Monetary		
	USD million	1 US dollar x 10^{6}
	USD billion	1 US dollar x 10^{9}
	USD trillion	1 US dollar x 10^{12}
Temperature		
	°C	degree Celsius
Gas		
	bcm	billion cubic metres
Oil		
	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
	Mboe/d	million barrels of oil equivalent per day
Power		
	kW	kilowatt (1 watt x 10^{3})
	MW	megawatt (1 watt x 10^{6})
	GW	gigawatt (1 watt x 10^{9})
	TW	kilowatt (1 watt x 10^{12})
Transport		
	km	kilometre

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World Energy Investment 2017

The second annual IEA benchmark analysis of energy investment – the lifeblood of the global energy system – presents diverse findings, with upbeat news in some quarters and bearish indicators in others.

World Energy Investment 2017 provides a critical foundation for decision making by governments, the energy industry and financial institutions.

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- Investments are growing the fastest in which fuels and technologies?
- How are oil and gas companies reinventing themselves to survive the new technology and price environments in the sector?
- How might energy investment trends affect energy security and climate change mitigation?
- How are business models evolving with the changing availabilities of capital for different energy sources?
- What are governments and the energy sector spending on energy R&D, and who are the biggest spenders?

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