World Energy Outlook 2018

International Energy Agency
Secure
Sustainable
Together

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 30 member countries, 8 association countries and beyond.

The four main areas of IEA focus are:

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

IEA member countries:

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

International Energy Agency
Secure Sustainable Together

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

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

The *World Energy Outlook* (*WEO*) provides a unique reference for the international debate on energy. It also plays an essential guiding role for the International Energy Agency's own strategic thinking, underpinning the Agency's role as the global energy authority.

The *WEO-2018* reminds us of the fundamental shift that is taking place in the geography of global energy demand towards developing economies. That is why, as one of the three pillars of the Agency's modernisation strategy, I have put such emphasis on "opening the doors" of the IEA to key energy players from around the world. With the support of our member countries, we have welcomed Mexico as a new member of the Agency and are building very close institutional ties with new Associate members: Brazil, China, India, Indonesia, Morocco, Singapore, South Africa and Thailand.

The special focus on electricity in this year's *Outlook* demonstrates not only the huge opportunities that arise with the transformation of the global power sector, but also some potential risks. The second pillar of our strategy at the IEA is to reinforce and reappraise our approaches to energy security: alongside work on oil and natural gas, electricity security is becoming a major focus for IEA analysis and engagement.

This new edition also underscores that the world is still a long way from meeting its environmental objectives, both in terms of climate and air quality. That is why the third pillar of our modernisation strategy is to transform the Agency into a global hub for co-operation on clean energy technologies and energy efficiency. Our new Clean Energy Transitions Programme is a clear signal of this ambition: a multi-year initiative to accelerate deployment of clean energy technologies, particularly in major developing economies.

Most importantly, the *WEO* underlines once again that *policies matter*. We should not underestimate the effort required to get to the outcomes described in our main scenario, the New Policies Scenario, which holds up a mirror to the ambitions of policy makers around the world, as they exist today. But nor should we underestimate the need and the potential to improve on these outcomes and to deliver a more secure, affordable, and sustainable energy future. The key message from this *WEO* is that decisions made by governments will play a critical role in this respect, and the IEA stands ready and willing to provide its support for these endeavours.

I would like to applaud the excellent work of the *WEO* team led by Laura Cozzi – who has taken on the role of the IEA's Chief Energy Modeller – and Tim Gould. I also take this opportunity to thank the many friends and colleagues from around the world that provided valuable comments and expertise during the preparation of the new *Outlook*.

Dr. Fatih Birol
Executive Director
International Energy Agency

This study was prepared by the *World Energy Outlook* (*WEO*) team in the Directorate of Sustainability, Technology and Outlooks (STO) in co-operation with other directorates and offices of the International Energy Agency. The study was designed and directed by **Laura Cozzi**, Chief Energy Modeller and Head of Division for Energy Demand Outlook, and **Tim Gould**, Head of Division for Energy Supply and Investment Outlook.

Timur Gül led the environment and demand modelling, and contributed to the electricity focus. The special focus on electricity was co-ordinated by **Brent Wanner**, lead on power sector modelling and analysis, and **Stéphanie Bouckaert**, lead on end-use modelling and analysis. **Christophe McGlade** led the work on the emissions intensity of oil and gas supply and the oil analysis. **Paweł Olejarnik** co-ordinated the oil, natural gas and coal supply modelling. Key contributions from across the *WEO* team were from: **Zakia Adam** (lead on data management, contributed to fossil fuel subsidies), **Ali Al-Saffar** (lead on producer economies), **Yasmine Arsalane** (lead on the European Union (EU) Energy Union analysis, power sector modelling), **David Attlmayr** (demand-side response analysis), **Adam Baylin-Stern** (industry, contributed to electricity focus), **Michela Cappannelli** (oil, gas, bioenergy), **Jean Chateau** (producer economies), **Olivia Chen** (energy access and environment, buildings), **Arthur Contejean** (energy access), **Hannah Daly** (lead on energy access), **Davide D'Ambrosio** (power sector modelling and data management, contributed to electricity focus), **Valeria Di Cosmo** (electricity focus), **Valentina Ferlito** (lead on renewables support, contributed to electricity focus), **Karthik Ganesan** (India analysis in the electricity focus), **Timothy Goodson** (co-lead on buildings demand, demand-side response and contributed to electricity focus), **Asbjørn Zachariassen Hegelund** (industry, contributed to electricity focus), **Paul Hugues** (lead on transport, contributed to energy efficiency and renewables), **Tae-Yoon Kim** (lead on petrochemicals, oil refining and trade, contributed to gas), **Aaron Koh** (electricity focus, renewables support), **Zeynep Kurban** (hydrogen), **Raimund Malischek** (coal, gas), **Wataru Matsumura** (producer economies, electricity focus), **Kieran McNamara** (electricity focus and contributed to renewables and efficiency chapter), **Claudia Pavarini** (lead on storage, power sector modelling), **Apostolos Petropoulos** (transport, contributed to electricity focus), **Andrew Prag** (lead on the Sustainable Development Scenario chapter, contributed to electricity focus), **Diana Alejandra Rodriguez Barrera** (producer economies, oil), **Andreas Schröder** (industry), **Toshiyuki Shirai** (producer economies, fossil fuel subsidies), **Glenn Sondak** (oil, gas), **Molly A. Walton** (lead on energy-water nexus), **Kira West** (industry), **David Wilkinson** (power sector hourly modelling, electricity focus) and **Peter Zeniewski** (lead on natural gas). **Teresa Coon**, **Eleni Tsoukala** and **Marina Dos Santos** provided essential support.

Edmund Hosker carried editorial responsibility. **Debra Justus** was the copy-editor.

The special focus on electricity was developed by a cross-agency Electricity Focus Working Group drawn from all relevant directorates and offices of the IEA, in addition to the *WEO* team. **Luis Munuera** from the Energy Technology Policy (ETP) Division led the analysis on flexibility in electricity systems. Also from the ETP Division, **Araceli Fernandez Pales**,

Peter Levi and **Tiffany Vass** contributed to the analysis on industry; **John Dulac** and **Thibaut Abergel** contributed to the analysis on buildings; **Jacob Teter** and **Marine Gorner** contributed to the analysis on transport; and **Uwe Remme** contributed to the analyses on energy storage and hydrogen. **George Kamiya** from the Energy Environment Division contributed to the analysis on buildings, transport and digitalization. **Kevin Lane**, **Joe Ritchie** and **Sacha Scheffer** from the Energy Efficiency Division contributed to the analysis on energy efficiency. **Heymi Bahar** from the Renewable Energy Division contributed to the analyses on distributed generation and affordability of electricity. From the System Integration of Renewables Unit, **Simon Mueller** and **Peerapat Vithayasrichareon** contributed to the analyses on renewables integration and flexibility; and **Zoe Hungerford, Enrique Gutierrez** and **Craig Hart** contributed to the analyses on India, renewables integration and flexibility. **Yugo Tanaka** from the Office of Global Energy Relations contributed to the India analysis. **Cesar Alejandro Hernandez** from the Gas, Coal and Power Markets Division, **Michael Waldron** and **Alberto Toril** from the Economics and Investment Office contributed to the analysis on investment, markets and security.

Mechthild Wörsdörfer, Director of STO, and David Turk, Acting Director of STO, provided valuable guidance at different stages of the work. Valuable comments and feedback were provided by senior management and numerous other colleagues within the IEA. In particular, Paul Simons, Keisuke Sadamori, Amos Bromhead, Rebecca Gaghen, Duncan Millard, Laszlo Varro, Neil Atkinson, Peter Fraser, Paolo Frankl, Brian Motherway, Aad Van Bohemen, Aya Yoshida, Christian Zinglersen, Simon Bennett, Niels Berghout, Thomas Berly, Alessandro Blasi, Toril Bosoni, Jean-Baptiste Dubreuil, Carlos Fernández Alvarez, Kathleen Gaffney, Peter Janoska, Caroline Lee, Juho Lipponen, Armin Mayer, Samantha McCulloch, Sara Moarif, Bruce Murphy, Yoko Nobuoko, Kristine Petrosyan, Cedric Philibert, Roberta Quadrelli, Céline Rouquette, Melanie Slade, Tristan Stanley, Jeremy Sung, Cecilia Tam, and Matthew Wittenstein. The Energy Data Centre provided support and assistance throughout the preparation of the report.

Thanks go to the IEA's Communication and Information Office for their help in producing the final report and website materials, particularly to Astrid Dumond, Christopher Gully, Jad Mouwad, Bertrand Sadin and Rob Stone. Diana Browne provided essential support to the peer review process.

Valuable input to the analysis was provided by: Markus Amman, Peter Rafaj, Janusz Cofala, Gregor Kiesewetter, Wolfgang Schöpp, Chris Heyes, Zbigniew Klimont, Jens Borken-Kleefeld, Pallav Purohit and Adriana Gómez-Sanabria (International Institute for Applied Systems Analysis); Colin Ward (King Abdullah Petroleum Studies and Research Center); Stephen J. Lee, Ignacio Pérez-Arriaga, Eduardo Sánchez, Andrés González and Pedro Ciller (MIT-Comillas Universal Energy Access Lab); Faisal Wahid and Christopher Andrey (Artelys); David Mooney and Anthony Lopez (National Renewable Energy Laboratory); Eric Masanet (Northwestern University); and Per Magnus Nysveen (Rystad Energy).

The work could not have been achieved without the support and co-operation provided by many government bodies, organisations and companies worldwide, notably: Chevron;

Council on Energy, Environment and Water, India; Enel; Energy Market Authority, Singapore; Eni; European Commission and European Union's Horizon 2020 research and innovation programme funding under grant agreement No 811148; Iberdrola; Imperial College London, United Kingdom; King Abdullah Petroleum Studies and Research Center, Saudi Arabia; Ministry of Economy, Trade and Industry, Japan; Ministry of Economic Affairs and Climate Policy, Netherlands; The Research Institute of Innovative Technology for the Earth, Japan; Schneider Electric; Shell and Toshiba. Activities within the IEA Clean Energy Transitions Programme provided valuable support to this analysis.

Thanks also go to the IEA Energy Business Council, IEA Coal Industry Advisory Board, IEA Energy Efficiency Industry Advisory Board and the IEA Renewable Industry Advisory Board.

A number of events were organised to provide input to this study. The participants offered valuable new insights, feedback and data for this analysis.

- High-level workshop on Electricity, Paris, 24 April 2018
- High-level roundtable meeting on Producer Economies, Paris, 26 April 2018

Further details on these events are at www.iea.org/workshops.

Peer reviewers

Many senior government officials and international experts provided input and reviewed preliminary drafts of the report. Their comments and suggestions were of great value. They include:

Amani Abou-Zeid	African Union Commission
Khaled Abu-Ismail	UN ESCWA
Tony Addison	UNU-WIDER
Sarah Anyang Agbor	African Union Commission
Keigo Akimoto	The Research Institute of Innovative Technology for the Earth, Japan
Majid Al-Moneef	Supreme Economic Council of Saudi Arabia
Hatem Al-Shanfari	Sultan Qaboos University
An Qi	Energy Research Institute
Venkatachalam Anbumozhi	Economic Research Institute for ASEAN and East Asia (ERIA)
Paul Appleby	BP
Marco Arcelli	EPH
Gigih Atmo	Asia Pacific Energy Research Centre (APERC)
Peter Bach	Danish Energy Agency
Rangan Banerjee	Indian institute of Technology, Bombay
Marco Baroni	Independent consultant
Thiago Barral	Energy Research Office (EPE), Brazil
Luiz Augusto Barroso	Comillas Pontifical University's Institute for Research in Technology
Paul Baruya	Clean Coal Centre

Igor Bashmakov	Center for Energy Efficiency (CENEf)
Tom Bastin	Department for Business Energy and Industrial Strategy, United Kingdom
Diana Bauer	Department of Energy, United States
Elie Bellevrat	TOTAL
Kamel Ben Naceur	ADNOC Group
Christian Besson	Independent consultant
Garrett Blaney	Agency for the Co-operation of Energy Regulators (ACER)
Peter Birch Sørensen	University of Copenhagen, Denmark
Paul Bjacek	Accenture
Kornelis Blok	Delft University of Technology
Rina Bohla Zeller	Vestas
Teun Bokhoven	Consolair
Clare Boland Ross	The Rockefeller Foundation
Jason Bordoff	Columbia University, United States
Nils Borg	European Council for an Energy Efficient Economy (ECEEE)
Chrissy Borskey	GE Power
Stephen Bowers	Evonik Industries AG
Mark Brownstein	Environmental Defense Fund, United States
David Buckrell	Ministry of Business, Innovation and Employment, New Zealand
Mick Buffier	Glencore
Barbara J. Burger	Chevron
Nick Butler	Independent consultant
Tim Callen	International Monetary Fund
Guy Caruso	Center for Strategic and International Studies, United States
Drew Clarke	Australian Energy Market Operator
Rebecca Collyer	European Climate Foundation
Emanuela Colombo	Politecnico di Milano, Italy
Erwin Cornelis	Tractebel - Engie
Joel Couse	Total SA
Ian Cronshaw	Independent consultant
Gumersindo Cué	Secretariat of Energy, Mexico
Noel Cunniffe	EirGrid, Ireland
Spencer Dale	BP
Ziad Daoud	Bloomberg
Francois Dassa	EDF
Jelte De Jong	Ministry of Economic Affairs Bezuidenhoutseweg
Marc Debever	EDF
Hem Dholakia	Council On Energy, Environment And Water (CEEW)
Ralf Dickel	Oxford Institute for Energy Studies, United Kingdom
Bo Diczfalusy	Nordic Energy Research
Jim Diefenderfer	Energy Information Administration, United States
Linda Doman	Energy Information Administration, United States

Dan Dorner	Department for Business Energy and Industrial Strategy, United Kingdom
Loic Douillet	GE Power
Gina Downes	Eskom
Kenneth Dubin	Energy Information Administration, United States
Michael Eckhart	Citigroup
Vladimir Feigin	Institute for Energy and Finance (FIEF)
Francesco Ferioli	DG Energy - European Commission
Nikki Fisher	Anglo American
Vivien Foster	World Bank
Nathan Frisbee	Schlumberger
Fu Sha	National Center for Climate Change Strategy and International Cooperation
Mike Fulwood	Nexant
David G. Hawkins	Natural Resources Defense Council, United States
Ashwin Gambhir	Prayas, Energy Group, India
Andrew Garnett	University of Queensland, Australia
Carlos Gascó Travesedo	Iberdrola
Francesco Gattei	Eni
Ivetta Gerasimchuk	IISD
Dolf Gielen	International Renewable Energy Agency
David Goldwyn	Atlantic Council, United States
Deborah Gordon	Carnegie Oil Endowment
Andrii Gritsevskyi	International Atomic Energy Agency
Rameshwar Gupta	NITI Aayog
Brian Gutknecht	GE Power
Mansoor Hamayun	BBOXX
Awwad Harthi	Ministry of Energy, Industry and Mineral Resources
Laury Haytayan	Natural Resource Governance Institute
Harald Hecking	EWI Energy Research and Scenarios
Jan Hein Jesse	JOSCO Energy Finance and Strategy Consultancy
Colin Henderson	Clean Coal Centre
James Henderson	Oxford Institute for Energy Studies, United Kingdom
Doug Hengel	German Marshall Fund of the United States
Laura Hersch	Energy Information Administration, United States
Masazumi Hirono	Tokyo Gas
Neil Hirst	Imperial College London, United Kingdom
Takashi Hongo	Mitsui Global Strategic Studies Institute, Japan
Didier Houssin	IFP Energies Nouvelles, France
Tom Howes	European Commission
Thad Huetteman	Energy Information Administration, United States
Jun Inoue	Japan Electric Power Information Center
James Jewell	Department of Energy, United States
Li Jingfeng	China Energy Investment Corporation Ltd. (China Energy)

Sohbet Karbuz	Mediterranean Observatory for Energy (OME)
Fabian Kesicki	E.ON SE
Kim Jihyun	Samsung SDI
Robert Kleinberg	Columbia University, United States
David Knapp	Energy Intelligence Group
Pawel Konzal	Chevron
Hans Korteweg	The European Association for the Promotion of Cogeneration (COGEN)
Ken Koyama	Institute of Energy Economics, Japan
Jim Krane	Baker Institute
Anil Kumar Jain	NITI Aayog
Ajay Kumar Saxena	The Energy and Resources Institute (TERI)
Atsuhito Kurozumi	Kyoto University of Foreign Studies
Vello Kuuskraa	Advanced Resources International
Sarah Ladislaw	Center for Strategic and International Studies (CSIS)
Glada Lahn	Chatham House
Cate Lamb	CDP – Global environmental reporting system
Francisco Laverón	Iberdrola
Benoit Lebot	International Partnership for Energy Efficiency Co-operation
Stine Leth Rasmussen	Danish Energy Association
Li Jiangtao	State Grid Energy Research Institute
Marcus Lippold	Saudi Aramco
Liu Xiaoli	Energy Research Institute, National Development and Reform Commission, China
Liu Yun Hui	China Energy Investment Group
Giacomo Luciani	Sciences Po
Luo Tianyi	World Resources Institute (WRI)
Joan MacNaughton	The Climate Group
Felix Matthes	Öko-Institut – Institute for Applied Ecology, Germany
Ritu Mathur	The Energy and Resources Institute (TERI)
Takeshi Matsushita	Mitsubishi Corporation
Ali Mawlawi	Al-Bayan Center for Planning and Studies
Pedro Antonio Merino Garcia	Repsol
Bert Metz	European Climate Foundation
Michelle Michot Foss	University of Texas
Cristobal Miller	Department of Natural Resources Canada
Tatiana Mitrova	Energy Research Institute of the Russian Academy of Sciences
Linus Mofor	United Nations Economic Commission for Africa
Fareed Mohamedi	SIA International
Francisco Monaldi	Baker Institute
Simone Mori	ENEL
Peter Morris	Minerals Council of Australia
Edward Morse	Citigroup

Isabel Murray	Department of Natural Resources, Canada
Steve Nadel	American Council for an Energy-Efficient Economy, United States
Sumie Nakayama	J-Power
Carole Nakhle	Crystol Energy
Christopher Namovicz	Energy Information Administration, United States
Susanne Nies	ENTSO-E
Koshi Noguchi	Toshiba of Europe Ltd.
Petter Nore	Nord University
Thomas Nowak	European Heat Pump Association
Bright Okogu	African Development Bank
Steven Oliver	Department of Environment and Energy, Australia
Steven Oltmanns	GE Power
Todd Onderdonk	ExxonMobil
Jon O'Sullivan	EirGrid, Ireland
Meghan L. O'Sullivan	Harvard Kennedy School
Henri Paillere	OECD Nuclear Energy Agency
Pak Yongduk	Korea Energy Economics Institute (KEEI)
Kristen Panerali	World Economic Forum
François Paquet	The European Association for the Promotion of Cogeneration (COGEN)
Adam Parums	CRU
Brian Pearce	International Air Transport Association
Kate Penney	Commonwealth Treasury, Australia
Glen Peters	CICERO
Pierre Porot	IFP Energies Nouvelles, France
Elisa Portale	World Bank
Prakash Rao	Lawrence Berkeley National Laboratory, United States
Anil Razdan	India Energy Forum
Alison Reeve	Australian Government Department of the Environment and Energy
Nicola Rega	Confederation of European Paper Industries (CEPI)
Christoph Richter	Solarway
Eduardo Roquero	Siemens Gamesa
Gulmira Rzayeva	Oxford Institute for Energy Studies, United Kingdom
Federica Sabbati	European Heating Industry (EHI)
Vineet Saini	Ministry of Science and Technology, India
Yasuhiro Sakuma	Ministry of Economy, Trade and Industry, Japan
Kaare Sandholt	National Renewable Energy Centre, China
Stijn Santen	CO2-Net BV
Aisha Sarihi	LSE Kuwait Centre
Steve Sawyer	Global Wind Energy Council
Hans-Wilhelm Schiffer	World Energy Council

Sandro Schmidt	Federal Institut for Geosciences and Natural Resources, Germany
Karl Schönsteiner	Siemens
Bora Şekip Güray	Sabancı Holding
Ujjval Shah	Schneider Electric
Shan Baoguo	State Grid Energy Research Institute
Adnan Shihab-Eldin	Foundation for the Advancement of Sciences, Kuwait
Maria Sicilia Salvadores	Enagas
Pierre Sigonney	Total
Katia Simeonova	United Nations Framework Convention on Climate Change
Fereidoon P. Sioshansi	Menlo Energy Economics
Jim Skea	Imperial College London, United Kingdom
Benjamin Donald Smith	Research Council of Norway
Bruce Smith	Abu Dhabi Water and Electricity Company
Christopher Snary	Department for Business, Energy and Industrial Strategy, United Kingdom
John Staub	Energy Information Administration, United States
James Steel	Department for Business Energy and Industrial Strategy, United Kingdom
Jonathan Stern	Oxford Institute for Energy Studies, United Kingdom
Bert Stuij	Netherlands Enterprise Agency
Kosuke Suzuki	Ministry of Economy, Trade and Industry, Japan
Minoru Takada	United Nations Department of Economic and Social Affairs
Yasuo Tanabe	Hitachi
Yuichiro Tanabe	Honda Motor
Kazushige Tanaka	Ministry of Economy, Trade and Industry, Japan
Wim Thomas	Shell
Timur Topalgoekceli	Hello Tomorrow
Dennis Trigylidas	Department of Natural Resources Canada
Johannes Trüby	Deloitte
Alexandra Tudoroiu-Lakavičė	The European Association for the Promotion of Cogeneration (COGEN)
Stefan Uhlenbrook	UN WWAP
Fridtjof Fossum Unander	Research Council of Norway
Sara Vakhshouri	SVB Energy International
Noe van Hulst	Permanent Representation of the Kingdom of the Netherlands to the OECD
Tom van Ierland	DG Climate Action, European Commission
Maarten van Werkhoven	TPA energy
Pierre Verlinden	IEEE
Frank Verrastro	Center for Strategic and International Studies, United States
Thomas Veyrenc	RTE
Andrew Walker	Cheniere Energy
Mads Warming	Danfoss

Paul Welford	Hess Corporation
Han Wenke	Energy Research Institute, National Development and Reform Commission, China
Peter Westerheide	BASF
Steve Winberg	Department of Energy, United States
Akira Yabumoto	J-Power
Fareed Yasseen	Government of Iraq
Mel Ydreos	International Gas Union
Zhang Chi	National Energy Administration, China
William Zimmern	BP
Christian Zinglersen	Clean Energy Ministerial
Anna Zyzniewski	Department of Natural Resources Canada

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

TABLE OF CONTENTS

PART A

GLOBAL ENERGY TRENDS

PART B

SPECIAL FOCUS ON ELECTRICITY

PART C

WEO INSIGHT

ANNEXES

Annexes 515

List of figures

Part A: Global Energy Trends

Figures for Chapter 1: Overview and key findings

Figures for Chapter 2: Energy and the Sustainable Development Goals

Figures for Chapter 3: Outlook for oil

Figures for Chapter 4: Outlook for natural gas

Figures for Chapter 5: Outlook for coal

Figures for Chapter 6: Energy efficiency and renewable energy

Part B: Special Focus on Electricity

Figures for Chapter 7: Electricity today

Figures for Chapter 8: Outlook for electricity demand and supply

Figures for Chapter 9: Alternative electricity futures

Figures for Chapter 10: Global implications of an electrifying future

Part C: WEO Insight

Figures for Chapter 11: Innovation and the environmental performance of oil and gas supply

Figures for Annex B: Design of the scenarios

Figures for Annex C: Definitions

List of tables

Part A: Global Energy Trends

Tables for Chapter 1: Overview and key findings

Tables for Chapter 2: Energy and the Sustainable Development Goals

Tables for Chapter 3: Outlook for oil

Tables for Chapter 4: Outlook for natural gas

Tables for Chapter 5: Outlook for coal

Tables for Chapter 6: Energy efficiency and renewable energy

Part B: Special Focus on Electricity

Tables for Chapter 7: Electricity today

Tables for Chapter 8: Outlook for electricity demand and supply

Tables for Chapter 9: Alternative electricity futures

List of boxes

Part A: Global Energy Trends

Boxes for Chapter 2: Energy and the Sustainable Development Goals

Boxes for Chapter 3: Outlook for oil

Boxes for Chapter 4: Outlook for natural gas

Boxes for Chapter 5: Outlook for coal

Boxes for Chapter 6: Energy efficiency and renewable energy

Part B: Special Focus on Electricity

Boxes for Chapter 7: Electricity today

Boxes for Chapter 8: Outlook for electricity demand and supply

Boxes for Chapter 9: Alternative electricity futures

Boxes for Chapter 10: Global implications of an electrifying future

Part C: WEO Insight

Boxes for Chapter 11: Innovation and the environmental performance of oil and gas supply

List of spotlights

Part A: Global Energy Trends

Part B: Special Focus on Electricity

Part C: WEO Insight

The world is gradually building a different kind of energy system, but cracks are visible in the key pillars:

- **Affordability**: The costs of solar PV and wind continue to fall, but oil prices climbed above $80/barrel in 2018 for the first time in four years; and hard-earned reforms to fossil fuel consumption subsidies are under threat in some countries.
- **Reliability**: Risks to oil and gas supply remain, as Venezuela's downward spiral shows. One-in-eight of the world's population has no access to electricity and new challenges are coming into focus in the power sector, from system flexibility to cyber security.
- **Sustainability**: After three flat years, global energy-related carbon dioxide (CO_2) emissions rose by 1.6% in 2017 and the early data suggest continued growth in 2018, far from a trajectory consistent with climate goals. Energy-related air pollution continues to result in millions of premature deaths each year.

Affordability, reliability and sustainability are closely interlinked: each of them, and the trade-offs between them, require a comprehensive approach to energy policy. The links between them are constantly evolving. For example, wind and solar photovoltaics (PV) bring a major source of affordable, low-emissions electricity into the picture, but create additional requirements for the reliable operation of power systems. The movement towards a more interconnected global gas market, as a result of growing trade in liquefied natural gas (LNG), intensifies competition among suppliers while changing the way that countries need to think about managing potential shortfalls in supply.

Robust data and well-grounded projections about the future are essential foundations for today's policy choices. This is where the *World Energy Outlook* (*WEO*) comes in. It does not aim to forecast the future, but provides a way of exploring different possible futures, the levers that bring them about and the interactions that arise across a complex energy system. If there is no change in policies from today, as in the *Current Policies Scenario*, this leads to increasing strains on almost all aspects of energy security. If we broaden the scope to include announced policies and targets, as in our main *New Policies Scenario*, the picture brightens. But the gap between this outcome and the *Sustainable Development Scenario*, in which accelerated clean energy transitions put the world on track to meet goals related to climate change, universal access and clean air, remains huge. None of these potential pathways is preordained; all are possible. The actions taken by governments will be decisive in determining which path we follow.

How is the world of energy changing?

In the New Policies Scenario, rising incomes and an extra 1.7 billion people, mostly added to urban areas in developing economies, push up global energy demand by more than a quarter to 2040. The increase would be around twice as large if it were not for continued improvements in energy efficiency, a powerful policy tool to address energy security and sustainability concerns. All the growth comes from developing economies, led by India. As recently as 2000, Europe and North America accounted for more than 40% of global energy demand and developing economies in Asia for around 20%. By 2040, this situation is completely reversed.

The profound shift in energy consumption to Asia is felt across all fuels and technologies, as well as in energy investment. Asia makes up half of global growth in natural gas, 60% of the rise in wind and solar PV, more than 80% of the increase in oil, and more than 100% of the growth in coal and nuclear (given declines elsewhere). Fifteen years ago, European companies dominated the list of the world's top power companies, measured by installed capacity; now six of the top-ten are Chinese utilities.

The shale revolution continues to shake up oil and gas supply, enabling the United States to pull away from the rest of the field as the world's largest oil and gas producer. In the New Policies Scenario, the United States accounts for more than half of global oil and gas production growth to 2025 (nearly 75% for oil and 40% for gas). By 2025, nearly every fifth barrel of oil and every fourth cubic metre of gas in the world come from the United States. Shale is adding to the pressure on traditional oil and gas exporters that rely heavily on export revenues to support national development.[1]

The energy world is connecting in different ways because of shifting supply, demand and technology trends. International energy trade flows are increasingly drawn to Asia from across the Middle East, Russia, Canada, Brazil and the United States, as Asia's share of global oil and gas trade rises from around half today to more than two-thirds by 2040. But new ways of sourcing energy are also visible at local level, as digitalization and increasingly cost-effective renewable energy technologies enable distributed and community-based models of energy provision to gain ground.

The convergence of cheaper renewable energy technologies, digital applications and the rising role of electricity is a crucial vector for change, central to the prospects for meeting many of the world's sustainable development goals. This vista is explored in detail in the *WEO-2018* special focus on electricity.

Electricity is the star of the show, but how bright will it shine?

The electricity sector is experiencing its most dramatic transformation since its creation more than a century ago. Electricity is increasingly the "fuel" of choice in economies that are relying more on lighter industrial sectors, services and digital technologies. Its share in global final consumption is approaching 20% and is set to rise further. Policy support and technology cost reductions are leading to rapid growth in variable renewable sources of generation, putting the power sector in the vanguard of emissions reduction efforts but requiring the entire system to operate differently in order to ensure reliable supply.

In advanced economies, electricity demand growth is modest, but the investment requirement is still huge as the generation mix changes and infrastructure is upgraded.

1. See the *WEO-2018 Special Report*, *Outlook for Producer Economies*.

Today's power market designs are not always up to the task of coping with rapid changes in the generation mix. Revenue from wholesale markets is often insufficient to trigger new investment in firm generation capacity; this could compromise the reliability of supply if not adequately addressed. On the demand side, efficiency gains from more stringent energy performance standards have played a pivotal role in holding back demand: eighteen out of the thirty International Energy Agency member economies have seen declines in their electricity use since 2010. Growth prospects depend on how fast electricity can gain ground in providing heat for homes, offices and factories, and power for transportation.

A doubling of electricity demand in developing economies puts cleaner, universally available and affordable electricity at the centre of strategies for economic development and emissions reduction. One-in-five kilowatt-hours of the rise in global demand comes just from electric motors in China; rising demand for cooling in developing economies provides a similar boost to growth. In the absence of a greater policy focus on energy efficiency, almost one-in-every-three dollars invested in global energy supply, across all areas, goes to electricity generation and networks in developing economies. This investment might not materialise, especially where end-user prices are below cost-recovery levels. But in highly regulated markets there is also a risk that capacity runs ahead of demand: we estimate that today there are 350 gigawatts of excess capacity in regions including China, India, Southeast Asia and the Middle East, representing additional costs that the system, and consumers, can ill afford.

Flexibility is the new watchword for power systems

The increasing competitiveness of solar PV pushes its installed capacity beyond that of wind before 2025, past hydropower around 2030 and past coal before 2040. The majority of this is utility-scale, although investment in distributed solar PV by households and businesses plays a strong supporting role. The *WEO-2018* introduces a new metric to estimate the competitiveness of different generation options, based on evolving technology costs as well as the value that this generation brings to the system at different times. This metric confirms the advantageous position of wind and solar PV in systems with relatively low-cost sources of flexibility. New solar PV is well placed to outcompete new coal almost everywhere, although it struggles in our projections to undercut existing thermal plants without a helping hand from policy. In the New Policies Scenario, renewables and coal switch places in the power mix: the share of generation from renewables rises from 25% today to around 40% in 2040; coal treads the opposite path.

The rise of solar PV and wind power gives unprecedented importance to the flexible operation of power systems in order to keep the lights on. There are few issues at low levels of deployment, but in the New Policies Scenario many countries in Europe, as well as Mexico, India and China, are set to require a degree of flexibility that has never been seen before at such large scale. The cost of battery storage declines fast, and batteries increasingly compete with gas-fired peaking plants to manage short-run fluctuations in supply and demand. However, conventional power plants remain the main source of system flexibility, supported by new interconnections, storage and demand-side response. The European Union's aim to achieve an "Energy Union" illustrates the role that regional integration can play in facilitating the integration of renewables.

The share of generation from nuclear plants – the second-largest source of low-carbon electricity today after hydropower – stays at around 10%, but the geography changes as generation in China overtakes the United States and the European Union before 2030. Some two-thirds of today's nuclear fleet in advanced economies is more than 30 years old. Decisions to extend, or shut down, this capacity will have significant implications for energy security, investment and emissions.

How much power can we handle?

A much stronger push for electric mobility, electric heating and electricity access could lead to a 90% rise in power demand from today to 2040, compared with 60% in the New Policies Scenario, an additional amount that is nearly twice today's US demand. In the *Future is Electric Scenario*, the share of electricity in final consumption moves up towards one-third, as almost half the car fleet goes electric by 2040 and electricity makes rapid inroads into the residential and industry sectors. However, some significant parts of the energy system, such as long-distance road freight, shipping and aviation, are not "electric-ready" with today's technologies. Electrification brings benefits, notably by reducing local pollution, but requires additional measures to decarbonise power supply if it is to unlock its full potential as a way to meet climate goals: otherwise, the risk is that CO_2 emissions simply move upstream from the end-use sectors to power generation.

Where does the rise of electricity, renewables and efficiency leave fossil fuels?

In the New Policies Scenario, a rising tide of electricity, renewables and efficiency improvements stems growth in coal consumption. Coal use rebounded in 2017 after two years of decline, but final investment decisions in new coal-fired power plants were well below the level seen in recent years. Once the current wave of coal plant projects under construction is over, the flow of new coal projects starting operation slows sharply post-2020. But it is too soon to count coal out of the global power mix: the average age of a coal-fired plant in Asia is less than 15 years, compared with around 40 years in advanced economies. With industrial coal use showing a slight increase to 2040, overall global consumption is flat in the New Policies Scenario, with declines in China, Europe and North America offset by rises in India and Southeast Asia.

Oil use for cars peaks in the mid-2020s, but petrochemicals, trucks, planes and ships still keep overall oil demand on a rising trend. Improvements in fuel efficiency in the conventional car fleet avoid three-times more in potential demand than the 3 million barrels per day (mb/d) displaced by 300 million electric cars on the road in 2040. But the rapid pace of change in the passenger vehicle segment (a quarter of total oil demand) is not matched elsewhere. Petrochemicals are the largest source of growth in oil use. Even if global recycling rates for plastics were to double, this would cut only around 1.5 mb/d from the projected increase of more than 5 mb/d. Overall growth in oil demand to 106 mb/d in the New Policies Scenario comes entirely from developing economies.

Natural gas overtakes coal in 2030 to become the second-largest fuel in the global energy mix. Industrial consumers make the largest contribution to a 45% increase in worldwide gas use. Trade in LNG more than doubles in response to rising demand from developing economies, led by China. Russia remains the world's largest gas exporter as it opens new routes to Asian markets, but an increasingly integrated European energy market gives buyers more gas-supply options. Higher shares of wind and solar PV in power systems push down the utilisation of gas-fired capacity in Europe, and retrofits of existing buildings also help to bring down gas consumption for heating, but gas infrastructure continues to play a vital role, especially in winter, in providing heat and ensuring uninterrupted electricity supply.

Where are we on emissions and access – and where do we want to be?

The New Policies Scenario puts energy-related CO_2 emissions on a slow upward trend to 2040, a trajectory far out of step with what scientific knowledge says will be required to tackle climate change. Countries are, in aggregate, set to meet the national pledges made as part of the Paris Agreement. But these are insufficient to reach an early peak in global emissions. The projected emissions trend represents a major collective failure to tackle the environmental consequences of energy use. Lower emissions of the main air pollutants in this scenario are not enough to halt an increase in the number of premature deaths from poor air quality.

In 2017, for the first time, the number of people without access to electricity dipped below 1 billion, but trends on energy access likewise fall short of global goals. The New Policies Scenario sees some gains in terms of access, with India to the fore. However, more than 700 million people, predominantly in rural settlements in sub-Saharan Africa, are projected to remain without electricity in 2040, and only slow progress is made in reducing reliance on the traditional use of solid biomass as a cooking fuel.

Our Sustainable Development Scenario provides an integrated strategy to achieve energy access, air quality and climate goals, with all sectors and low-carbon technologies – including carbon capture, utilisation and storage – contributing to a broad transformation of global energy. In this scenario, the power sector proceeds further and faster with the deployment of low-emissions generation. Renewable energy technologies provide the main pathway to the provision of universal energy access. All economically viable avenues to improve efficiency are pursued, keeping overall demand in 2040 at today's level. Electrification of end-uses grows strongly, but so too does the direct use of renewables – bioenergy, solar and geothermal heat – to provide heat and mobility. The share of renewables in the power mix rises from one-quarter today to two-thirds in 2040; in the provision of heat it rises from 10% today to 25% and in transport it rises from 3.5% today to 19% (including both direct use and indirect use, e.g. renewables-based electricity). For the first time, this *WEO* incorporates a water dimension in the Sustainable Development Scenario, illustrating how water constraints can affect fuel and technology choices, and detailing the energy required to provide universal access to clean water and sanitation.

Can oil and gas improve their own environmental performance?

Natural gas and oil continue to meet a major share of global energy demand in 2040, even in the Sustainable Development Scenario. Not all sources of oil and gas are equal in their

environmental impact. Our first comprehensive global estimate of the indirect emissions involved in producing, processing and transporting oil and gas to consumers suggests that, overall, they account for around 15% of energy sector greenhouse gas emissions (including CO_2 and methane). There is a very broad range in emissions intensities between different sources: switching from the highest emissions oil to the lowest would reduce emissions by 25% and doing the same for gas would reduce emissions by 30%.

Much more could be done to reduce the emissions involved in bringing oil and gas to consumers. Many leading companies are taking on commitments in this area that, if widely adopted and implemented, would have a material impact on emissions. Reducing methane emissions and eliminating flaring are two of the most cost-effective approaches. There are also some more "game-changing" options, including the use of CO_2 to support enhanced oil recovery, greater use of low-carbon electricity to support operations, and the potential to convert hydrocarbons to hydrogen (with carbon capture). Many countries, notably Japan, are looking closely at the possibility of expanding the role of zero-emissions hydrogen in the energy system.

Is investment in fossil fuel supply out of step with consumption trends?

Today's flow of new upstream projects appears to be geared to the possibility of an imminent slowdown in fossil fuel demand, but in the New Policies Scenario this could well lead to a shortfall in supply and a further escalation in prices. The risk of a supply crunch looms largest in oil. The average level of new conventional crude oil project approvals over the last three years is only half the amount necessary to balance the market out to 2025, given the demand outlook in the New Policies Scenario. US tight oil is unlikely to pick up the slack on its own. Our projections already incorporate a doubling in US tight oil from today to 2025, but it would need to more than triple in order to offset a continued absence of new conventional projects. In contrast to oil, the risk of an abrupt tightening in LNG markets in the mid-2020s has been eased by major new project announcements, notably in Qatar and Canada.

Government policies will shape the long-term future for energy

Rapid, least-cost energy transitions require an acceleration of investment in cleaner, smarter and more efficient energy technologies. But policy makers also need to ensure that all key elements of energy supply, including electricity networks, remain reliable and robust. Traditional supply disruption and investment risks on the hydrocarbons side are showing no signs of relenting and indeed may intensify as energy transitions move ahead. The changes underway in the electricity sector require constant vigilance to ensure that market designs are robust even as power systems decarbonise. More than 70% of the $2 trillion required in the world's energy supply investment each year, across all domains, either comes from state-directed entities or responds to a full or partial revenue guarantee established by regulation. Frameworks put in place by the public authorities also shape the pace of energy efficiency improvement and of technology innovation. Government policies and preferences will play a crucial role in shaping where we go from here.

The *World Energy Outlook (WEO)-2018* provides a framework for thinking about the future of global energy. It does not make predictions about the future. Instead, it sets out what the future could look like on the basis of different scenarios or pathways, with the aim of providing insights to inform decision making by governments, companies and others concerned with energy.

The three main scenarios in the *WEO-2018* are:

- The **New Policies Scenario** provides a measured assessment of where today's policy frameworks and ambitions, together with the continued evolution of known technologies, might take the energy sector in the coming decades. The policy ambitions include those that have been announced as of August 2018 and incorporates the commitments made in the Nationally Determined Contributions under the Paris Agreement, but does not speculate as to further evolution of these positions. Where commitments are aspirational, this scenario makes a judgement as to the likelihood of those commitments being met in full. It does not focus on achieving any particular outcome: it simply looks forward on the basis of announced policy ambitions.
- Among recent policy announcements, the New Policies Scenario includes the European Union's new, more ambitious 2030 renewable energy and energy efficiency targets. It likewise includes the June 2018 announcement by China of a new three-year action plan for cleaner air. It reflects the impact of the planned revision of the Corporate Average Fuel Economy standards in the United States, as well as the announced US Affordable Clean Energy rule that replaces the previous Clean Power Plan. It also takes account of Japan's revised basic energy plan and Korea's 8th National Electricity Plan. It is the New Policies Scenario to which we devote most space and attention.
- The **Current Policies Scenario** is based solely on existing laws and regulations as of mid-2018, and therefore excludes the ambitions and targets that have been declared by governments around the world. It provides a baseline for the *WEO* analysis.
- The **Sustainable Development Scenario**, introduced for the first time in the *WEO-2017*, starts from selected key outcomes and then works back to the present to see how they might be achieved. The outcomes in question are the main energy-related components of the Sustainable Development Goals, agreed by 193 countries in 2015:
  - Delivering on the Paris Agreement. The Sustainable Development Scenario is fully aligned with the Paris Agreement's goal of holding the increase in the global average temperature to "well below 2 °C".
  - Achieving universal access to modern energy by 2030.
  - Reducing dramatically the premature deaths due to energy-related air pollution.

  The Sustainable Development Scenario sets out the major changes that would be required to deliver these goals simultaneously. This year's edition also incorporates the linkages between energy and water.

These three scenarios are the main points of reference for the discussion in this *World Energy Outlook*. They are accompanied by multiple supplementary analyses and case studies.

The principal quantitative tool used to generate the underlying projections is the World Energy Model, a large-scale simulation model developed at the International Energy Agency (IEA) over many years to capture the evolving nature of energy markets and technologies.[1] Information on the inputs used to generate the scenarios, including the underlying assumptions for economic growth, population, policies and the trajectories for energy and carbon dioxide (CO_2) prices, is found in Annex B.[2] Assumed rates of growth for global gross domestic product (average of 3.4% per year to 2040) and population (an increase to just over 9 billion people in 2040) are constant across the scenarios, whereas policies, costs and equilibrium prices differ substantially.

Box 1 ▷ A new way to navigate the *WEO*

Regular readers of the *World Energy Outlook* will notice some changes to the presentation of this year's results, especially if they also visit the IEA website at www.iea.org. This reflects the priority given to move towards a more "digital IEA". It also reflects feedback from readers and commissioned customer research. There are three main changes:

- **Online presence**: Headline findings are now more readily available on a revamped *WEO* website (www.iea.org/weo).
- **Ease of use**: Chapters in Part A now have summaries and reference material concentrated at the outset of each chapter, followed by more in-depth analysis on selected topics.
- **Accessible data**: We have improved access to underlying data, including all tables and figures, which are available in Excel format to all *WEO* purchasers.

The changes in *WEO-2018* are part of a process of continual improvement that reflects our determination to remain the gold standard for long-term energy research. We welcome your comment.

The *WEO-2018* is structured as follows:

Chapter 1 provides an overview of the implications of the *WEO* projections and considers some of the key policy, technology and price uncertainties that could affect how scenarios play out in practice. The remainder of **Part A** presents the main updates to the scenario projections, starting with a dedicated chapter on the Sustainable Development Scenario,

1. Details related to the World Energy Model are available at www.iea.org/weo/weomodel.
2. Scenario descriptions and background information are available at www.iea.org/weo/.

and then working through the main elements of the outlook by fuel, including renewables and energy efficiency.

Part B presents a detailed focus on electricity. At the IEA, 2018 is the "year of electricity". This special focus in *WEO-2018* is the centrepiece of a broad analytical effort in the IEA to examine the forces that are reshaping electricity demand and supply, transforming the operation of the power system, and requiring a fresh look at electricity security. The analysis includes modelling of the Future is Electric Scenario (FiES).

Part C focuses on the links between innovation and the environmental performance of oil and gas supply. The energy and emissions characteristics of different sources of oil and gas can vary widely. We explore the reasons for these variations and look at possible measures to reduce the energy and environmental footprint of oil and natural gas delivered to consumers.

Comments and questions are welcome and should be addressed to:

Laura Cozzi and Tim Gould
Directorate of Sustainability, Technology and Outlooks
International Energy Agency
31-35, rue de la Fédération
75739 Paris Cedex 15
France

E-mail : weo@iea.org

More information about the *World Energy Outlook* is available at www.iea.org/weo.

PART A
GLOBAL ENERGY TRENDS

Part A of the World Energy Outlook *provides updated analysis, based on the latest data, to show what different policy choices might mean for the energy sector to 2040.*

The chapters examine what today's technology trends and policy announcements might mean for the energy sector to 2040.

It also outlines an integrated way to meet multiple sustainable development goals: limiting the global temperature rise in line with the Paris Agreement, addressing air pollution and ensuring universal access to energy.

The intention of scenario analysis is not to describe what will happen – there are no forecasts in the World Energy Outlook (WEO) *– but to explore possible futures and the actions that could bring them about.*

OUTLINE

Part A presents energy projections to 2040, by scenario, for all energy sources, regions and sectors.

Chapter 1 provides an overview of key findings from this year's *WEO*. It covers the main results of the scenario projections and considers the implications for the three dimensions of long-term energy security: reliability, affordability and sustainability.

Chapter 2 assesses the benefits and challenges of pursuing an integrated approach to achieving three key energy-related Sustainable Development Goals (SDGs): universal energy access, reducing the impacts of air pollution and tackling climate change. It also considers the role of energy in reaching the SDG on clean water and sanitation.

Chapter 3 explores the outlook for oil and evaluates three key questions for the future. How is fuel efficiency and fuel switching affecting oil use in the world's cars and trucks? Are we heading for an oil supply shock? And what do energy transitions mean for oil products?

Chapter 4 focuses on natural gas, looking in detail at the role of emerging Asian economies in gas demand, the prospects for exporters in an increasingly competitive and interconnected global gas market, and the future of natural gas in the European Union.

Chapter 5 analyses the outlook for coal, examining how coal fares in a rapidly changing power sector and the prospects for exporters in a demand-constrained world.

Chapter 6 examines renewables and energy efficiency, going into detail on their importance for the future of transport, and the role of heat from renewables and improved efficiency in Europe's building sector. It also tracks country-by-country progress on the SDG 7 targets in both these areas.

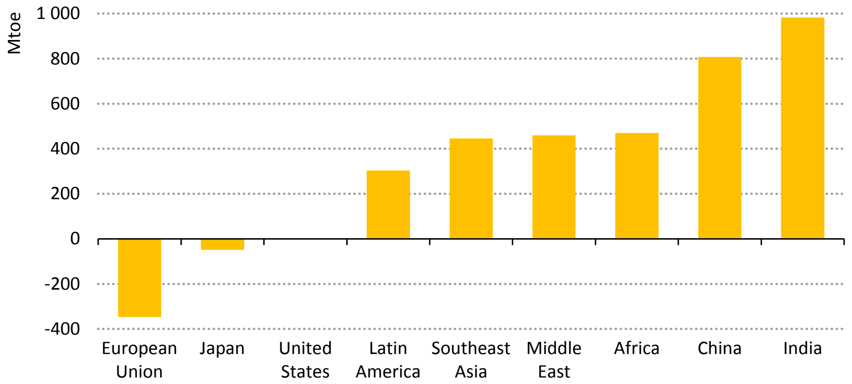
Overview and key findings

Energy policy in a time of transitions

S U M M A R Y

- In the New Policies Scenario, global primary energy demand expands by over 25% between 2017 and 2040. Without improvements in energy efficiency, the rise would be twice as large. India's energy demand more than doubles to 2040, becoming the single largest source of global growth. China's energy use also grows strongly, but the rate of growth is only one-fifth of that seen from 2000 to 2017. Energy demand remains around today's level in the United States and it falls in Japan and the European Union.

Figure 1.1 ▷ Change in total primary energy demand in selected regions in the New Policies Scenario, 2017-2040



The world is witnessing a major shift in energy demand from advanced to developing economies, with demand growing fastest in India

- Demand for electricity increases by 60% in the New Policies Scenario, the fastest growth among the major energy carriers, and its share in global final consumption reaches one-quarter by 2040. Nearly 90% of the growth in electricity demand occurs in developing economies. On the generation side, declining renewable energy costs, increasing local pollution concerns and climate-related targets are set to reshape the global electricity mix. Coal and renewables switch positions: the share of coal declines from around 40% today to a quarter in 2040 while that of renewables grows from a quarter to around 40% over the same period.

- As the share of wind and solar photovoltaics (PV) grows, so does the need for flexibility to ensure reliable power supply. Available resources for this purpose double by 2040, with thermal and hydropower plants to the fore, and interconnections, battery storage and demand response all playing increasingly important roles. The transformation of the power sector is pushing electricity security up the policy agenda, part of a broader reappraisal of energy security risks in a changing energy system.

- The pace of oil demand growth slows, and all of the 11.5 million barrels per day (mb/d) increase between 2017 and 2040 takes place in developing economies. Demand growth is consistently strong in the Middle East and India, particularly for trucks and petrochemical feedstocks. But it is China that becomes the world's biggest oil consumer and, by 2040, the largest net oil importer in history.
- Investment in new conventional upstream oil projects is currently well below what would be required to meet demand in the New Policies Scenario. This divergence in trends between strong consumption growth and weak investment in new supply, if left unchecked, points to damaging price spikes in the 2020s. It would be risky to rely on US tight oil production more than tripling from today's level by 2025 in order to offset the absence of new conventional crude oil projects.
- On the back of strong demand growth, revised up since last year's *Outlook*, China soon becomes the world's largest gas-importing country and its imports approach the level of the European Union by 2040. There are signs that the logjam in new liquefaction projects since mid-2016 is being broken, but there is still uncertainty over the business models that will prevail in a changing global gas market.
- Energy-related carbon dioxide (CO_2) emissions resumed growth in 2017 after three years in which they were flat. They remain on a slow but steady upward path in the New Policies Scenario, in line with the trajectory implied by the Nationally Determined Contributions but a long way from the early peak and rapid subsequent decline that would be consistent with the objectives of the Paris Agreement.
- Under current and planned policies, the world is also set to fall short on other energy-related Sustainable Development Goals. The number of people worldwide without access to electricity has dipped below 1 billion for the first time, but by 2030 there are 650 million people still without access in the New Policies Scenario and more than 2 billion globally still cooking with solid fuels. Premature deaths from poor air quality also remain stubbornly high. The Sustainable Development Scenario outlines an integrated path to achieve access, air quality and climate goals, maximising the synergies between them.
- Government policies and preferences will play a crucial role in shaping where we go from here. More than 70% of the $42 trillion in investment in energy supply in the New Policies Scenario, across all domains, is either conducted by state-directed entities or responds to a full or partial revenue guarantee put in place by governments. Only just over a quarter comes from private enterprises responding to prices set on competitive markets.

Introduction

The latest energy data are sending some mixed signals about the pace and direction of change in the global energy system. Electricity generated from renewables now accounts for a quarter of global generation and solar photovoltaics (PV) are cheaper than ever; yet there are signs that near-term deployment of new solar capacity might be slowing. The demise of coal has been widely predicted and consumption fell for two years straight from 2015, but bounced back in 2017. Energy efficiency is a proven way of meeting multiple energy policy goals, but the flow and stringency of new policies appears to be weakening. Nations have expressed a commitment to address climate change, but after three flat years, energy-related carbon dioxide (CO_2) emissions are on the rise again.

These signals point to today's energy transitions as complex, uneven, multi-speed processes in a system that is under pressure to meet rising demand for energy services. Untangling the various strands, the New Policies Scenario provides a measure of the real advances that are being made in many countries around the world, as well as the areas in which the world is falling short of some shared objectives to ensure universal access, cleaner air and reduced emissions – an assessment enabled by comparison with the Sustainable Development Scenario.

The first section of this chapter covers the main results of the scenario projections from different angles, looking at demand, supply, end-use sectors, efficiency, emissions, trade, and investment, and highlighting briefly the main findings. The second part takes up the theme of energy security, how this is evolving in a time of energy transition, and how various vulnerabilities play out in our scenarios to 2040. Drawing on the analysis from across this year's *World Energy Outlook (WEO)*, we highlight seven themes that are critical to a reliable, affordable and sustainable energy future:

- Adapt power systems to the transformation that is underway in the electricity sector, or risk compromising the reliability of electricity supply.
- Realise the full potential of energy efficiency, the one policy instrument that can reliably target all aspects of energy security.
- Reduce emissions from power but do not forget the rest of the energy system, in particular the parts that electricity cannot reach.
- Think strategically about the role of gas infrastructure in meeting long-term energy and environmental goals.
- Watch out for shortfalls in investment across the board, not only in clean energy technologies, but also in traditional elements of supply.
- Seek out gains from co-operation: regional integration and international collaboration can play a major role in improving outcomes.
- Work to bring universal access to modern energy, the lack of which is the most extreme form of energy insecurity.

Figures and tables from this chapter may be downloaded from www.iea.org/weo2018/secure/.

Scenarios

1.1 Overview

Table 1.1 ▷ World primary energy demand by fuel and scenario (Mtoe)

			New Policies		Current Policies		Sustainable Development	
	2000	2017	2025	2040	2025	2040	2025	2040
Coal	2 308	3 750	3 768	3 809	3 998	4 769	3 045	1 597
Oil	3 665	4 435	4 754	4 894	4 902	5 570	4 334	3 156
Gas	2 071	3 107	3 539	4 436	3 616	4 804	3 454	3 433
Nuclear	675	688	805	971	803	951	861	1 293
Renewables	662	1 334	1 855	3 014	1 798	2 642	2 056	4 159
Hydro	225	353	415	531	413	514	431	601
Modern bioenergy	377	727	924	1 260	906	1 181	976	1 427
Other	60	254	516	1 223	479	948	648	2 132
Solid biomass	646	658	666	591	666	591	396	77
Total	**10 027**	**13 972**	**15 388**	**17 715**	**15 782**	**19 328**	**14 146**	**13 715**
Fossil fuel share	*80%*	*81%*	*78%*	*74%*	*79%*	*78%*	*77%*	*60%*
CO_2 emissions (Gt)	**23.1**	**32.6**	**33.9**	**35.9**	**35.5**	**42.5**	**29.5**	**17.6**

Notes: Mtoe = million tonnes of oil equivalent; Gt = gigatonnes. Solid biomass includes its traditional use in three-stone fires and in improved cookstoves.

The overall share of fossil fuels in global primary energy demand has not changed over the last 25 years. Oil, coal and gas remain central to today's global energy system, though energy efficiency has had a significant impact in moderating the growth in energy demand. New contenders are however emerging, led by wind and solar PV, and are helping to push electricity into new parts of the energy system. How they fare depends to a large extent on the level of policy ambition and technology innovation, which will determine to a large extent the trajectory of energy-related emissions.

In the **New Policies Scenario**, global primary energy demand grows by over a quarter between today and 2040. The overarching structural trends that shape demand are population growth, urbanisation and economic growth. Energy policies also play a critical role, notably those relating to energy efficiency, renewable resources, measures to curb air pollution and the phasing-out of fossil fuel subsidies. In the Sustainable Development Scenario, demand is almost flat out to 2040, reflecting in part the continuing potential of energy efficiency to reduce demand. Our scenario-based projections show where policy choices lead the energy sector.

In the **Current Policies Scenario**, continued strong growth among the incumbent fuels leaves only a small amount of headroom for renewables to step in and meet incremental demand. Coal use rises on the back of strong consumption in the developing world. In the absence of significant additional commitments to improve vehicle fuel efficiency, oil demand climbs by 25% to 2040.

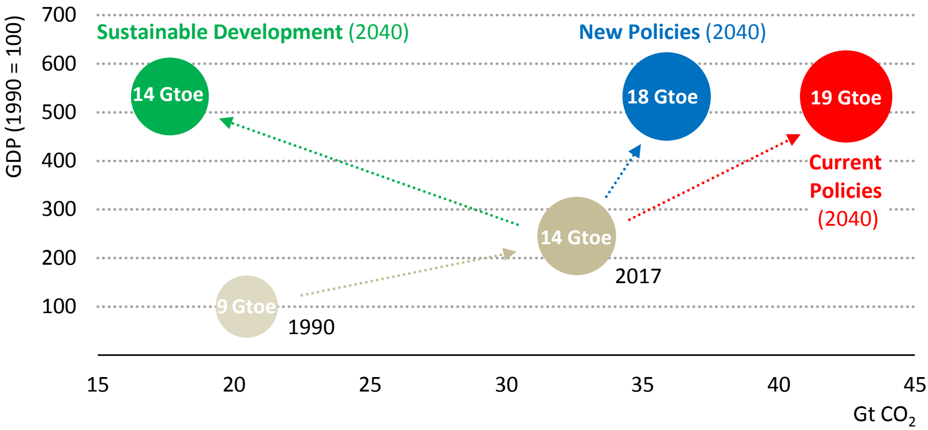
In the New Policies Scenario, coal, and oil to a degree, have to make room for others, not least because of rapid rise in the share of renewables in electricity generation. Strong policy headwinds, including commitments to phase out coal use in some countries, mean that global coal consumption levels off. Oil use in cars also peaks in the 2020s due to advances in fuel efficiency and an increased use of biofuels and electricity. However, trucks, aviation, shipping and petrochemicals continue to push up overall oil use.

In the **Sustainable Development Scenario**, coal moves to the back of the pack: demand of 1 600 million tonnes of oil equivalent (Mtoe) of coal in 2040 is in line with the level of 1975, when the global economy was barely a quarter the size of today. Oil demand reaches a peak and begins to decline.

Natural gas consumption grows in every scenario, underpinned by its versatility and environmental advantages relative to other combustible fuels. Its growth prospects are, however, curtailed in the Sustainable Development Scenario by higher efficiency and the push towards full decarbonisation of the energy system.

There is still a strong link between economic growth and global energy-related CO_2 emissions in the Current Policies Scenario. This is weakened in the New Policies Scenario, but emissions keep rising to almost 36 gigatonnes of carbon dioxide (Gt CO_2) in 2040. In the Sustainable Development Scenario, the share of fossil fuels in the primary energy mix drops to 60% by 2040 and the emissions trend parts company with economic growth (Figure 1.2).

Figure 1.2 ▷ World primary energy demand and energy-related CO_2 emissions by scenario



Achieving sustainable development goals requires a complete reversal of the historic relationship between economic growth, energy demand and emissions

Notes: Bubble size and numbers represent total primary energy demand. Gtoe = gigatonnes of oil equivalent or 1 000 Mtoe; Gt CO_2 = gigatonnes of CO_2.

1.2 Primary energy demand by region

Table 1.2 ▷ Total primary energy demand by region in the New Policies Scenario (Mtoe)

	2000	2017	2025	2030	2035	2040	2017-2040 Change	2017-2040 CAAGR
North America	2 678	2 624	2 675	2 667	2 661	2 693	69	0.1%
United States	2 271	2 148	2 185	2 162	2 139	2 149	1	0.0%
Central and South America	449	667	730	784	847	916	249	1.4%
Brazil	184	285	315	338	363	391	106	1.4%
Europe	2 028	2 008	1 934	1 845	1 779	1 752	-256	-0.6%
European Union	1 693	1 621	1 512	1 404	1 321	1 274	-347	-1.0%
Africa	490	829	980	1 086	1 192	1 299	470	2.0%
South Africa	103	131	133	132	135	138	7	0.2%
Middle East	353	740	846	957	1 085	1 200	460	2.1%
Eurasia	742	911	943	960	986	1 019	108	0.5%
Russia	621	730	745	744	754	769	39	0.2%
Asia Pacific	3 012	5 789	6 803	7 344	7 798	8 201	2 412	1.5%
China	1 143	3 051	3 509	3 684	3 787	3 858	807	1.0%
India	441	898	1 238	1 465	1 683	1 880	982	3.3%
Japan	518	428	415	403	390	379	-48	-0.5%
Southeast Asia	383	664	826	923	1 018	1 110	446	2.3%
International bunkers	274	404	476	525	578	635	231	2.0%
Total	**10 027**	**13 972**	**15 388**	**16 167**	**16 926**	**17 715**	**3 743**	**1.0%**
Current Policies			15 782	16 943	18 125	19 328	5 356	1.4%
Sustainable Development			14 146	13 820	13 688	13 715	-257	-0.1%

Notes: CAAGR = Compound average annual growth rate. International bunkers include both marine and aviation fuels.

Growth in the New Policies Scenario is led by developing economies, where demand increases by some 45% between 2017 and 2040. As recently as 2000, North America and Europe accounted for more than 40% of global energy demand and developing economies in Asia for around 20%. By 2040, this situation is completely reversed. This represents a huge change in the geography of global energy consumption.

India is the largest single source of growth and its demand more than doubles over the outlook period: by 2040, energy demand in India is around half that of China, up from less than 30% today. China cements its position as the world's largest energy consumer. Outside Asia, the Middle East and North Africa see the most rapid growth, with demand more than 60% higher in 2040 than today.

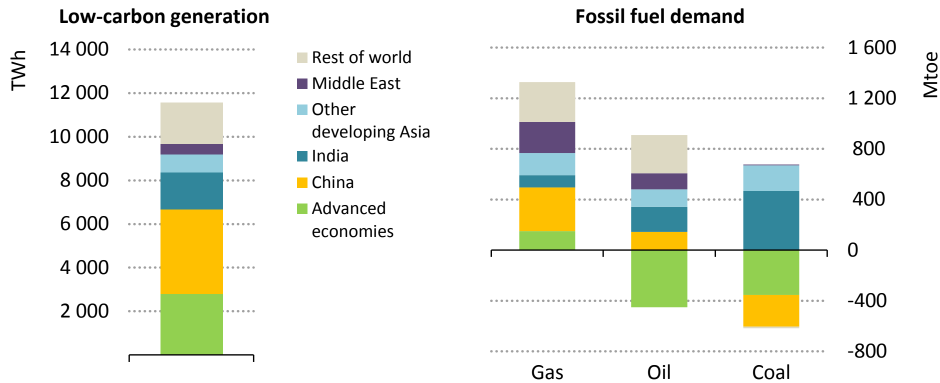
Energy use in Africa as a whole rises by just under 60% and surpasses that of the European Union towards the end of the outlook period, although it remains the lowest consumer of energy on a per-capita basis.

Demand in Central and South America grows less rapidly than in many other developing economies, but still rises by almost 40% by 2040. Demand in Eurasia increases by only just over 10% as robust increases in Caspian countries are mitigated by much more subdued growth in Russia.

The corollary of the rising share of primary energy demand going to developing economies is a reduction in the share accounted for by advanced economies. But a noticeable decline is only visible in the European Union and Japan, where demand falls by 20% and 10% respectively. In North America, demand remains flat throughout the period.

Demand for coal falls in advanced economies and China, which together account for more than half of the global increase in energy from low-carbon technologies and around 40% of the growth in natural gas. In India and most other fast-growing developing Asian economies, demand increases for all fuels and technologies (Figure 1.3).

Figure 1.3 ▷ Change in low-carbon generation and fossil fuel demand by region in the New Policies Scenario, 2017-2040



Demand growth in advanced economies and China is met by low-carbon technologies and gas, while India and other developing Asia mobilise all fuels and technologies

Note: TWh = terawatt-hours; Mtoe = million tonnes of oil equivalent.

Global primary energy demand grows by almost 40% between today and 2040 in the Current Policies Scenario, although existing policies are sufficient to secure a continued decline in energy use in the European Union and Japan (demand has already been falling in these regions since the mid-2000s).

In the Sustainable Development Scenario, demand is essentially flat, underscoring the importance of demand-side measures to achieve an outlook compatible with sustainable development goals. China's demand is on a downward trend by the latter years of this scenario, although India's energy use continues to grow through to 2040.

1.3 Total final consumption and efficiency

Table 1.3 ▷ Total final consumption in the New Policies Scenario (Mtoe)

	2000	2017	2025	2030	2035	2040	2017-2040 Change	2017-2040 CAAGR
Industry	1 863	2 855	3 265	3 460	3 648	3 833	977	1.3%
Transport	1 958	2 794	3 144	3 313	3 447	3 617	823	1.1%
Buildings	2 450	3 047	3 276	3 439	3 602	3 759	711	0.9%
Other	765	999	1 187	1 260	1 320	1 373	374	1.4%
of which feedstock	439	535	667	720	767	813	278	1.8%
Electricity	1 090	1 846	2 206	2 457	2 717	2 985	1 139	2.1%
District heat	248	289	301	302	303	302	14	0.2%
Direct use of renewables	271	456	583	669	755	844	388	2.7%
of which modern bioenergy	262	408	505	567	625	687	278	2.3%
Gas	1 118	1 503	1 790	1 964	2 139	2 298	795	1.9%
Oil	3 123	3 940	4 297	4 405	4 458	4 541	601	0.6%
Coal	542	1 004	1 029	1 027	1 021	1 020	15	0.1%
Solid biomass	646	658	666	649	624	591	-67	-0.5%
Total	**7 036**	**9 696**	**10 871**	**11 474**	**12 018**	**12 581**	**2 885**	**1.1%**
Current Policies			11 103	11 911	12 704	13 510	3 815	1.5%
Sustainable Development			10 126	10 007	9 946	9 958	262	0.1%

Notes: CAAGR = Compound average annual growth rate; Solid biomass includes its traditional use in three-stone fires and in improved cookstoves.

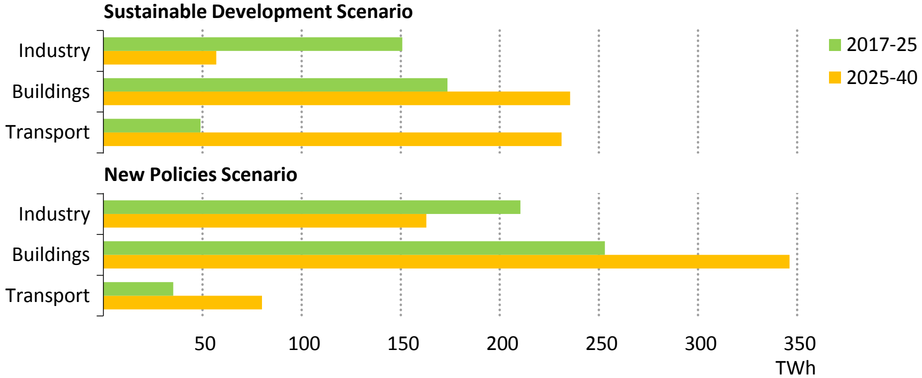
Developing economies in Asia and the Middle East account for three-quarters of the global growth in total final consumption to 2040 in the New Policies Scenario. The reorientation of China's economy from heavy industrial sectors towards domestic consumption slows growth in China to one-fifth of the pace seen since 2000. In India, final consumption more than doubles to 2040.

Among end-use sectors, industry is the largest contributor to overall growth in final consumption, with gas and electricity accounting for almost 80% of this increase. In the transport sector, oil accounts for less than 50% of the growth in demand, down from a share of nearly 90% for the period since 1990. In the buildings sector, global energy demand growth would have been nearly 40% higher without efficiency improvements, although the New Policies Scenario by no means exhausts the potential for further efficiency gains.

Electricity (40%) and gas (around 30%) underpin the rise in total final consumption in the New Policies Scenario, taking an increasing share of overall end-use consumption at the expense of coal and oil; the share of electricity rises from 19% today to 24% in 2040. Existing and announced efficiency measures avoid over 3 000 Mtoe in final consumption (a quarter of projected energy use) in 2040.

The share of electricity in 2040 reaches 28% in the Sustainable Development Scenario (four percentage points higher than in the New Policies Scenario). Buildings remain the largest consumer of electricity, but consumption in the transport sector is more than double the level in the New Policies Scenario as a result of a much bigger push for electric mobility (Figure 1.4).

Figure 1.4 ▷ Average annual change in total final electricity consumption by scenario and sector, 2017-2025 and 2025-2040



Buildings remain the largest source of growth for electricity demand; the transport sector increases its contribution to growth significantly in the Sustainable Development Scenario

Electricity demand in developing economies expands by more than 90% to 2040 in the New Policies Scenario; industrial motors are the largest source of growth, followed by demand for space cooling and household appliances. Nonetheless, per-capita electricity use in 2040 in developing economies is still only around 40% of the level in advanced economies today. The outlook for electricity demand in advanced economies is much flatter – a rise of just over 15%.

In 2017, more than 50% of total final consumption was used to supply heat. Just over half of all heat was consumed in industry, and almost all of the rest used for space and water heating in the buildings sector. In the New Policies Scenario, the contribution of heat from renewable sources rises from 10% today to 15% of the total by 2040.

Sales of electric cars escalate by over 30% every year for the next five years in the New Policies Scenario and there are 300 million electric cars on the road by 2040; there are also 740 million electric bikes, scooters and tuk-tuks, almost 30 million light- and heavy-duty electric trucks and 4 million electric buses worldwide. In total, these consume nearly 1 200 terawatt-hours (TWh) in 2040 (3% of total electricity demand in 2040).

1.4 Power generation and energy supply

Table 1.4 ▷ World electricity generation by fuel, technology and scenario (TWh)

			New Policies		Current Policies		Sustainable Development	
	2000	2017	2025	2040	2025	2040	2025	2040
Coal	6 001	9 858	9 896	10 335	10 694	13 910	7 193	1 982
Oil	1 212	940	763	527	779	610	605	197
Gas	2 747	5 855	6 829	9 071	7 072	10 295	6 810	5 358
Nuclear	2 591	2 637	3 089	3 726	3 079	3 648	3 303	4 960
Hydro	2 618	4 109	4 821	6 179	4 801	5 973	5 012	6 990
Wind and solar PV	32	1 519	3 766	8 529	3 485	6 635	4 647	14 139
Other renewables	217	722	1 057	2 044	1 031	1 653	1 259	3 456
Total generation	**15 441**	**25 679**	**30 253**	**40 443**	**30 971**	**42 755**	**28 859**	**37 114**
Electricity demand	*13 156*	*22 209*	*26 417*	*35 526*	*26 950*	*37 258*	*25 336*	*33 176*

Notes: TWh = terawatt-hours. Electricity demand equals total generation minus own use (for generation) and transmission and distribution losses. Total generation includes other sources.

Power generation

Global electricity generation increases by some 60% (15 000 TWh) between 2017 and 2040 in the New Policies Scenario. Fossil fuels remain the major source for electricity generation, but their share falls from around two-thirds today to under 50% by 2040.

Coal and renewables switch their position in the power mix. The share of coal declines from around 40% today to a quarter in 2040 while that of renewables grows from a quarter to just over 40% over the same period. The share of natural gas remains steady at over 20%.

Hydropower remains the largest low-carbon source of electricity in the New Policies Scenario, contributing 15% of total generation in 2040. Renewables altogether account for over 70% of the increase in electricity generation. Solar PV costs are projected to fall by more than 40% to 2040, underpinning a ninefold growth in solar PV generation, mainly in China, India and the United States. Low-carbon technologies account for half of the world's electricity generation by 2040.

Output from nuclear plants remains at around 10% of the global power mix. The nuclear fleet in advanced economies is ageing: around two-thirds of the fleet (220 GW) is older than 30 years today. China becomes the country with the largest generation of nuclear-based electricity.

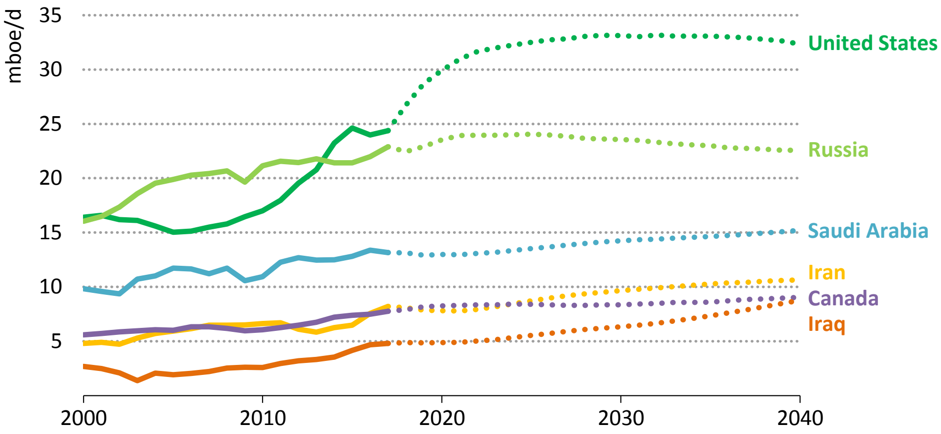
Energy supply

Global oil and natural gas production expands by more than 20% to 2040. Having become the world's largest gas and oil producer in 2015, the United States continues the remarkable growth of recent years, accounting for more than half of global supply increase to 2025 (over 70% for oil and 40% for gas); in 2025, nearly every fifth barrel of oil and every fourth cubic metre of gas in the world is produced in the United States.

After the mid-2020s, shale output from the United States levels off and conventional oil and gas production in the Middle East and unconventional production from a diverse range of countries accelerate to fill the gap. Shale gas and tight oil production outside the United States picks up in the latter part of the projection period, led by Argentina, Canada, China and Mexico. A variety of enhanced oil recovery techniques collectively manage to squeeze an additional 2.4 million barrels per day (mb/d) out of existing oil fields by 2040.

Global conventional crude oil production peaked in 2008 at 69.5 mb/d and has since fallen by around 2.5 mb/d. In the New Policies Scenario, it drops by a further 3 mb/d between 2017 and 2040, and its share in the global oil supply mix falls steadily from 72% today to 62% in 2040. The level of conventional crude oil resources approved for development in recent years is far below the demand requirements of the New Policies Scenario, creating the risk of sharp market tightening in the 2020s.

Figure 1.5 ▷ Oil and gas production for selected countries in the New Policies Scenario



The rise in US production of tight oil and shale gas since 2010 is the largest parallel increase in oil and gas output in history

Note: mboe/d = million barrels of oil equivalent per day.

Coal production in China declines at an average rate of 0.4% per year. India overtakes Australia and the United States in the early 2020s to become the second-largest coal producer.

1.5 Emissions

Table 1.5 ▷ World energy-related CO_2 emissions by fuel and scenario (Mt)

			New Policies		Current Policies		Sustainable Development	
	2000	2017	2025	2040	2025	2040	2025	2040
Coal	8 951	14 448	14 284	14 170	15 207	17 930	11 335	3 855
Oil	9 620	11 339	11 862	11 980	12 303	13 984	10 657	6 886
Gas	4 551	6 794	7 757	9 731	7 945	10 561	7 543	6 906
Total CO_2	**23 123**	**32 580**	**33 902**	**35 881**	**35 454**	**42 475**	**29 535**	**17 647**

Note: Mt = million tonnes.

After plateauing for three years, global energy-related CO_2 emissions rose in 2017 by more than 500 million tonnes (Mt). In the **New Policies Scenario**, total energy-related CO_2 emissions continue to rise, going up by 10% to 36 gigatonnes (Gt) in 2040. Most of the growth comes from gas and oil, reflecting the trends in demand, but coal (with 39% of the total) remains the largest source of emissions in 2040, followed by oil (33%) and gas (27%).

There is little overall change in the projected trajectory for energy-related CO_2 emissions in the New Policies Scenario compared with the *WEO-2017*. The projection remains slightly below the level implied solely by countries' Nationally Determined Contributions submitted as part of the Paris Agreement, meaning that, in aggregate, countries are broadly on course to deliver what they had planned in their international commitments (see Chapter 2). However, these commitments are far from sufficient to set the world on the emissions pathway of the Sustainable Development Scenario.

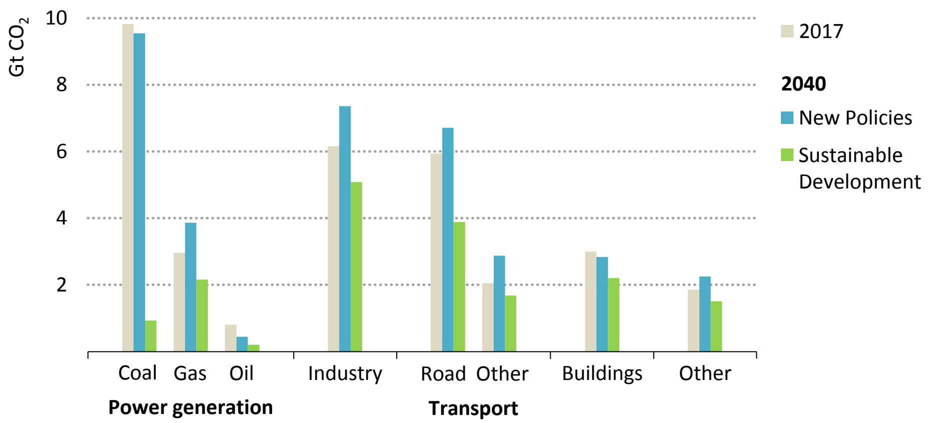
Emissions across advanced economies have fallen by an average of 0.9% each year since 2005, a rate that increases marginally in the New Policies Scenario. Among developing economies, China's emissions are largely flat through to the mid-2020s and then start to decline, projected at around 2% lower in 2040 than today. India's CO_2 emissions are among the lowest in the world on a per-capita basis. India's emissions continue to grow to 2040, but at a slower pace than in the past and its CO_2 emissions intensity halves by 2040.

Direct CO_2 emissions rise by around 20% to 2040 in the industry and transport sectors. Growth from industry comes despite a rise in electricity and gas use, at the expense of coal, that reduces the CO_2 intensity of the sector. Increasing sales of electric cars and improvements in vehicle and logistics efficiency limit CO_2 emissions growth in road transport to less than 15%, but CO_2 emissions in other transport modes rise by more than 40%. The buildings sector sees a slight dip in direct emissions, underpinned by fuel switching to electricity and gas and continued efficiency improvements.

In the power sector, 2040 emissions of CO_2 are only around 2% higher than today despite an increase in electricity consumption of some 60%. The rapid penetration of low-carbon sources of electricity helps to offset the increase in electricity demand, together with improvements in the average efficiency of the global thermal coal and gas fleets.

Emissions of the three major air pollutants – sulfur dioxide (SO_2), nitrogen oxides (NO_X) and fine particulate matter ($PM_{2.5}$) – decline in the New Policies Scenario: SO_2 emissions from the power sector halve by 2040. This helps alleviate some adverse health impacts, but in 2040 there are still more than 6 million premature deaths attributable to air pollution.

Figure 1.6 ▷ World energy-related CO_2 emissions by sector in the New Policies and Sustainable Development scenarios



The industry and transport sectors take a growing share of energy-related CO_2 emissions while the power sector emissions remain broadly constant in the New Policies Scenario

Note: Gt CO_2 = gigatonnes of carbon dioxide.

In the **Sustainable Development Scenario**, energy-related CO_2 emissions are reduced by more than 45% to 17.6 Gt by 2040. The power sector witnesses the most dramatic change, with the share of low-carbon technologies reaching 85% in 2040 (up from 35% today). Emissions from passenger cars halve, despite the number of cars nearly doubling. Transport is the largest emitting sector in 2040 in this scenario, followed by industry. Emissions from the power sector comprise just nearly 20% of total CO_2 emissions in 2040 (down from 42% today) while those from industry rise to nearly 30% (up from 19% today) (Figure 1.6).

The increase in CO_2 emissions caused by achieving universal energy access (which leads to a very slight increase in fossil fuel consumption) is more than offset by reductions in methane emissions from sharp falls in the traditional use of biomass as a cooking fuel.

Emissions of all three major air pollutants decline sharply from today's levels, and power sector emissions of SO_2 are all but eliminated. Emissions of NO_X, which today occur predominantly in the transport sector, drop by nearly half by 2040.

1.6 Trade

Table 1.6 ▷ Net import (shaded) **and export shares by fuel and region in the New Policies Scenario**

	Oil		Natural gas		Coal		Total	
	2017	2040	2017	2040	2017	2040	2017	2040
North America	10%	21%	2%	11%	12%	16%	2%	16%
United States	*30%*	*1%*	*0%*	*14%*	*11%*	*12%*	*7%*	*10%*
Central and South America	18%	32%	7%	7%	45%	39%	24%	26%
Brazil	*15%*	*48%*	*26%*	*22%*	*90%*	*90%*	*19%*	*34%*
Europe	76%	75%	53%	66%	50%	61%	39%	33%
European Union	*88%*	*91%*	*74%*	*89%*	*49%*	*62%*	*47%*	*39%*
Africa	50%	23%	33%	38%	35%	38%	46%	38%
Middle East	76%	71%	22%	24%	77%	90%	61%	53%
Eurasia	71%	65%	34%	41%	42%	48%	48%	47%
Asia Pacific	77%	85%	23%	41%	3%	5%	16%	22%
China	*69%*	*82%*	*42%*	*54%*	*8%*	*3%*	*18%*	*21%*
India	*82%*	*91%*	*46%*	*52%*	*31%*	*23%*	*16%*	*24%*
World trade on production	**46%**	**44%**	**20%**	**24%**	**21%**	**20%**	**25%**	**22%**

Notes: Shaded orange cells indicate net imports; white cells indicate net exports. Import shares for each fuel are calculated as net imports divided by primary demand. Export shares are calculated as net exports divided by production. Total also includes bioenergy, hydropower, nuclear and renewables.

Global energy trade continues to expand over the course of the New Policies Scenario, although not all fuels follow the same pattern. Oil remains the most traded product while natural gas trade grows by 70% between today and 2040. Total coal trade decreases slightly.

Oil trade is underpinned by mounting import needs in developing economies in Asia. Despite flattening demand after 2030, China becomes the world's largest oil importer.

North America switches its role in international oil trade during the projection period, becoming a net exporting region largely thanks to burgeoning tight oil production in the United States. The United States becomes a net oil exporter in the early 2020s.

The Middle East remains the world's largest oil exporter by a wide margin. Crude oil exports represent the majority of its exports today but, as the region's refining activity expands by more than 50% to 2040, the bulk of future export growth comes from oil products.

Natural gas trade increases much faster than the pace of demand growth. Driven by policy efforts to improve air quality, China's net import needs more than triple over the outlook period, and its gas imports rise to the level of the European Union. Russia remains the world's largest natural gas exporter throughout the period, followed by the Middle East and North America.

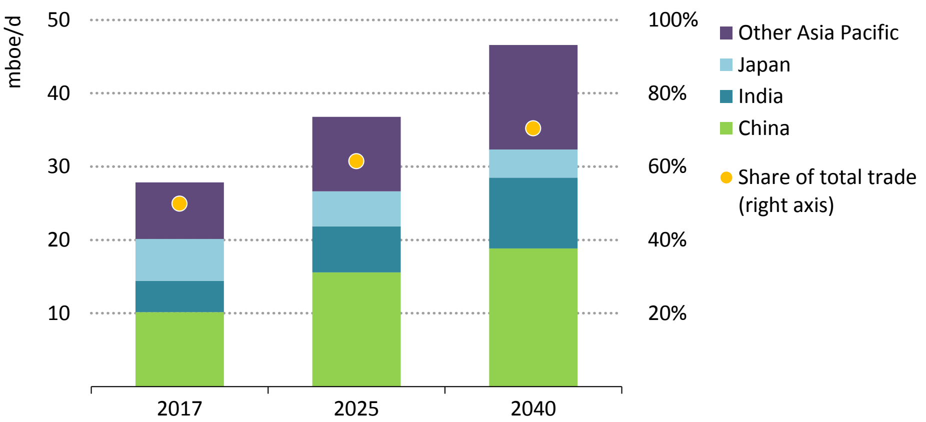
Liquefied natural gas (LNG) represents the bulk of the growth in trade. Global LNG trade more than doubles between 2017 and 2040, increasing its share in global gas trade from around 40% to more than 60% by 2040.

Coal trade is underpinned by two different movements: steam coal trade is affected by weaker demand for power generation and flattens out, while coking coal trade increases at a rate of 1% per year. India becomes the world's largest coal importer, overtaking China.

But uncertainty looms large: small changes in the supply-demand balance in either China or India can quickly have substantial implications for traded coal. Australia continues to be well positioned to serve the Asian markets with low-cost coking coal in a growing international coking coal market. Indonesian exports are affected by surging domestic consumption that limits export potential.

A common trend across all fuels is a growing concentration of trade flows to Asia. Overall, Asia's share of global oil and gas trade rises from around half today to around two-thirds by 2040 (Figure 1.7). China accounts for much of this, and our projections suggest a deepening in energy ties between China and key suppliers in the Middle East, Russia and Central Asia.

Figure 1.7 ▷ Net oil and gas imports by Asian destination in the New Policies Scenario



More than two-thirds of global oil and gas imports flow to Asia by 2040

Aggregate net oil import requirements in developing Asia expand by 80% between today and 2040, and around half of the world's traded gas finds a home in Asia by 2040. Coal imports in developing Asia more than double due to the increasing use of coal for power generation.

1.7 Investment

For the third consecutive year, global energy investment registered a slight decline in 2017, falling to $1.8 trillion. Increases in investment in several sectors, including energy efficiency and upstream oil and gas, were more than offset by a drop in power sector investment.

Nonetheless, the largest share of global investment went to the electricity sector, as it was in 2016, reflecting the growing importance of electricity in the energy system. China was the main destination for energy investment, over one-fifth of the total (IEA, 2018a).

Table 1.7 ▷ Global annual average energy investment by type and scenario ($2017 billion)

		New Policies		Current Policies		Sustainable Development	
	2010-17	2018-25	2026-40	2018-25	2026-40	2018-25	2026-40
Fossil fuels	1 171	967	1 081	1 043	1 407	830	574
Renewables	293	331	380	295	296	467	663
Electricity networks	264	313	387	334	397	286	462
Other	20	61	62	60	57	67	150
Total supply	**1 749**	**1 672**	**1 909**	**1 732**	**2 157**	**1 649**	**1 848**
Fuel supply	*58%*	*52%*	*53%*	*53%*	*60%*	*46%*	*32%*
Power supply	*42%*	*48%*	*47%*	*47%*	*40%*	*54%*	*68%*
Energy efficiency	236	397	666	299	496	505	828
Other end-use	124	148	246	122	143	203	581
Total end-use	**360**	**545**	**912**	**421**	**640**	**708**	**1 409**
Total investment	**2 109**	**2 216**	**2 821**	**2 153**	**2 796**	**2 357**	**3 257**
Cumulative 2018-2040		60 042		59 168		67 713	

Notes: The historical value for energy efficiency includes only 2017. Other includes nuclear, battery storage and carbon capture, utilisation and storage (CCUS) in the power sector. Other end-use includes direct use of renewables in end-use sectors (except biofuels, which are included in supply), electric vehicles and CCUS in industry.

In the **New Policies Scenario**, energy investment amounts to $2.2 trillion each year between 2018 and 2025 on average and $2.8 trillion each year thereafter. A pick-up in oil and gas investment to balance the near-term market, together with a slight rise in costs, mean that spending on fossil fuels regains a larger share in total supply investments than electricity.

Average annual upstream oil and gas spending rises in the New Policies Scenario from $580 billion between today and 2025 to $740 billion each year between 2025 and 2040. The United States accounts for almost 20% of total upstream oil and gas investment globally, followed by the Middle East with almost 15%.

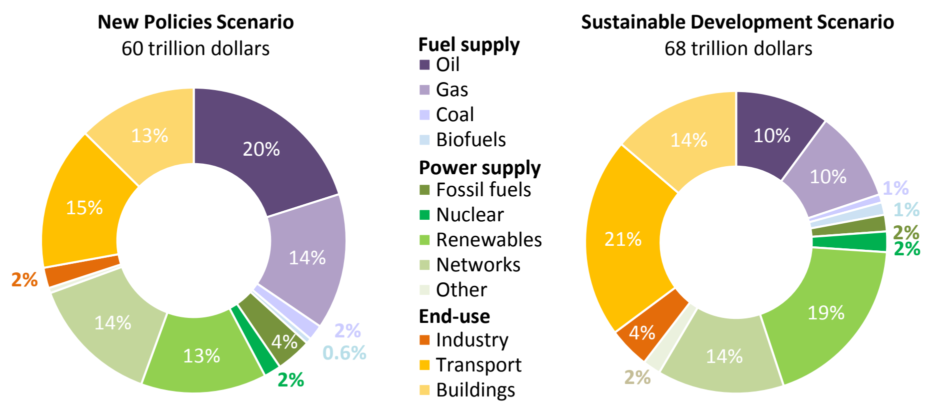
Renewables represent over half of the investment made in power plants since 2010 and continue to take the largest share of investment in the New Policies Scenario, with an average annual spend of $350 billion. Continued declines in costs mean that a constant investment in dollar terms buys a steadily increasing amount of capacity.

Once the wave of global coal-fired capacity currently under construction is completed, total annual investment in coal-fired plants halves in the New Policies Scenario, compared with the average of the last five years.

Energy efficiency investment increases in all end-use sectors in the New Policies Scenario. The buildings sector accounts for almost 40% of cumulative investment in energy efficiency, nearly 60% of which supports more energy-efficient houses, appliances and equipment. More than two-thirds of the investment in the transport sector goes to light-duty vehicles.

The **Sustainable Development Scenario** requires around 15% more capital than the New Policies Scenario, and puts much more emphasis on investment in end-use efficiency and clean energy technologies (Figure 1.8). Electricity demand follows a lower trajectory in the Sustainable Development Scenario owing to increased energy efficiency in all end-use sectors. Continued investment in oil and gas supply, however, remains essential even in the Sustainable Development Scenario to 2040, as decline rates at existing fields leave a substantial gap that needs to be filled with new upstream projects.

Figure 1.8 ▷ Cumulative investment needs by sector in the New Policies and Sustainable Development scenarios, 2018-2040



Total investment in the Sustainable Development Scenario is only about 15% higher than in the New Policies Scenario, but there is a marked difference in capital allocation

Note: Other includes battery storage and carbon capture, utilisation and storage.

Key themes

1.8 Energy policy in a time of transitions

The scenario structure of the *World Energy Outlook* provides a variety of lenses through which to view the long-term components of a secure energy system: reliability, affordability and sustainability.[1] The main concerns about reliability and affordability have traditionally been directed at the adequacy of investment in conventional oil resources and in natural gas, given that these resources are unevenly distributed around the world. The question of who supplies this energy and on what terms remains a very important strand of the energy security debate, even if it has been substantially reshaped by the rise of shale in the United States.

However, as analysed in detail in Part B of this year's *Outlook*, questions of electricity security are rising up the policy agenda worldwide. Moreover, the investments required to buttress long-term energy security are also inseparable from questions of sustainability, especially as countries step up their response to a range of environmental challenges. The risks from a changing climate are a strong motivating force, especially given that energy-related CO_2 emissions resumed growth in 2017. But for policy makers in many countries (and not only developing countries), a near-term priority is to reduce the health impacts caused by poor air quality. More than 5 million premature deaths each year are attributable to air pollution. Most of these deaths are from outdoor pollution in cities, with the remainder from smoky indoor environments due to cooking over open fires using solid biomass. The challenge for energy policy in a time of transitions is therefore twofold: to accelerate and broaden investment in cleaner, smarter and more efficient energy technologies, while ensuring at the same time that all the key elements of energy supply, including electricity networks, remain reliable and robust.

Two energy revolutions

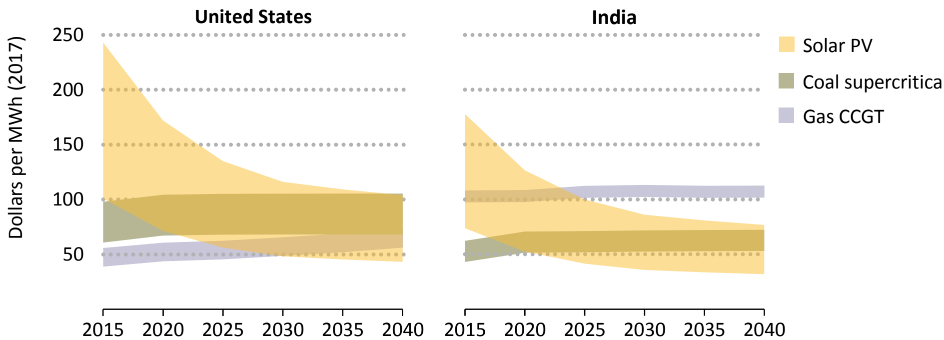
Two energy revolutions are having a major influence on this picture: the rise of shale in the United States and the transformation of the global power sector.

The shale revolution, which has brought a rise of oil and gas production in the United States that is unparalleled in the history of the hydrocarbons industry, has eased traditional concerns for importing countries related to the concentration of conventional resources. But it has also raised new questions over how major hydrocarbon-dependent economies will fare in the face of increased uncertainty over their long-term oil and gas revenues (the focus of *Outlook for Producer Economies*, a special report in the *WEO-2018* series [IEA, 2018b]). Uncertainty about the direction of long-term policy and technology has

1. Energy security also has an important short-term component, related to the resilience of the energy system and its ability to react promptly to sudden changes in the supply-demand balance. The focus here is on longer term security, which mainly deals with timely investments to supply energy in line with economic development and environmental needs.

also embedded an increasing preference for shorter cycle investments in the strategies of many oil and gas companies, and the limited appetite for large, capital-intensive projects is becoming an important element in the debate about future supply.

Figure 1.9 ▷ Levelised costs of selected new sources of electricity generation in selected countries in the New Policies Scenario



Cost reductions for solar PV put it on track to be among the cheapest options for new generation in many countries around the world

Notes: WACC = weighted average cost of capital. CCGT = combined cycle gas turbine. Costs for renewable energy are discussed in more detail in Chapter 8.

The impacts of the renewable energy revolution and the upheaval underway in the electricity sector have been no less far-reaching. In many countries (as the examples of the United States and India illustrate in Figure 1.9), solar PV is becoming among the least expensive options to produce electricity – especially if projects have access to relatively inexpensive financing. Pairing solar PV with storage raises the levelised costs, but also increases its value by easing its integration into power systems.[2] These developments have undercut the case for new investment in thermal generation in some countries, especially in coal-fired power: final investment decisions in new coal plants in 2017 were at one-third of the level seen in 2010, and the fall in China has been particularly abrupt. Our projections in the New Policies Scenario suggest that investment in coal-fired generation will not return to the peak level seen in 2015.

The accessibility and cost-competitiveness of wind and solar PV mean that some arguments often heard in favour of incumbent fuels, focusing on their affordability and their role in providing energy access, no longer hold as much water as they once did. Of those gaining

2. A full evaluation of the competitiveness of different generation options requires consideration of both the costs and value, discussed in Chapter 8.

access to electricity since 2000, most have done so through grids with generation from fossil fuels, primarily coal. But this balance is changing. The most common route for those gaining access in our projections to 2030 is via renewable energy sources, and off-grid and mini-grid systems provide a mode of delivery much better adapted than grids to the rural areas where the access problem is increasingly concentrated. Access to modern energy is indispensable for social and economic welfare, and low-cost renewables are making an important contribution to development in many of the world's poorest countries.

Choice of scenario

How these different elements play out, and how potential vulnerabilities evolve, depends on which scenario the world follows. The Current Policies Scenario provides the clearest illustration of the hazards that lie ahead: a business-as-usual approach that heads into increasingly perilous territory for all aspects of energy security. The New Policies Scenario paints a much more nuanced picture: a concerted effort to move to cleaner and more efficient technologies, with the power sector in the vanguard of change, and a large and expanding role for natural gas, with LNG underpinning the emergence of an increasingly competitive global gas market. But there remains a significant gap between the outcomes in the New Policies Scenario and those in the Sustainable Development Scenario; this is gradually narrowing, but at nowhere near the pace required (Box 1.1).

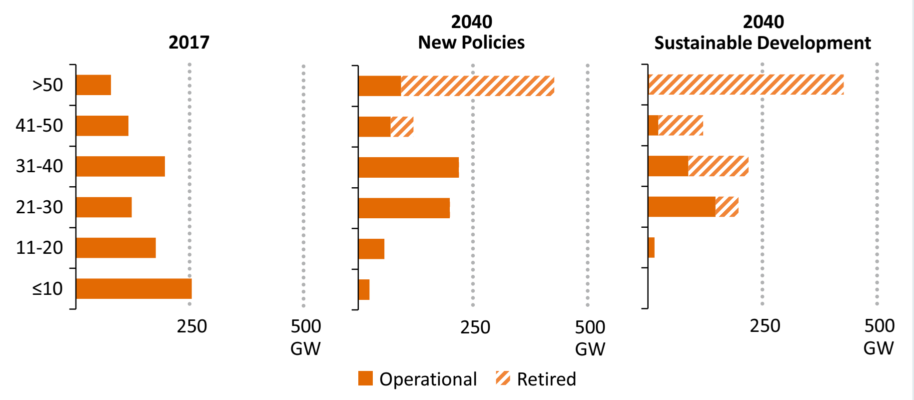
Box 1.1 ▷ Do we have one foot on the bridge?

In 2015, a *WEO Special Report* (IEA, 2015) identified five cost-effective opportunities for countries to reach an early peak in energy-related greenhouse gas (GHG) emissions. While not sufficient on their own to avoid severe impacts from climate change, these measures – if implemented in full – nonetheless could keep the door open for further action later and provide a bridge (hence the name "Bridge Scenario") to an emissions trajectory consistent with long-term decarbonisation goals. A few years later, we can assess progress in these five areas. Overall, the rise in global emissions in 2017 has started to open a gap between the world's emissions trajectory and what would be needed to stay with the Bridge Scenario.

- **Increasing energy efficiency** in the industry, buildings and transport sectors. The coverage and stringency of energy efficiency policies have increased in recent years, but two-thirds of final energy use is still not covered by mandatory efficiency standards, and the pace of global improvement in energy efficiency slowed down in 2017.
- **Increasing investment in renewable energy technologies.** This is the brightest spot. Investment in renewable power fell in monetary terms in 2017 to $300 billion, but that brought in more than 175 GW of new capacity worldwide. Deployment of solar PV and offshore wind remain on a rising trend, although annual additions of onshore wind have been falling.

- **Removing inefficient fossil fuel subsidies**. We estimate that artificially low prices for fossil fuels for end-users around the world involved subsidies totalling just over $300 billion in 2017. This is lower than in 2015, thanks in part to pricing reforms in many countries, but these reforms are coming under pressure as oil prices rise.
- **Reducing methane emissions** from oil and gas production. As highlighted in last year's *Outlook*, there is an opportunity here for action that is still not being taken up at scale. We estimate that worldwide methane leaks from oil and gas supply chains are still on the rise.
- **Phasing out the least-efficient coal-fired power plants**. Investment in new coal plants has slowed sharply, especially for the least-efficient subcritical coal technologies. However, 60% of today's operating coal plants are subcritical and almost half are under 20 years old, locking in emissions for the future (Figure 1.10).

Figure 1.10 ▷ Subcritical coal-fired capacity by age and scenario



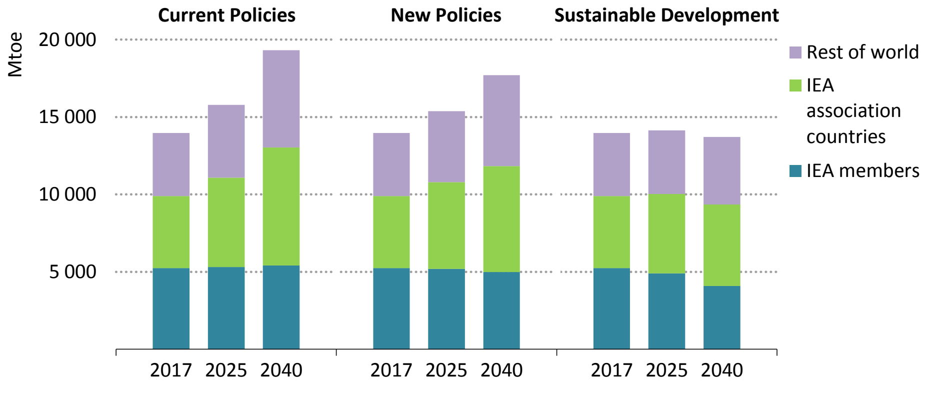
Half of the subcritical coal-fired fleet in operation today is less than 20 years old; without strong policy action, they are unlikely to close before reaching 40-50 years old

This is a mixed picture and more progress would be needed to get a firm foothold on the "bridge". Our analysis suggests that emissions are tracking the levels implied by their Nationally Determined Contributions, submitted under the Paris Agreement (see Chapter 2). In aggregate, countries are doing roughly what they had promised; the problem is that this still leaves them a long way from where they might wish to end up.

Shifting sources of global growth

The extent, composition and geography of global demand growth are crucial variables in determining the evolving nature of energy security challenges. Our projections in the *World Energy Outlook* vary widely by scenario, but a common denominator is that growth in energy demand is overwhelmingly concentrated in the developing economies of Asia. Furthermore, our projections consistently show that, within Asia, sources of growth are moving away from China (where the huge rise in energy demand in recent years slows in all scenarios) and towards India and other countries in South and Southeast Asia. This growth in demand is the main reason why the International Energy Agency (IEA) is putting strong emphasis on "opening its doors" to key emerging economies and working with them on clean energy transitions.

Figure 1.11 ▷ IEA member and association countries in world primary energy demand by scenario



IEA member and association countries now account for over two-thirds of global energy demand

Note: Since November 2015, eight countries have joined the IEA as association countries: Brazil, China, India, Indonesia, Morocco, Singapore, South Africa and Thailand.

To the extent that future demand growth continues the patterns of the past, the stage looks set for a return to some traditional strains in the system, especially in oil markets. Since 2015, oil consumption has been growing at a rate well over 1 mb/d per year: the Current Policies Scenario sees this continuing and the world becoming reliant on unprecedented volumes from the main conventional resource-holders in the Middle East, even though higher prices encourage non-OPEC supply. Production in Saudi Arabia pushes up to 15 mb/d in 2040, and Iran and Iraq each produce around 7 mb/d. This scenario reminds us that, although eclipsed today by other concerns, we may not have heard the last of the peak oil supply debate.

However, new policies and the pace of technological change mean that past trends are unlikely to be a good guide to the future. In the New Policies Scenario, demand growth is restrained by the increasing coverage and strength of energy efficiency policies, and renewables and natural gas account for 80% of the growth in energy demand to 2040. The position of coal erodes in the face of strong policy headwinds, meaning that its share in the global energy mix falls behind that of natural gas by 2030. And the hold of oil over the energy mix weakens, with its share falling from 32% in 2017 to 28% in 2040, even without a projected peak in demand.

Changing face of energy

China is emblematic of the changing face of global energy use. Even as it overtakes the United States to become the single largest consumer of oil globally in the 2030s, a combination of industrial strategy, rising import dependence and concerns about air quality mean that oil consumption is set to plateau in China at around 4 barrels per capita per year, far below the levels reached historically in Europe or North America. China is already a leader in electric mobility, accounting for more than half of global electric car sales in 2017 and an even higher share of electric buses and two-wheelers. Oil demand growth in China almost comes to a halt by the 2030s as oil use in road transport starts to fall, and coal use declines by some 15% to 2040, but natural gas demand rises very strongly – almost to the level of the United States today – and China also leads the global deployment of renewables and nuclear. In the electricity sector, with far and away the largest roll-out of smart meters worldwide, China is taking the lead in applying many of the digital technologies that are playing an increasing role in the energy sector (Box 1.2).

Box 1.2 ▹ Digitalization: the next big thing, for better or worse

The increased application of digital technologies is set to be a transformative shift for the energy sector, although it cannot be taken for granted that all of the changes set in motion by these technologies push in the direction of a more secure and sustainable energy system. As ever, which face of digitalization we end up seeing – the good or the bad – will largely depend on whether policy makers are able to get ahead of the curve with regulation and oversight that adapts to the types of innovations that are coming into play.

Digitalization is influencing trends all across the energy sector (for example, it is widely seen as the next frontier for cost reductions in upstream oil and gas), but is likely to have the largest impact in electricity. On the demand side, it is pushing up electricity use while also making demand smarter and more flexible. As billions more connected devices and machines enter the market over the coming years, they not only draw electricity at the plug, but also push up growth in demand for data centre and data transmission network services. So far, efficiency gains from improvements of servers, storage devices, network switches and data centre infrastructure, as well as a shift to much higher shares of highly efficient cloud and hyper-scale data centres, have kept demand from this sector in check. But demand growth looks set to continue to rise relentlessly: connected devices account for 20% of the growth in buildings sector electricity consumption through to 2040 in the New Policies Scenario.

There is even greater uncertainty over potential growth areas for electricity consumption like bitcoin mining and autonomous vehicles. Bitcoin's contribution to today's electricity demand is subject to a wide range of estimates. For the moment the range is still small on a global scale (0.1-0.3% of global electricity use), but this source of demand is fast becoming a concern in regions, including parts of China, Georgia, Iceland and Quebec (Canada), that are key bitcoin mining centres. In Iceland, for example, electricity use from bitcoin mining could soon exceed the entire country's household electricity consumption. Autonomous vehicles could potentially reduce costs while improving the safety, accessibility and convenience of road transport. But the consequences of automation on long-term energy demand and emissions could go in different directions, depending on the combined effect of changes in technological progress, vehicle technology, policy intervention and consumer behaviour.

Digitalization is already starting to enable demand to become more responsive to supply signals through smart metering. As our special focus on electricity makes clear, digitalization also presents a huge opportunity to improve the operational flexibility, efficiency and stability of power systems, by optimising performance across a range of equipment, appliances and sources of generation and storage. Investment in smart grid technologies such as improved monitoring, control and automation technologies reached $13 billion in 2017. However, increasing digitalization could raise digital security risks, both in terms of the grid's vulnerability to cyber-attacks as well as concerns around data privacy and ownership for consumers.

Digitalization is bringing new players and business models into play, especially in the electricity sector where demand aggregators, virtual power plants[3], energy service companies and other third parties are blurring traditional distinctions between generators, networks, retailers and consumers. Software companies and international oil and gas companies are also appearing as investors in the power sector. Meanwhile there has been a huge change in the composition of the world's largest electricity companies. Fifteen years ago, the *World Energy Investment Outlook* (IEA, 2003) provided a list of the ten-largest power companies in the world, ranked by installed capacity. European utilities dominated the list. This year we repeated the exercise, and Chinese-owned utilities now occupy six of the top-ten places, with EDF the only European company in the top-five rank.

3. Virtual power plants (VPP) are networks of distributed energy resources (behind-the-meter storage, rooftop PV, demand-side response resources) that are aggregated and connected to markets and services to which they might not otherwise have access. Virtual power plants can provide bulk electricity, system services such as adequacy, capacity or power quality like their physical counterparts, by aggregating through digital technologies a multitude of small resources. In 2017 there were 18 GW of VPP in Europe.

If the future is electric, then there are new resources in play

In 2016, the power sector became the principal destination for global investment in energy supply for the first time. It happened again in 2017, with global investment in electricity generation, networks and storage reaching $750 billion, 5% more than investment in oil and gas (IEA, 2018a). This is in part a reflection of the precipitous fall in upstream spending on new hydrocarbon projects, which – even if offset in part by lower costs – is raising the spectre of a new boom and bust cycle in oil (see below and Chapter 3). But it also points to a longer term shift in the balance of investment flows towards electricity and clean energy technologies that needs to accelerate very rapidly in the Sustainable Development Scenario. In this scenario, the global power sector accounts for two-thirds of all capital flows into new energy supply and nearly $20 trillion is spent on clean energy technologies as a whole, bringing a new set of energy resources and investment uncertainties into play (Spotlight).

S P O T L I G H T

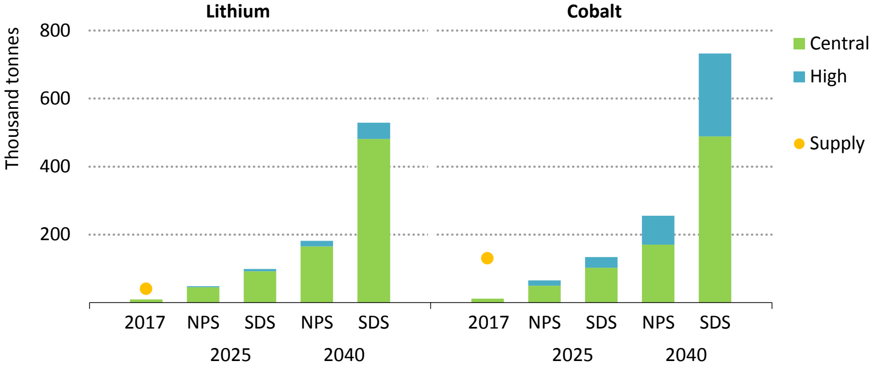
A new brand of resource politics?

The faster the energy economy changes, the more it requires new conversations about resources. The rise of clean energy technologies is leading to significant growth in demand for a wide range of minerals and metals, such as aluminium, copper, lead, cobalt, lithium, manganese, nickel, silver, iron ore, zinc and rare earth minerals. Rapid growth in electric vehicles in particular is bringing the energy sector closer to other commodity sectors that are subject to volatility and, in some cases, strong concentrations of resource ownership. Lithium and cobalt are both essential components of batteries for electric vehicles. More than half of cobalt production and reserves are in a single country, the Democratic Republic of Congo. China has 60% of the refining capacity for cobalt, up from only 3% in 2000, and has a strong position in production and reserve levels in practically every key mineral and metal required under low-carbon scenarios.

The growth in electric vehicles projected in the New Policies Scenario, and even more so in the Sustainable Development Scenario, represents a level of demand for lithium and cobalt that is considerably higher than today's supply. This means large investment to open new mining operations and expand production capacity. Today's market prices offer a substantial incentive to do so. However, given that it takes several years to bring new mine capacity online, the risk remains that bottlenecks in the supply chain will lead to tight supply and price spikes in the early 2020s. This would have implications along the value chain, as raw material costs make up around 20% of the total battery pack cost, and as the cost of the battery is the main determinant of the price of an electric vehicle.

Pressures on primary production could be eased over the longer term by recovering material from existing batteries, or re-using old batteries for stationary storage, even though current recycling rates are low. If there are serious constraints on supply, any shortage would also create strong incentives to innovate and find alternative technological solutions; there is a lot of current research on different battery chemistries that could alleviate potential shortages of cobalt. Whichever way things evolve, the energy sector needs to widen its discussions about energy resources.

Figure 1.12 ▷ Lithium and cobalt requirements for electric vehicle batteries in the New Policies and Sustainable Development scenarios



Major new supplies of lithium and cobalt will be needed as the number of electric vehicles expands

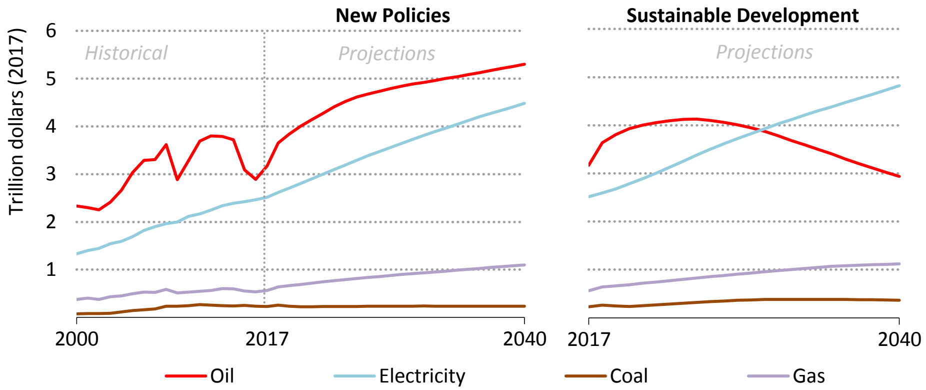
Notes: The range between the central and high variant in each year depends on the chemistry of the batteries being produced. NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

The broader picture

The affordability of energy remains a major element of long-term energy security, and the level and composition of consumer spending on energy varies substantially between scenarios. Generating sufficient supply to meet demand in the Current Policies Scenario requires high prices, making affordability a key concern. In the New Policies Scenario, end-user spending on oil products remains the largest single component of the total. Even though the oil intensity of the global economy has been decreasing steadily with time, this suggests that both the absolute level and the volatility of oil prices are set to remain a central concern of consumers and policy makers in this scenario (Figure 1.13). The likelihood of oil price volatility does not diminish in the Sustainable Development Scenario (arguably the opposite is the case), but the decline in oil demand that starts in the 2020s means that, by 2030, electricity has become the largest element in consumer energy spending.

A critical element of the broader picture is the implications of our projections for global emissions. In the New Policies Scenario, emissions of all the major air pollutants decline, but premature deaths attributable to poor air quality remain stubbornly high; a much more sustained effort on both urban air quality and clean cooking would be required to bring these numbers down. Today the world is already around 1 °C warmer than in pre-industrial times. The rise in energy-related CO_2 emissions in the New Policies Scenario together with emissions of other GHGs (including those from outside the energy sector) would put the world on course for a global mean temperature rise of roughly 2.7 °C by 2100, as against the rise of between a 1.7-1.8 °C which is consistent with the Sustainable Development Scenario.[4]

Figure 1.13 ▷ Global end-user energy spending by fuel and scenario



In the Sustainable Development Scenario, electricity takes over from oil as the main element of consumer spending on energy

The implications of the difference between these two outcomes are huge. Quantifying the changes in physical hazards is subject to a large degree of uncertainty, but the higher the temperature rise, the greater the risks of extreme weather events such as heat waves, droughts, river and coastal floods and crop failures. Limiting the average global surface temperature rise to 1.7 °C would already lead to an increase in the risks of extreme weather events from today's levels. But risks are amplified for every increment in the temperature. For example, between 1981 and 2010 the global average chance of a place experiencing an extreme heat wave was around 5%.[5] With an average temperature increase of 1.7 °C, this rises to 40%; with a 2.7 °C increase it rises further to 67%. Similarly, a major river flood is, on average, nearly twice as likely to occur with a 1.7 °C temperature rise than was the case on average between 1981 and 2010 and is two-and-half times more likely under a 2.7 °C rise (Arnell et al., 2018).

4. Post-2040 emissions trends are not modelled in detail here, but by comparing trends to 2040 with other long-term emissions scenarios, the Sustainable Development Scenario puts the energy sector on a trajectory towards a long-term temperature rise of between 1.7 and 1.8 °C above pre-industrial levels (see Chapter 2). These temperature rises refer to the average increase globally; in reality, the temperature rise in some regions would be much higher than in others.

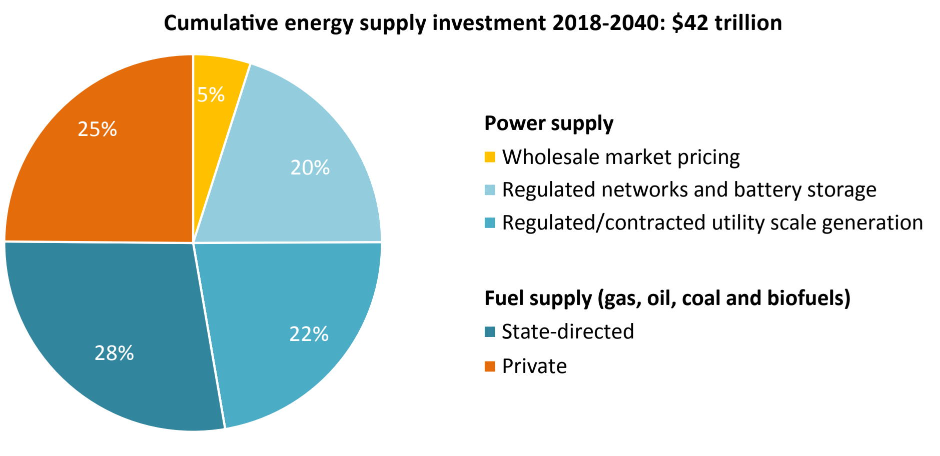
5. A heat wave is defined here as at least four days when the temperature is higher than the 99th percentile of the warm season temperature in that region.

Aside from the broader impacts on society and welfare, these changes would also amplify some of the challenges facing the energy sector, which would have to contend with the sudden and destructive effect of more frequent extreme weather events on energy infrastructure, as well as the more gradual impacts of changes to heating and cooling demand, and the effect of shifting weather patterns on hydropower.

Policies will determine which way investment flows

How government policies evolve remains an important key to future developments. In the power sector, for example, over 95% of global investment is made in areas where revenues are fully regulated or affected by mechanisms to manage the risk associated with variable prices on competitive wholesale markets (IEA, 2018a). In many areas of fuel supply, investments are made by companies in which the state is the sole or the majority shareholder. Of the cumulative $42 trillion in investment in energy supply required to 2040 in the New Policies Scenario, we estimate that more than 70% is made either by state-directed entities or where revenues are fully or partially guaranteed by regulation (Figure 1.14).

Figure 1.14 ▷ Cumulative energy supply investment by type in the New Policies Scenario



More than 70% of investments in energy supply are either made by state-directed entities or respond to a regulatory or other incentive

Against this backdrop, we highlight seven areas from the *WEO-2018* analysis where choices made by policy makers play a crucial role in determining the future reliability, affordability and sustainability of the energy system.

1.9 How can policy makers enhance long-term energy security?

Adapt power systems to the transformation that is underway

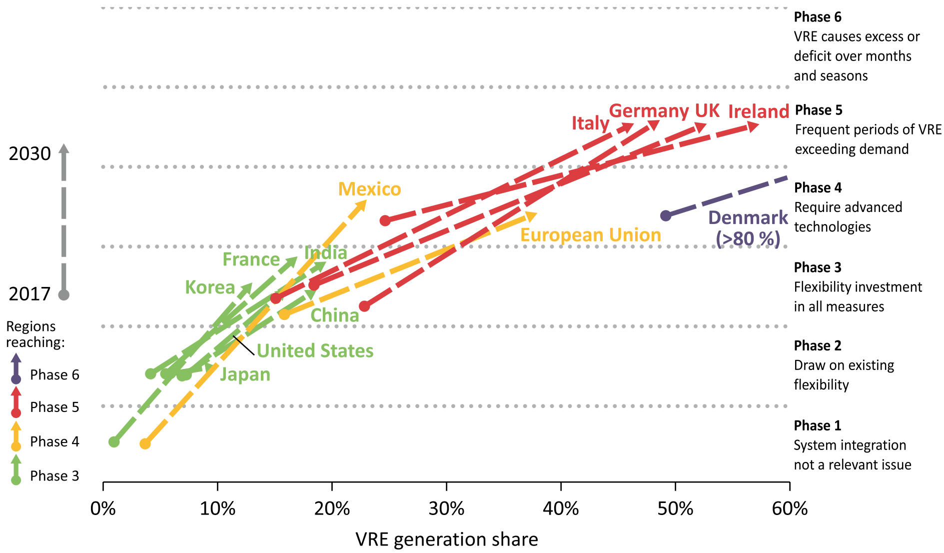
Power systems have always needed flexibility: electricity supply needs to balance demand at all times, and demand patterns have always changed hourly, daily, weekly and seasonally. But the flexibility needs of future power systems are rising, in some cases quite rapidly, due to the rapid emergence of non-dispatchable sources of generation such as wind and solar PV. The number of countries with a share of wind and solar PV above 5% of total electricity generation has increased from less than 10 in 2010 to more than 40 in 2017. Countries in the 10-20% range include Austria, Belgium, Greece, Italy, Netherlands, Sweden and United Kingdom. Germany, Ireland, Portugal and Spain are all at shares of more than 20%; Denmark was up to a share of around 50% in 2017.

The IEA categorises the integration of variable renewables into six distinct phases which are intended to assist in the identification and prioritisation of integration measures. These cover all possible levels of variable renewable penetration from a first phase – where deployment of the first tranche of wind and solar power plants has no noticeable impact at the system level – to an energy system relying on variable renewables as the dominant source of generation (IEA, 2018c).

There are four main sources of flexibility to balance electricity systems: the remainder of the power generation fleet; the interconnection of electricity grids to allow for balancing over a wider area; flexibility on the demand side; and energy storage. In the special focus on electricity in Part B of this *WEO*, we look in detail at both the increasing demand for flexibility in power systems in our scenarios, and how this can most cost effectively be provided. At present, the ability of thermal and hydropower plants to ramp up and down their own generation provides more than 85% of the flexibility available to power systems: interconnections provide around another 5%, and pumped storage a further 4%. Digitalization is unlocking new, small and more distributed sources of flexibility, especially in terms of demand-side response, and battery storage has grown quickly, especially behind-the-meter, but the contribution of these new forms of flexibility currently accounts for only around 1% of the total.

In the New Policies Scenario, the composition of the global power plant fleet changes fast. Within a decade, gas-fired capacity takes the lead from coal. Solar PV's rapid rise pushes it past wind capacity in the near term, and then past hydropower around 2030 and coal just before 2040. The evolution of the generation mix differs widely by country, but overall the share of wind power in global generation grows strongly from 4% to 12%, overtaking nuclear as the second-largest low-carbon source of electricity behind hydropower. Solar PV provided only around 2% of global generation in 2017, but widespread deployment and falling costs boost its global share to almost 10% by 2040. Battery storage costs are also set to decline rapidly, and global battery storage capacity reaches 220 GW by 2040, challenging the role of oil and gas-fired peaking plants.

Figure 1.15 ▷ Evolving flexibility needs in the power sector in the New Policies Scenario



The need for extra flexibility in power systems rises substantially as new wind and solar PV resources are added

Note: VRE = variable renewable energy sources.

In all markets, the need for electricity system flexibility increases as the share of variable renewables rises (Figure 1.15). Available resources for the provision of flexibility double by 2040, with power plants remaining the cornerstone of system flexibility, but contributions from interconnections, storage and demand response all increasing. The speed at which countries climb through different integration phases varies, depending not just on the shares of variable renewables in the system but also on the specific characteristics of the system itself. For instance, where there is a good match between the output of VRE and demand, as is the case in many countries with solar PV and cooling demand, their integration is less challenging than in other cases. In the New Policies Scenario, Mexico and India make large leaps in the need to draw upon flexibility, while countries with high penetrations at present (primarily in Europe) reach levels where no country is today. Without the provision of adequate flexibility, the low-carbon transformation of the power sector may well become associated with risks to electricity security, a development that would not only be disruptive for economies, but also put the brakes on the pace of change.

Realise the full potential of energy efficiency

Global energy intensity, the ratio of primary energy supply to gross domestic product, fell by 1.7% in 2017 – the smallest annual decline since 2012. Improvements in energy efficiency are the main instrument to bring down global energy intensity, and offer one of the few ways of simultaneously addressing all aspects of energy security. Global energy intensity would need to fall by an annual average of 3.4% to be consistent with the Sustainable Development Scenario, but there are indications that the flow of effective new efficiency policies may have waned in recent years, linked in part to lower international oil and gas prices.

The contest between efficiency, technological innovation and the rise of alternative fuels on the one hand and economic and population growth on the other is at the heart of the debate surrounding the future of oil demand in road transport. The rise of electric vehicles is often seen as the key variable, and indeed their rapid growth has a significant influence on overall fuel use for passenger cars, but our analysis suggests that changes in the fuel efficiency of the traditional fleet are set to have a much greater influence. Many of these savings do not require technological breakthroughs: if the fuel efficiency of the global car fleet was in line with that of cars in the European Union today (7.3 litres/100 km), this would already reduce global oil consumption by almost 6 mb/d.

Road transport – encompassing cars, trucks, two/three-wheelers and buses – is the largest segment of global oil demand today, accounting for 41 mb/d out of the current 95 mb/d of total consumption. In the absence of any additional efficiency measures or growth in the use of alternative fuels, rising demand for road transport services in the New Policies Scenario would theoretically lead to an increase of about 28 mb/d of oil demand between 2017 and 2040. Yet our projections show growth of less than 4 mb/d, with fuel use in cars around the same as today and all of the increase coming from the freight sector.

How can we explain this 24 mb/d of "missing" oil demand, and all that this implies for reduced local air pollution, global emissions, consumer spending and oil import bills? By far the largest contribution comes from more stringent fuel-economy and emissions standards, and from improvements in engines and hybrid technologies; this avoids around 15 mb/d of potential oil demand. Another 4 mb/d is displaced by biofuels and natural gas. As well, in the New Policies Scenario there are around 300 million electric cars on the road in 2040, 740 million electric bikes, scooters and tuk-tuks, 30 million electric light- and heavy-duty trucks and 4 million electric buses: taken together, these displace over 5 mb/d in 2040.

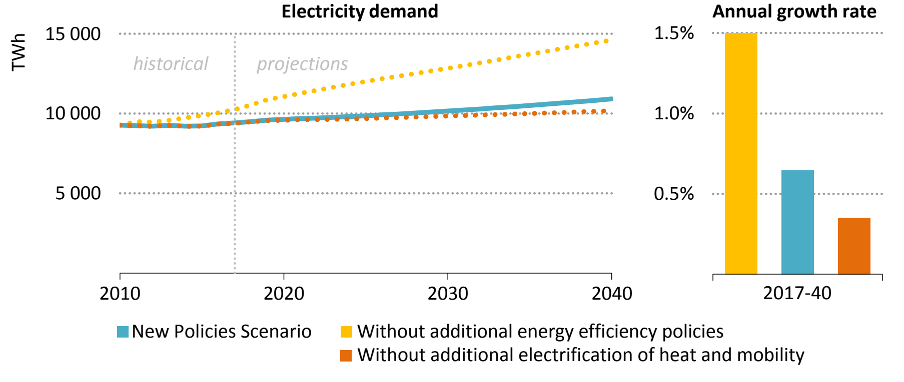
Efficiency also plays a major role in shaping our outlook for electricity. More than 90% of global electricity demand today is concentrated in the buildings and industry sectors, and here too there is a huge volume of potential consumption that is avoided because of efficiency gains through to 2040. In the industry sector, efficiency measures (mostly for motor systems) help to avoid nearly 3 600 TWh of additional electricity consumption by 2040, cutting industrial electricity demand growth in the New Policies Scenario by nearly half. In the buildings sector, an additional 4 000 TWh is saved by 2040, mostly due to more stringent implementation of minimum energy performance standards for appliances and cooling equipment. The improvements seen in the New Policies Scenario by no means exhaust the global potential in this area; but the 7 600 TWh avoided in these two areas already amounts to more than one-third of today's global electricity demand. In advanced economies, efficiency improvements are largely responsible for breaking the link between rising incomes and rising electricity consumption (Box 1.3).

Box 1.3 ▷ The mysterious case of the IEA's disappearing electricity demand

Electricity is at the heart of modern life, but in many advanced economies you would not necessarily know it from the data. Eighteen out of the thirty IEA member economies have seen declines in their electricity demand since 2010 and, in the rest, demand growth has slowed considerably. There is much debate about the causes: structural changes in the economy are often cited. But a detailed decomposition of trends, conducted as part of this year's *WEO* special focus on electricity, highlights that improvements in energy efficiency are the main underlying factor.

Efficiency improvements, typically because of strict minimum energy performance standards, have reined in growth in electricity demand. Without them, electricity demand among IEA member countries since 2010 would have grown at 1.5% per year; with them, it has crawled up by an average of 0.2% per year (Figure 1.16). Total energy use by certain classes of appliances has already peaked: energy use for refrigerators (98% of which are covered by performance standards) is well below the high point reached in 2009, and energy use for lighting has also declined. The world may be electrifying, but – for the moment at least – that does not necessarily mean that advanced economies are using much more electricity.

Figure 1.16 ▷ Electricity demand in IEA member countries and demand without efficiency policies or without new electricity uses



Electricity demand in IEA member countries has been essentially flat since 2010; energy efficiency improvements continue to subdue growth through to 2040

Electricity demand collectively edges higher in IEA countries in the New Policies Scenario, mainly because electricity is in demand for new uses such as electric cars, connected devices and space heating. Of the 1 500 TWh in demand growth in IEA countries from today to 2040 in the New Policies Scenario, around 40% comes from the electrification of mobility and heat.

Reduce emissions from power, but don't forget the rest

In the New Policies Scenario, electricity generation increases by 60%, but global CO_2 emissions from power generation are essentially flat. This means a reduction by one-third in the carbon intensity of electricity generation, largely due to the rapid increase in the contribution of renewables to power generation, but also because of some coal-to-gas switching and continued efficiency improvements in coal and gas-fired power plants. It puts the power sector firmly in the vanguard of change in the energy sector, although an even greater pace would be required to meet the emissions reductions objectives of the Paris Agreement and other sustainable development goals.

By 2040, the share of the power sector in global energy-related CO_2 emissions falls below 40%. But what about the rest of the energy sector? With power sector emissions flat, the reason why total emissions continue to rise in the New Policies Scenario lies elsewhere, primarily in industry and transport (emissions from the buildings sector, which consumes more electricity than any other end-use sector, do not rise). A central pillar of most low-emissions strategies is to couple the future of these sectors as much as possible to a decarbonising power sector, by increasing the electrification of end-uses. In the Future is Electric Scenario, part of the special focus on electricity in this *WEO*, we explore the potential – and the limits – of such an approach.

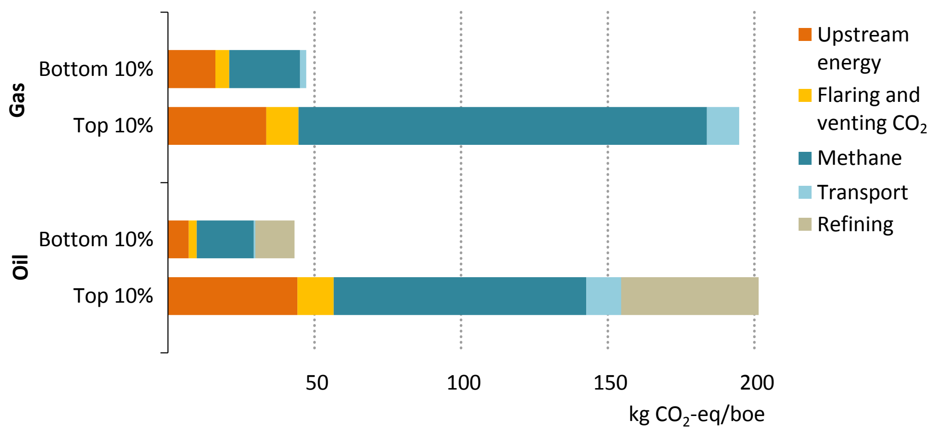
At present, electricity accounts for just under 20% of global final consumption. This share has been steadily increasing, and it rises further to 24% in the New Policies Scenario, and to 28% in the Sustainable Development Scenario. In the Future is Electric Scenario, we assume that a range of electric technologies are widely taken up as soon as they become cost-competitive by removing any constraints related to infrastructure, supply chains or consumer preference for existing technologies. We also accelerate the pace at which universal access to electricity is achieved. As a result, the share of electricity in final consumption rises to 31% by 2040. This is mainly thanks to a much more rapid adoption of heat pumps in buildings and for the provision of low-temperature heat in industry, and a swift transformation in the transport sector that puts almost a billion electric cars on the road by 2040.

This is an impressive result and implies wholesale changes to the energy system, although it would not in itself bring major reductions in global emissions unless accompanied by additional new measures to decarbonise electricity supply. But some 70% of final consumption would still be met by other sources, primarily by oil and gas. Even if the complete technical potential for electrification were deployed, there would still be sectors requiring other energy sources (given today's technologies), with most of the world's shipping, aviation and certain industrial processes not yet "electric-ready".

Finding solutions for these sectors requires a different approach, including further clean technology research and development spending and much more attention to areas such as carbon capture, utilisation and storage (CCUS). In this *WEO*, on the basis of a unique global assessment of the lifecycle emissions intensity of all sources of oil and gas, we also find that there is much more that could be done to make the provision of liquid fuels and gases compatible with a low-emissions future, or at least to lessen their contribution to the emissions that are causing climate change.

There is a broad range of emissions intensities for the oil and gas delivered to consumers today, taking into account all the energy use and emissions during their production, transportation and processing, including methane leaks to the atmosphere. For all but the very worst cases, this does not change our conclusion from the *WEO-2017* that natural gas brings environmental gains compared with coal (especially in relation to air pollutants, where the advantages of gas are undisputed), but there is ample scope to reinforce these benefits by further reducing emissions, not least since the most emissions-intensive sources of oil and gas produce around four-times more emissions than the least-emitting sources (Figure 1.17).

Figure 1.17 ▷ Emissions intensity of the supply of the least- and most-emitting sources of oil and gas worldwide



Emissions from producing, processing and transporting the most emissions-intensive sources of oil and gas are around four-times larger than those from the cleanest sources

Note: kg CO_2-eq/boe = kilogrammes of CO_2 equivalent per barrel of oil equivalent.

Oil and gas supply chains generate around 9% of today's global CO_2 emissions, and this share is set to rise slightly in the New Policies Scenario, despite enhanced efficiency efforts. We therefore explore various "game-changing" options that could have a more fundamental impact, including the use of CO_2 to support enhanced oil recovery, increased use of low-carbon electricity to support operations, and the potential to expand the role of zero-emissions (or "green") hydrogen in the energy system (Box 1.4). We find that the application of measures that would be economic with a \$50 per tonne of carbon dioxide (t CO_2) price would cut CO_2 emissions from the oil and gas supply chains in 2040 by nearly 30%. Deploying these technologies would also yield indirect benefits. If the oil and gas industry were to mobilise the vast knowledge, institutional and capital resources at its disposal to support the development of zero-carbon technologies, this would provide a major boost to energy transitions.

Box 1.4 ▷ Is hydrogen heading back to the future?

Interest in hydrogen as a solution to the world's energy and environmental problems has ebbed and flowed over the years, but it is again on an upward path. Japan is accelerating efforts aimed at promoting hydrogen alongside renewable energy, and a number of countries in Europe are actively exploring the injection of hydrogen into their gas networks. The case for hydrogen is straightforward: it can be deployed in nearly all end-use sectors and used for electricity generation; it can be stored; it releases no GHG emissions or air pollutants when used. But it remains relatively costly and has yet to gain a durable foothold in the energy system.

Around 60 Mt of hydrogen is produced today: it is central to many processes in oil refineries, in chemicals manufacturing, and in the production of iron and steel. Nearly all of this hydrogen is produced today through the reformation of natural gas or via coal gasification. There are various options to produce low-carbon hydrogen, either by adding CCUS to the main fossil fuel-based methods used today, or by using zero-carbon electricity in electrolysers to break down water (electrolysis). The latter option could be particularly promising for renewables-rich locations that are far from any existing electricity demand centres; producing hydrogen remotely and then transporting it to consumers (either in liquefied form, as with LNG, or as a hydrogen-rich fuel) offers one of the few ways to exploit this remote renewables potential.

If costs come down, and CO_2 prices go up, a number of possible uses for hydrogen come into view. A first target for green hydrogen would be to replace the existing feedstock used in the chemicals and refining sectors. In the shipping sector, hydrogen has emerged as one of the few fuel options able to achieve the International Maritime Organization agreement to reduce CO_2 emissions at least by 50% by 2050 from 2008 levels. The Sustainable Development Scenario therefore now includes the use of hydrogen-based fuels in the shipping sector and by 2040 this is on a rising trend, in anticipation of the 2050 deadline. To help decarbonise the buildings and industry sectors, hydrogen could be injected into existing gas networks (current regulatory blending limits are relatively low, but up to 20% of hydrogen could be injected into natural gas networks).[6] In the power sector, with increasing levels of renewables deployed, hydrogen is one option to provide sizeable seasonal storage to help manage mismatches between supply and demand. If large-scale, dedicated hydrogen networks were to be established, hydrogen could also be used as a fuel in road and rail (hydrogen vehicles benefit from shorter refuelling times and longer ranges than electric vehicles) as well as in buildings and industry.

6. A 20% blend of hydrogen in the European natural gas grid today would reduce CO_2 emissions by around 60 Mt (a 7% reduction).

With multiple possible roles in the future energy system, low-carbon hydrogen could provide the answer to a variety of questions. But much greater effort is needed if the potential of hydrogen is to be realised. Stepping up policy support for research, development and deployment, and the creation of new market-based instruments would be essential to make a shift towards green hydrogen a more attractive proposition.

Think strategically about gas infrastructure

Consumption of natural gas rises strongly in the New Policies Scenario: the projected increase of 45% to 2040 is above that in last year's *Outlook*, mainly on the back of lower prices (thanks to another upward revision in the resource estimates for shale gas in the United States) and higher projected demand in China.

Changes in the way natural gas markets operate also play strongly into our analysis. A period of ample availability of LNG, driven largely by new liquefaction capacity in Australia and the United States, has deepened market liquidity and the ability to procure gas on a short-term basis. New projects and exporters are increasing the range of potential suppliers and competition for customers. Destination-flexible US exports are reducing the rigidity of LNG trade. More gas is being priced on the basis of benchmarks that reflect the supply-demand balance for natural gas, rather than the price of alternative fuels. The contours of a new, more globalised gas market are becoming visible, in which gas takes on more of the features of a standard commodity market.

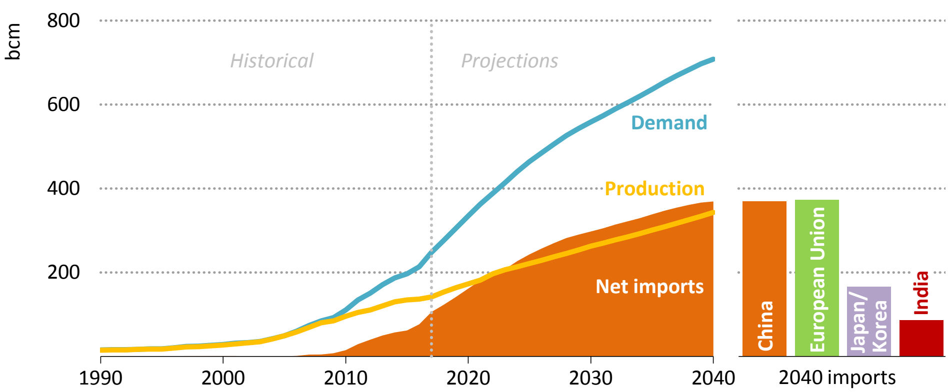
But even if more natural gas is traded on spot markets, the reliance of gas on capital-intensive infrastructure means that the gas business always requires a long-term horizon. Whereas oil and coal can both find ways to market relatively easily, dedicated transportation infrastructure is a pre-requisite for natural gas. Iraq, for example, is producing associated gas along with its oil and has an urgent need to increase the reliability of electricity provision, but pending the long-awaited addition of gas gathering and transmission pipelines it continues to flare large quantities of gas (an estimated 18 bcm [billion cubic metres] in 2017).

In the New Policies Scenario, around half of global gas demand growth comes from developing Asian economies where gas consumption is often relatively low today. Much of this gas will need to be imported and midstream infrastructure is today quite limited: building up infrastructure (especially given the relative abundance of coal and renewable resources across the region) requires conscious choices in favour of natural gas. This cannot be taken for granted.

Such a conscious choice has already been made in China. Gas occupies only a 7% share of China's primary energy mix today, but the potential for growth is increasingly being tapped. Demand grew by an astonishing 16% in 2017, and the indications for 2018 look similarly strong. This is mainly attributable to the strong policy push for coal-to-gas switching in industry and buildings as part of the drive to "turn China's skies blue again" and improve air quality. In 2017, the government set targets for clean winter heating in Beijing, Tianjin and 26 other cities and announced medium-term targets for the whole of northern China. The continued push for cleaner sources of heat is set to have a huge impact on demand for gas, and also for electricity, at the expense of coal. China has also introduced incentives to use compressed natural gas for passenger vehicles and LNG for trucks.

As a result, in the New Policies Scenario gas makes strong inroads in every sector in China, taking total demand in China to 710 bcm by 2040 (three-times higher than today, and 14% of total energy demand in 2040) (Figure 1.18). Despite steady projected growth in domestic production, China's gas imports almost reach the level of those into the European Union by 2040. Securing affordable and reliable supply of gas, ensuring supplier diversification, and building infrastructure in a timely way (this has already proved a constraint, as shown by a winter gas shortage in 2017-18) become critical challenges for Chinese policy makers.

Figure 1.18 ▷ China natural gas balance in the New Policies Scenario



China started gas import at scale barely ten years ago, but is already on the verge of becoming the world's largest gas-importing country

The need for strategic choices about infrastructure applies also to countries with existing gas networks, especially if – as in Europe – efforts to promote efficiency and to electrify end-uses start to push gas demand down. In our projections, EU gas consumption enters a gradual decline from the mid-2020s, reaching 410 bcm in 2040 (compared with a peak in 2010 of 545 bcm, and a level of 480 bcm in 2017). The issue for policy makers is that, although the average utilisation of Europe's gas infrastructure declines, this infrastructure still fulfils an indispensable seasonal role in ensuring security of supply. Gas might be needed less in aggregate, but when it is needed during the winter months (especially during any period when wind power output is low), there is no obvious, cost-effective alternative way to ensure that homes are kept warm and lights kept on: the amount of energy that gas delivers to the European system in winter is almost double the current consumption of electricity. What is more, the importance of this function and the difficulty of maintaining it both increase the further that Europe proceeds with decarbonisation: that is why there is increasing interest in the potential for alternative gases, such as biomethane or hydrogen, to fill at least part of the role played by natural gas today.

Against this backdrop, there are two imperatives for exporters and suppliers. The first is to ensure that adequate and cost-effective investment in new supply keeps gas as competitive as possible with other fuels. In the near term, this requires ways to match buyers' expectations of more flexible contractual terms with what sellers require to underpin major new infrastructure projects: the flow of new investment decisions on LNG plants may have picked up in the latter part of 2018, but there is continued uncertainty on the commercial models that can bridge this gap. The second is to burnish the environmental credentials of gas through concerted and visible action to reduce methane emissions, and through serious exploration of the possibilities to further decarbonise gas supply in the future (see Chapter 11).

Over the longer term, greater liquidity in international gas markets helps to increase confidence in the reliability and affordability of gas supply. International gas markets are evolving in a way that allocates traded volumes much more efficiently than in the past. However, there are some caveats. On the supply side, the high cost of putting gas infrastructure in place means that there are few incentives to build slack into the system: it is difficult to see Russia's current (and, in all likelihood, temporary) surplus of production capacity in the Yamal peninsula as an analogue to the spare capacity held in oil markets. So there is no guarantee that a significant shortfall in a gas-importing region can quickly or economically be replaced by calling on extra international supply.

The demand side, too, may become less responsive to price as the balance of consumption moves gradually away from power generation and towards the industry and the buildings sectors; fuel switching possibilities in power are also diminishing in many advanced economies as coal capacity is retired. The largest and most price-responsive element of demand may ultimately be the power sector in Asia. The extent to which this emerges as a new buffer in the system will depend not only on investment choices, but also on the progress made in developing well-functioning gas and electricity markets, so as to allow price signals from international markets to feed through into decisions further down the chain.

Watch out for shortfalls in investment across the board

One of the greatest threats to long-term energy security is a mismatch between the investment required to meet energy service demand and actual investments in the system: this *WEO* highlights a number of areas of potential concern. This applies not only to investment in clean energy technologies and energy efficiency, which would need to be stepped up dramatically in order to reach sustainability goals, but also to some "traditional" aspects of energy supply. In electricity markets, the challenges differ according to the type of system, but we find that there are difficulties on the horizon in many liberalised markets as well as in regulated ones. In oil, there is a growing divergence between robust demand growth in the near term and the pipeline of new conventional projects being approved for development; if this situation persists, there is a substantial risk of volatility and price spikes in the 2020s, with damaging consequences for the global economy.

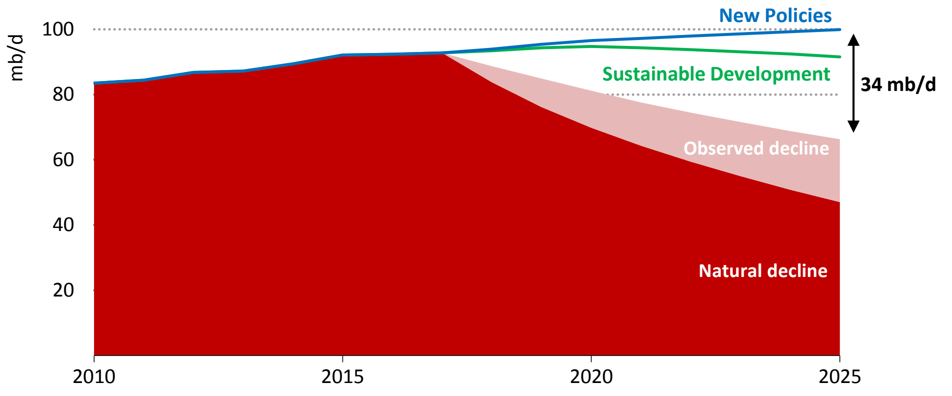
In many competitive electricity markets, power generators are struggling to manage a widening deficit between revenue from electricity sales and total generation costs. In the European Union, for example, this gap rose from 23% in 2010 to 45% in 2017, and is projected to grow to 55% in 2030. The considerations vary by country, but key factors have been increased volumes of generation from renewables and lower natural gas prices together putting downward pressure on wholesale electricity prices; the growth of distributed generation is also disrupting the traditional utility model in some cases. Periods of reduced profitability are a natural part of competitive markets, but declining revenue in lean systems – which we see in some markets today – signals the potential need to re-evaluate market designs to ensure their ability to deliver investment. Scarcity pricing can provide a signal for investment in new power plants and energy storage capacity, but it may also be both necessary and desirable to create new non-energy revenues for market participants in the form of payments for the provision of system or ancillary services or a variety of capacity remuneration mechanisms.

The situation in many regulated markets is quite different. Although demand is growing more quickly, the concern here is the impact of over investment in new electricity supply. Where investment outpaces the needs of the system, there are negative impacts on affordability and the profitability of the power plant fleet, undermining the financial health of the sector. Our analysis suggests that excess capacity, already substantial today in many countries in the Middle East, North Africa and developing Asia, is set to increase in the near term. If this over-build were to persist, additional supply costs could total $400 billion to 2040, or an extra $15 per household per year. The centralised power afforded to authorities in regulated markets enables them to address recognised market failures directly. They have the tools at their disposal to temper investment, improve the accuracy of demand projections and develop flexible power sector development plans.

In oil markets, the key underlying driver for new investment is declining output from existing fields. If no new fields were to enter operation and there were to be no capital expenditure as of 2018 in all current sources of supply, then oil production would fall by more than 8% per year to 2025 (the "natural" decline rate). In practice, companies do invest in their current sources of supply and this slows the aggregate drop in production to the observed decline rate of just over 4% (Figure 1.19). If no new fields were to enter operation in the meantime, by 2025 there would be 34 mb/d difference between demand and supply. There would likewise be a substantial gap even in the much more constrained demand outlook of the Sustainable Development Scenario.

A looming gap between demand and supply, caused by declining output from existing fields, is not in itself a cause for concern; it is a permanent feature of oil markets. Some 20 mb/d of the 34 mb/d gap in the New Policies Scenario looks likely to be filled by projects that are currently under development as well as by growth in tight oil production, natural gas liquids and other unconventional sources of oil. But what does cause concern is the relative paucity of new conventional project approvals to fill the remaining 13 mb/d gap by 2025.

Figure 1.19 ▷ Declines in current oil production and demand in the New Policies and Sustainable Development scenarios



Observed and natural declines in oil production are much faster than the drop in demand in the Sustainable Development Scenario: new upstream investment remains crucial

We estimate that around 16 billion barrels of new conventional crude oil resources would need to be approved each year between now and 2025 to avoid any potential "mismatch" between supply and demand. However, the average annual level of new resources approved in the three years since the oil price fall in 2014 was around 8 billion barrels (approvals picked up slightly in 2017, but still remained well below the levels seen in the early 2010s). The level of conventional crude oil approvals therefore needs to double if there is to be a smooth matching between supply and demand.

There is a real risk that this level of approvals will not materialise. Many national oil companies are facing constrained capital budgets, which limit their ability to invest in new projects. In Russia, while investment levels did not drop as fast as in many other regions after the oil price crash, companies are largely focusing on how to reduce decline rates in mature West Siberian fields rather than embarking on major new greenfield development programmes. Major international oil companies are currently placing much greater emphasis on cost management and executing projects with short pay-back periods than on seeking to expand their conventional reserve base.

One possibility would be for US tight oil to grow at a higher rate than is projected in the New Policies Scenario (which reaches a plateau around 2025 at about 9 mb/d). If annual approvals of conventional projects were to stay at today's level, then tight oil in the United States would need to grow by an additional 6 mb/d between now and 2025, reaching around 15 mb/d in 2025. With a sufficiently large resource base (much larger than we assume in the New Policies Scenario), this level of tight oil production could be possible. However growth in tight oil production from the Permian Basin was recently held back because of bottlenecks in the necessary distribution infrastructure. Against this backdrop, it would appear risky to rely on US tight oil production more than tripling from today's level by 2025 in order to offset the absence of new conventional crude oil projects.

A supply crunch, if it were to occur, would clearly have potential energy security implications for many importing economies and would be bad news for affordability. Some argue that it might contain some silver lining for sustainable energy transitions in the form of accelerated efficiency improvements and fuel switching. Demand destruction would certainly be a possible outcome, but it is not axiomatic that the supply side consequences would benefit low-carbon energy. In practice, as the 2010-14 period shows, a period of higher prices presents an opportunity to bring some higher cost oil down the cost curve. Moreover, while record high LNG prices during this period did contribute to improving efficiency and the competitiveness of renewables, they also resulted in an upswing in coal use.

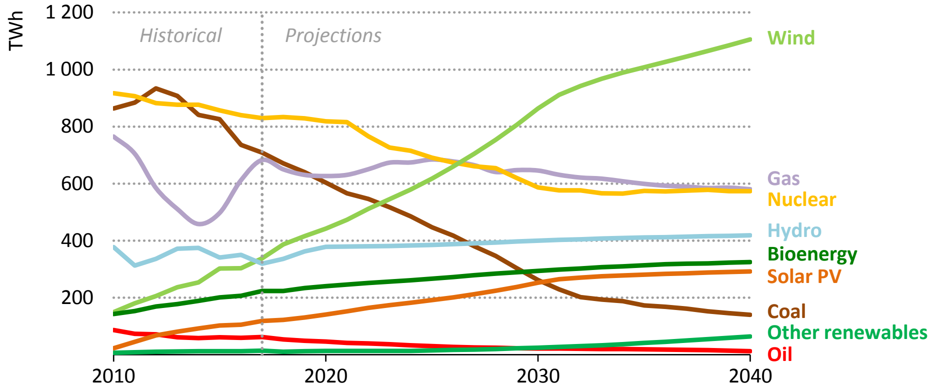
It is not just the upstream sector where there are potential imbalances on the horizon. A new regulation from the International Maritime Organization to limit the sulfur content in marine fuels to no more than 0.5%, due to come into force in 2020, is providing an illustration of how changes in product demand can send ripples through the refining industry and then through the wider energy economy. Compliance with this regulation is set to entail a large increase in the use of marine gasoil (similar to diesel) that could easily lead to a spike in diesel prices. Similar pressures could emerge in the future because of other shifts in oil product demand, for example if innovation and policy action were concentrated narrowly on passenger vehicles while other sectors of oil – such as trucks, aviation, shipping and petrochemicals – were left relatively untouched. In such a case, even if some naphtha was diverted to the petrochemicals sector, it would be difficult to avoid a glut of gasoline on the market once demand started to fall back. As a result, efforts to curb oil use in passenger vehicles would face much stronger headwinds because cheap gasoline would hinder efficiency improvements and electrification. Anticipating and mitigating these feedbacks from the supply side needs to be a larger element of the discussion about orderly energy transitions.

Seek out gains from co-operation

Regional co-operation and integration can ease many of the strains facing the energy sector today. There are many actual or potential examples of this, from Southeast Asia to the Southern Cone in Latin America. In this *WEO*, we include detailed analysis of what Europe's "Energy Union" could mean for the electricity and gas outlook across the continent in light of the new 2030 targets for renewables and energy efficiency, and the revisions to the EU's Emission Trading System.[7]

Our projections in the New Policies Scenario illustrate the scale of the transformation underway in Europe's power generation mix, much of which is driven by policy choices. The two largest sources of generation today, nuclear power and coal, both decline; the drop in coal-fired generation is particularly sharp. Wind power, bolstered by the rapid growth of offshore wind, is set to become the first source of electricity generation within a decade, and overall generation from renewables reaches 55% in 2030 (and 63% in 2040). The share of variable renewables increases to 40% by 2040.

Figure 1.20 ▷ Electricity generation by source in the European Union in the New Policies Scenario



A wholesale transformation of Europe's electricity generation pushes wind out in front, while gas and hydropower become the main sources of flexibility

Alongside other sources of flexibility, cross-border electricity transmission infrastructure among European countries remains a key asset to ensure reliability of the power system. National electricity systems are gradually integrating into regional power pools with increasing trade volumes and converging wholesale prices. In the New Policies Scenario, assumed implementation of the Energy Union framework includes timely and adequate expansion of physical infrastructure to avoid network congestion; new interconnection lines and better use of existing links between power pools; and deployment of demand-side response and storage to meet system flexibility requirements. A counterfactual case, in which there are more limited physical interconnections and a lack of proper investment

7. Several international initiatives, in which European Union countries feature strongly, also play strongly into our projections; 26 countries have committed to stop building new unabated coal capacity by 2020 and 14 of them have joined the "Power Past Coal Alliance" to close existing traditional coal-fired power plants over the coming decades.

signals for new flexible power plants, exhibits disruptions to electricity supply in some zones, higher curtailment of available renewable production, electricity price spikes and significant cross-border network congestion.

In the case of natural gas, a key consideration in the Energy Union is to promote security and diversity of supply, given the EU's high reliance on imported gas. As noted, overall gas consumption is projected to decline to 2040, but import needs remain substantial – not least because of a more pronounced fall in the EU's own gas production. A well-functioning internal gas market, alongside some strengthening of gas interconnections, can ensure that all parts of Europe have access to multiple sources of gas, allowing competition for markets among various sources of pipeline gas and LNG. As with the analysis of electricity, we also modelled a counterfactual case in which gas cannot move as easily across the internal market, due to a combination of infrastructure and regulatory constraints. In this case, some countries in central and southeastern Europe, in particular, would have less scope to procure gas on competitive terms and would also be more vulnerable in case of any interruptions to supply.

Overall, the analysis underlines the potential for an Energy Union to boost energy security, bring down underlying costs and lead to a more efficient allocation of resources. It also highlights the interactions across different aspects of European policy, and the importance of good policy co-ordination to avoid unintended consequences. For example, meeting the 32% renewables target in gross final consumption[8] leads in our projections to a 60% reduction in power sector CO_2 emissions by 2030 (compared with 2005, the reference year for the EU emissions trading system). To the extent that this is not counterbalanced by the newly created Market Stability Reserve of the Emissions Trading System, this could lead in turn to a lower CO_2 price signal that would be insufficient on its own to incentivise coal-to-gas switching.

Work to bring universal access to modern energy

The most extreme form of energy insecurity is faced by those that lack access to any form of modern energy. *WEO's Energy Access Outlook* (IEA, 2017) mapped a path to universal access to modern, sustainable energy for all by 2030, an ambition included as part of the UN Sustainable Development Goals. In this year's *WEO*, we update our assessment of progress towards this goal, with cautious optimism about some of the trends on electrification and even a glint of better news about access to clean cooking, an area that has lagged behind.

On electrification, the number of people without access to electricity fell below one billion for the first time in 2017,[9] helped by growing policy attention to the challenge. India has been the star performer: in April 2018, the government announced that all villages in the country had an electricity connection, a huge step towards universal household access. Other Asian countries have delivered similarly impressive results. In Bangladesh,

8. Calculated according to specific provisions of the European Directive 2009/28/EC.

9. Country level data for 2017 and projections to 2030 on energy access can be found at: iea.org/sdg.

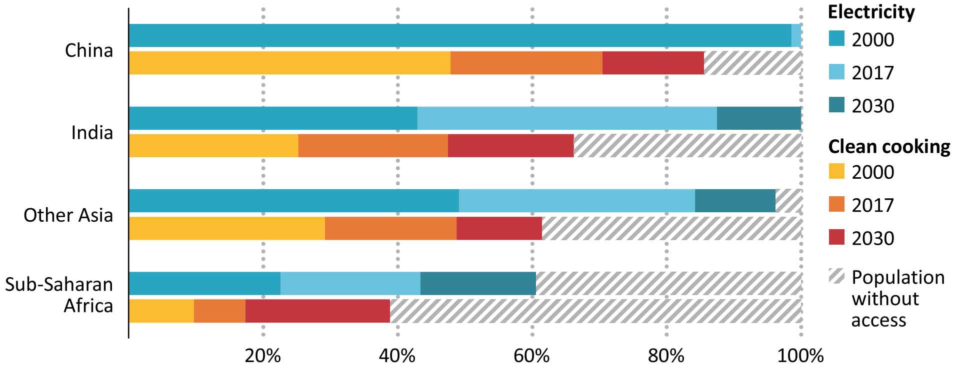
electricity now reaches 80% of the population, from 20% in 2000, while electricity reaches nearly 95% of the population in Indonesia. Progress typically slows as a country nears full electrification, as the last communities or households without access are those that are hardest to reach or comprise the poorest households, making the issue of affordability particularly acute. For comparison, it took China around two decades to reach the last 10% of population without electricity access. But trends across much of developing Asia are encouraging. Rapid expansion of the grid has underpinned much of the progress thus far, but there is also significant momentum in the mini-grid and off-grid sector due to the falling cost of decentralised renewable options.

Progress with electrification has been slower in sub-Saharan Africa. Even though the overall electrification rate in this region has almost doubled since 2000, rising by 20 percentage points to 43%, population growth has meant that the absolute number without access has still grown by some 80 million people over this period. More than 600 million people in sub-Saharan Africa remain without electricity today. And the progress in recent years has been very uneven: more than half of those gaining access since 2011 are concentrated in just four countries: Kenya, Ethiopia, Tanzania and Nigeria.

Some 2.7 billion people, half the population in developing countries, still rely primarily on biomass, coal and kerosene for their main household cooking needs, and this dependence that has serious health consequences. The estimated 2.6 million premature deaths from indoor pollution each year are greater than the number of deaths caused by HIV/AIDS and malaria combined. The more hopeful development is that, there has been a gradual decline in recent years in the global number of people without clean cooking access. As with electricity, progress across countries has been highly uneven, with China and India accounting for nearly three-quarters of those who have gained clean cooking access since 2011, while in sub-Saharan Africa the picture is still deteriorating and there are now over 270 million more people without access than there were in 2000.

The lack of access to modern fuels in the home has many damaging consequences, in particular for women. This is not only because they are more exposed to the negative health effects of polluting fuels, but also because the time and labour that is typically required to support households in the absence of modern fuels limits prospects for productive activity outside the home. Growth in economic productivity in advanced economies over the course of the 20th century was linked in large measure to women entering the workforce, which was enabled in turn by modern energy and cooking fuels and by appliances that depend on modern energy: energy development, economic growth and gender equality are very much intertwined. There are also important linkages between energy and other sustainable development goals, including access to clean water and sanitation (covered in detail in Chapter 2).

Figure 1.21 ▷ Access to electricity and clean cooking in the New Policies Scenario



The population without access to electricity in 2030 is increasingly concentrated in sub-Saharan Africa

Based on today's trends and access policies, the New Policies Scenario projects a continued decline in the global population without access to electricity to 650 million in 2030. The remaining population without access becomes increasingly concentrated in sub-Saharan Africa as developing countries in Asia reach a 99% electrification rate, with universal access achieved by the mid-2020s in India and Indonesia (Figure 1.21). The number of people without access to clean cooking falls, but only to 2.2 billion by 2030. So even though there are some encouraging signs, our projections suggest that the world is still well off-track to meet its 2030 objectives. As outlined in the Sustainable Development Scenario, there are strategies and technologies to close this gap and to ensure that every household has access to a reliable supply of electricity and a clean and environmentally sustainable cooking fuel (see Chapter 2). Progress in these areas is fully compatible with attaining climate goals and improving air quality.

Energy and the Sustainable Development Goals

Can an integrated approach spur faster action?

SUMMARY

- The Sustainable Development Scenario starts with the UN Sustainable Development Goals (SDGs) most closely related to energy: achieving universal energy access (SDG 7), reducing the impacts of air pollution (SDG 3.9) and tackling climate change (SDG 13). It then works back to set out what would be needed to deliver these goals in the most cost-effective way. The benefits in terms of prosperity, health, environment and energy security would be substantial, but achieving these outcomes would require a profound transformation in the way we produce and consume energy.

- There has been some recent progress towards the three SDGs on which our Sustainable Development Scenario is based. Energy access policies continue to bear fruit, with 2017 data showing promising signs. For the first time the number of people without access to electricity fell below 1 billion, and updated data show that the number of people without clean cooking facilities is declining gradually. India completed the electrification of all villages in early 2018, and plans to achieve universal access to electricity by the early 2020s. Meanwhile over 400 million people have gained access to clean cooking since 2011 in India and China as a result of liquefied petroleum gas (LPG) programmes and clean air policies. Despite significant steps forward in Kenya, Ethiopia, Tanzania and Nigeria, more than 600 million people are still without access to electricity in sub-Saharan Africa, and nearly 2.7 billion people worldwide still do not have access to clean cooking.

- Today energy-related outdoor air pollution leads to around 2.9 million premature deaths globally, and household air pollution, mostly from smoke due to cooking, is linked to more than 2.6 million premature deaths. Significant new policies have been announced to tackle pollution, including a three-year clean air action plan in China, but sustained progress in reducing health impacts still looks a long way off. At the same time, global energy-related carbon dioxide (CO_2) emissions increased in 2017 after three years of remaining flat, driven by economic growth and a slowdown in the spread of energy efficiency policies, despite increased deployment of renewables.

- Looking forward, current and planned policies, as embodied in the New Policies Scenario, are set to fall short of achieving each of the three energy-related SDGs. By 2030, 650 million people are still without electricity access, almost all in Africa, and 2.2 billion people worldwide still cook with solid fuels. Lower levels of air pollutants are insufficient to halt an increase in premature deaths linked to outdoor air pollution, projected to rise through 2030 to reach 4 million annually by 2040. Energy-related CO_2 emissions are set to rise gradually to 35.8 gigatonnes (Gt) in 2040.

- Our Sustainable Development Scenario provides a very different perspective. Enhanced efforts deliver universal access to electricity and clean cooking facilities by 2030. Sharp reductions in emissions of air pollutants lead to significantly cleaner air, bringing considerable health benefits: premature deaths from outdoor air pollution are half a million lower in 2040 than today. As well, CO_2 emissions decline rapidly in line with the objectives of the Paris Agreement.

- Analysis of the Sustainable Development Scenario suggests that there are important synergies between the three energy-related goals at its core. Decentralised renewables mean that a least-cost approach to electricity access does not significantly increase CO_2 emissions, and a move away from traditional use of biomass for cooking means that universal energy access can reduce overall greenhouse gas (GHG) emissions. Energy access also reduces premature deaths linked to smoke from cooking by 70% compared with current pathways.

- Energy efficiency is an essential component of the Sustainable Development Scenario, contributing to all three SDGs, as well as to energy security. Stronger policy action leads to substantially higher investment in energy efficiency, such that energy demand in 2040 is close to today's level, despite economic output more than doubling. On the supply side, there is a significant shift in investment towards low-carbon sources, particularly for power generation.

- Our analysis shows that further action on key cost-effective measures for reducing CO_2 emissions can reverse the increasing trend to achieve a near-term peak in emissions. Of five key measures with no net cost, proposed by the International Energy Agency (IEA) in 2015, only increasing investment in renewables is on track; there is ample scope for additional cost-effective action to reduce methane emissions from the oil and gas sector, to phase out the most inefficient forms of coal-fired power, to reduce fossil fuel subsidies and to boost energy efficiency. Strengthening the synergies with other development goals, including reducing air pollution, could bolster implementation of these measures to go further towards the objectives of the Sustainable Development Scenario.

- The Sustainable Development Scenario now also includes a water dimension, focusing both on the water needs of the energy sector and the energy needs of the water sector. As well as achieving the SDGs on energy access, air pollution and climate change, the Sustainable Development Scenario has the lowest water withdrawals among *World Energy Outlook* (*WEO*) scenarios, due in particular to a shift from thermal power to renewables. The analysis also reveals the benefits of an integrated approach to SDG 7 on energy access and SDG 6 on clean water and sanitation: decentralised renewables deployed in rural areas for energy access can also provide clean drinking water. Achieving universal access to clean water and sanitation would add less than 1% to global energy demand in 2030.

Introduction

Energy is essential to human society and economic activity, and providing access to affordable modern energy services is a prerequisite for eliminating poverty and reducing inequalities. In addition, energy is a major source of air pollution that causes severe health problems around the world, and it is the principal global source of greenhouse gas (GHG) emissions. For these reasons, energy features prominently in the United Nations Sustainable Development Goals (SDGs), agreed by 193 nations in 2015.

This chapter presents the Sustainable Development Scenario, depicting an energy future that simultaneously delivers on the SDGs most closely related to energy: universal energy access (SDG 7), reducing impacts of air pollution (part of SDG 3) and tackling climate change (SDG 13). Recognising that energy is also fundamental to many other aspects of development, we also explore links between the energy sector and access to fresh water and sanitation (SDG 6), as well the link between energy access and gender equality.

The first part of this chapter explains the rationale for the Sustainable Development Scenario, presents its outcomes, and provides an overview of the energy sector transformation required to meet these outcomes.

The second part of the chapter contains in-depth analysis of three topical themes:

- How are current global efforts progressing towards the objectives related to energy access, air pollution and carbon dioxide (CO_2) emissions? This section tracks recent progress and examines the outlook to 2040 in our New Policies Scenario. Incorporating new data on energy access as well as emissions, it provides an essential benchmark for assessing the impact of existing and announced policies.
- What measures in the energy sector could help reduce emissions further in the short term while also helping to deliver other development goals? This section assesses progress made on five measures, the components of the "Bridge Scenario" first put forward by the IEA in a *World Energy Outlook* (*WEO*) *Special Report* (IEA, 2015), and explores the scope for exploiting synergies with other development goals and for seeking better alignment across energy policies.
- What are the interactions between energy and water in terms of development goals? This section focuses on the energy implications of achieving the objectives of SDG 6 on water and sanitation, as well as the implications of the energy choices in the Sustainable Development Scenario for water use. The analysis quantifies the water needs of the energy-related SDGs and the energy required to fulfil SDG 6, as well as the links and synergies between them.

Figures and tables from this chapter may be downloaded from www.iea.org/weo2018/secure/.

Sustainable Development Scenario

2.1 Scenario design and overview

Our Sustainable Development Scenario shows how the energy sector can achieve the objectives of the UN SDGs most closely related to energy. Introduced as an integrated scenario for the first time in the *WEO-2017*, the scenario builds on decades of IEA work on energy access, air pollution emissions and energy-related CO_2.

The Sustainable Development Scenario starts with a set of desired outcomes, as defined by the relevant SDGs (Table 2.1). It then works back to show how the energy sector would need to change to achieve those goals in an integrated and cost-effective way. To do this, we first assess implications for the energy sector of achieving universal energy access. We then consider in parallel the outcomes related to reduction of air pollution and CO_2 emissions, in order to describe in detail an energy system that delivers all three goals. Additionally, we assess the water implications of the scenario as well as the energy needs of achieving universal access to clean water and sanitation.

The scenario clearly underscores that achieving these goals would require a profound transformation of the energy sector (Table 2.2).

Table 2.1 ▷ SDG outcomes in the Sustainable Development Scenario

SDG	SDG Objective	Outcomes in the Sustainable Development Scenario
SDG 7	By 2030, ensure universal access to affordable, reliable and modern energy services.	Universal access to both electricity and clean cooking achieved by 2030.
SDG 3	Ensure healthy lives and promote well-being for all (including target 3.9, substantially reduce the number of deaths and illnesses from hazardous chemicals and air, water and soil pollution).	Substantial reductions in major air pollutant emissions, so that by 2040 there are half a million fewer premature deaths linked to outdoor air pollution than today, and those linked to household pollution are reduced by nearly two million.
SDG 13	Take urgent action to combat climate change and its impacts.	Energy-related CO_2 emissions peak and then decline, fully in line with the objectives of the Paris Agreement. The CO_2 emissions trajectory to 2040 is consistent with a long-term global average temperature rise of 1.7-1.8 °C above pre-industrial levels.
SDG 6	Ensure availability and sustainable management of water and sanitation for all.	Water withdrawals are lower than in other *WEO* scenarios, including climate scenarios. While SDG 6 targets are not embodied in the outcomes of the Sustainable Development Scenario, we assess what achieving SDG 6 might look like under the conditions of the scenario, and find that the energy needs of achieving universal access to water and sanitation amount to less than 1% of global energy demand.

Table 2.2 ▷ Key energy indicators for the Sustainable Development Scenario

		Sustainable Development			New Policies	
	2017	2025	2030	2040	2030	2040
Access (million people)						
Population without access to electricity	993	382	0	0	649	720
Population without access to clean cooking	2 677	1 159	0	0	2 188	1 815
Related premature deaths	2.61*	1.60	0.60	0.67	2.38	2.23
Energy-related GHG emissions (Mt)						
CO_2 emitted	32 581	29 535	25 482	17 647	34 576	35 881
CO_2 captured via CCUS	8	150	710	2 364	50	83
CH_4 emitted	128	79	49	38	115	102
of which from oil and gas operations	79	40	19	18	66	55
Air pollution						
Premature deaths from energy-related outdoor air pollution (million people)	2.93*			2.39		4.04
Share of population exposed to $PM_{2.5}$ level above WHO guideline (Asia only)**	92%	88%	82%	68%	91%	91%
Primary energy supply						
Total primary energy supply (Mtoe)	13 972	14 146	13 820	13 715	16 167	17 715
Share of non-fossil energy sources	19%	23%	28%	40%	23%	26%
Energy intensity of GDP (toe/$1 000)	110	83	68	50	80	64
Power generation						
CO_2 intensity of generation (g CO_2/kWh)	484	332	221	69	368	315
Share of low-carbon generation	35%	49%	63%	86%	46%	51%
Final consumption						
Total final consumption (Mtoe)	9 696	10 126	10 007	9 958	11 474	12 581
Share of non-combustible fuels	23%	25%	27%	33%	25%	27%
Industry						
Energy intensity (toe/$1 000 VA)	0.13	0.11	0.10	0.08	0.10	0.09
CO_2 intensity (t CO_2/$1 000 VA)	0.27	0.22	0.18	0.12	0.21	0.18
Transport						
Electric PLDVs (million)	3	69	236	933	108	304
Carbon intensity of new PLDVs (g CO_2/v-km)	170	96	57	30	111	97
Carbon intensity of freight vehicles (g CO_2/t-km)	93	74	59	39	71	60
Shipping emissions (Mt CO_2)	854	847	830	684	1 064	1 194
Aviation emissions (Mt CO_2)	925	902	871	803	1 163	1 408
Buildings						
Energy intensity of residential buildings (toe/dwelling)	1.04	0.84	0.71	0.64	0.94	0.91
Energy intensity of services buildings (toe/$1 000 VA)	0.017	0.014	0.012	0.010	0.014	0.012

*Data for year 2015. **World Health Organization guideline (average $PM_{2.5}$ concentration of 10 μg/m^3). Notes: See Annex B for details of the scenarios. Mt = million tonnes; CCUS = carbon capture, utilisation and storage; GDP = gross domestic product; $PM_{2.5}$ = particulate matter with a diameter of less than 2.5 micrometres, CH_4 = methane; WHO = World Health Organization; Mtoe = million tonnes of oil equivalent; toe = tonnes of oil equivalent; t = tonnes; $ = US dollar (2017); g = gramme; kWh = kilowatt-hour; VA = value added; PLDVs = passenger light-duty vehicles; v-km = vehicle-kilometre; t-km = tonne-kilometre.

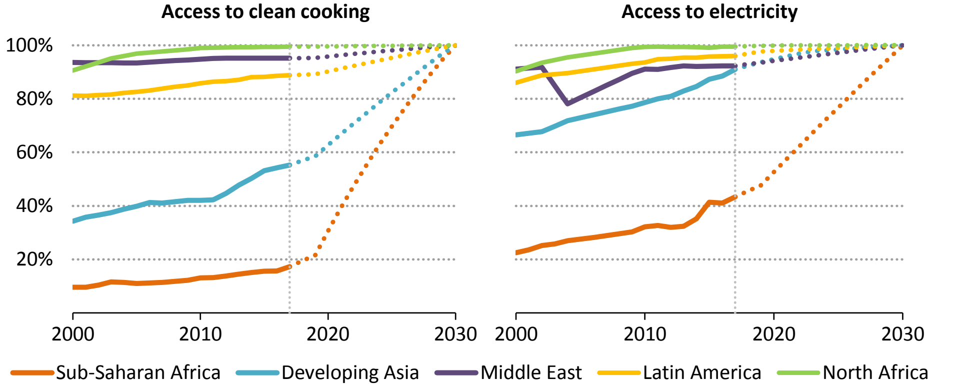
2.2 Scenario outcomes: Universal energy access

In the Sustainable Development Scenario, universal access to both electricity and clean cooking facilities is achieved by 2030, in line with target 7.1 of SDG 7 (Figure 2.1). Targets 7.2 (on renewables) and 7.3 (on energy efficiency) are also achieved in the scenario (see Chapter 6). Given expected strong population growth over that period, particularly in countries where many people still lack access, achieving universal access means a cumulative total of around 1.2 billion new electricity connections to 2030, and around 2.5 billion people gaining access to cleaner cooking facilities for the first time over the period. This reduces the health impact of air pollution, brings gender equality dividends, and is achieved without increasing GHG emissions (IEA, 2017a).

The least expensive way to achieve universal electricity access in many areas is with renewable energy sources, thanks to the declining costs of small-scale solar photovoltaic (PV) for off-grid and mini-grid electricity and the increasing use of renewables for grid-connected electricity. This is especially the case in rural areas in African countries, home to many of the people still deprived of electricity access.

The means of achieving clean cooking depends on the availability of biomass and liquefied petroleum gas (LPG) in different regions. Overall, LPG is the most cost-effective means to access clean cooking in more than half of all cases, with most of the rest moving to improved and more energy-efficient biomass cookstoves. The resulting increase in LPG demand leads to a small increase in CO_2 emissions, but the overall GHG effect is more than offset by reduced methane emissions from incomplete combustion of biomass as those using LPG turn away in many cases from burning wood and other biofuels (IEA, 2017a; Singh, Pachauri and Zerriffi, 2017).

Figure 2.1 ▷ Proportion of population with access to electricity and clean fuels for cooking in the Sustainable Development Scenario



A rapid acceleration in access rates is required, in particular for clean cooking in sub-Saharan Africa and developing Asia

2.3 Scenario outcomes: Air pollution

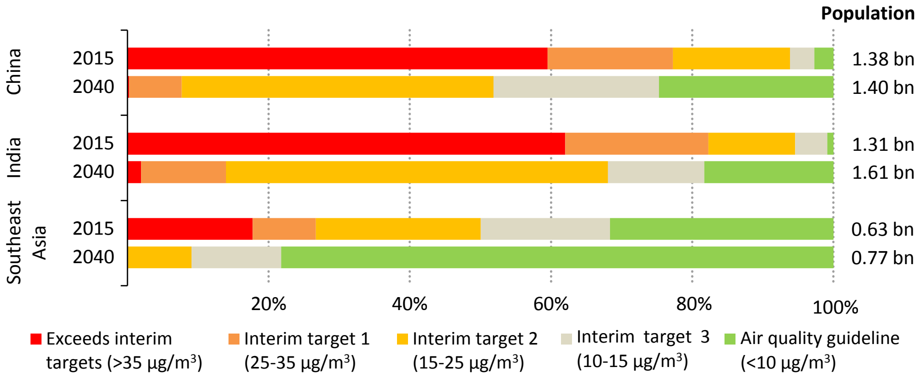
Air pollution is a major health and environmental issue. Outdoor air pollution is linked to 2.9 million premature deaths globally each year, and household air pollution, mostly from the traditional use of biomass as a cooking fuel, to more than 2.6 million premature deaths. Air pollution is the fourth-largest threat to human health globally (HEI, 2018).

In the Sustainable Development Scenario, emissions of the three major air pollutants – sulfur dioxide (SO_2), nitrogen oxides (NO_X) and fine particulate matter ($PM_{2.5}$) – decline sharply from current levels, despite global energy demand remaining nearly constant. The result is a major reduction in health impacts; premature deaths linked to outdoor air pollution fall by half a million and premature deaths from household air pollution by 1.9 million. Reduced exposure to $PM_{2.5}$ is particularly important in this respect (IEA, 2016a), and far more people enjoy lower levels of $PM_{2.5}$ in 2040 than today (Figure 2.2).

Power sector emissions of SO_2 are almost eliminated in the Sustainable Development Scenario, with industry becoming the main source of emissions by 2040, albeit at levels less than half of today. Emissions of NO_X, which occur predominantly in the transport sector, drop by nearly half by 2040, thanks to improved pollution controls and fuel switching.

Universal access to clean cooking is instrumental in almost eliminating residential $PM_{2.5}$ emissions, with industry becoming the largest direct source of these emissions by 2040, followed by transport. Nearly a quarter of particulate emissions from transport are from non-combustion sources, such as abrasion of brakes and tyres, which are just as much of an issue with electric vehicles as with other vehicles fuelled by oil-based products.

Figure 2.2 ▷ Exposure to fine particulate pollution ($PM_{2.5}$) in selected regions, 2015, and in the Sustainable Development Scenario, 2040



The proportion of populations exposed to high levels of fine particulates drops dramatically, with far fewer people exposed to levels exceeding the lowest interim WHO target

Notes: bn = billion; μg/m³ = micrograms per cubic metre. Interim targets and Air Quality Guideline refer to World Health Organization exposure thresholds.

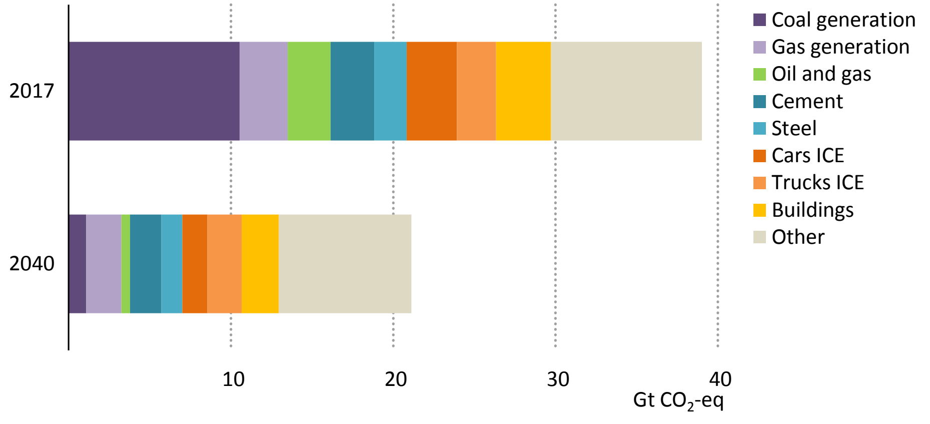
Source: IEA analysis; International Institute for Applied Systems Analysis.

2.4 Scenario outcomes: CO_2 and other GHG emissions

In the Sustainable Development Scenario, global energy-related CO_2 emissions peak around 2020 and then enter a steep and sustained decline, fully in line with the trajectory required to achieve the objectives of the Paris Agreement on climate change. By 2040, the global emissions profile is very different from today.

In 2017, GHG emissions from energy and industrial processes (including methane and nitrous oxide as well as CO_2) amounted to about 39 gigatonnes of CO_2 equivalent (Gt CO_2-eq). Three-quarters of this is accounted for by only eight source categories (Figure 2.3). The largest category by far is coal-fired power generation, with 2 053 gigawatts (GW) of capacity accounting for 27% of emissions. Buildings made up nearly 9% in 2017, followed by about 8% each for gas-fired power generation and petroleum-fueled cars (more than 1 billion cars). Emissions from cement production and oil and gas operations accounted for 7% each,[1] with trucks (202 million vehicles) making up 6% and steel around 5% of the total.

Figure 2.3 ▷ GHG emissions from selected sectors, 2017, and in the Sustainable Development Scenario, 2040



Eight source categories account for three-quarters of today's energy-related GHG emissions; power sector emissions drop by 76% by 2040 in the Sustainable Development Scenario

Notes: Includes CO_2, methane and nitrous oxide emissions from fuel combustion and CO_2 emissions from industrial processes. ICE= internal combustion engine. Other includes energy-related GHG emissions from other sectors. 100-year global warming potential of fossil methane = 30, nitrous oxide = 265.

In the Sustainable Development Scenario, GHG emissions from fuel combustion and industrial processes fall to about 21 Gt CO_2-eq in 2040. The same eight categories account for around 60% of emissions in 2040, but the split between them changes.

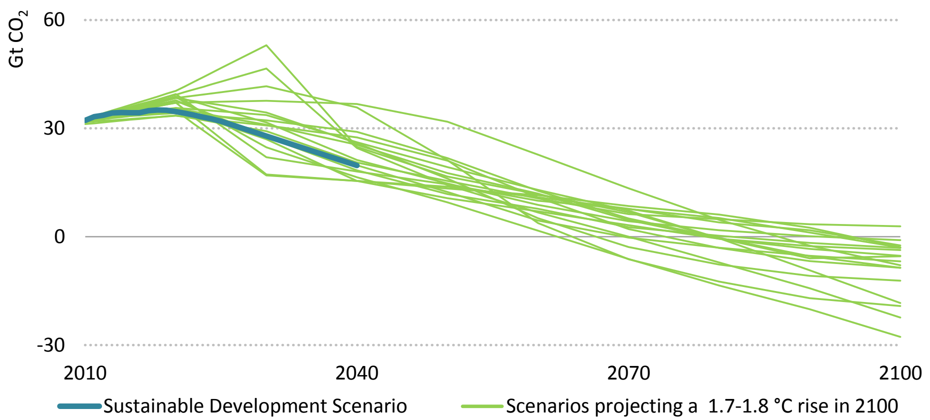
1. See Chapter 11 for a detailed life-cycle analysis of GHG emissions from the oil and gas sector, including emissions from refining and transportation of oil and gas, as well as venting of CO_2 and flaring of methane. The broader scope of that analysis results in oil and gas accounting for a higher proportion of total energy-related emissions than is reported here.

Emissions from coal-fired power fall by 90% to account for only 5% of total GHG emissions. Buildings become the largest emitter in 2040 (11%) followed by gas-fired power generation and trucks (around 10% each). Emissions from trucks nevertheless decrease in absolute terms by 15%, as efficiency improvements absorb a 40% increase in vehicle stock. Cement production accounts for 9% of emissions (of which the majority is process emissions). Emissions from cars fall by half, despite the number of cars increasing by more than 60% (of which about 50% are electric), and those with internal combustion engines (ICEs) have vastly improved efficiency (see Chapter 3). Oil and gas sector emissions reduce significantly, mostly due to improvements in the GHG intensity of supply (see Chapter 11).

The CO_2 emissions trajectory to 2040 in the Sustainable Development Scenario is lower than most published decarbonisation scenarios based on limiting long-term global average temperature rise to 1.7-1.8 °C above pre-industrial levels (Figure 2.4, CO_2 only). What happens after 2040 is also critical for the climate outcome, and a continuation of the pre-2040 emissions reduction rate in the scenario would lead to global energy-related CO_2 emissions falling to net-zero by 2070.

Maintaining or accelerating the rate of reduction of energy- and process-related emissions up to and beyond 2040 is likely to require robust technological innovation. The power sector decarbonises rapidly before 2040, highlighting the importance of other sectors, including those where emissions reductions are more challenging, such as industry and freight transport (Table 2.3). Other important sectors for innovation include carbon capture, utilisation and storage (CCUS) and so-called "negative emissions" technologies that allow CO_2 to be withdrawn from the atmosphere at scale in the second-half of the century.

Figure 2.4 ▷ CO_2 emissions in the Sustainable Development Scenario and other "well below 2 °C" scenarios (1.7-1.8 °C)



The CO_2 emissions trajectory to 2040 in the Sustainable Development Scenario is at the lower end of a range of scenarios projecting a global temperature rise of 1.7-1.8 °C in 2100

Notes: Figure shows energy-related CO_2 emissions, including CO_2 emissions from industrial processes. Scenarios projecting a median temperature rise in 2100 of around 1.7-1.8 °C above pre-industrial levels are those following Representative Concentration Pathway (RCP) 2.6 in the Shared Socioeconomic Pathways database. See https://tntcat.iiasa.ac.at/SspDb/.

Table 2.3 ▷ Energy-related CO_2 emissions by sector and fuel in the Sustainable Development Scenario

			CO_2 emissions (Mt)				CAAGR	
	2000	2017	2025	2030	2035	2040	2000-17	2017-40
By sector								
Power	9 305	13 587	10 656	7 839	5 127	3 292	2.3%	-6.0%
Industry	3 922	6 154	6 273	5 936	5 481	5 081	2.7%	-0.8%
Transport	5 757	7 986	7 932	7 326	6 373	5 563	1.9%	-1.6%
Buildings	2 714	2 997	2 767	2 593	2 367	2 202	0.6%	-1.3%
Other	1 424	1 856	1 907	1 788	1 633	1 510	1.6%	-0.9%
By fuel								
Coal	8 951	14 448	11 335	8 335	5 577	3 855	2.9%	-5.6%
Oil	9 620	11 339	10 657	9 501	8 032	6 886	1.0%	-2.1%
Gas	4 551	6 795	7 543	7 645	7 373	6 906	2.4%	0.1%
Total	**23 123**	**32 581**	**29 535**	**25 482**	**20 982**	**17 647**	**2.0%**	**-2.6%**
New Policies Scenario			*33 902*	*34 576*	*35 157*	*35 881*	*2.0%*	*0.4%*
Current Policies Scenario			*35 454*	*37 748*	*40 103*	*42 475*	*2.0%*	*1.2%*

Notes: CAAGR = compound average annual growth rate. Data are for CO_2 only and exclude process-related emissions in industry. Industry includes blast furnaces and coke ovens. Other includes energy-related emissions in energy transformation and agriculture.

2.5 Energy sector transformation in the Sustainable Development Scenario

2.5.1 Total final consumption

In the Sustainable Development Scenario, the world energy system undergoes a series of sustained changes from now until 2040. Energy consumption patterns shift, driven first and foremost by energy efficiency across all major sectors. The result is that total final energy consumption stays nearly flat through to 2040, despite economic output more than doubling. The importance of energy efficiency for reducing CO_2 emissions is analysed in more detail in *Energy Efficiency 2018* (IEA, 2018a).

Within this more efficient energy system, there is a general trend towards more use of electricity and increased direct use of renewable energy. The proportion of electricity in total final consumption rises from 19% today to 28% in 2040.

Industry is the only end-use sector to see a substantial increase in energy consumption from 2017 to 2040: energy efficiency gains in industry do not quite keep up with growth of industrial economic output in the Sustainable Development Scenario (Table 2.4). Across the industry sector, there is a shift away from direct use of coal towards electricity and the direct use of solar thermal and geothermal (see Chapter 9).

Total final consumption in the transport sector stays almost flat through to 2040, though its use of electricity expands on average by 11% every year. By 2040, electricity is powering more than 900 million electric cars worldwide, accounting for over 50% of the fleet. The implication of electric vehicles (EVs) for climate change efforts depends, however, on measures to decarbonise the power sector (see section 2.8.2). Oil use in transport, by far the dominant energy source for transport today, falls by nearly 40% by 2040, partly due to growth in EVs, but mostly because of improvements in the efficiency of internal combustion engines.

Improved energy efficiency means energy use in the buildings sector is close to today's level by 2040, despite a rapidly growing stock of buildings in developing countries. Electricity and district heating, already the dominant energy carriers, grow strongly, mainly because of increased appliance ownership and cooling demand. Coal and oil both decline in favour of cleaner fuels for heating. A further marked change is a sharp reduction of the traditional use of biomass for cooking, an evolution that goes hand-in-hand with energy access and helps to reduce health impacts of indoor air pollution.

Table 2.4 ▷ Total final consumption in the Sustainable Development Scenario (Mtoe)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
Industry	1 863	2 855	3 121	3 155	3 162	3 197	12%	0.5%
Electricity and heat	563	908	1 013	1 027	1 034	1 053	16%	0.6%
Renewables	162	205	248	277	309	340	66%	2.2%
Coal	400	803	799	760	707	665	-17%	-0.8%
Oil	326	321	319	303	286	272	-15%	-0.7%
Gas	412	618	741	788	827	866	40%	1.5%
Transport	1 958	2 794	2 945	2 895	2 748	2 640	-6%	-0.2%
Electricity	19	33	66	130	245	364	1 020%	11.1%
Biofuels	10	86	208	280	319	351	308%	6.3%
Oil	1 871	2 567	2 500	2 243	1 877	1 581	-38%	-2.1%
Other*	58	109	172	242	307	344	217%	5.1%
Buildings	2 450	3 047	2 905	2 755	2 802	2 860	-6%	-0.3%
Electricity	579	982	1 101	1 205	1 305	1 405	43%	1.6%
District heating	143	145	143	141	137	134	-8%	-0.4%
Direct renewables**	93	152	208	256	306	358	136%	3.8%
Coal	109	127	81	55	29	13	-90%	-9.3%
Oil	346	319	280	252	221	201	-37%	-2.0%
Gas	535	665	696	703	691	672	1%	0.0%
Traditional use of biomass	646	658	396	144	112	77	-88%	-8.9%
Other TFC	765	999	1 155	1 201	1 234	1 261	26%	1.0%
Total	**7 036**	**9 696**	**10 126**	**10 007**	**9 946**	**9 958**	**3%**	**0.1%**
New Policies Scenario			*10 871*	*11 474*	*12 018*	*12 581*	*30%*	*1.1%*
Current Policies Scenario			*11 103*	*11 911*	*12 704*	*13 510*	*39%*	*1.5%*

*Other in the transport sector includes gas, hydrogen and coal. **Direct renewables in the buildings sector refers to geothermal, solar thermal and the modern use of biomass. Note: CAAGR = compound average annual growth rate; TFC = total final consumption.

2.5.2 Primary energy demand

Overall primary energy demand stays flat in the Sustainable Development Scenario, despite strong economic growth, as supply-side energy efficiency keeps pace with end-use efficiency gains (Table 2.5). The shifts in energy consumption and power generation mean that renewables increase by a factor of eight in primary energy terms by 2040 (excluding hydro and bioenergy). The uptake of modern uses of solid bioenergy increases, although the costs of ensuring low levels of air pollutant emissions constrain deployment. Traditional use of biomass declines dramatically, an effect of achieving universal energy access.

Total demand for coal (including power generation, industry, buildings and other uses) falls to less than half of today's level. Use of coal in unabated power plants (not equipped with CCUS) drops by more than 90%.

Declining demand in the transport sector means that total oil demand peaks in 2020, though its subsequent decline is slowed somewhat by continued robust demand for oil products as a feedstock for petrochemicals (see Chapter 3).

Demand for natural gas continues to grow until 2030 before flattening through to 2040. Gas use is driven primarily by heating and industrial demand, offset by slowing demand from power generation. In the Sustainable Development Scenario, there is a major reduction in methane emissions from the production and transport of natural gas (see section 2.8).

Table 2.5 ▷ Primary energy demand in the Sustainable Development Scenario (Mtoe)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
Coal	2 308	3 750	3 045	2 416	1 917	1 597	-57%	-3.6%
Oil	3 665	4 435	4 334	3 985	3 515	3 156	-29%	-1.5%
Gas	2 071	3 107	3 454	3 554	3 532	3 433	10%	0.4%
Nuclear	675	688	861	1 013	1 182	1 293	88%	2.8%
Renewables*	662	1 334	2 056	2 707	3 430	4 159	212%	5.1%
Hydro	225	353	431	492	548	601	70%	2.3%
Modern biomass	377	726	976	1 132	1 283	1 427	96%	3.0%
Other	60	254	648	1 083	1 598	2 132	739%	9.7%
Traditional use of biomass	646	658	396	144	112	77	-88%	-8.9%
Fossil fuel share	80%	81%	77%	72%	65%	60%		
of which equipped with CCUS	*0%*	*0%*	*1%*	*2%*	*6%*	*10%*		
Energy intensity (toe/$1 000 GDP-PPP)	0.14	0.11	0.08	0.07	0.06	0.05	-55%	-3.4%
Total	**10 027**	**13 972**	**14 146**	**13 820**	**13 688**	**13 715**	**-2%**	**-0.1%**
New Policies Scenario			*15 388*	*16 167*	*16 926*	*17 715*	*27%*	*1.0%*
Current Policies Scenario			*15 782*	*16 943*	*18 125*	*19 328*	*38%*	*1.4%*

* Renewables excludes the traditional use of biomass. Note: CAAGR = Compound average annual growth rate; CCUS = carbon capture, utilisation and storage; toe = tonnes of oil equivalent; PPP = purchasing power parity.

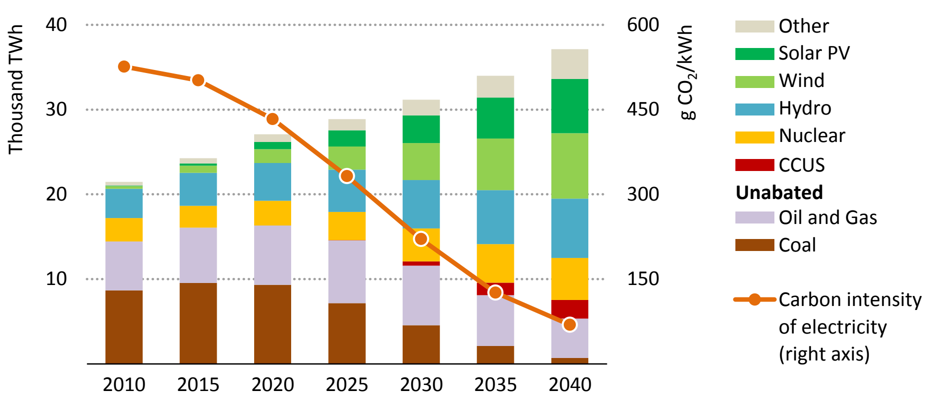
2.5.3 Power generation

With a rising proportion of electricity in final energy use, in the Sustainable Development Scenario the power sector plays an increasingly critical role in delivering the access, air pollution and climate outcomes. While total electricity generated increases by nearly 45% to reach 37 000 TWh by 2040 in the Sustainable Development Scenario, the share of renewables in generation nearly triples to 66%. The biggest growth in generation comes from solar PV, which increases by a factor of sixteen, and from wind, which increases by a factor of seven. Renewables account for more than 80% of new capacity additions by 2025.

Coal-fired power generation rapidly loses ground in the Sustainable Development Scenario. By 2040, it accounts for only 5% of total generation, and two-thirds of remaining coal generation is from plants equipped with CCUS. Plant retirements average around 60 GW per year to 2040. Natural gas-fired generation initially grows, playing a role to balance renewables and to displace coal, helped by its low air pollution emissions and lower carbon intensity.

The average carbon intensity of electricity generated continues its decline from around 500 grammes of CO_2 per kilowatt-hour (g CO_2/kWh) today to around 70 g CO_2/kWh in 2040 (Figure 2.5). The falling carbon intensity of power generation is an essential pillar of the Sustainable Development Scenario, especially with electricity playing a rapidly growing role in meeting end-use energy demands. (The role of the power sector in the Sustainable Development Scenario is explored in more detail in Chapter 9.)

Figure 2.5 ▷ Power generation and carbon intensity of electricity in the Sustainable Development Scenario



The power sector evolves rapidly with low-carbon sources accounting for 50% of power generation by 2025 and 85% by 2040

Note: TWh = terawatt-hours; g CO_2/kWh = grammes of CO_2 per kilowatt-hour; CCUS = carbon capture, utilisation and storage.

2.6 Investment in the Sustainable Development Scenario

Average annual supply-side investment in the Sustainable Development Scenario through to 2040, including fuel supply and power supply, increases by about 15% from today's level. However, this masks a significant reallocation away from fossil fuels towards renewables and other low-carbon sources, for both fuel supply and power generation (Figure 2.6).

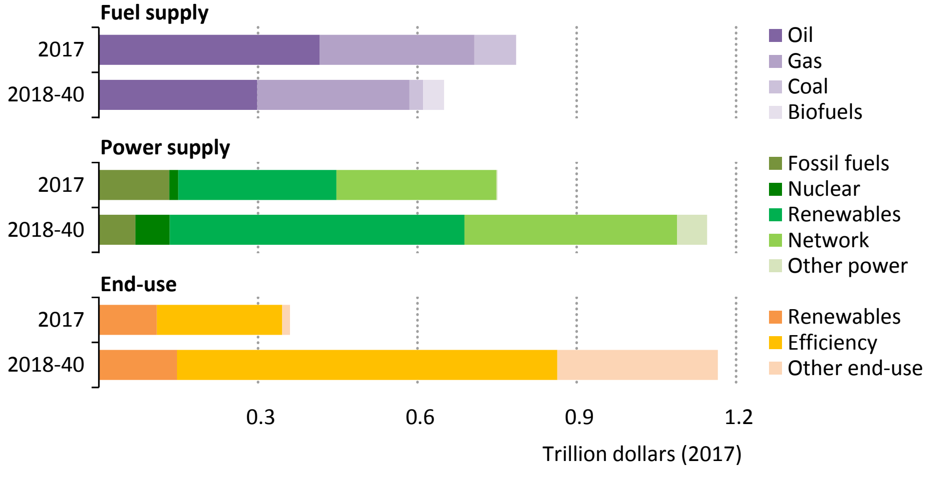
Continued investment in oil supply is required to compensate for declines in existing production; without investment, production would taper off far faster than the fall in oil demand, even in the Sustainable Development Scenario (see Chapter 3). In the case of gas, investment is also required to meet the increase in demand to 2030.

The story is different on the demand side. Annual demand-side investment needs in the Sustainable Development Scenario are more than three-times higher than today's level. This reflects the importance of energy efficiency in achieving energy transitions.

Demand-side investment needs are particularly large in the buildings and transport sectors. In buildings, this includes efficiency measures such as thermal insulation and efficient lighting, as well as measures for appliances. In transport, the investment total includes the shift towards EVs as well as the costs of more efficient internal combustion engines.

Total investment in energy to 2040 in the Sustainable Development Scenario is around 13% higher than in the New Policies Scenario. Payback periods for efficiency investments vary over time and across sectors (IEA, 2018b).

Figure 2.6 ▷ Energy sector investment in 2017 and average annual investment in the Sustainable Development Scenario, 2018-2040



Total supply-side investment stays almost at today's level, with a reallocation towards renewables. Demand-side investment increases substantially.

Note: Other power includes CCUS and battery storage. Other end-use includes CCUS in industry and alternative power trains in transport (e.g. electric cars, natural gas vehicles, fuel cell vehicles).

The investment needed to achieve universal energy access is small relative to the broader investment needs of the energy sector. Achieving universal energy access requires investment of some $55 billion per year between 2018 and 2030, the lion's share of it for electricity access. This is about 2% of the total annual energy sector investment in the scenario from today until 2030, but is almost double the investment for energy access in the New Policies Scenario, with 82% of the additional investment needed in sub-Saharan Africa.

About 25% of investment for energy access is required for infrastructure to extend and reinforce grid transmission and distribution, and to build mini-grid distribution networks to deliver universal electricity access. Nearly 70% is required for investment in new generation: of this, over three-quarters is for generation from renewable sources, mostly for mini-grid and stand-alone renewables. Only about 7% of the investment for universal access is required for clean cooking facilities.

Key themes

2.7 Tracking progress towards energy-related SDGs

The Sustainable Development Scenario outlines what is needed to deliver the agreed Sustainable Development Goals in a cost-effective manner. Current policies and trends, as embodied in the New Policies Scenario, fall a long way short of those outcomes. This is true for each of the three core dimensions of the scenario: energy access, air pollution and CO_2 emissions.

The 2018 update of the IEA's *Tracking Clean Energy Progress*[2] benchmarked global progress on a wide range of clean energy developments against the deployment levels required to achieve the three parallel outcomes of the Sustainable Development Scenario in 2025 and 2030 (IEA, 2018c). In power generation, only solar PV has been growing in line with what would be required to deliver the projected levels. On the demand side, EVs and light emitting diodes (LEDs) show recent growth rates aligned with the trajectory of the Sustainable Development Scenario. Most other energy supply and demand technologies have been developing in ways that are not in line with the vision of the Sustainable Development Scenario.

2.7.1 Progress and outlook for energy access

Status of electricity access

Our latest country-by-country assessment shows that the number of people without electricity access dipped below 1 billion for the first time in 2017.[3] The fact that 99 million people gained access to electricity during 2017 is a reflection of the ongoing strong policy

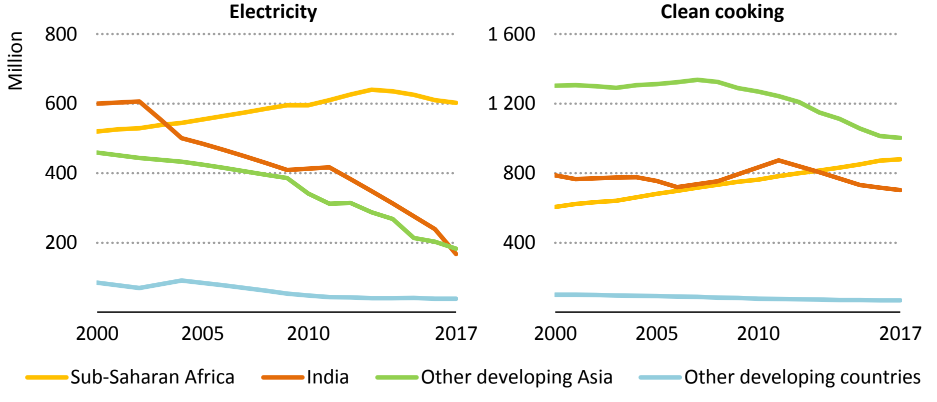
2. See: www.iea.org/tcep/.

3. Country-by-country data through 2017 and projections though 2030 on energy access can be found at: www.iea.org/sdg. The IEA's methodology for quantifying and modelling energy access can be found at: www.iea.org/energyaccess/methodology.

efforts reported in a *WEO Special Report – Energy Access Outlook 2017* (IEA, 2017a). However, the pace of progress varies greatly among regions, with around three-quarters of the 550 million people who have gained access since 2011 concentrated in Asia (Figure 2.7).

Over 900 million people have gained access to electricity in developing economies in Asia since 2000, with 91% of the region having access to electricity in 2017 compared with 67% in 2000. Nearly 60% of this progress has occurred in India, which continues to make remarkable progress towards its target to deliver universal electricity access. Many other Asian countries have also seen significant progress. In Bangladesh, electricity now reaches 80% of the population, up from 20% in 2000, and in Indonesia, the electrification rate is now nearly 95%.

Figure 2.7 ▷ Population without modern energy access



Electricity access has outpaced population growth in all world regions since 2013, but the picture is still deteriorating for clean cooking in sub-Saharan Africa

The number of people without access to electricity in sub-Saharan Africa continues to decline, albeit slowly. Over 200 million people have gained access since 2000, less than the overall population increase. As a result, there remain more than 600 million people without access, despite an increase in the access rate of 20 percentage points to 43%. Furthermore, recent efforts have been uneven, with around 60% of the progress seen since 2011 concentrated in just four countries (Kenya, Ethiopia, Tanzania and Nigeria), which together account for only 31% of the population without electricity access in sub-Saharan Africa. In Kenya, the access rate has increased by over 65 percentage points from 2000 to 73% today, and the Last Mile Connectivity Project aims to deliver universal access by 2022. In Ethiopia, electricity now reaches 45% of the population compared with 5% in 2000. The National Electrification Program, launched in 2017, outlines a plan to reach universal access by 2025, aiming to reach 35% of the population with off-grid solutions. In South Africa, while the current electrification rate is relatively high (84%) it has been declining since 2014, in large part because electrification in urban areas has not kept pace with migration from rural areas.

SPOTLIGHT

Empowering women: the link between gender equality and energy access

The proliferation of modern energy and appliances in the 20th century played a critical role in empowering women in developed countries. Achieving modern energy for all (SDG 7.1) will play an equally critical role in empowering women who do not yet have such access, helping to improve gender equality, an ambition articulated by SDG 5. The two goals are symbiotic – consideration of gender issues bolsters the success of on-the-ground universal energy access programmes. Recognition of these synergies is growing, as governments begin to consider gender issues in mainstream energy access policies (ENERGIA, World Bank and UN Women, 2018), and as the wider energy community begins to pay attention to issues of women's empowerment, education and leadership, for example through the IEA's Clean Energy Education and Empowerment Technology Collaboration Programme (C3E TCP).

A lack of modern energy access disproportionally affects women. Typically responsible for cooking, cleaning, and fetching fuelwood and water, women in developing countries suffer from exposure to household smoke, and often spend significant amounts of time on domestic chores, limiting their participation in education and economic activities. Time use surveys from Mexico reveal that women in households with a refrigerator, gas stove and washing machine spend up to seven fewer hours on domestic labour weekly than those in households without them (Orozco Corona and Gammage, 2017). The rise in female employment in advanced countries in the 20th century has been attributed to the time savings stemming from the diffusion of modern technologies within the home (Lewis, 2014), a trend which has supported economic growth and better gender equality (Tsani et al., 2013). Time saved from chores may allow more attention to child and health care, which in turn can facilitate better education and can help to drive down both child mortality and fertility rates.

For women to reap the benefits of modern energy, the provision of access needs to go beyond providing households with electricity connections. Equitable outcomes cannot be met unless modern energy is made available for a wide range of services, especially those strongly related to gendered roles in society. This requires more than a basic level of electricity supply. For example:

- Over 1.7 billion households have an electricity supply, but still rely on polluting sources for cooking. Providing clean cooking facilities costs a fraction compared to electricity access, but often is a low priority, with a few exceptions (Box 2.1).
- In rural areas, electricity for water pumps tends to prioritise agriculture. If these pumps would also provide water for domestic use, they would significantly reduce women's workload (Winther, 2006).

Further progress on making sure energy policies reduce gender inequalities can also be achieved by:

- Considering gender when designing fiscal policies, in particular fuel subsidies (Kusumawardhani et al., 2017). Recognising this, India recently introduced the Pradhan Mantri Ujjwala Yojana (PMUY) policy for LPG connections specifically targeting poorer women.
- Involving women in the energy access supply chain. This has been shown not only to give women opportunities for rewarding income generation, but also to improve community confidence in the supply chain and encourage the uptake of off-grid electricity systems and clean cooking solutions (Winther et al., 2018). Women's hands-on involvement in the technical and entrepreneurial aspects of energy supply can also challenge existing norms and empower women in decision making. For example, the Barefoot College in India trains women with little education to install and maintain solar home systems, helping to establish women as entrepreneurs and to promote female education.

Status of clean cooking access

Nearly 2.7 billion people lack access to clean cooking facilities, relying on biomass, coal or kerosene as their primary cooking fuel. In the past, progress has been very limited compared to progress in electricity access. However, this year the *WEO* reports a turning point, with updated data showing a gradual decline in the number of people worldwide without clean cooking access.

Developing Asia is home to around 65% of the global population without access, with 1.7 billion people lacking clean cooking facilities. Five-times more people lack clean cooking access than electricity in this region. However, the latest data shows promising signs, with 525 million people gaining access since 2011, compared with only 250 million between 2000 and 2011. In India and China, access rates have reached 47% and 70% respectively. In India, national data show a reduction of 14 percentage points in the share of population relying on biomass and kerosene between 2011 and 2015, with most now using LPG instead. Since 2015, government figures indicate that an additional 50 million free LPG connections have been provided to poor households via the high-profile PMUY scheme (Box 2.1). In China, natural gas infrastructure development is helping to reduce the use of biomass and kerosene. Several other countries in developing Asia are also making efforts to promote clean cooking, employing different methods depending on the national context.

The challenge in sub-Saharan Africa remains acute, with a deteriorating picture. Only 17% of the population have clean cooking access. The vast majority of the 890 million people without access rely on gathering biomass for cooking, in particular in rural areas. This damages health and impairs productivity improvements. Strong population growth means that almost 275 million more Africans now lack clean cooking access than in 2000.

Deforestation, linked to biomass collection, is also becoming a major concern: the region lost 13% of its forest area between 1990 and 2015.

However, 68 million people have gained clean cooking access in sub-Saharan Africa since 2000, mostly in Ethiopia, Ghana, Kenya, Nigeria, South Africa and Sudan. In Sudan, around half of the urban population uses domestically refined LPG for cooking, though the government seeks to import LPG to supplement local supply. In Kenya, LPG is now used by 24% of urban households. It is displacing kerosene as government initiatives aim to reduce biomass use, however, 96% of rural households still use biomass. In Ethiopia, LPG is the primary cooking fuel for less than 0.5% of households, but gains in electricity access are beginning to make an impact, with nearly a quarter of urban households cooking with electricity in 2016 compared with only 3% in 2011. In South Africa, electricity is the main clean cooking fuel, used by three-quarters of households nationally.

Box 2.1 ▹ On the boil: how are countries improving clean cooking access?

Despite slow progress globally, a number of countries are bucking the trend and making significant progress in delivering clean cooking access. Cross-analysing household surveys of cooking fuel use with national energy balances and policies reveals that governments are taking various approaches to achieve clean cooking access.

Concerned about an estimated 640 000 premature deaths annually attributed to household air pollution, the Indian government has given free LPG connections to over 50 million households living below the poverty line, providing a gas stove, one cylinder and the first fill.[4] In 2018, the government increased the ambition of the target from 50 million to 80 million households by 2020.[5] The Ujjwala scheme (PMUY) provides the subsidy directly to women's bank accounts that are linked to a national database to prevent duplication and identity theft. There is an emphasis on promoting employment through locally made equipment. The next challenge is to ensure the consistent use of LPG to displace biomass, which is typically free. Government figures show that households who have received a free connection buy around 3.5 cylinders of LPG per year, displacing around one-quarter of fuelwood in the households that have taken up the scheme, or 6% of total biomass used in India's households.

In Bangladesh, surveys show that reliance on biomass, now at 77%, fell by nine percentage points between 2011 and 2016. Use of natural gas has increased, and it is now the main cooking fuel for over 20% of households. The promotion of natural gas for domestic purposes is relatively unusual in developing countries. Now that the government seeks to secure gas supply for industrial development and power generation, it plans to refocus support for households on LPG, which can reach villages

4. http://www.pmujjwalayojana.com/.

5. https://energy.economictimes.indiatimes.com/news/oil-and-gas/omcs-defer-loan-amount-recovery-from-ujjwala-beneficiaries-for-next-6-refills/63433001.

without a piped supply of gas, given adequate transport infrastructure. The main national development finance institution, Infrastructure Development Company Ltd. (IDCOL), also promotes improved cookstoves in support of the target of 100% coverage by 2030 set out in Bangladesh's Country Action Plan for Clean Cookstoves.

In Myanmar, policy makers are promoting clean cooking in part because of the high rate of deforestation, which has reached an annual rate of 2%. Reliance on biomass fell from 94% of the population in 2009 to 76% in 2015, with biomass mainly replaced by electricity. The government is now subsidising LPG connections to free up electricity supply and further move away from biomass use.

In sub-Saharan Africa, few countries have reached a high level of LPG penetration, but several have set ambitious goals. In Cameroon, where the LPG penetration rate is currently 21%, the government has published the region's first "masterplan" setting out concrete measures to increase the share of households using LPG, targeting 58% by 2030. Motivated by development, health and deforestation concerns, the planning process involves six ministries and many national and international stakeholders. LPG currently only reaches 2% of rural households, compared to 39% in urban areas. Fuelwood and other biomass made up 93% of total final consumption in rural Cameroon in 2014, the same share as 2000.

Can we infer a "recipe for success" in delivering clean cooking access? Most progress has taken place in lower middle-income countries where incomes are rising, and have involved targeted government support for clean cooking fuels. Making clean fuels affordable is key – it is difficult to motivate people to give up a free fuel (which biomass typically is in rural areas, except for the opportunity cost of the time spent gathering the fuel). Subsidies for the initial outlay in equipment in particular are often necessary to make clean cooking affordable. What remains a concern is the lack of examples of low-income countries making significant progress.

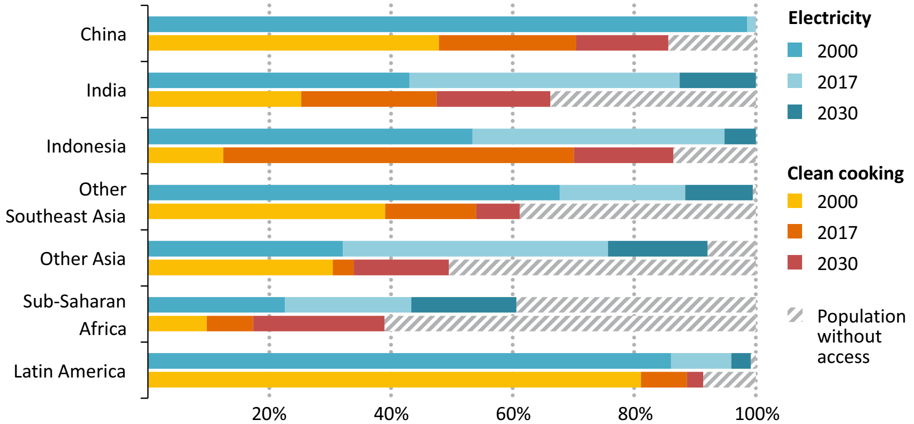
Outlook for energy access

In the New Policies Scenario, the number of people without access to electricity declines to around 650 million in 2030 and then rises again to 720 million in 2040 (staying at around 8% of the global population). Continued progress in developing Asia sees the region reach an electrification rate of 99% by 2030, with universal access by the mid-2020s in India and Indonesia (Figure 2.8). In sub-Saharan Africa, the population with access to electricity more than doubles from today's level, but those without access continue to number around 600 million in the face of rapid population growth and uneven progress across the region.

Annual electricity access investment averages $30 billion. Cumulative additional capacity for electricity access totals 108 GW, nearly 40% of which takes the form of grid extensions powered through centralised generation. Renewables play an increasingly important role, accounting for 70% of new electricity connections between now and 2030, nearly half of which are for off- and mini-grid solar PV.

The number of people in the New Policies Scenario without access to clean cooking facilities falls to 2.2 billion in 2030 and 1.8 billion in 2040. Developing Asia still hosts the largest population without access in 2040. In China, access to clean cooking is slow to reach the last 10-15% of the population, leaving 105 million people without access in 2040, the majority relying on biomass. In India, the access rate is 76% by 2040, which means around 390 million remain without access. In sub-Saharan Africa, the switch to clean cooking turns a corner around 2030, so that by 2040 fewer than 820 million people do not have clean cooking access. Globally, average annual investment in clean cooking facilities from 2018-30 is $1 billion.

Figure 2.8 ▹ Progress since 2000 and outlook to 2030 for electricity and clean cooking access in the New Policies Scenario



While universal access to electricity is within reach for many parts of Asia, sub-Saharan Africa risks being left behind, and global progress on clean cooking access lags

Overall, the New Policies Scenario points to a world where energy access is not universal by 2030. Without modern energy for all, other development objectives will be much harder, and perhaps impossible, to meet, notably objectives concerned with improving health outcomes and gender equality. There are many opportunities for further action on energy access: for example, only 30% of access deficit countries currently have established a policy environment that fosters electrification (World Bank, 2018). Box 2.2 outlines priority policy areas to achieve universal access by 2030. Universal energy access is an essential part of the African Union's Agenda 2063 goal to harness all African energy resources to ensure modern, efficient, reliable, cost effective, renewable and environmentally friendly energy to all African households.

Box 2.2 ▷ How to accelerate progress on energy for all? Priority actions for the first UN review of SDG 7

In 2018, the IEA provided technical input in collaboration with other agencies to the High-Level Political Forum, in which the United Nations reviewed progress on SDG 7 for the first time. The following actions were identified as priorities (United Nations, 2018):

Electricity access

- Elevate universal access to electricity on the political agenda, backing up commitments with strategic planning, clear policies and dedicated institutions.
- Identify strong national champion institutions for electrification, with a clear mandate, necessary authority and resources, and thorough accountability.
- Establish de-risking tools, affordable financing and a clear enabling policy framework to attract private investment. To achieve the estimated $51 billion per year investment necessary to deliver universal access, private investment is needed to complement public spending.
- Consider other development goals in household electrification strategies, including opportunities for energy access to stimulate sustainable economic activity.
- Take into account the dynamic and integrated nature of energy demand and storage in electrification planning, and ensure technical standards and energy efficiency in end-use appliances.
- Address affordability by lowering upfront costs with targeted financing and subsidies, harnessing new business models such as the pay-as-you-go model and integrating energy-efficient appliances with access solutions.

Clean cooking access

- Prioritise clean cooking solutions in policy making, and translate global commitments into concrete evidence-based policies and plans.
- Mobilise funds from various stakeholders to scale up promising enterprises, increase consumer choice and financing, and stimulate additional private investment.
- Engage diverse public and private stakeholders across the development and climate spectrum, as successful clean cooking solutions are inherently cross-sectoral; mainstream clean cooking in relevant development interventions, such as those impacting health, gender, climate and environment.
- Move people towards clean cooking solutions that meet local cultural and social needs, with women involved in designing and delivering solutions. Resources are needed to spur innovation and identify affordable and scalable solutions.
- Improve monitoring of household energy use to accurately track, measure impact, and assess progress towards achieving universal access.

2.7.2 Progress and outlook for air pollution

Recent progress

Local air pollution is an increasingly prominent policy priority in many countries. Premature deaths linked to air pollution now amount to 2.9 million from outdoor air pollution, and a further 2.6 million from household pollution.

While urban air pollution is a major issue all around the world, it has become particularly pressing in big cities in major developing countries. In 2016, the World Health Organization (WHO) reported that half of the world's top twenty most polluted cities (measured by particulate concentrations) were in India (WHO, 2016). In this context, a number of major new policy measures have been announced since the *WEO-2017*. In July 2018, for example, China announced a new three-year action plan. The plan covers the whole country, with a particular focus on the Beijing-Tianjin-Hebei region. As well as setting targets for pollution levels, the plan aims to curb coal use for new industrial capacity and to promote low-emissions vehicle production and use. China has also implemented a new plan for 2017-21 to support cleaner heating in 14 northern provinces with substantial current coal heating demand.

Globally, transport is a major contributor to air pollution, in particular accounting for around half of current global NO_X emissions. The effects of pollution from transport are especially important in cities, where there are large numbers of people and vehicles in close proximity. As a result, transport pollution standards are increasingly being adopted at the city government level, as well as nationally. The C40 Cities Initiative "Fossil-fuel-free streets declaration" was signed by the leaders of 26 major cities across six continents in 2018. It declares their commitment to allow only zero-emissions bus sales by 2025 and to establish fossil fuel-free districts by 2030. A number of city governments have also put forward specific future access restrictions for conventional vehicles, including for diesel cars in Paris and Rome as soon as 2024, with Paris extending the ban to petrol cars by 2030.

China, India, Brazil and other countries meanwhile continue to tighten emissions standards for both light- and heavy-duty vehicles. For example, the newly released China VI standard requires all new diesel heavy-duty vehicles (HDVs) introduced to the market after July 2021 to have diesel particulate filters and to be soot-free, affecting around 15% of global HDV sales anticipated in 2021.

The power sector remains a major source of sulfur pollution, mostly due to emissions of SO_2 from coal-fired power generation. Many countries already have strong regulations in place to limit and further decrease SO_2 emissions from coal, and, in some cases, existing regulations are being strengthened. At the 2018 National People's Congress of China, the government reiterated its commitment to air pollution controls. Korea has announced stronger regulations on coal-fired power plants, which are expected to significantly reduce emissions of fine particulates.

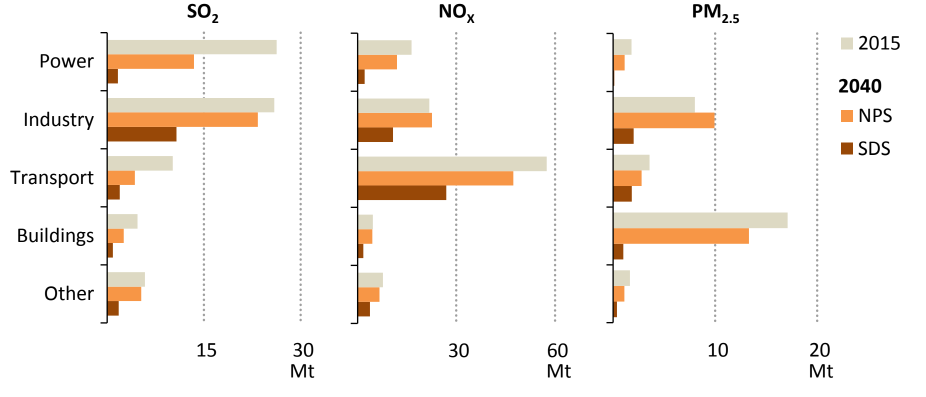
Air pollution regulations in industry have also been tightened. In India, for example, new standards are now in place for ceramics, foundries, glass, lime kiln and reheating furnaces, as well as industrial boilers. In the European Union, the Medium Size Combustion Plants Directive was due to be transposed by member states in 2017, while the Best Available Techniques reference document for large combustion plants was published in 2017, with expectations that member states implement standards within four years.

Future outlook

These new policies, adding to an already rich landscape of air pollution policies, mean that total levels of all major pollutants are set to fall in absolute terms in the New Policies Scenario, even as energy demand continues to grow strongly (Figure 2.9).

However, these reductions are much less than in the Sustainable Development Scenario, and are insufficient to prevent continued severe health effects of air pollution. The relationship between levels of emissions of air pollutants and human health is complex, depending on atmospheric conditions, and exposure levels and timing (IEA, 2016a). Overall, the number of premature deaths from outdoor air pollution actually rises in the New Policies Scenario, increasing to 4 million per year by 2040. The health impacts of indoor air pollution are also set to remain severe in the New Policies Scenario, with 2.2 million premature deaths still in 2040, due in large part to particulate emissions from cooking smoke, a direct result of a lack of access to clean cooking facilities (see section 2.7.1).

Figure 2.9 ▷ Air pollution emissions by sector and scenario, 2015 and 2040



Pollutant emissions generally fall in the New Policies Scenario, but in most cases by much less than in the Sustainable Development Scenario

Notes: NPS = New Policies Scenario; SDS = Sustainable Development Scenario. Industry includes fuel combustion in the industry sector and transformation processes other than power generation.

Source: IEA analysis; International Institute for Applied Systems Analysis.

2.7.3 Progress and outlook for CO_2 emissions

Recent progress

The latest IEA *Global Energy and CO_2 Status Report* showed that global energy-related CO_2 emissions rose in 2017 after three years of remaining flat.[6] This increase was due to a combination of factors, including strong economic growth – as despite a weakening link, emissions growth is still related to economic activity – as well as continued low oil and gas prices, and a slowdown in the spread of energy efficiency standards.

The upward trend was not universal around the world. Energy-related CO_2 emissions dropped in the United States, largely due to the increased use of renewables. Emissions increased in most other regions, with 75% of the increase occurring in Asia. In China, the economy grew by 7%, while emissions grew by 2%, with the lower rate of emissions growth reflecting changes in the economy as well as increased use of renewables and coal-to-gas switching (described in the *WEO-2017* [IEA, 2017b]).

There have been a number of policy changes targeting CO_2 emissions since the *WEO-2017*. In the European Union, substantial reforms to the EU Emissions Trading System were agreed. These have led to an increase in the price of permits, and are expected to result in the current surplus of permits reducing rapidly over coming years. National GHG reduction targets up to 2030 were also agreed for the sectors not covered by the EU Emissions Trading System. In China, a national emissions trading system was announced in late 2017, and a pilot phase for the power sector will begin in 2019. In Canada, as part of the Pan-Canadian Framework on Clean Growth and Climate Change, the federal government announced national carbon pricing measures as a backstop for provinces and territories that do not introduce their own measures.

An increasing number of countries are also introducing specific taxes on carbon, often in the context of delivering on their pledges to combat climate change (OECD, 2018). Argentina, Singapore and South Africa have proposed carbon taxes to be implemented in 2019. Argentina's tax targets emissions from transport fuels and coal and aims to cover 20% of the country's GHG emissions, with a gradually increasing tax rate. Singapore will apply a tax on facilities with emissions of 25 thousand tonnes of CO_2-equivalent (kt CO_2-eq) or more per year, with rates increasing over time.

Many other policies indirectly influence CO_2 emissions, ranging from subsidies to market mechanisms to regulations. These include demand-side policies, such as for energy efficiency, as well as supply-side technology and market policies. Policies targeting air pollution can also influence CO_2 emissions, as discussed in the next section. Examples of policy announcements since the *WEO-2017* with an important bearing on CO_2 emissions include: reforms of fossil fuel subsidies (see section 2.8.1); changes in feed-in tariffs and other price support policies (such as the cap on solar PV projects in China, described in Chapter 8); and updates to overall energy mandates and targets (such as the newly agreed

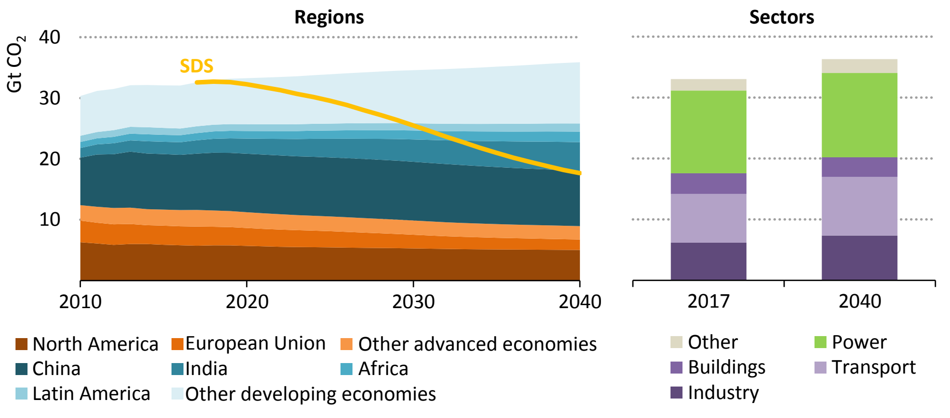
6. See www.iea.org/geco.

renewables and energy efficiency targets in the European Union). Some ambitious new energy efficiency policies have been implemented, including India's tightened emissions standards for both light-duty vehicles (LDVs) and HDVs, and the EU's update to the Energy Performance of Buildings Directive that mandates that member states implement transitions towards "nearly zero-energy buildings".

Future Outlook

After taking into account all relevant policies and commitments, the New Policies Scenario projects CO_2 emissions continuing to grow through to 2040.[7] This is a very different trajectory to the steep reductions embodied in the Sustainable Development Scenario (Figure 2.10).

Figure 2.10 ▷ CO_2 emissions by region and sector in the New Policies Scenario



CO_2 emissions continue to rise through to 2040, with particular growth seen in the transport and industry sectors

Notes: SDS = Sustainable Development Scenario. Shows CO_2 emissions from fuel combustion only.

Overall, projected CO_2 emissions are higher in the short term than they were in the 2017 New Policies Scenario, but mid-term plans lead to slower growth in emissions through the 2020s in this year's *Outlook*. The net effect is that emissions in 2040 in the New Policies Scenario are broadly similar to the *WEO-2017* projection.

The outlook for CO_2 emissions in the New Policies Scenario varies considerably across regions. In the European Union, the implementation of the new Clean Energy Package sees

7. The New Policies Scenarios takes into account countries' Nationally Determined Contributions (NDCs), insofar as policies or other implementing measures have been announced to ensure the achievement of those NDCs. Some NDCs contain specific CO_2-related objectives and policies, others contain targets related to specific energy technologies or efficiency, and yet others contain both types of goals.

emissions reduce from 2017 levels by 29% in 2030 and by 45% in 2040, led by power sector emissions cuts. In the United States, emissions decline by 15% from 2017 levels by 2040: power sector emissions fall due to wider use of cost-competitive wind, solar and gas, while emissions from transport overtake those from the power sector in 2020. China's emissions grow slowly in the New Policies Scenario through to 2030 and then begin to decline. India's emissions continue to grow to 2040, but at a slower rate than recent years.

One key international policy announcement since the *WEO-2017* is the agreement by members of the International Maritime Organization (IMO) to reduce total CO_2 emissions from shipping by at least 50% from the level of 2008 by 2050. This ambitious goal is not yet supported by concrete measures to enforce its achievement, and so is not included in the New Policies Scenario. The implications of the target are however included in the Sustainable Development Scenario.

2.8 Boosting efforts to meet the energy-related SDGs

The previous section emphasised that the world is not on track to achieve the energy-related SDGs and that global CO_2 emissions started rising again in 2017. To help inform decision making on actions to reverse these trends, this section provides quantitative assessments of concrete policy actions that offer scope for: (i) further developing measures proven to be cost effective for reducing CO_2 emissions, focusing on those in the IEA's 2015 "Bridge Scenario"; (ii) maximising synergies between different sustainable development objectives; (iii) ensuring alignment across the energy sector.

2.8.1 Revisiting the Bridge Scenario – five cost-effective measures for near-term action

As countries prepared their (Intended) Nationally Determined Contributions (NDCs) in the run up to the Paris Agreement in 2015, the IEA identified five measures that could provide cost-effective opportunities to achieve a peak in energy-related GHG emissions (IEA, 2015). Three years later, we take stock of progress on these measures and re-evaluate their potential contributions to CO_2 and methane abatement by 2030, as well as the part they could play in further action towards achieving the Sustainable Development Scenario. The analysis is also relevant for the Talanoa Dialogue of the UN Framework Convention on Climate Change, a stocktaking process that aims to reveal opportunities for increasing the ambition of national climate change mitigation contributions for the period to 2030.

The five measures, endorsed by energy ministers[8], are:

- Increasing energy efficiency in the industry, buildings and transport sectors.
- Increasing investment in renewable energy technologies (including hydropower) over time.

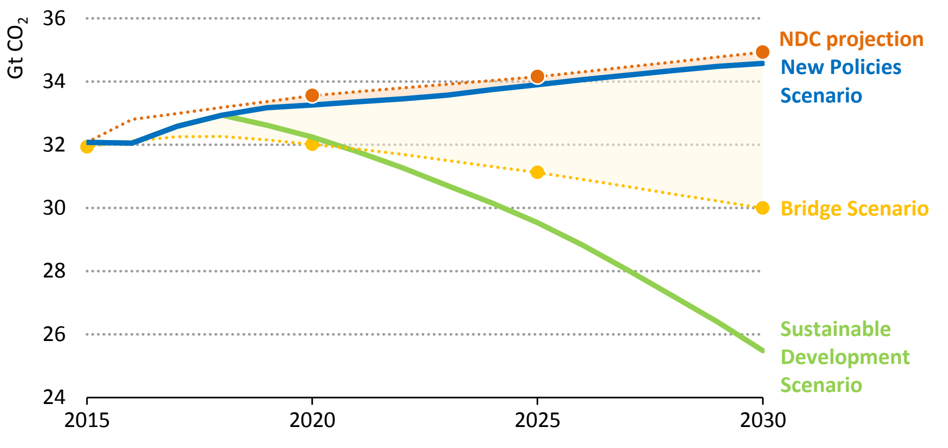
8. For the ministerial statement, see: www.iea.org/media/news/2015/press/IEA_Ministerial_Statement_on_Energy_and_Climate_Change.pdf.

- Phasing out the use of the least-efficient coal-fired power plants.
- Gradual phasing out of inefficient fossil fuel subsidies to end-users.
- Reducing methane emissions from oil and gas production.

These five measures were incorporated into the "Bridge Scenario" which showed that, if implemented universally, the measures would lead to a peak in energy-related GHG emissions at no net cost, thereby keeping the door open to accelerate reductions in line with global climate change goals.

Nevertheless, the 2018 update of our New Policies Scenario, incorporating current policies and plans, shows that energy-related CO_2 emissions are expected to be only slightly lower in 2030 than the level implied when the NDCs were submitted in the context of the Paris Agreement in 2015 (Figure 2.11). In aggregate terms, therefore, countries appear to be on course with what they planned in their international commitments, but emissions are higher than the level of the Bridge Scenario and far from the trajectory implied by the goals of the Paris Agreement. The picture varies across regions. The latest New Policies Scenario projection for the European Union shows emissions in 2030 about 7% below the level estimated in 2015, with reductions led by the power sector. Likewise, projected emissions in China in 2030 are now 5% lower than the level we projected in 2015 based on China's NDC submission, despite GDP projections for 2030 having risen, with lower emissions stemming from the power and industry sectors.

Figure 2.11 ▷ CO_2 trajectories relative to aggregate emissions levels implied by NDCs, 2015-2030

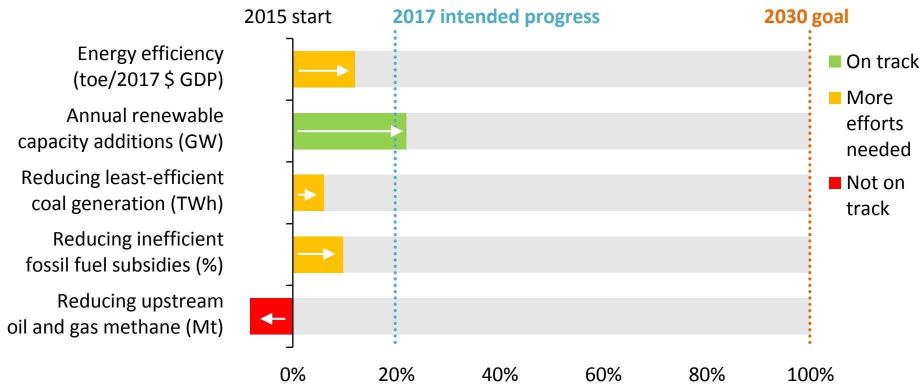


CO_2 emissions are currently higher than the level projected in the Bridge Scenario, and on a trend far from the trajectory of the Sustainable Development Scenario

Notes: NDC = Nationally Determined Contributions. Shows CO_2 emissions from fuel combustion only.

The rise in CO_2 emissions in 2017 means that global CO_2 emissions were about 330 Mt CO_2 above the level that would have been achieved if the Bridge Scenario measures had been expeditiously implemented from 2015. Taking a look at the five measures in the Bridge Scenario shows that progress has been mixed (Figure 2.12). Only investment in renewables, measured by capacity additions, is in line with what was originally projected in the Bridge Scenario for 2017. Progress on phasing out least-efficient coal has been steady, but well below the rate set out in the Bridge Scenario. Energy efficiency is close to being on track, but policy efforts appear to be slowing. Some progress has been made on phasing out inefficient fossil fuel subsidies, but less than was projected in the Bridge Scenario. Estimates of methane emissions from oil and gas operations have risen over the period in proportion to production, implying almost no progress on the measure.

Figure 2.12 ▷ Progress on key measures for achieving a peak in energy-related GHG emissions in the Bridge Scenario, 2015-2017



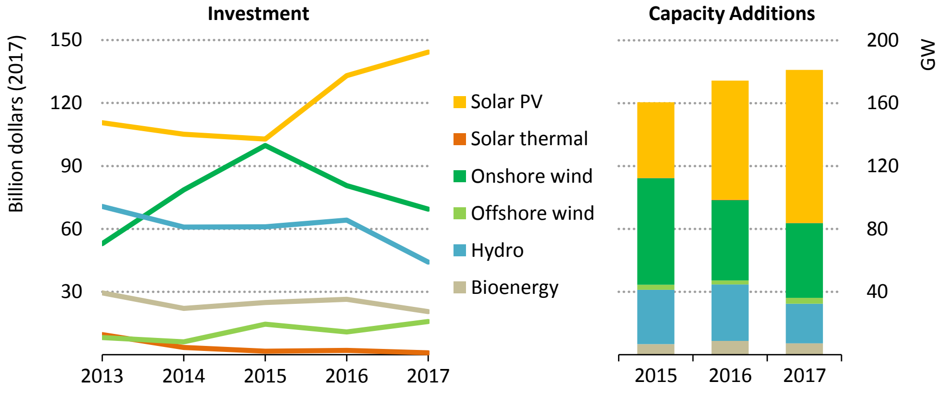
Progress on the five measures is mixed; investment in renewables in power generation is on track with the Bridge Scenario, but efforts on other measures lag

Energy efficiency improvements have slowed over the last two years. Energy intensity, a proxy for energy efficiency measured in energy consumption per unit of economic output, has seen year-on-year improvement slow to 1.7% in 2017 (IEA, 2018d). While policy coverage rates have increased steadily since 2013 for industrial electric motors, electric appliances and heating, other dominant end-uses such as space cooling and refrigeration have seen little increase in policy coverage (IEA, 2018a). Further progress has the potential to reduce CO_2 emissions in cost-effective ways while also improving energy security.

Renewable energy investment in the power sector totalled $300 billion in 2017, 6% less than in 2016 and slightly lower than 2015 (IEA, 2018e). However, declining technology costs mean that capacity additions of renewables still rose in 2017 by 3% to 178 GW (including 97 GW of solar PV). Capacity additions are therefore outstripping the rate implied by the investment objective stated in the Bridge Scenario, even though actual investment numbers are lower.

Different renewables technologies have seen varying trends since 2015. Investment in solar PV increased by an annual average of 18%, encouraged by falling costs and continuing policy support. Rapid solar growth has offset declines in capacity additions of other renewables (Figure 2.13). Deployment of offshore wind capacity increased to over 18 GW in 2017, boosted by public-private initiatives in countries bordering the North Sea in Europe (IEA, 2018f). By contrast, investment in onshore wind and hydro both decreased.

Figure 2.13 ▷ Renewable electricity investment and capacity additions, 2013-2017

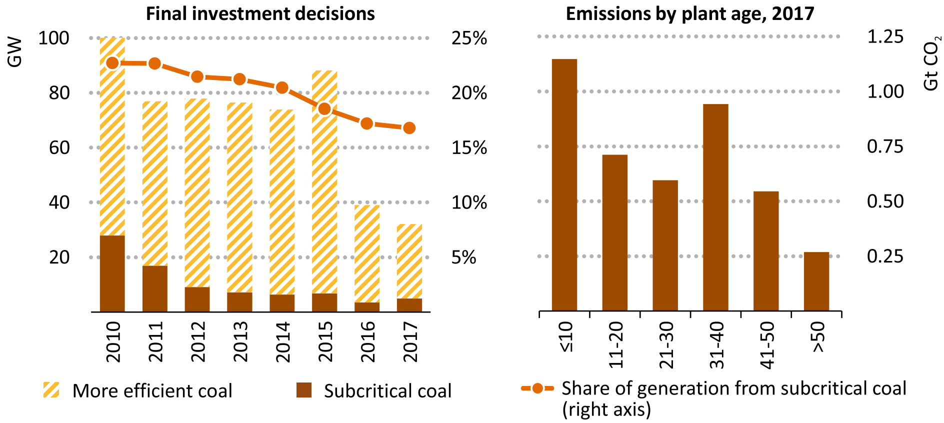


Growth in solar PV investment offsets declines in other technologies. Overall, renewable energy capacity additions expand even with lower total investment levels.

Phasing out of least-efficient coal-fired power plants has made some progress. Globally, generation from subcritical coal plants has decreased by an annual average of 2% since 2015, though it still contributes 17% of electricity generation. Mostly this is due to a reduction in operating hours of subcritical plants, as capacity so far remains nearly constant. There has nevertheless been a marked decrease in planned investment for new subcritical coal in the last two years (Figure 2.14). However, subcritical technology is still prevalent in emerging economies, and many of the plants are young. Around 9 GW of new subcritical coal capacity was added in 2017, 95% of which was in Asia, and about 45% of all subcritical coal capacity currently in operation is less than 20 years old. This implies a potential to influence CO_2 trajectories far into the future, in the absence of further measures to reduce operational hours or encourage early retirements (see Chapter 7).

Progress is also evident in actions to **phase out fossil fuel consumption subsidies**. Many countries have initiated fossil fuel subsidy reforms, including several producer economies (Box 2.3). The level of subsidies has decreased by 4% since 2015, although the proportion of global energy-related CO_2 emissions covered by fossil fuel subsidies has remained unchanged at around 13%. Reform measures had been facilitated by relatively low international oil and gas prices in the last few years (Figure 2.15), but in 2017 higher oil prices led to a partial rebound in total subsidy value. The 15% rise in subsidies was however considerably less than the 25% rise in oil price. In mid-2018, there were signs of a slow-down in reform efforts. Further and deeper reforms would reduce government spending pressures while also creating a price environment that facilitates long-run decarbonisation.

Figure 2.14 ▷ Tracking subcritical coal-fired power investment and CO_2 emissions



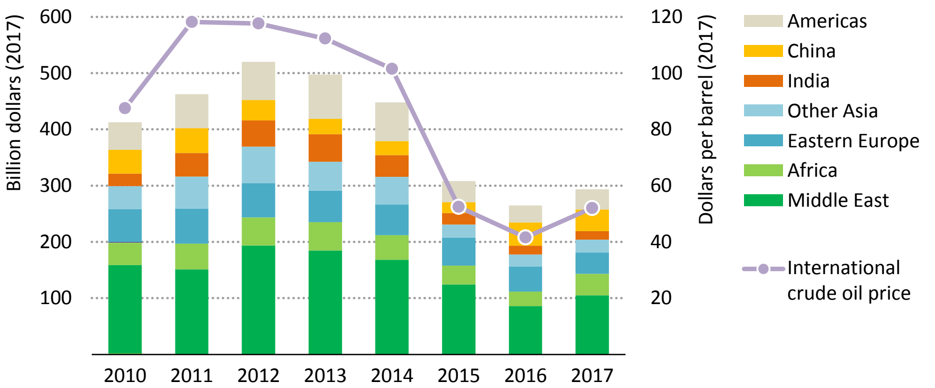
Investment in and generation from subcritical coal plants have declined, but the young fleet will generate for years to come absent further actions towards phase out

Box 2.3 ▷ Recent progress on fossil fuel consumption subsidies

In 2016, India introduced a direct cash transfer scheme for residential kerosene consumers and launched a programme to raise kerosene prices progressively. East and Southeast Asia have also had several subsidy reforms in recent years: for example, Malaysia abolished gasoline and diesel subsidies, and raised electricity tariffs in 2014, and then increased domestic gas prices for the power and industrial sectors in late 2016 (though some changes are foreseen in 2018).

Saudi Arabia introduced price increases for gasoline, natural gas and electricity in 2015, which have contributed to an annual average 13% reduction in subsidies. Kuwait, Iran, Qatar, Egypt and Algeria have also all reformed their subsidies or raised domestic fossil fuel price caps in recent years. Although the value of consumption subsidies in the Middle East decreased by 15% between 2015 and 2017, the region still accounts for 35% of the global total.

Figure 2.15 ▷ Fossil fuel consumption subsidies in selected regions



Subsidies increased slightly in 2017, but by less than the rise in oil price

Methane emissions from the oil and gas sector have increased by an average 2% each year since 2015, reaching 79 Mt in 2017. Over 80% of the emissions arise from upstream processes, 36 Mt from oil and 29 Mt from natural gas. Methane (CH_4) emissions continue to track levels of oil and gas production, particularly for upstream gas, but there is significant potential to decouple methane emissions from fuel production, and to do so in a cost-effective way. Up to 45% of oil and gas sector methane (43 Mt) could be eliminated at no net cost (see Chapter 11, section 11.4.1). Green completions, whereby methane is recovered from flowback fluids after hydraulic fracturing is complete, have proven especially effective. Methane's high global warming potential and short half-life means that reductions would have a real impact in the short term.

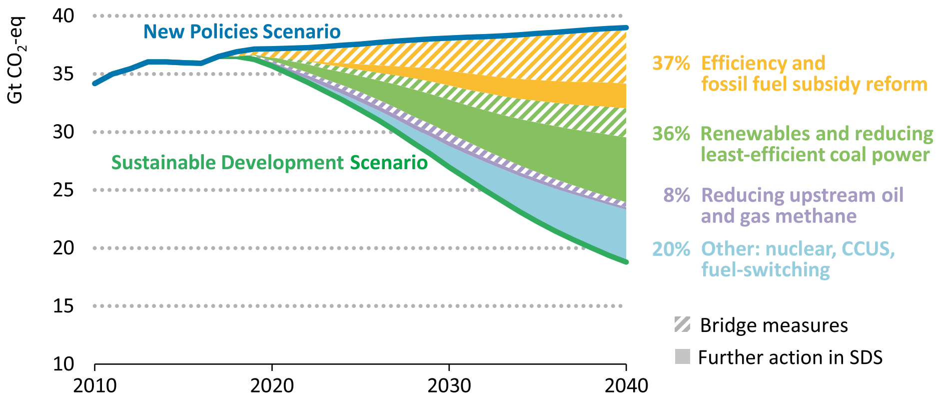
Several recent commitments have been made from the private sector. Sixteen major companies recently signed a voluntary commitment regarding the "guiding principles on reducing methane emissions across the natural gas value chain". Additionally, in 2018 the Oil and Gas Climate Initiative, with a membership covering 30% of global oil and gas production, established a collective target to reduce the average methane intensity of upstream operations by one-fifth by 2025. There has also been progress on the regulatory side, such as new federal requirements in Canada.

Extending the bridge to a more sustainable future

Together, full implementation of the five measures proposed in the Bridge Scenario in 2015 would achieve a peak in energy-related CO_2 and methane emissions, but would account for less than half of the CO_2 and methane savings needed by 2030 to achieve the objectives of the Sustainable Development Scenario (Figure 2.16). While an early peak in emissions is important, the subsequent trajectory towards net-zero emissions will be central to achieve the objectives of the Paris Agreement (Box 2.4).

For countries to move beyond the Bridge Scenario and towards the trajectory of the Sustainable Development Scenario, where would the other half of the emissions reductions come from? Around a third of the additional reductions in the Sustainable Development Scenario come from other low-carbon energy sources such as continued use of nuclear power in countries where it is acceptable, as well as from fuel switching to less carbon-intensive fuels and the deployment of CCUS. The remaining two-thirds come from going further with the Bridge Scenario measures, implying a range of further sector and country-specific policies in support of these measures.

Figure 2.16 ▷ CO_2 and methane emissions reductions by measure in the Sustainable Development Scenario relative to the New Policies Scenario



Implementation of five measures at no net economic cost would bridge less than half of the gap between current trends and a Paris Agreement trajectory

Notes: Gt CO_2-eq = gigatonnes of CO_2 equivalent; CCUS = Carbon, Capture, Utilisation and Storage; SDS = Sustainable Development Scenario; 100-year global warming potential of methane = 30.

The measures are clearly interlinked. Improving end-use efficiency remains the most prominent driver of CO_2 reductions and it is directly supported by phasing out fossil fuel consumption subsidies (which by their nature encourage consumption). Investment in renewables is by itself the second-largest source of savings, but it cannot be seen in isolation of action to phase out the most inefficient coal plants, as part of a combined strategy for reducing the carbon intensity of power generation. Together these four types of measures make up more than 70% of the gap between the New Policies and Sustainable Development scenarios. One avenue for ensuring better cost-effectiveness of emissions savings is to look beyond the measures individually to consider how they interact, as well as factors such as competition with other economic and social development priorities. The next two sections aim to shed light on where countries can build on synergies with other development goals, and how an approach to energy sector policy alignment can optimise CO_2 savings.

Box 2.4 ▷ Framing low-carbon pathways: an evolving challenge

In the Paris Agreement, 195 countries agreed to the ambitious objective of "holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C". This high-level objective is challenging to interpret because it spans a range of outcomes. Moreover, attributing a long-term temperature outcome to any particular pathway for energy-related GHGs is not straightforward, and is becoming increasingly challenging.

The concept of a "carbon budget" has long been used to link emission levels and long-term climate outcomes. A carbon budget is based on the near-linear relationship between the global temperature increase and cumulative CO_2 emissions (see for example IEA, 2016b). It provides an easily conveyed metric that simply explains the importance and urgency of tackling climate change, but is not without challenges.

The recent Intergovernmental Panel on Climate Change (IPCC) special report on the impacts of global warming of 1.5 °C (IPCC, 2018) provided new, and generally much higher, estimates of the remaining CO_2 budget than those previously used in the literature, such as the budgets reported by the IPCC Fifth Assessment Report (IPCC, 2014). An additional challenge with estimating the remaining global carbon budget is that it applies only to CO_2, meaning that additional assumptions are required about other GHG emissions such as nitrous oxides and methane, as well as other air pollutants having climate effects, such as black carbon and various aerosols.

While carbon budgets provide a useful high-level indicator that illustrates the need for emissions reductions, the inherent uncertainty makes it challenging to attribute a specific budget (or a specific emissions pathway) to a particular temperature outcome. This in turn increases the challenge of using and interpreting carbon budgets for policy makers seeking to establish explicit emission reduction targets or objectives. Increasing attention is therefore focusing on alternative means to assess and compare the level of ambition of energy-related CO_2 emissions reduction targets. The Paris Agreement itself sets three parameters for emissions trajectories: that GHG emissions peak soon, enter a steep decline and ultimately reach net-zero in the second-half of this century. A number of other factors are important to clarify fully any emissions pathway, such as the reduction in non-CO_2 emissions and the magnitude of carbon sinks or other means to remove CO_2 from the atmosphere. However, focusing on the date when CO_2 emissions fall to zero, and stages to get there, could provide a more concrete goal for policy makers to define the ambition of their emission reduction pathways.

The CO_2 emissions trajectory of the Sustainable Development Scenario is lower than most published decarbonisation scenarios aiming for a temperature rise of well below 2 °C (see Figure 2.4). The scenario implies a profound and rapid shift on both the demand and supply sides of the energy sector, with the result that CO_2 emissions peak soon and then decline rapidly on a course towards net-zero emissions by 2070.

2.8.2 Exploiting synergies with other energy-related SDGs

An important finding of the Sustainable Development Scenario is that different energy-related development goals have a number of points in common. Analyses of the scenario indicate that the trade-offs between different objectives are smaller than often assumed, and that in some cases there are significant opportunities to exploit synergies between policies targeting the different objectives. Understanding these interactions can help inform choices about effective policies so as to minimise trade-offs and make the most of the synergies between different energy-related SDG objectives. This goes well beyond the three core dimensions of the Sustainable Development Scenario (Spotlight).

SPOTLIGHT

How does the Sustainable Development Scenario relate to other aspects of energy and sustainable development?

The role of the energy sector in sustainable development goes much further than the three core dimensions of the Sustainable Development Scenario. As access to modern energy is an essential tool for alleviating poverty, energy has a key role to play in the overarching goal of SDG 1, ending poverty everywhere. Affordability therefore needs to be at the heart of energy transition strategies. Additionally, other key energy interactions with the SDGs include:

- Water and sanitation (SDG 6): covered in detail in section 2.9.
- Sustainable cities and communities (SDG 11): With 4.2 billion people living in cities today, urban areas account for 75% of global energy consumption and 70% of global GHG emissions (UNDESA, 2018). As the proportion of the global population living in urban areas increases, the interactions between urbanisation and access to energy, air pollution and climate action will intensify. The Global Covenant of Mayors for Energy and Climate now brings together over 9 000 cities committed to climate mitigation. More and more cities have committed to 100% renewable energy targets, with important implications for national energy policies. Climate change also poses a direct threat to future city livelihoods. Many high-density cities are located in low-lying coastal regions, vulnerable to storm surges and sea-level rise. By 2030, climate change could force up to 77 million urban residents into poverty (World Bank, 2018). This highlights the close links between targets SDG 13.1 (on strengthening resilience to climate change) and SDG 11.5 (on reducing human casualties and economic losses caused by disasters).
- Responsible consumption and production (SDG 12): Considerable economic activity currently depends on materials produced through energy-intensive processes; cement, iron and steel, chemicals and aluminium account between them for 17% of total CO_2 emissions. In some cases, material efficiency measures can help to reduce energy use: for example, vehicles can be made more fuel efficient through

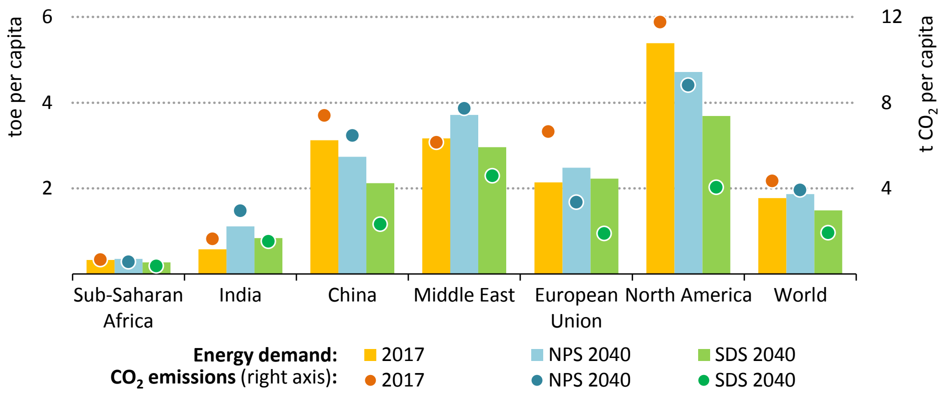
light-weighting (IEA, 2018b). However, energy efficiency is sometimes achieved at the expense of material efficiency – for example, reducing energy demand in buildings through better insulation requires more materials. Increased recycling also has energy implications. Enhanced recycling of plastics can act to reduce growth in oil demand from the petrochemical industry, set to be one of the biggest continued drivers of oil consumption over the coming decades (IEA, 2017b). This is reflected in the Sustainable Development Scenario, where a doubling of recycling collection rates relative to the New Policies Scenario leads to a reduction in oil demand of 1.5 mb/d by 2040 (IEA, 2018g).

Can pursuing energy access be beneficial for climate action?

As most new electricity connections to date have been achieved through grid-connected electricity powered by coal, the traditional assumption has been that action on energy access comes at the expense of action on climate change. However, IEA analysis has shown that this is not the case for access to either electricity or clean cooking. The *Energy Access Outlook 2017* (IEA, 2017a) found that pursuing a least-cost strategy for closing the energy access gap has no negative impact on the climate. Indeed, there may actually be a net climate benefit in displacing the traditional use of biomass for cooking. There are a number of factors underlying this finding:

- First, the amount of modern energy needed to satisfy household needs is small, contributing a negligible increase in energy demand. Even assuming that every household's energy consumption reaches the regional average around a dozen years after gaining access, the additional demand only amounts to 338 TWh in 2030 in the Sustainable Development Scenario, or 1.1% of the global total. LPG use for clean cooking access has a similarly small impact, requiring around 1 mb/d, or 0.8% of global oil demand in 2030. Further, people living in sub-Saharan Africa, the region with the highest access deficit, currently emit on average 13-times less energy-related CO_2 emissions per capita compared with advanced economies. In the Sustainable Development Scenario, despite universal energy access being achieved everywhere, the gap only closes to eight-times in 2040 (Figure 2.17).
- Second, recent changes in technology costs and improvements in low-carbon technologies are set to make new access connections less emissions-intensive than previously. Renewables are the most cost-effective route for around three-quarters of those gaining access in the Sustainable Development Scenario. Energy-efficient appliances are helping to bring down the cost and energy intensity of providing access, and helping to make off- and mini-grid uptake more affordable to households. There is evidence that energy efficiency is increasingly considered in the context of new access connections – LED lightbulbs are now regularly packaged with solar home systems, and larger energy-efficient appliances are also beginning to penetrate the market. For example, MKopa, the largest solar home system company in East Africa, is beginning to sell super-efficient televisions with their off-grid bundle.

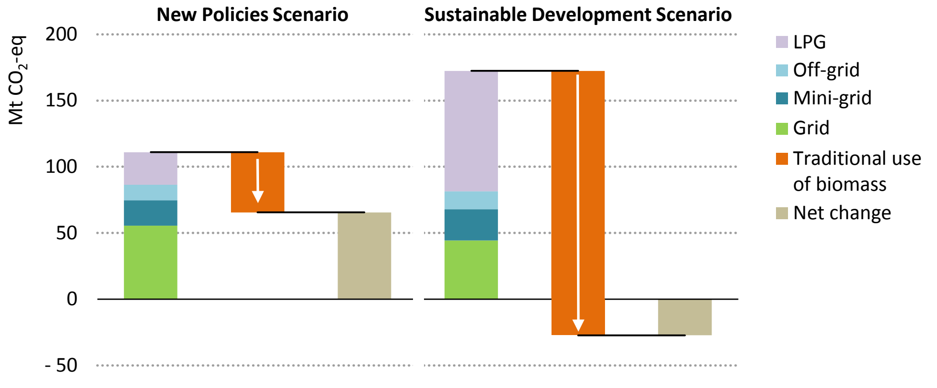
Figure 2.17 ▷ **Total primary energy demand and CO_2 emissions per capita by selected region and scenario**



Achieving universal access to modern energy does not increase the (already very small) CO_2 footprint of the population living in sub-Saharan Africa

Notes: NPS = New Policies Scenario; SDS = Sustainable Development Scenario. Total primary energy demand excludes traditional use of biomass.

Figure 2.18 ▷ **Energy access-related GHG emissions from electricity and clean cooking access by scenario**



Higher CO_2 emissions from increased fossil fuel consumption for access are more than offset by a reduction in other GHGs, notably methane, from traditional use of biomass

Notes: Mt CO_2-eq = million tonnes of CO_2 equivalent. The reduction in emissions from the traditional use of biomass assumes an average emission factor of 11.1 kt CH_4/Mtoe (265 kg CH_4/terajoule [TJ]), which is at the lower end of the default IPCC range (100 to 900 kg/TJ). 100-year global warming potential of methane from biomass = 28, nitrous oxide = 265. Other non-CO_2 forcers such as black carbon may also have an effect, but are not included here.

- Third, the increase in emissions from higher end-use consumption can be more than offset by emissions savings from fuel switching. The traditional use of biomass is associated with high levels of GHG emissions, mainly in the form of methane and to a lesser extent nitrous oxide. While the range of uncertainty is high, even a conservative calculation shows a net climate benefit from switching to LPG and other modern cooking fuels, including electricity and natural gas (Figure 2.18). The real benefit may be greater, as we do not account for the fact that biomass and charcoal for cooking often exacerbate deforestation and associated environmental and water stresses. Similarly, a reliable electricity connection typically displaces kerosene, candles, generators and batteries, all of which are inefficient and polluting as well as relatively expensive. Overall, CO_2 emissions are lower in 2040 in sub-Saharan Africa in the Sustainable Development Scenario than in the New Policies Scenario.

Can efforts to tackle air pollution be beneficial for climate change?

Sources of energy-related air pollution have traditionally been tackled by measures that reduce, control or ban emissions of major pollutants, whether through improved combustion techniques, "end-of-pipe" removal of pollutants through scrubbers and filters or compulsory fuel switching. Such measures can be costly, and can result in an energy efficiency penalty, meaning that slightly more fuel is required to deliver the same energy output once the end-of-pipe measure is in place. This means that reducing air pollution could lead to an increase in energy use and in CO_2 emissions, all else being equal. In addition, some local pollutants such as SO_2 actually have a cooling effect on the climate, so reducing their concentration can run counter to reductions of CO_2 and other GHGs. At the same time, there are potential synergies at the energy systems level between action to reduce air pollution and action to reduce CO_2 emissions.

In the Sustainable Development Scenario, CO_2 emissions are reduced concurrently with emissions of air pollutants, while also achieving universal energy access. The scenario therefore incorporates both strong climate ambition and strict regulation of pollution. To what extent do the air pollution gains come from end-of-pipe measures, and to what extent from measures that avoid air pollution while also contributing to climate ambition?

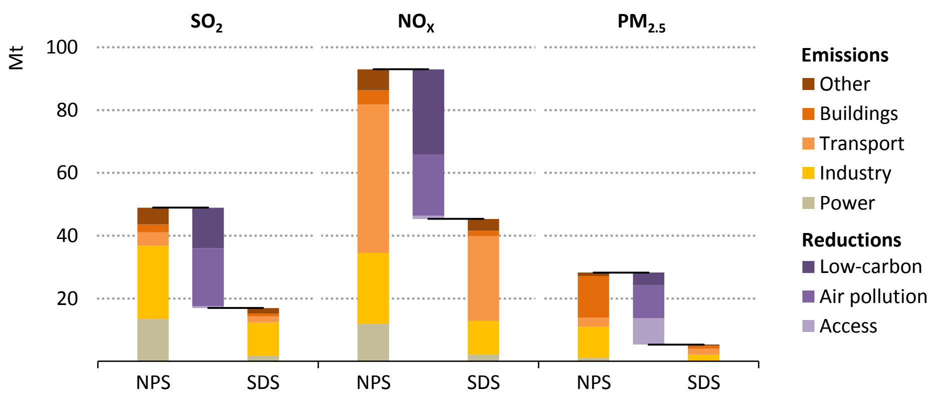
The answers vary by pollutant and by sector (Figure 2.19):

- For NO_X, low-carbon measures, including renewables and efficiency, account for more than half of all reductions in the Sustainable Development Scenario relative to the New Policies Scenario. The transport sector is currently the biggest contributor to NO_X emissions, and this is set to remain the case despite ambitious plans to reduce emissions in the New Policies Scenario. The additional NO_X reductions from the transport sector in the Sustainable Development Scenario are largely driven by energy efficiency and switching to electric vehicles – considered a low-carbon measure – rather than by additional end-of-pipe regulation.
- For SO_2, around 40% of the reductions in the Sustainable Development Scenario over and above those in the New Policies Scenario are attributable to low-carbon measures. By 2040, the majority of additional reductions in SO_2 emissions occur in the power

and industry sectors. In the power sector, significant policies for end-of-pipe pollution control are already included in the New Policies Scenario, and remaining savings are largely due to expanded use of renewables. Industry, however, is more reliant on pollution control measures.

- For $PM_{2.5}$ emissions, more than half of current emissions are in the buildings sector, almost entirely due to smoky indoor environments in countries where many people still cook with solid fuels. The proportion is set to remain almost unchanged in the New Policies Scenario. In the Sustainable Development Scenario, universal energy access leads to an almost total elimination of $PM_{2.5}$ emissions in buildings and to a slight reduction in CO_2 emissions. Efforts to increase energy access are well aligned with this particular pollution goal.

Figure 2.19 ▷ Drivers of pollutant emissions reductions in the Sustainable Development Scenario relative to the New Policies Scenario



Low-carbon measures, rather than measures specific to air pollution, account for 57% of NO_X and 40% of SO_2 emissions reductions

Note: Industry includes fuel combustion and process emissions.

Source: IEA analysis; International Institute for Applied Systems Analysis.

This analysis shows that, in countries where reducing health impacts of air pollution is an urgent issue, low-carbon measures that reduce the overall quantity of fossil fuels being used – including energy efficiency measures on the demand side, and a shift to renewables on the supply side – are likely to be an important part of an action plan to tackle those health-related impacts.

2.8.3 Aligning energy policies to unlock faster CO_2 reductions

Energy technology is changing fast, opening new opportunities to make rapid progress on reducing CO_2 emissions in parallel with other development objectives. These opportunities will not be realised without the alignment of policy making across the energy system (IEA, 2017c). This section highlights the importance of some of these policy areas, and makes links with other parts of this *Outlook* where they are covered in more detail (including the focus on electricity in Part B).

Key energy policy areas in terms of alignment include:

- **Electricity demand and supply policies**: In the Sustainable Development Scenario, a combination of energy efficiency and increased use of electricity, in particular for transport, leads to a higher percentage of electricity in the energy mix than in the New Policies Scenario. The share of electricity increases substantially across all end-use sectors, and the increasing role of electricity has clear potential benefits for end-users. However, the potential for electrification to contribute to radically reducing CO_2 emissions – and to some extent air pollutants – can only be realised in parallel with concerted action in the power sector. Chapter 9 explores the importance of this alignment in more detail.
- **Optimisation and flexibility in the power system:** Policies supporting investment in renewable electricity capacity additions are not in themselves sufficient to drive emissions reductions. Support for renewable electricity has led to rapidly rising installed capacity of variable renewables in many countries, but the impact on CO_2 emissions has been much more modest. What counts is not theoretical capacity but actual electricity generation from renewables. Improving the capacity factors of renewables, for example through lower curtailment of renewable electricity generation, relies on action to improve the flexibility of the power system, through some combination of electricity storage, demand-side response, improved grid infrastructure and use of dispatchable power generation technologies. Chapters 8 and 9 discuss strategies for increased power system flexibility.
- Lifecycle emissions in the **transport sector**: Policy discussions tend to focus on technology-based measures such as encouraging fuel switching and improving fuel efficiency. The CO_2 impact of fuel switching depends very much on the lifecycle emissions of the alternative fuel, e.g. the carbon intensity of electricity generation or of biofuel production. Chapter 6 discusses this in more detail.
- **Changes in mobility patterns:** A shift to a less carbon-intensive transport sector depends on understanding behavioural choices, which in turn depends partly on the quality of transport options available in different countries. This goes far beyond energy modelling. Nevertheless, for the first time this *World Energy Outlook* explores the implications of "avoid" and "shift" policies on the composition of transport demand. "Avoid" policies are those that either reduce the need for mobility altogether, for example through more compact urban design, or by providing incentives to eliminate unnecessary journeys. "Shift" policies are those that encourage different forms of transport. In the Sustainable Development Scenario, avoid and shift policies lead to a decrease in global CO_2 emissions of 3% of total transport emissions by 2040. This is due to a reduction in passenger car stock of 200 million cars in favour of light two/three wheel vehicles and public transport. The effect is partly offset by an increase in public transport use, including rail, but the overall CO_2 benefit is still notable.

- **International transport:** The international nature of both aviation and shipping has traditionally made it difficult to reach alignment on regulatory measures, especially since their long-distance nature reduces the low-carbon options. IMO member countries have now agreed on a reduction of at least 50% in total GHG emissions from international shipping by 2050. The International Civil Aviation Organisation has agreed to aim for carbon-neutral growth from 2020, and has initiated the Carbon Offsetting and Reduction Scheme for International Aviation in support of this target. The International Air Transport Association has also proposed a roadmap for carbon-neutral growth from 2020, and a reduction in net aviation CO_2 emissions of 50% by 2050 from 2005 levels.

2.9 Water-energy nexus and SDG 6

Today, more than 2.1 billion people lack access to safe drinking water. More than half the global population – about 4.5 billion people – lacks access to proper sanitation services (UN Water). More than a third of the global population is affected by water scarcity. Roughly 80% of wastewater is discharged untreated, adding to already problematic levels of water pollution. Around 200 million hours are spent every day collecting water, overwhelmingly by women and children, and almost 850 000 people die each year from diarrhoea related to unsafe drinking water and poor sanitation (UNICEF, 2016a).

Box 2.5 ▹ Targets in SDG 6, clean water and sanitation for all

6.1: Universal and equitable access to safe and affordable drinking water for all.

6.2: Universal access to adequate and equitable sanitation and hygiene for all, and end open defecation, paying special attention to the needs of women and girls.

6.3: Improve water quality by reducing pollution, halve the proportion of untreated wastewater and substantially increase recycling and safe reuse globally.

6.4: Increase water use efficiency across all sectors, ensure sustainable withdrawals and supply for freshwater to address water scarcity and lower number of people suffering from water scarcity.

6.5: Implement Integrated Water Resource Management at all levels.

6.6: Protect and restore water-related ecosystems.

6 A/B: Expand international co-operation and capacity building support to developing countries and strengthen participation by local communities.

Note: This analysis focuses on the first four targets, outlined in green.

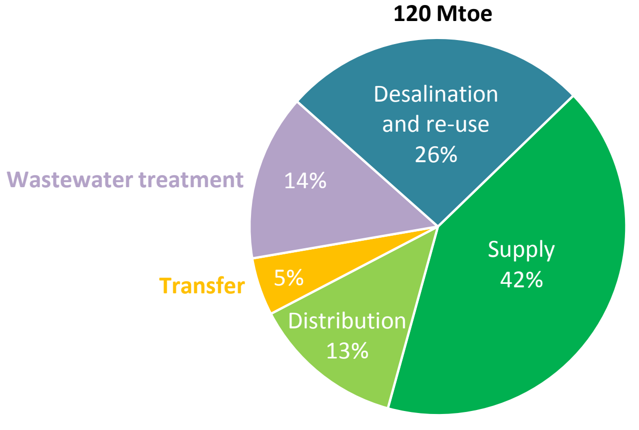
Source: UNDESA (n.d).

One of the 17 UN SDGs – SDG 6 – seeks to address these challenges and provide clean water and sanitation for all by 2030 (Box 2.5). As past *World Energy Outlooks* have shown, water and energy questions are fundamentally intertwined. With both water and energy needs set to increase, the interdependencies between energy and water are likely to intensify. How this nexus is managed will have significant implications for economic and social development, and the achievement of the UN SDGs.

2.9.1 Energy for water to achieve SDG 6

The provision of freshwater from surface water, groundwater or desalination, its transport and distribution, and the collection and treatment of water and wastewater all depend on energy.[9] The water sector globally uses roughly 120 Mtoe per year, almost as much energy as Australia (Figure 2.20). More than half of this is in the form of electricity (850 TWh), representing around 4% of global electricity consumption. Water supply and wastewater treatment are the two largest consumers of electricity in the water sector today. The remaining 50 Mtoe is used for desalination and diesel pumps.

Figure 2.20 ▷ Global energy use in the water sector, 2016



The amount of energy consumed in the water sector is almost equivalent to the entire energy demand of Australia

Notes: Supply includes water extraction from groundwater and surface water as well as water treatment. Transfer refers to large-scale inter-basin transfer projects.

Sources: IEA analysis; IEA (2016c); Luck, et al. (2015); Bijl, et al. (2016); Wada, et al. (2016).

9. For an in-depth look at the water-energy nexus, including the energy requirements for the water sector, see *WEO-2016 Special Report: Water-Energy Nexus* (IEA, 2016c) available free at: www.iea.org/water.

By 2030, the amount of energy consumed by the water sector in the Sustainable Development Scenario – without additional effort to achieve SDG 6 – would increase by around 50%, with upward pressure coming from several sources:

- Desalination: An increased reliance on desalination to bridge the water supply gap in water-scarce regions, such as the Middle East and North Africa, is the single largest element that propels energy consumption higher. Desalination is an energy-intensive process, though the amount of energy required depends on the technology used (see Chapter 2 in *Outlook for Producer Economies* [IEA, 2018h]).
- Large-scale water transfer projects: Pumping water from areas of abundance to areas of scarcity, such as the South-North Water Transfer Project in China, is another significant source of energy demand growth in the water sector.
- Wastewater treatment: The increased collection of wastewater and rising water quality standards pushes up energy demand, but efficiency improvements temper overall growth.
- Water supply and distribution: Energy use declines in these sectors as they become more efficient, as diesel pumps are slowly replaced by more efficient electric ones, and as the water supplies start to include more water from desalination and more re-used water.

The 2018 UN High-Level Political Forum concluded that, despite progress, the world is far from on track to achieving SDG 6. This analysis shows that providing access for all can be achieved without a dramatic increase in global energy consumption.[10] This is because the additional water demand from meeting target 6.1 is only a fraction of global water demand today, and because the energy intensity of many of the technologies and solutions available for meeting targets 6.1-6.3 is low, especially in rural areas.

Target 6.1: Universal access to clean drinking water

Of the 2.1 billion who do not have access to safely managed drinking water today[11], around 1.6 billion must walk to get their water[12] while almost 600 million drink directly from an unprotected well, spring or surface water, risking illness from contaminated water (WHO/UNICEF JMP). India has the largest total number of people without access, followed by Ethiopia, Nigeria and China. Sub-Saharan Africa is home to nine of the ten countries with

10. While the SDG targets 6.1-6.3 are not embedded in the Sustainable Development Scenario, the remaining analysis in this section provides a what if case to assess what the additional energy needs of achieving these targets might be under the framework of the Sustainable Development Scenario.

11. Safely managed drinking water is defined as use of an improved drinking water source that is located on premises, available when needed and free from contamination. According to the World Health Organization (WHO) and United Nations Children's Fund (UNICEF), improved water solutions include piped water, boreholes or tubewells, protected dug wells and springs, rainwater and packaged or delivered water.

12. Around 1.3 billion people without access have a basic water service that is an improved drinking water source that can be collected in 30 minutes or less round trip. About 300 million people must travel more than 30 minutes to get their water, classified as a limited service.

the lowest rates of access to clean water—just a quarter of its population has access to safely managed drinking water. Elsewhere, almost two-thirds have access in Central and South America and almost 60% have access in Eastern and South-eastern Asia.

A majority of those who achieve access to safely managed drinking water in the Sustainable Development Scenario gain it with solutions that require energy. Despite this, providing clean drinking water for all by 2030 in the Sustainable Development Scenario would add less than 2 Mtoe to global energy demand, amounting to less than 1% of total energy demand for the water sector in 2030. [13]

In urban areas, most of the remaining 600 million who lack access are likely to rely on piped water supplies and connect to an existing water utility. Improvements to the quality and reliability of services are also required: in South Africa for example, a fifth of households already with municipal piped water regularly had interruptions lasting more than two days (Slaymaker and Bain, 2017). The suite of technologies used in rural areas to provide access to the 1.5 billion currently without access to safe drinking water is unlikely to resemble that used in urban areas, as the lower population density is likely to make the cost of constructing similar water systems uneconomic. Currently, a majority of those in rural areas use either a rope and bucket, often collecting water from a contaminated unsealed well, or a hand pump. However, the average lifespan of these hand pumps are only one-to-five years and they often break—it is estimated that 40% of all hand pumps in sub-Saharan Africa are out of action at any one time (Rural Water Supply Network, 2009; UNICEF, 2016b).

In the Sustainable Development Scenario, solutions that do not require energy, such as protected wells and hand pumps, are part of the answer, together with water purification methods such as gravity-driven water filtration systems and solar disinfection. However, as many of those without access to drinking water in rural areas also lack electricity, there is an opportunity to use plans for the provision of electricity in pursuit of SDG 7 (energy for all) to provide access to safely managed drinking water (Figure 2.21).[14] As a result, in the Sustainable Development Scenario, almost two-thirds of those who gain access in rural areas to safely managed drinking water do so through electrified solutions.

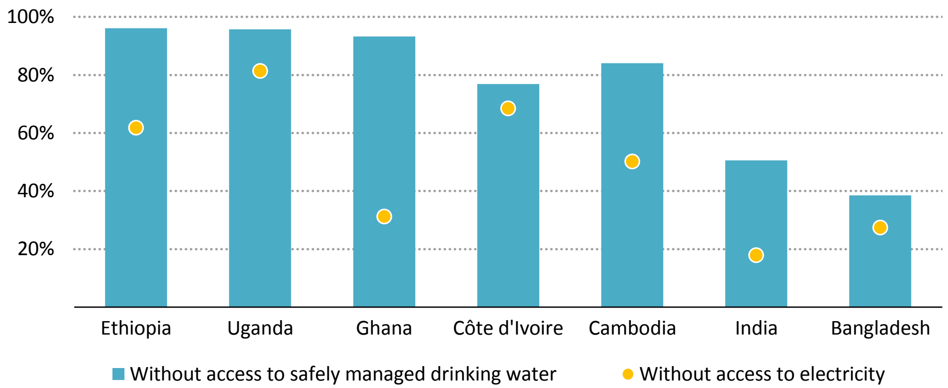
For areas where it is too expensive for the main grid to reach, community solar-powered water pumps are one option to replace labour-intensive hand pumps or more expensive diesel pumps. While the initial investment for solar pumps is higher, they are more durable and have lower operating costs than diesel pumps. Solar pumps range in size—a typical mid-size system is about 1-3 kilowatt peak (kWp)—and can provide up to 250 000 litres of water per day—enough to provide water to 5 000 people per day (Noble, 2012). However, their deployment will depend on a range of local factors such as solar irradiation, depth of pumping, water demand, financing and local capacity for maintenance. There is also a

13. Assuming the minimum baseline water consumption of 50 litres/day per person as recommended by the United Nations and the WHO.

14. See section 2.2 for more on energy access and SDG 7.

risk that, unless proper pricing signals and policy instruments are in place, the use of these pumps could spur unsustainable levels of water withdrawals.

Figure 2.21 ▹ Share of population without access to electricity or water in rural areas today



Almost two-thirds of those without access to clean drinking water in rural areas also lack access to electricity, opening opportunities to co-ordinate solutions

Sources: IEA analysis; WHO/UNICEF JMP.

While there are many water filtration solutions available that require no or minimal energy, the use of energy can help increase their reliability and the amount of clean water available at a given point in time. For example, mini-grids – which provide electricity to almost 45% of those who gain access in rural areas in the Sustainable Development Scenario – can be used to power filtration technologies to produce clean drinking water. Reverse osmosis (RO) systems are another promising solution: they are efficient even at a small scale and are increasingly economic when paired with mini-grids. In India, some private companies are integrating RO filtration systems with solar mini-grids. Under one business model, consumers pay $3 per month for 20 litres of clean water per day. A 10 kilowatt (kW) solar RO system runs 10-15 hours a day and provides 2 000 litres of clean water each hour, serving 1 000 homes daily (Power for All, 2017).

As with energy access, providing access to clean water is just a start. Ensuring it is reliable, affordable and able to scale up to meet continued demand from rising standards of living and population growth is another challenge. Off-grid solutions tend to be more cost effective for areas of low population density, and they provide almost a third of all new electricity access in rural areas. However, growing household water demand is likely in time to require a higher energy load than can be met by many of today's off-grid systems.[15]

15. Such as the off-grid systems that provide a basic bundle of energy services, including several lightbulbs, task lighting, phone charging and a radio.

Approaching water and electricity access in an integrated way may shift the emphasis away from off-grid solutions towards mini-grid or grid-connected solutions, especially where water services can provide an "anchor load" for power generation and assist with balancing and storage. This will require a well-designed regulatory framework that allows for the integration of decentralised solutions into the grid should it arrive. Better co-ordination between stakeholders in the water and energy communities on funding, technology deployment, stakeholder engagement and capacity building, will also be important.

Targets 6.2 and 6.3: Sanitation for all and halving the proportion of untreated wastewater

Today, over 60% of the global population lacks access to safely managed sanitation,[16] and just 20% of wastewater is collected and treated. This is damaging to human health, the environment and the provision of clean drinking water and it creates a strong link between the SDG targets on sanitation and wastewater (6.2 and 6.3) and the target on fresh water (6.1).

Roughly half of those without safely managed sanitation (4.5 billion people) lack even basic sanitation. A majority of those without basic sanitation use rudimentary latrines such as a slab or a bucket (890 million) or practice open defecation (890 million people, mostly in rural areas) (WHO/UNICEF JMP). Almost 60% of the latter live in India and 25% in sub-Saharan Africa (UN Water, 2017).

Improper sanitation management is both a rural and an urban challenge. In urban areas, where almost 2.3 billion people still lack access to safely managed sanitation, the provision of sanitation, and the treatment and management of municipal and industrial wastewater is a critical part of broader questions of urban design and management. The energy consumed by water and wastewater utilities can account for 30-50% of municipal energy bills. The increase in wastewater treatment capacity to meet SDG 6 could therefore have a significant impact on a municipality's energy expenditure, and those costs may in some cases be passed on to consumers (depending on how or if water is priced). It could also have an impact on efforts to combat climate change. It is estimated that the wastewater sector accounts for 3% of GHG emissions, while the emissions from untreated wastewater are three-times higher than conventional wastewater treatment plants (US EPA, 2008; International Water Association, 2018).

Focusing on municipal wastewater management provides a useful illustration of how technology choices can influence the additional electricity demand required to meet targets 6.2 and 6.3:

16. Defined as an improved sanitation facility that is not shared with other households and where excreta are disposed of in situ or transported and treated off-site. Improved facilities include flush/pour to piped sewer systems, septic tanks or pit latrines, ventilated improved pit latrines, composting toilets or pit latrines with slabs.

- If cities modelled new centralised wastewater capacity needs on today's blueprint for wastewater management, the amount of electricity consumed for urban municipal wastewater treatment could increase by more than 680 TWh over the period to 2030.[17]
- Instead, if cities deploy economically viable energy efficiency technologies in all new centralised wastewater facilities – the pathway pursued in the Sustainable Development Scenario – the increase in electricity consumption could be reduced by around 10%. This would involve the deployment of variable speed drives, fine bubble aeration and more efficient compressors; better sludge management; and more efficient pipes and pipe maintenance for wastewater pumping. This pathway also sees higher rates of energy recovery; 30% of the electricity needed to meet the targets could be generated from the wastewater itself compared to just 6% if the current blueprint for wastewater management is used.
- A third possibility, at the frontier of today's technology, is for cities to build energy neutral or energy-positive facilities, where the energy needs of a treatment facility are entirely satisfied by own-generation, with the potential to produce more energy than needed through energy recovery. If all the new capacity implemented these additional energy efficiency measures, the amount of electricity consumed for urban municipal wastewater treatment would increase by less than 460 TWh over the period to 2030 – 30% less than projected in the Sustainable Development Scenario (Figure 2.22). Additionally, if new capacity was equipped with energy recovery units for biogas and a high efficiency combined heat and power unit, utilities could generate 50% more electricity than they need and sell the excess. While this represents an upper boundary and would not be a viable option for all utilities, it highlights the potential opportunities that exist for tempering rising energy demand from meeting SDG 6.

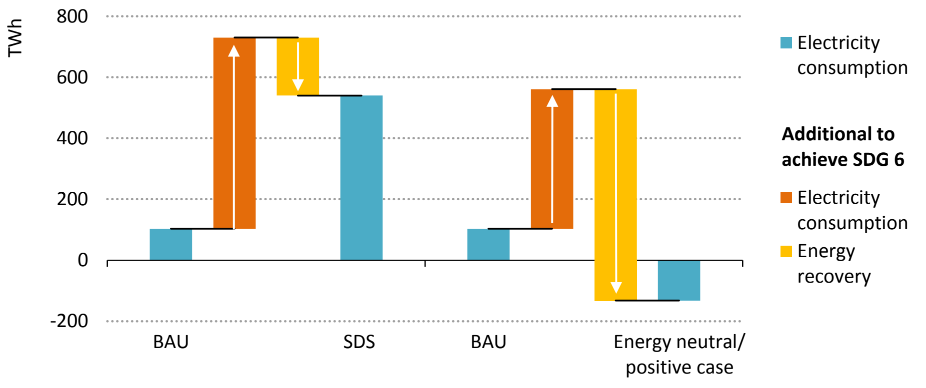
Increasing the collection and treatment of wastewater in more efficient, energy producing wastewater treatment plants would not only lower energy demand but could also lead to lower GHG emissions. However, the implementation of technologies to improve process efficiency and harness the embedded energy in wastewater will not happen on its own. Improved technology options are capital intensive, so questions of affordability and financing need to be addressed to ensure widespread deployment. Regulations on water quality, appropriate pricing mechanisms for water and electricity, land availability and the development of natural gas infrastructure (so that utilities can offload or sell their excess biogas) are also vital parts of the picture.

In rural areas, providing access for the remaining 2.2 billion people without access to safely managed sanitation continues to rely on more decentralised technologies and solutions that require no energy such as bio-latrines, pour-flush toilets and ventilated improved

17. This represents an upper bound for additional electricity demand as it assumes that all of those without access in urban areas will gain it via a centralised wastewater treatment plant.

latrines, but the safe collection, disposal and treatment of waste remains a challenge. Just as in urban areas, biogas presents an opportunity to utilise waste to generate energy that could reduce indoor air pollution, help prevent deforestation, save women time and contribute towards the achievement of SDG 7.1.2 (clean cooking for all). Biogas can be generated at a household or community level from anaerobic digestion and used for a variety of domestic energy needs. Biogas digesters are often too expensive for most households – costing anywhere from $100 to $1 000, depending on their size – plus there are other barriers related to scalability, proper installation and maintenance, and local circumstances. Efforts to scale up the use of anaerobic digesters as a solution to SDG 6.2 (sanitation for all), however, could provide additional impetus for biogas to become a larger part of the solution to SDG 7.1.2 (clean cooking for all) by lowering costs and providing an incentive to address the other barriers. If waste from all those who lack access to safely managed sanitation in rural areas today was captured and digested, the biogas potential could be roughly 20-50 billion cubic metres (bcm). This could be enough to provide a clean cooking fuel to around 60-180 million households.[18]

Figure 2.22 ▷ Electricity consumption in urban municipal wastewater treatment facilities from achieving SDG targets 6.2 and 6.3 in 2030



SDG 6 could dramatically increase electricity consumption in municipal wastewater utilities, but energy efficiency and recovery measures could offset additional demand

Notes: BAU = the amount of electricity consumed (less 60 TWh from energy recovery) from municipal wastewater treatment excluding SDG 6 in 2030 in the Sustainable Development Scenario. SDS = total electricity consumption from urban municipal wastewater treatment plants in the Sustainable Development Scenario if SDG 6 were achieved. Energy neutral/positive case = total electricity consumption from urban municipal wastewater treatment plants in the Sustainable Development Scenario if all new capacity built to achieve SDG 6 was energy neutral or energy-positive. The negative values indicate that more energy is generated than needed and can be sold.

18. This is based on an assumed consumption of roughly 3.64 megajoules per meal per household from Fuso Nerini et al., (2017).

2.9.2 Water for energy to achieve SDG 6[19]

Target 6.4: Reduce water scarcity, improve water use efficiency

SDG 6 is not just about supplying water and sanitation: it is also about ensuring that water is used more efficiently. If current consumption patterns persist, global water demand could exceed total supply by 40% in 2030 (International Resource Panel, 2016). The energy sector's share of total global water use today is relatively low – accounting for roughly 10% of total global withdrawals and 3% of consumption[20] – but demand from the energy sector could be reduced further. Changes in the fuel and technology mix, improving power plant efficiency, deploying advanced cooling systems, and making better use of non-freshwater and water recycling can all help the energy sector improve its water use efficiency and contribute to target 6.4.

Efforts to take urgent action on climate change (SDG 13), if not properly managed, could limit efforts on target 6.4. In a scenario aimed at reaching climate goals (but not factoring in linkages to other SDGs)[21], water withdrawals by the energy sector in 2030 rise slightly relative to the New Policies Scenario, and consumption increases by around 10 bcm (Figure 2.23). This is because some low-carbon fuels and technologies such as nuclear, concentrating solar power (CSP), biofuels and carbon capture are relatively water-intensive. This means that, in areas where water resources are scarce, decarbonisation efforts could exacerbate water stress or be limited by it.

Shifting the emphasis away from an approach focused only on decarbonisation towards an integrated approach to the SDGs, as in the Sustainable Development Scenario, results in significantly lower water withdrawals in 2030 compared with the New Policies Scenario (-20%). This makes the Sustainable Development Scenario the best option of those assessed here for achieving target 6.4 and for reducing the energy sector's vulnerability to potential water disruptions (such as drought) and to the effects of climate change on water availability.[22] If not properly managed, however, the higher level of consumption (+10% relative to the New Policies Scenario) could constrain technology or fuel choices or increase the potential for competition over water resources in some regions. This underlines the importance of factoring water use into energy policy decisions (Spotlight).

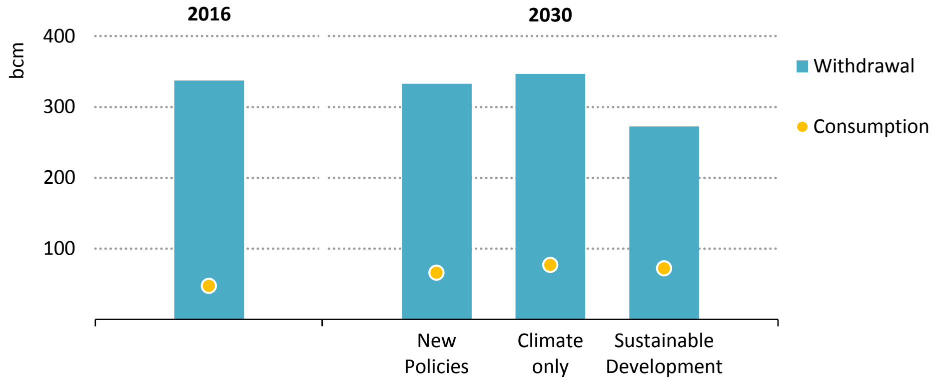
19. Analysis in this section focuses on freshwater use.

20. Water withdrawals are defined as the volume of water removed from a source and are always greater than or equal to water consumption. Water consumption is defined as the volume withdrawn that is not returned to the source (i.e. is evaporated or transported to another location) and is by definition no longer available for other users.

21. From 2008 to 2016, the *WEO* presented the 450 Scenario to highlight the policy, technology development and investment required to meet global climate change goals.

22. It is expected that climate change will alter the intensity, frequency, seasonality and amount of rainfall as well as the temperature of the resource, which may reduce the ability of power plants to discharge cooling water into these water bodies.

Figure 2.23 ▷ Global water use by the energy sector by scenario



A focus on an integrated approach rather than just a decarbonisation approach results in the lowest level of water withdrawals in 2030

Notes: New Policies = New Policies Scenario; Sustainable Development = Sustainable Development Scenario. Results for 2030 for the climate only scenario are from the *WEO* water-energy work in 2016, which was the last year that the *WEO* produced the 450 Scenario, a scenario meeting global climate goals.

S P O T L I G H T

A current of change for the energy sector's water use?

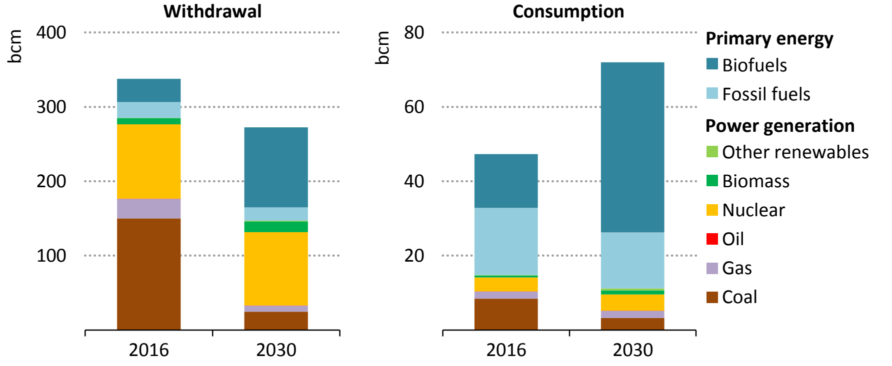
Water is needed for all phases of energy production, and it has become increasingly important to consider water needs when assessing the physical, economic and environmental viability of energy projects. In 2016, the energy sector withdrew around 340 bcm of water and consumed roughly 50 bcm.[23] The power sector is responsible for the majority of water withdrawals, with coal-fired power generation using once-through cooling systems accounting for over one-third of energy-related water withdrawals. Primary energy production is responsible for over two-thirds of water consumption, with the production of fossil fuels and biofuels responsible for roughly 40% and 30% of energy sector water consumption respectively.

In the Sustainable Development Scenario, global freshwater withdrawals in the energy sector decline to reach roughly 275 bcm in 2030, while consumption rises 50% to reach almost 75 bcm in 2030 (Figure 2.24). Increased energy efficiency, the move away from coal-fired power generation, and the increased deployment of solar PV and wind

23. The *WEO* does not present ranges for withdrawals and consumption for hydropower. While a majority of the water withdrawn is returned to the river, hydropower's water consumption varies depending on a range of factors. Thus, the amount consumed is site specific and a standardised measurement methodology is not yet agreed, though academic papers are beginning to develop methodologies.

power all contribute to overall lower water withdrawals in the energy sector. However, a rise in power generation from nuclear, bioenergy and CSP sources, together with increased use of CCUS and expanded biofuels production, contribute to increases in both withdrawal and consumption.

Figure 2.24 ▷ Global water use in the energy sector by fuel and power generation type in the Sustainable Development Scenario



The technology and policy choices in the Sustainable Development Scenario lower the energy sector's water withdrawals by 20%, but increase consumption by 50%

Notes: Other renewables include wind, solar PV, CSP and geothermal. Hydropower is excluded.

While the energy sector has a direct impact on water, the reverse is also true: the availability of water can influence the type of cooling system used. Once-through technologies are the most efficient and have the lowest capital costs, but have the highest water withdrawal rate; wet-tower cooling withdraws less water but consumes more; and dry cooling uses very little water but is the most expensive and the least efficient. Our analysis shows that, in areas where the level of water stress rises by 2030, more new power generation capacity is built with wet-tower cooling or dry cooling systems.[24] This helps with progress towards SDG target 6.4 because it lowers water withdrawals in the power sector by around 50% and water consumption by 25% by 2030.

24. Level of water stress is estimated using the business-as-usual scenario for water stress for today and 2030 from the World Resource Institute's Aqueduct Water Risk Atlas.

2.9.3 Energy, water and an integrated approach to sustainable development

The interactions between energy and water highlight the importance of an integrated approach to sustainable development. Energy is vital to provide water and sanitation, but the Sustainable Development Scenario underscores that achieving SDG 6 does not have a large impact on the global energy balance. Ensuring 2.1 billion people have access to clean drinking water, 4.5 billion have safely managed sanitation, collecting and treating more wastewater and using water more efficiently adds less than 1% to global energy demand in the Sustainable Development Scenario in 2030.

Our analysis highlights a range of potential synergies between SDGs 6 and 7. In rural areas, considering water supply needs when planning electricity provision can open different pathways for both, which can in turn bring down the cost of electricity for households. The production of biogas from waste can facilitate cleaner cooking in households that currently rely on wood and charcoal for cooking. When wastewater management in urban areas requires new infrastructure, integrating energy efficiency from the start can have a significant impact on the energy and GHG emissions footprint of the wastewater sector. As such, integrated thinking is essential to avoid unintended consequences and to mitigate future stresses on both sides of the energy-water nexus.

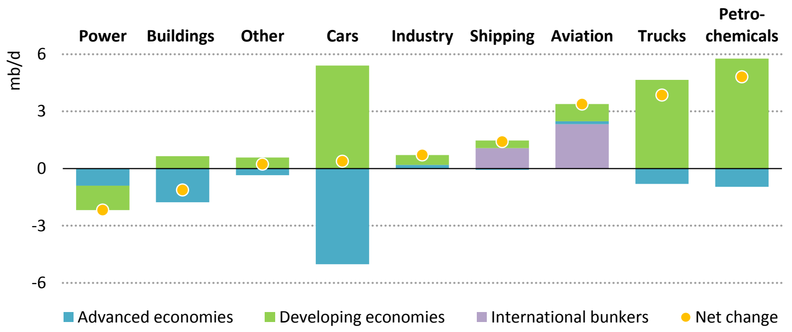
Outlook for oil

Can tight oil avoid a tight oil market?

S U M M A R Y

- Global oil demand grows by around 1 million barrels per day (mb/d) on average each year to 2025 in the New Policies Scenario; thereafter average annual demand growth slows to around 0.25 mb/d, but global demand does not peak before 2040. All of this growth occurs in developing economies; demand in advanced economies drops by over 0.4 mb/d on average each year to 2040 (Figure 3.1).

Figure 3.1 ▷ Change in global oil demand by sector in the New Policies Scenario, 2017-2040



Petrochemicals, trucks and aviation dominate future oil demand growth

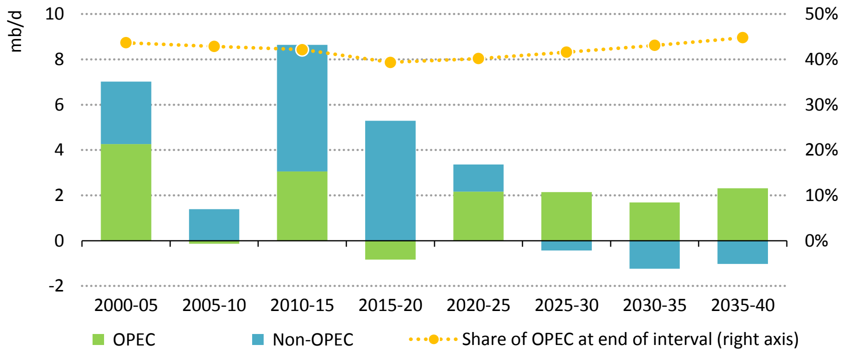
- China overtakes the United States in the New Policies Scenario to become the world's largest oil consumer and by 2040 China is the largest net oil importer in history, importing over 13 mb/d. Demand growth is strong in India and the Middle East: both become larger sources of oil consumption than the European Union around 2030.

- Oil use in cars peaks in the mid-2020s in the New Policies Scenario, even though the global car fleet grows by 80% to over 2 000 million in 2040. Some 300 million electric cars on the road in 2040 avoid 3.3 mb/d of additional demand growth. But efficiency measures are even more important to stem oil demand growth: improvements in the efficiency of the non-electric car fleet avoid over 9 mb/d of oil demand in 2040.

- However, this pace of change is not matched elsewhere. Oil demand for trucks grows by 4 mb/d over the period to 2040, even though vehicle and logistical efficiencies avoid nearly 5.5 mb/d additional demand growth in 2040. Oil use in petrochemicals sees the largest growth (5 mb/d) of any sector. Efforts to increase recycling do not offset the underlying growth in demand for chemical products. If recycling rates were to double, this would cut demand in 2040 by 1.5 mb/d.

- On the supply side, the United States provides nearly 75% of the increase in global oil production to 2025. After 2025, members of OPEC are central to meeting oil demand growth (Figure 3.2). US tight oil reaches 9.2 mb/d in the mid-2020s before declining slowly. But tight oil increases elsewhere, most notably in Argentina.

Figure 3.2 ▷ Change in global oil production in the New Policies Scenario



Non-OPEC countries dominate near-term production increases, but this stalls as US tight oil plateaus and the recent dearth in new approvals hampers growth elsewhere

- The level of conventional crude oil resources approved for development in recent years is in line with the needs of the Sustainable Development Scenario but is far below the level needed to meet demand growth in the New Policies Scenario. If these approvals do not pick up sharply from today's levels, US tight oil production would need to grow to over 15 mb/d by 2025 to satisfy demand. If neither happens, there is a real prospect of damaging price spikes and increased price volatility.

- A wave of 17 mb/d of new refining capacity comes online in the period to 2040, mainly in Asia and the Middle East. This leads to a gradual reshuffling of the competitive landscape for the refining industry. By 2040, China's refinery runs are similar to those in the United States. Near-term pressure on product markets comes from new regulations on the sulfur content of marine fuels which enter into force in 2020. These exert upward price pressure on diesel that only slackens as new fuels are developed and scrubbers are installed across the maritime fleet.

- In the Sustainable Development Scenario, demand not only falls by 25 mb/d between 2017 and 2040, but there is also a major shift in the composition of demand towards lighter products. Adapting to this would represent an unprecedented challenge for refiners, and would bring a risk of mismatches between product demand and refinery configurations that could lead to sharp price movements for individual products.

Introduction

In the wake of the fallout from the 2014 oil price crash, the continued expansion of tight oil production in the United States and the prospect of major structural changes in oil consumption underpinned a view that the oil price was set to stay lower for longer, perhaps for ever. The reality has been different. On the supply side, while tight oil has proved remarkably resilient, the pace of growth has been held back by infrastructure constraints. Geopolitical events, the slump in Venezuelan output, and decisions by major exporters have also weighed on production prospects. Meanwhile, on the demand side, oil consumers responded to lower prices to the extent that the share of oil in the global energy mix has increased in recent years. In September 2018, the oil price surpassed $80/barrel for the first time since 2014.

Where do we go from here? The forces of change in oil markets remain strong. A maturing shale sector is now poised to make money; the cost of new upstream projects has come down; and sales of electric cars continue to break records. But elements of continuity are likewise formidable, and another boom and bust commodity price cycle cannot be ruled out. Against this background, our three main scenarios consider a range of possible future developments. The New Policies Scenario shows a world where oil demand continues to rise, but where its growth is moderated by a variety of new policies. The Current Policies Scenario shows how a failure to implement planned policies could lead to persistent oil demand growth of over 1 mb/d every year to 2040. In contrast, the Sustainable Development Scenario highlights the implications of a near-term peak in oil demand and a long-lasting lower oil price.

The second section of this chapter discusses some key topics in detail:

- What are the drivers of oil demand in road transport, and what is the outlook for cars and trucks in particular? Road transport was the largest source of oil demand growth over the past 15 years and will be central to efforts to stem rises in the future. We set out some of the key uncertainties in projecting transport demand and examine the role of efficiency and alternative fuels in slowing the growth in oil use.
- Are we heading for a possible supply shock? New sources of supply will be needed whether or not demand peaks. As the oil price plummeted in 2014, so did the level of new conventional crude oil projects approved for development. In the *World Energy Outlook-2016 (WEO-2016)* we highlighted the risk that this posed for the long-term equilibrium of oil markets. We revisit this discussion and look at what could fill the gap if approvals do not pick up in the future.
- What are the prospects for the various oil products? The prospects for oil consumption are usually discussed in aggregate terms, but structural changes in demand could mean very different things for individual oil products. Starting from an assessment of the International Maritime Organization (IMO) regulation on marine fuels, which takes effect in 2020, we explore potential shifts in oil product demand and their implications for the refining industry.

Figures and tables from this chapter may be downloaded from www.iea.org/weo2018/secure/.

Scenarios

3.1 Overview

Table 3.1 ▷ Global oil demand and production by scenario (mb/d)

			New Policies		Current Policies		Sustainable Development	
	2000	2017	2025	2040	2025	2040	2025	2040
Road transport	30.1	41.2	44.7	44.9	46.2	53.6	40.5	23.0
Aviation and shipping	8.3	11.5	13.2	16.3	13.8	18.5	11.2	9.3
Industry and petrochemicals	14.5	17.8	20.7	23.3	20.9	23.8	20.0	20.7
Buildings and power	14.3	12.5	11.2	9.2	11.8	10.9	10.2	6.5
Other sectors	10.1	11.8	12.6	12.6	12.9	13.6	12.0	10.4
World oil demand	**77.3**	**94.8**	**102.4**	**106.3**	**105.5**	**120.5**	**93.9**	**69.9**
Share of Asia Pacific	*25%*	*32%*	*35%*	*37%*	*35%*	*37%*	*36%*	*38%*
Biofuels	0.2	1.8	2.8	4.7	2.5	3.5	4.4	7.3
World liquids demand	**77.5**	**96.6**	**105.2**	**110.9**	**108.0**	**124.1**	**98.3**	**77.2**
Conventional crude oil	64.8	66.9	65.6	63.8	67.2	72.6	59.8	40.2
Tight oil	-	4.8	9.8	11.0	10.3	12.1	9.1	7.3
Natural gas liquids	8.9	16.7	19.0	21.1	19.8	22.9	17.5	15.6
Extra-heavy oil and bitumen	1.0	3.7	4.2	5.5	4.3	7.0	3.9	3.5
Other production	0.5	0.7	1.3	2.1	1.4	2.7	1.2	1.3
World oil production	**75.2**	**92.8**	**99.9**	**103.4**	**102.9**	**117.2**	**91.6**	**68.0**
Share of OPEC	*42%*	*43%*	*40%*	*45%*	*40%*	*45%*	*40%*	*44%*
Processing gains	1.8	2.3	2.5	2.9	2.6	3.3	2.3	1.9
World oil supply	**77.0**	**95.1**	**102.4**	**106.3**	**105.5**	**120.5**	**93.9**	**69.9**
IEA crude oil price (2017$/barrel)	**39**	**52**	**88**	**112**	**101**	**137**	**74**	**64**

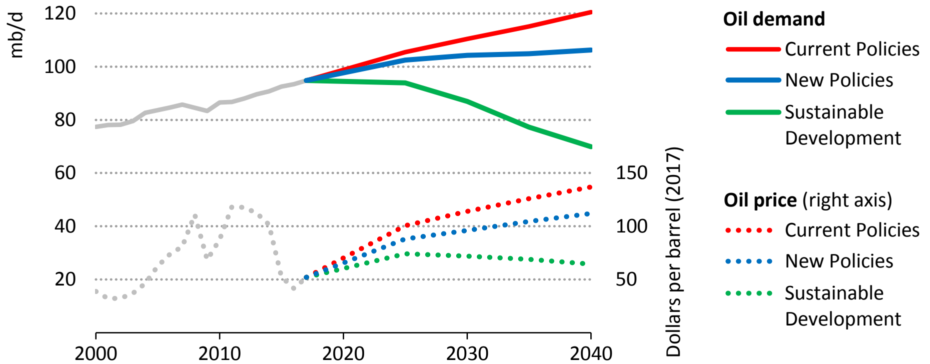
Notes: Other production includes coal-to-liquids, gas-to-liquids, additives and kerogen oil. See Annex C for other definitions. Differences between historical supply and demand volumes are due to changes in stocks.

In the **Current Policies Scenario**, global oil demand rises by around 1.1 million barrels per day (mb/d) on average every year and shows no discernible slowdown to 2040 (Table 3.1). Without strengthened policies on fuel efficiency or the use of alternative fuels, there is little restraint – except steadily higher prices – on the dominant position of gasoline and diesel in the road transport sector, where demand grows by over 7 mb/d by 2025.

China and India are responsible for nearly half of the total increase in demand to 2040. The heavy lifting on supply is led initially by the United States, but later on the Organization of the Petroleum Exporting Countries (OPEC) steadily increases its share of total oil supply.

In the **New Policies Scenario**, demand in 2040 has been revised up by more than 1 mb/d compared with last year's outlook largely because of faster near-term growth and changes to fuel efficiency policies in the United States (Figure 3.3). China leads oil demand growth to 2025, then India and the Middle East take over between the late 2020s and 2040. The United States dominates production growth to 2025, with production increasing by 5.2 mb/d. As in the Current Policies Scenario, US production then starts to fall and OPEC's share of the market starts to climb, reaching 45% in 2040.

Figure 3.3 ▷ Global oil demand and prices by scenario



In 2040, oil demand in the Current Policies Scenario is 51 mb/d higher than in the Sustainable Development Scenario

In the **Sustainable Development Scenario**, determined policy interventions to address climate change lead to a peak in global oil demand around 2020 at 97 mb/d. Demand peaks in nearly all countries before 2030. The main exceptions are India and countries in sub-Saharan Africa where demand grows to at least 2035 (albeit at a subdued pace).

By 2040, cars that rely solely on gasoline and diesel are 40% more efficient than today; there are 930 million electric cars on the road (50% of the global car fleet); a quarter of buses are electric; and nearly 20% of fuels used by trucks are low or zero carbon. As a result, demand in road transport in 2040 in this scenario is more than 18 mb/d lower than today. Demand in aviation falls by 0.8 mb/d by 2040 as a result of enhanced efficiency measures and 1.3 mboe/d growth in biofuels.

The only sector to register any growth is petrochemicals. Plastics recycling increases significantly from today's levels which offsets the need for around 1.5 mb/d of oil demand in 2040. However, with few alternatives available, oil use as a petrochemical feedstock grows by 3.3 mb/d in the period to 2040.

On the supply side, lower demand and prices mean that production levels are down across the board. Although containing many of the least-cost suppliers, members of OPEC are assumed to maintain a policy of market management in this scenario (as in the other scenarios) and so their share of the market remains below 45% to 2040.

3.2 Oil demand by region

Table 3.2 ▷ Oil demand by region in the New Policies Scenario (mb/d)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
North America	23.5	22.3	22.0	21.0	19.9	19.3	-3.0	-0.6%
United States	19.6	17.9	17.8	16.8	15.6	15.1	-2.9	-0.8%
Central and South America	4.5	5.8	5.9	6.0	6.2	6.3	0.5	0.4%
Brazil	1.9	2.4	2.5	2.6	2.7	2.8	0.4	0.7%
Europe	14.9	13.2	12.1	10.9	9.6	8.7	-4.5	-1.8%
European Union	13.1	11.1	9.9	8.6	7.3	6.4	-4.7	-2.4%
Africa	2.2	4.0	4.8	5.3	5.8	6.3	2.3	2.0%
South Africa	0.4	0.5	0.6	0.7	0.7	0.7	0.2	1.3%
Middle East	4.3	7.4	8.4	9.0	9.7	10.6	3.2	1.6%
Eurasia	3.1	3.7	4.1	4.2	4.2	4.2	0.5	0.5%
Russia	2.6	3.0	3.3	3.3	3.2	3.2	0.2	0.3%
Asia Pacific	19.4	30.5	35.8	38.0	39.0	39.5	9.0	1.1%
China	4.7	12.3	14.9	15.7	15.7	15.8	3.5	1.1%
India	2.3	4.4	6.2	7.4	8.4	9.1	4.7	3.2%
Japan	5.1	3.6	3.1	2.7	2.4	2.0	-1.6	-2.5%
Southeast Asia	3.1	4.7	6.0	6.4	6.7	6.8	2.1	1.6%
International bunkers	5.4	8.0	9.2	9.9	10.6	11.4	3.4	1.6%
World oil	**77.3**	**94.8**	**102.4**	**104.3**	**104.9**	**106.3**	**11.5**	**0.5%**
Current Policies			105.5	110.5	115.1	120.5	25.7	1.0%
Sustainable Development			93.9	86.9	77.3	69.9	-24.9	-1.3%
World biofuels	0.2	1.8	2.8	3.4	4.0	4.7	2.8	4.1%
World liquids	**77.5**	**96.6**	**105.2**	**107.7**	**108.9**	**110.9**	**14.3**	**0.6%**

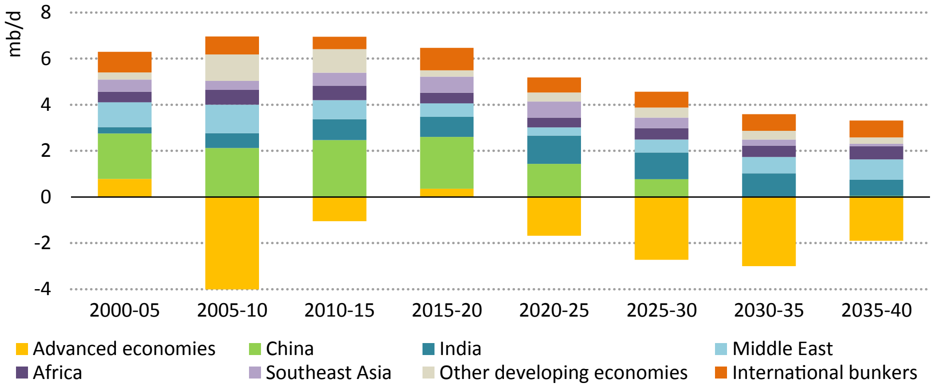
Notes: CAAGR = Compound average annual growth rate. International bunkers include both marine and aviation fuels. See Annex C for definitions.

The 11.5 mb/d global oil demand growth over the outlook period in the New Policies Scenario occurs almost exclusively in **developing economies** (Table 3.2). As demand drops in the United States, China becomes the world's single largest consumer of oil in the 2030s. China's demand growth then grinds to a halt, with the increasing deployment of electric vehicles causing a fall in oil use in road transport.

Oil demand growth is consistently strong in the Middle East and India, and these countries respectively become the world's third- and fourth-largest oil-consuming markets by 2040 (Figure 3.4). India's demand however has been revised down since last year's *Outlook* due to higher projected growth in electric vehicles (see Chapter 8). Nevertheless, increases in these two regions are most pronounced in trucks (oil demand for trucks in India triples to nearly 2.5 mb/d by 2040) and oil use as a petrochemical feedstock (the Middle East becomes the second-largest producer of high-value chemicals soon after 2030).

The pace of oil demand growth in African countries is second only to India's. By 2040, Africa consumes almost as much oil as the European Union, although per capita oil consumption is still 75% lower. Growth in Africa is led by increases in passenger road transport, offset by a 20% improvement in the fuel efficiency of the car fleet: the number of cars on the road in Africa more than doubles between 2017 and 2040.

Figure 3.4 ▷ Change in oil demand in the New Policies Scenario, 2000-2040



Demand in advanced economies falls by 10 mb/d by 2040. Growth in China grinds to a halt after 2030 but increases in India and the Middle East are more consistent.

Note: International bunkers include both marine and aviation fuels.

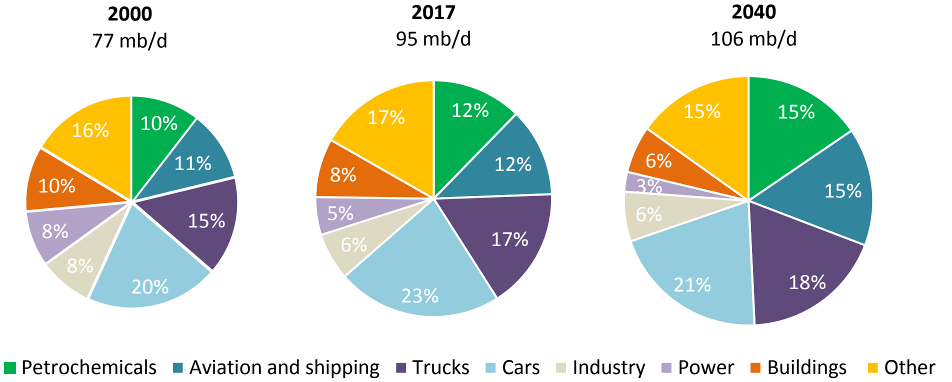
Total oil demand in **advanced economies** falls by over 10 mb/d over the period to 2040. The largest reductions are in road transport, with a 25% drop in North America, a 40% drop in advanced Asian economies and a 45% drop in the European Union. In total, road transport demand in advanced economies falls by over 6 mb/d between 2017 and 2040. In advanced economies, the only sectors to register any significant growth are aviation and shipping, which grow by 0.7 mb/d over the period to 2040.

In the European Union, a new target was set in 2018 to improve energy efficiency by 32.5% by 2030 (compared with a baseline projection of energy demand). New vehicle emissions standards have also been proposed to improve the performance of new cars, vans and heavy-duty vehicles from 2025. As a result, the projected drop in EU oil demand between 2017 and 2040 is 0.3 mb/d steeper than in the *WEO-2017*.

In the United States, improvements in vehicle fuel efficiencies after 2020 have been reviewed to reflect the announced revision to the Corporate Average Fuel Economy (CAFE) standards (see section 3.9). This increases US oil demand in cars in 2040 by 1.2 mb/d compared with the level in the *WEO-2017*.

3.3 Oil demand by sector

Figure 3.5 ▷ Global oil demand by sector in the New Policies Scenario



The share of petrochemicals, trucks, aviation and shipping in total oil demand grows from around one-third in 2000 to one-half by 2040

In the New Policies Scenario, oil use as a petrochemical feedstock grows by nearly 5 mb/d to 2040, the largest increase in any sector (Figure 3.5).[1] While there are increasing efforts to reduce single-use plastics and boost recycling rates, this is more than offset by population and economic growth and by the increasing use of plastics in place of other materials.

The average collection rate for plastic recycling worldwide rises from 15% today to 17% in 2040, mainly as a result of policies to encourage recycling in advanced economies. If average collection rates for recycling were to rise to 34% in 2040 (the level achieved in the Sustainable Development Scenario), this would reduce oil demand by 1.5 mb/d in 2040, but oil demand for petrochemicals would still increase by 3.3 mb/d.

Of the near 4 mb/d increase in oil demand in trucks globally, 40% occurs in India. Goods transport demand in India expands by a factor of four in the period to 2040, but the growth in oil demand is moderated by the new fuel-economy standards that entered into force this year (trucks are discussed in detail in section 3.9).

Oil use in cars in 2040 is only marginally higher than today despite an 80% expansion in the global car fleet to over 2 000 million vehicles. This comes about because of improvements in fuel efficiency, which avoid around 9 mb/d of oil demand in 2040, and because of the rise of alternative fuels (electricity, biofuels and natural gas), which avoid a further 7.5 mb/d in 2040. The number of electric cars on the road exceeds 40 million in 2025 and 300 million in 2040, with broadly equal shares of battery electric and plug-in hybrid vehicles. China leads the way in electric mobility: over 40% of the electric cars in the world are in China in 2040, as well as nearly 60% of the electric buses.

1. For a detailed discussion on petrochemicals, see IEA (2018a).

Oil demand in aviation increases by over 50% over the outlook period and approaches 10 mb/d in 2040. Demand in 2040 is 0.4 mb/d greater than in the *WEO-2017* because of a downward revision to the assumed rate of efficiency improvement of new planes. The energy efficiency of the aviation sector improves by 1.6% each year on average to 2040, slightly below the 2% aspirational goal of the International Civil Aviation Organization. Biofuels account for almost 5% of total fuel use in planes in 2040.

In shipping, the International Maritime Organization (IMO) regulation to limit the sulfur content of marine fuels to no more than 0.5% by 2020 leads to a 2 mb/d drop in high sulfur fuel oil (HSFO) consumption around this time. HSFO is initially replaced by marine gasoil.[2] This exerts upward pressure on diesel prices that slackens only as refiners develop new 0.5% sulfur bunker fuels (such as "very low sulfur fuel oil" made by blending HSFO and gasoil) and as the number of scrubber installations increases (see section 3.11). The share of HSFO in international marine bunker fuels drops from 75% today to less than 25% in 2040, all of which is used in ships equipped with scrubbers. The share of low sulfur fuel oil and marine gasoil grows to 60% in 2040. Use of liquefied natural gas (LNG) as an international bunker fuel also grows in importance, with consumption increasing to nearly 50 billion cubic metres (bcm) in 2040.

The IMO also announced a strategy to reduce greenhouse gas (GHG) emissions from the shipping sector by 50% by 2050 (compared with 2008 levels); this is not achieved in the New Policies Scenario since implementing measures are yet to be defined. This target is achieved in the Sustainable Development Scenario (see Chapter 2).

Oil has lost competitiveness as a fuel source in the industry sector in most regions. Today it provides just over 10% of total energy use in industry. Demand in industry edges up by 0.7 mb/d in the New Policies Scenario, but the share of oil in the sector falls steadily to 2040 in the face of greater growth in all other fuel sources.

Oil consumption in buildings in developing economies grows by 0.6 mb/d to 2040. This takes place mainly in India and sub-Saharan Africa as they switch away from the traditional use of biomass for cooking. However this growth is outweighed by a 1.8 mb/d decline in advanced economies, where oil is displaced by electricity and natural gas.

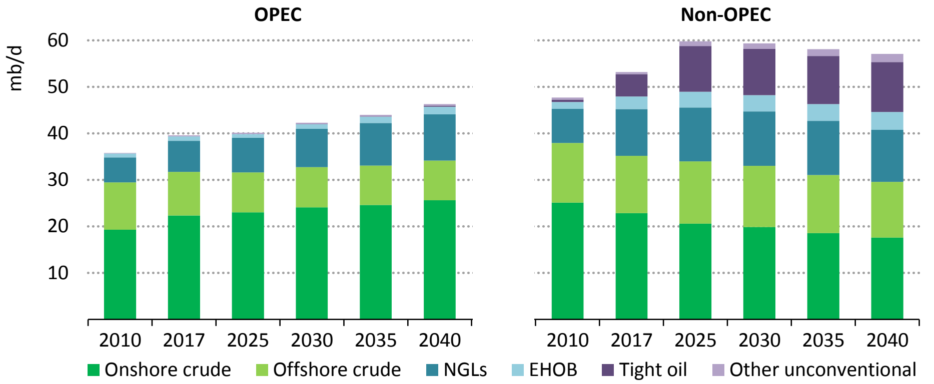
Nearly 5 mb/d of oil is consumed in the world's power sector today, of which almost 40% is in the Middle East. Oil use in the power sector falls across almost all regions and is generally replaced by natural gas and renewables. The decline is slower in the Middle East, where large volumes of low-cost (and often subsidised) oil are available and the region accounts for half of the 2.7 mb/d oil used for power in 2040.

Oil use in other sectors such as agriculture, petroleum refineries, oil extraction, transport modes such as trains, and some non-energy uses (e.g. asphalt, bitumen and lubricants) creeps up by just under 0.2 mb/d over the *outlook* period.

2. Marine gasoil is similar to diesel.

3.4 Oil supply by type

Figure 3.6 ▷ Oil production by type in the New Policies Scenario



NGLs and unconventional oil provide nearly half of non-OPEC oil supply in 2040

Note: NGLs = natural gas liquids; EHOB = extra-heavy oil and bitumen.

Global conventional crude oil production peaked in 2008 at 69 mb/d and has since fallen by just over 2.5 mb/d. In the New Policies Scenario, it drops by a further 3 mb/d by 2040 and its share in the global supply mix falls from 72% today to 62% in 2040 (Figure 3.6).

Onshore conventional crude oil production worldwide grows by less than 0.5 mb/d between 2017 and 2040. OPEC production grows by 5 mb/d but this is largely offset by Non-OPEC declines.

Offshore projects were often delayed or cancelled in the wake of the oil price crash in 2014. Revised designs were proposed that simplified, standardised and often downsized plans, and costs for new projects have fallen substantially. Project approvals are now picking up from a low ebb, but offshore conventional crude oil production remains around today's level of 27 mb/d to the mid-2020s.

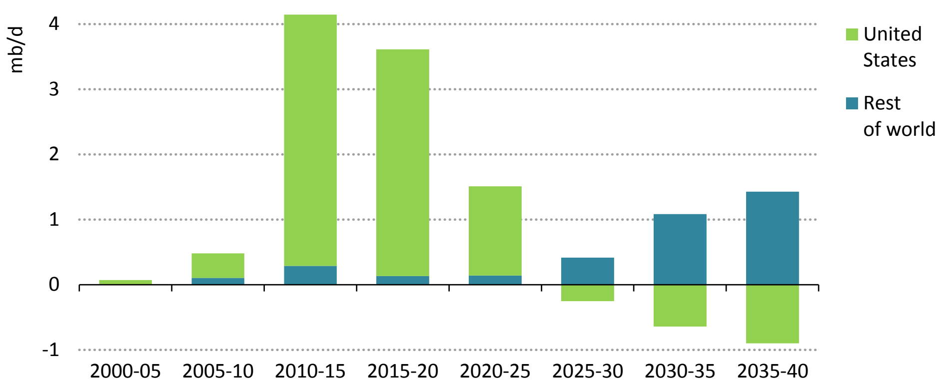
The offshore sector becomes increasingly reliant on production from deepwater fields to stem declines in more mature shallow water areas. Brazil is by far the largest source of future deepwater growth, nearly doubling its current output by 2040. There have also been a number of large deepwater discoveries in Guyana, whose giant Liza field is due to come online around 2020. Mexico successfully tendered a new round of exploration licenses in 2018 and this helps deepwater production growth in the long term. In total, the share of deepwater in total offshore production rises to 30% in 2040 (from 23% today). A number of projects on the Arctic shelf have begun production or been approved; these are relatively high-cost and output from the Arctic offshore reaches 0.4 mb/d in 2040.

Enhanced oil recovery (EOR) is being considered in an increasing number of countries as a means to reinvigorate production in mature basins. EOR production rises slowly to 2025 and then accelerates as investment opportunities dry up elsewhere. Total production more than doubles from today to reach 4.6 mb/d in 2040.

Natural gas liquids (NGLs) grow by nearly 2.5 mb/d to 2025 – a 15% increase in line with the increase in gas production. NGLs production continues to rise after this, but at a slower pace, reflecting a shift towards the development of drier gas resources.

Tight oil production in the United States more than doubles to 9.2 mb/d by 2025 as infrastructure constraints in the Permian Basin are gradually resolved. Thereafter, as the core areas within plays are depleted, production reaches a plateau in the mid-2020s and eventually falls by 1.5 mb/d during the 2030s (Figure 3.7). Tight oil resources have been increased by 10% to 116 billion barrels in this year's *Outlook*, and production in 2025 is around 0.9 mb/d higher than in the *WEO-2017.*

Figure 3.7 ▷ Change in tight oil production in the New Policies Scenario



The United States dominates tight oil production until the mid-2020s, when resource constraints hold back further expansion and output elsewhere starts to ramp up

Tight oil growth outside the United States ramps up after 2025. Most of this occurs in Argentina, Russia, Canada and Mexico, but there are also increases in Australia, China and the United Arab Emirates, which all hold good tight oil resource potential. There is more than 3.5 mb/d of tight oil production from areas outside the United States in 2040.

Extra-heavy oil and bitumen (EHOB) production rises by 2 mb/d in the period to 2040. Multiple new projects approved before the drop in oil prices come on stream in Canada, where EHOB production increases around 0.7 mb/d by 2025. Production growth then slows markedly until a new wave of in-situ projects come online in the 2030s. No new greenfield mining projects are commissioned. Extra-heavy oil production in Venezuela has proved more resilient than other sources of production; while it is not immune from the economic and political issues engulfing the country, it can provide the basis for a long-term recovery in output.

3.5 Oil supply by region

Table 3.3 ▷ Non-OPEC oil production in the New Policies Scenario (mb/d)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
North America	14.2	20.3	26.2	26.3	26.1	25.3	5.0	1.0%
Canada	2.7	4.9	5.6	5.7	5.9	6.0	1.1	0.9%
Mexico	3.5	2.2	2.1	2.4	2.7	3.1	0.9	1.5%
United States	8.0	13.2	18.5	18.3	17.5	16.2	3.0	0.9%
Central and South America	3.2	4.6	5.4	5.9	6.5	7.1	2.5	1.9%
Argentina	0.9	0.6	0.6	0.7	0.9	1.2	0.6	3.2%
Brazil	1.3	2.7	3.7	4.3	4.8	5.2	2.4	2.8%
Europe	7.1	3.7	4.0	3.5	3.1	2.8	-0.9	-1.2%
Norway	3.3	2.0	2.5	2.2	1.9	1.8	-0.2	-0.5%
Africa	1.2	1.4	1.4	1.5	1.4	1.3	-0.1	-0.3%
Middle East	2.2	1.2	1.2	1.2	1.2	1.2	-0.1	-0.3%
Eurasia	7.9	14.3	14.6	14.2	13.3	12.6	-1.6	-0.5%
Kazakhstan	0.7	1.8	2.1	2.4	2.5	2.5	0.6	1.3%
Russia	6.5	11.4	11.5	10.9	10.0	9.4	-2.0	-0.8%
Asia Pacific	7.8	7.7	7.0	6.7	6.6	6.8	-0.9	-0.6%
China	3.2	3.9	3.3	3.2	3.1	3.1	-0.7	-0.9%
India	0.8	0.9	0.9	0.9	0.9	0.9	0.0	0.2%
Conventional crude oil	36.4	35.2	34.0	33.0	31.0	29.6	-5.6	-0.7%
Tight oil	-	4.8	9.8	10.0	10.4	10.8	5.9	3.6%
United States	-	4.4	9.2	8.9	8.3	7.4	3.0	2.3%
Natural gas liquids	6.1	10.0	11.6	11.7	11.6	11.2	1.1	0.5%
Canada oil sands	0.6	2.7	3.4	3.5	3.6	3.8	1.1	1.5%
Other production	0.4	0.5	1.0	1.2	1.5	1.7	1.3	5.9%
Total non-OPEC	**43.6**	**53.2**	**59.8**	**59.3**	**58.1**	**57.1**	**3.9**	**0.3%**
Non-OPEC share	*58%*	*57%*	*60%*	*58%*	*57%*	*55%*	*-2%*	*n.a.*
Current Policies			61.3	62.5	63.5	64.2	11.0	0.8%
Sustainable Development			54.7	49.0	42.7	38.1	-15.1	-1.4%

Notes: CAAGR = Compound average annual growth rate. See Annex C for definitions.

The United States provides around 75% of the global increase in production to 2025 in the New Policies Scenario and there is also pronounced growth in Brazil and Canada (Table 3.3). As a result, non-OPEC's share in global oil production rises to 60% by 2025. However, US tight oil plateaus after 2025 and the baton gradually passes to OPEC to meet continued (albeit slowing) growth in global oil demand. A number of OPEC members are currently facing adverse political and security environments that are affecting production and investment levels: our projections assume a gradual improvement in these areas over time.

Table 3.4 ▷ OPEC oil production in the New Policies Scenario (mb/d)

	2000	2017	2025	2030	2035	2040	2017-2040 Change	2017-2040 CAAGR
Middle East	21.3	30.0	31.6	33.6	34.6	36.1	6.0	0.8%
Iran	3.8	4.7	4.8	5.2	5.4	5.5	0.8	0.7%
Iraq	2.6	4.6	5.1	5.6	6.1	6.8	2.3	1.8%
Kuwait	2.2	3.0	3.4	3.5	3.5	3.4	0.4	0.6%
Qatar	0.9	2.0	2.2	2.4	2.5	2.6	0.6	1.1%
Saudi Arabia	9.3	12.0	12.2	12.7	12.9	13.3	1.3	0.4%
United Arab Emirates	2.6	3.8	3.9	4.1	4.2	4.4	0.6	0.7%
Non-Middle East	10.3	9.5	8.5	8.7	9.4	10.2	0.7	0.3%
Algeria	1.4	1.5	1.4	1.4	1.3	1.3	-0.2	-0.6%
Angola	0.7	1.7	1.4	1.4	1.5	1.5	-0.2	-0.6%
Congo	0.3	0.3	0.3	0.2	0.2	0.1	-0.1	-2.8%
Ecuador	0.4	0.5	0.4	0.4	0.4	0.3	-0.2	-2.1%
Equatorial Guinea	0.1	0.2	0.1	0.1	0.1	0.1	-0.1	-4.5%
Gabon	0.3	0.2	0.2	0.1	0.1	0.1	-0.1	-2.7%
Libya	1.5	0.9	1.2	1.2	1.4	1.6	0.8	2.8%
Nigeria	2.2	2.0	2.1	2.2	2.4	2.6	0.7	1.3%
Venezuela	3.4	2.2	1.5	1.7	2.1	2.5	0.3	0.5%
Conventional crude oil	28.4	31.7	31.6	32.7	33.1	34.2	2.4	0.3%
Natural gas liquids	2.8	6.6	7.4	8.2	9.1	9.9	3.2	1.7%
Venezuela extra-heavy oil	0.4	1.0	0.8	1.0	1.3	1.7	0.7	2.4%
Other production	0.1	0.3	0.3	0.3	0.4	0.6	0.3	3.5%
Total OPEC	**31.6**	**39.6**	**40.1**	**42.3**	**44.0**	**46.3**	**6.7**	**0.7%**
OPEC share	*42%*	*43%*	*40%*	*42%*	*43%*	*45%*	*2%*	*n.a.*
Current Policies			41.6	45.2	48.6	53.0	13.4	1.3%
Sustainable Development			36.8	35.8	32.5	29.9	-9.7	-1.2%

Notes: CAAGR = Compound average annual growth rate. See Annex C for definitions.

In the **United States**, tight oil accounts for a third of total US oil production today. This grows to 50% over the next five years. Costs for new deepwater projects have fallen substantially and there has been an uptick in interest in new projects in the Gulf of Mexico. Offshore US production nevertheless falls as new developments are not sufficient to offset declines from existing sources of production.

Mexico has recently seen an acceleration in field declines. It will take time for new projects, launched as a result of recent licensing rounds, to bear fruit. Production falls to a low of just over 2 mb/d in the early 2020s, before increases are led first by shallow offshore fields and then by deepwater projects, EOR and tight oil.

Canada and **Brazil** follow a similar pattern to 2025. A number of major unconventional and ultra-deepwater projects were sanctioned in these countries prior to the oil price crash. These projects have long lead times and production from them continues to rise in the coming years. However after 2025 the rate of production growth in these countries stalls given the severe drop in new project approvals since 2015.

Production in **Norway** increases to 2025 as the giant Johan Sverdrup field more than offsets declines elsewhere. In the longer term, despite some projected growth from the Arctic, production falls to 1.8 mb/d in 2040.

Companies in **Russia** have weathered the storm since 2014 relatively well, helped by the impact of a lower rouble on production costs. The Vienna Agreement constrained output somewhat in 2017, but near-term prospects look strong. Over the longer term, the difficulty to bring on more remote (e.g. Arctic) or hard-to-develop resources (e.g. tight oil), especially if sanctions are maintained, pushes projected output into gradual decline.

There are plans to resume production from the Neutral Zone, held jointly by Saudi Arabia and Kuwait, in 2019: this would help compensate for underlying declines in other mature basins. As reliance on the **Middle East** increases in the second-half of the outlook period, production from Saudi Arabia rises by over 1 mb/d after 2025. NGLs contribute nearly 70% of the increase in production as new gas projects such as the Karan field come online.

Iraq has increased production by more than 2 mb/d since 2009, largely because of investments from international companies in existing fields. Investment has fallen back in recent years and the Iraqi authorities have sought to adjust contract terms to speed up development. Our projected growth in Iraq is slower than the official capacity target of 6.5 mb/d by 2022: this level of output is reached in the 2030s in the New Policies Scenario.

Prospects for oil production in Iran have worsened since the recent re-imposition of US sanctions targeting oil exports and foreign investment. We have adjusted downwards our projection of major new investments that could raise long-term capacity in Iran. Production growth to 2025 is muted and production in 2025 is 0.3 mb/d lower than in last year's *Outlook*.

Bahrain recently discovered a low permeability offshore oil field with 80 billion barrels of oil in place. There are likely to be many technical hurdles to overcome and pending appraisal we are cautious at this point, but this represents considerable upside potential for Bahrain from today's production level of 0.2 mb/d. Many producers, even in resource-rich areas, are facing the need to go after more challenging fields.

It has been over a decade since **Nigeria** conducted bidding rounds for new offshore licences and production has fallen by over 0.5 mb/d since its peak in 2010. Our outlook sees a continuation of this decline over the next five years but there is an uptick in investment from the mid-2020s, leading to steady growth in both onshore and deepwater areas during the 2030s.

3.6 Refining and oil product demand

Table 3.5 ▷ World liquids demand in the New Policies Scenario (mb/d)

	2017	2025	2030	2035	2040	Change 2017-40
Total liquids	**96.6**	**105.2**	**107.7**	**108.9**	**110.9**	**14.3**
Biofuels	1.8	2.8	3.4	4.0	4.7	2.8
Total oil	94.8	102.4	104.3	104.9	106.3	11.5
CTL, GTL and additives	0.7	1.3	1.4	1.7	2.0	1.3
Direct use of crude oil	1.0	0.6	0.4	0.3	0.2	-0.8
Oil products	93.1	100.6	102.4	102.9	104.1	11.0
LPG and ethane	11.3	14.0	14.4	14.8	15.1	3.9
Naphtha	5.8	7.3	8.0	8.6	9.2	3.5
Gasoline	24.1	25.4	25.4	24.5	23.8	-0.3
Kerosene	7.3	8.0	8.6	9.4	10.3	3.0
Diesel	27.4	29.9	29.9	29.9	30.2	2.8
Fuel oil	7.1	6.4	6.4	6.4	6.4	-0.7
Other products	10.3	9.7	9.6	9.3	9.1	-1.2
Fractionation products from NGLs	9.9	12.0	12.3	12.6	12.5	2.6
Refinery products	83.2	88.6	90.1	90.2	91.6	8.4
Refinery market share	*86%*	*84%*	*84%*	*83%*	*83%*	*n.a.*

Notes: CTL = coal-to-liquids; GTL = gas-to-liquids; NGLs = natural gas liquids; LPG = liquefied petroleum gas; n.a. = not applicable. See Annex C for definitions.

Demand for petrochemical feedstocks (ethane, liquefied petroleum gas [LPG] and naphtha) and for kerosene increases by 1.6% per year to 2040. This is almost three-times the rate of growth in total liquids demand. In contrast, gasoline demand peaks in the late-2020s. There is also a sharp downturn in fuel oil use around 2020 as the IMO sulfur regulation comes into force. These changes lead to a shift in the composition of demand towards lighter products in the New Policies Scenario, a move that is amplified in the Sustainable Development Scenario (see section 3.11).

The New Policies Scenario sees robust growth of biofuels and products fractionated from NGLs. These liquids bypass the refining sector, so the increase in demand for refinery products (8.4 mb/d) is 40% lower than demand growth for total liquids (Table 3.5). To add to the pressure on refiners, a wave of 17 mb/d of new refining capacity (a 13 mb/d net increase) comes online in the period to 2040, almost entirely in the east of Suez region (Asia Pacific and the Middle East). Since new refineries in general are more efficient than older ones, and since they tend to benefit from either low-cost feedstock or demand growth in adjacent markets, this results in a gradual reshuffling of the competitive landscape of the refining industry.

Table 3.6 ▷ Refining capacity and runs by region in the New Policies Scenario (mb/d)

	Refining capacity			Refinery runs			Capacity at risk
	2017	2025	2040	2017	2025	2040	2040
North America	22.5	23.1	22.1	19.3	18.8	17.3	3.0
Europe	16.2	16.0	14.9	13.8	12.3	9.7	5.1
Asia Pacific	34.0	38.8	42.3	28.5	31.3	35.3	3.4
Japan and Korea	6.7	6.5	5.9	6.3	5.4	4.5	1.6
China	15.3	18.0	18.2	11.3	13.0	14.2	1.7
India	4.8	5.7	7.8	5.0	5.6	7.5	-
Southeast Asia	4.9	6.2	7.8	4.1	5.3	6.9	-
Middle East	9.0	11.4	13.0	7.5	9.9	11.7	-
Russia	6.6	6.8	6.6	5.7	5.4	4.6	1.5
Africa	3.4	4.3	5.1	1.8	3.3	4.4	0.1
Brazil	2.2	2.2	2.5	1.7	2.0	2.3	-
Other	4.8	5.0	5.0	2.9	3.3	3.5	1.0
World	**98.6**	**107.4**	**111.4**	**81.2**	**86.1**	**88.6**	**14.2**
Atlantic Basin	55.1	56.8	55.6	44.9	44.5	41.2	10.7
East of Suez	43.5	50.7	55.8	36.3	41.6	47.4	3.4

Notes: "Capacity at risk" is defined as the difference between refining capacity and refinery runs, with the latter including a 14% allowance for downtime. Projected shutdowns beyond those publicly announced are also counted as "capacity at risk".

Today, refinery outputs from the east of Suez region are smaller than those from the traditional refining centres in advanced economies. This situation is reversed by the late-2020s. Refinery runs in the Middle East overtake those in Europe around 2030. By 2040, China's refinery runs approach the level of those in the United States (today's largest refining centre) and India becomes the third-largest refining centre in the world. As a result, refining activity in the east of Suez region is 15% higher than in the Atlantic Basin in 2040. (Table 3.6).

Almost all new refining capacities under development today integrate some petrochemical processes (IEA, 2018b). This appears to be part of a long-term strategy both to seek additional margins and to hedge against the perceived risk of a peak in global oil demand (since demand for petrochemical feedstock is likely to increase even if total oil demand peaks). This trend continues in the New Policies Scenario, bringing the refining and petrochemical industries closer together than ever before.

This challenge for the refining industry in the New Policies Scenario is increased in the Sustainable Development Scenario, in which refinery outputs in 2040 are some 35% lower than in the New Policies Scenario (see section 3.11).

3.7 Trade[3]

Table 3.7 ▷ Oil trade by region in the New Policies Scenario

Net importer in 2040	Net imports (mb/d)				As a share of demand			
	2000	2017	2025	2040	2000	2017	2025	2040
China	1.7	8.9	12.2	13.3	34%	69%	77%	79%
Other Asia Pacific	2.1	5.5	7.6	10.2	40%	67%	77%	84%
India	1.5	3.4	5.4	8.4	65%	74%	84%	88%
European Union	10.7	11.0	10.3	7.5	73%	85%	86%	88%
Japan and Korea	7.3	6.2	5.9	4.5	97%	95%	97%	96%
Rest of world	-1.4	1.1	0.5	0.8	n.a.	30%	14%	21%
Net exporter in 2040	**Net exports (mb/d)**				**As a share of production**			
	2000	2017	2025	2040	2000	2017	2025	2040
Middle East	18.9	23.1	23.6	25.8	80%	74%	71%	69%
Russia	3.9	8.2	7.9	5.9	59%	71%	69%	62%
North America	-9.7	-2.3	4.1	5.6	n.a.	n.a.	15%	22%
Central and South America	2.4	1.1	1.0	3.1	33%	15%	13%	31%
Caspian	0.8	2.2	2.2	2.2	59%	74%	72%	68%
Africa	5.3	4.0	3.0	2.1	68%	48%	37%	23%

Note: n.a. = not applicable.

Robust demand growth in developing economies in Asia leads to mounting import needs; total net import requirements expand by 80% in the period to 2040. China becomes not only the largest net oil importer in the world by 2040, but also the largest net oil importer in the history of oil markets.

India's import needs grow by two-and-a-half times during the outlook period, surpassing those of the European Union in the late 2030s. Declining demand in advanced economies leads to a further shift in global oil trade flows towards Asia (Table 3.7).

The Middle East remains the world's largest oil exporter by a wide margin. Crude oil exports represent the majority of its exports today, and although production increases by 6 mb/d between 2017 and 2040, this is matched by a 2 mb/d increase in oil use for petrochemical feedstocks and a 4 mb/d increase in refining activity. The bulk of future export growth therefore comes from oil products rather than crude oil.

Increases in tight oil production lead the United States to become a net oil exporter in the early 2020s. As a result, North America becomes the world's third-largest oil exporting region by 2040. Robust production growth in Brazil increases Central and South America's net exports after 2025. Russia's net exports decline steadily as a result of waning production.

3. Unless otherwise stated, trade figures in this chapter reflect volumes traded between regions modelled in the *WEO*, and therefore they do not include intra-regional trade.

3.8 Investment

Table 3.8 ▷ Cumulative oil and natural gas supply investment by region in the New Policies Scenario, 2018-2040 ($2017 billion)

	Total oil and gas	Upstream oil and gas	Transport		Refining oil	Annual average upstream oil and gas
			Oil	Gas		
North America	5 258	4 295	163	666	134	187
Central and South America	1 875	1 609	102	120	44	70
Europe	1 758	1 270	25	375	89	55
Africa	2 033	1 703	80	185	66	74
Middle East	2 989	2 283	205	317	184	99
Eurasia	2 716	2 273	57	334	53	99
Asia Pacific	3 651	2 296	85	822	448	100
Shipping	427	n.a.	299	128	n.a.	n.a.
World	**20 708**	**15 730**	**1 015**	**2 946**	**1 017**	**684**
Current Policies	25 316	19 520	1 348	3 172	1 277	849
Sustainable Development	13 455	9 824	452	2 531	649	427

Note: n.a. = not applicable.

In the New Policies Scenario, upstream oil and gas spending rises from $450 billion in 2017 to an annual average of $580 billion between 2018 and 2025 and $740 billion between 2025 and 2040. The upstream investment required between 2018 and 2040 is around 5% larger than in the *WEO-2017* ($640 billion per year). In total, nearly $10 trillion investment in upstream oil projects is required to 2040. If this level of investment does not materialise, there would be a real risk of a mismatch between supply and demand, especially in the medium term (see section 3.10).

Global average upstream costs for conventional crude oil projects fell by about 30% between 2014 and 2017, and are expected to increase only modestly in 2018 (IEA, 2018b). Some of these reductions are assumed to be structural: together with continued technological innovation, these help keep costs down. As oil demand and prices rise, however, unit costs increase and projects become more complex and less productive. In the New Policies Scenario, the average capital cost of executing a project in 2025 remains below the 2014 level, but it is 30% higher than today.

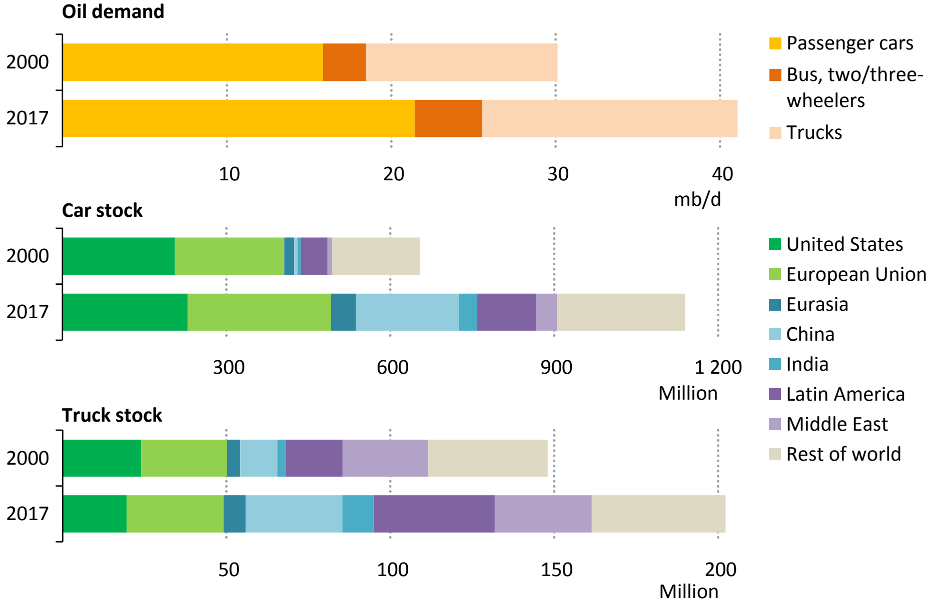
In the Sustainable Development Scenario, fewer new developments are required and there is less need to develop projects at the top of the supply cost curve. Lower demand and prices also lead to lower unit costs for supplies and services and to even greater incentives for companies to maintain strict control over budgets and project execution. The result is average annual upstream oil and gas investment in the Sustainable Development Scenario of nearly $430 billion between 2018 and 2040 (Table 3.8). This is 40% lower than in the New Policies Scenario, but only marginally lower than the amount spent in 2017.

Key themes

3.9 Will road transport remain the stronghold of oil demand?

Nearly 90% of the cars, trucks, motorbikes and buses on the road today rely on engines fuelled by oil. Road transport is responsible for 44% of consumption globally: by far the largest single component of global oil demand. Despite the attention paid to alternative modes of road transport in recent years, oil demand in road transport has grown by around 11 mb/d since 2000, the largest increase in any sector over this period. Around half of this increase came from cars, nearly 40% from road freight and the remainder from two/three-wheelers and buses (Figure 3.8). Yet this increase would have been even bigger were it not for the use of alternative fuels such as biofuels, which avoided a further 2.5 mb/d increase in oil demand, and the proliferation of energy efficiency improvements, which avoided another 1.2 mb/d.[4]

Figure 3.8 ▷ Oil demand by road vehicles, and car and truck fleets by region



Cars are responsible for half of the increase in global road transport oil demand since 2000, reflecting a large increase in the number of cars in developing economies

4. A review of current policies and the outlook for energy efficiency and biofuel deployment is presented in Chapter 6. Part B discusses the current state of play and future deployment of electric road vehicles.

This battle between efficiency, technological innovation and the rise of alternative fuels on the one hand, and economic and population growth on the other, is central to the future of oil demand in road transport, and, by extension, the future of global oil demand. In this section we unpick the causes of oil demand growth in road transport and look in detail at the outlook for demand in cars and trucks in the New Policies Scenario.

What drives road transport oil demand?

When modelling the outlook for road transport demand it is helpful to consider separately cars (passenger cars, sport-utility vehicles, crossovers and pick-ups), trucks (light commercial vehicles, medium-duty trucks and heavy-duty trucks) and other passenger transport modes (motorbikes, tuk-tuks and buses). For cars, the two key demand factors are the number of cars on the road and the distances that they are driven (usually combined into a single activity metric called "vehicle kilometres"). Growth in both of these is a function of growth in gross domestic product (GDP) and population, fuel prices, population density, urban population and public transport policies. For trucks, the increase in freight activity (usually given in "tonne-kilometres") is related to GDP growth and domestic industrial output.

New mobility services such as car leasing, ride sharing and hailing, as well as the application of new technologies such as platooning, automation and connected vehicles, will all likely have a major impact on mobility. But this is subject to a huge degree of uncertainty. They could lead to increased vehicle occupancy, optimised routes and congestion reduction, but they could just as easily lead to the opposite.[5]

How road transport demand translates into oil demand depends on the types of vehicles used and the amount of fuel they consume. There is wide geographic variation in this, with distinctions caused partly by different consumer preferences, partly by variations in fuel taxes and partly by differing fuel-economy policies, emissions standards and levels of support for alternative fuels. Biofuels and electric vehicles have enjoyed the most policy support in the past, but LPG and compressed natural gas (CNG) have also been promoted in some countries to encourage fuel diversification and to reduce local air pollution.

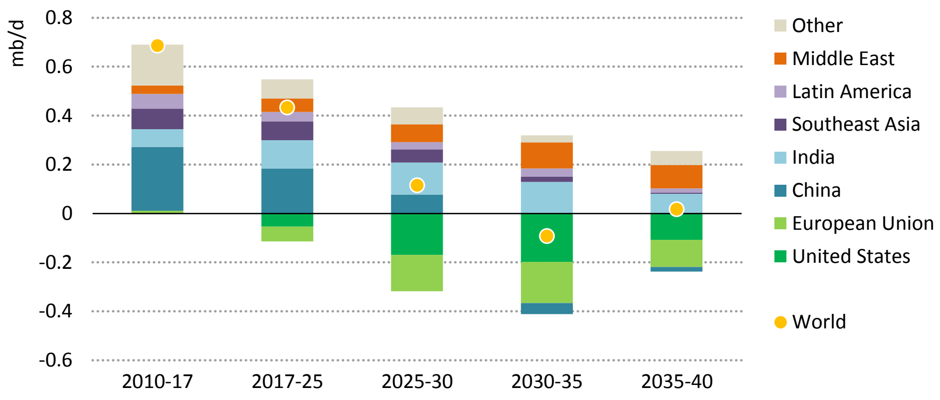
In the New Policies Scenario, the increase in oil demand for road transport (cars, trucks and other modes) slows markedly from the growth rates observed historically. The average annual increase of 0.6 mb/d between 2000 and 2017 drops to 0.4 mb/d to 2025 and then scarcely grows for the 15 years after that. The increase to 2025 is mainly caused by growth in demand in emerging economies in Asia, offset slightly by decreases in demand in the United States and the European Union as a result of energy efficiency improvements and fuel switching away from oil (Figure 3.9).

After 2025, efficiency measures and alternative fuels continue to supress demand in advanced economies, and growth slows in developing economies. This is particularly the case

5. See the forthcoming IEA publication, *Automated, Connected, Electric and Shared Vehicles* (2019).

in China, where oil demand in road transport falls after 2030 in response to its major push for energy efficiency, and plug-in hybrid and battery electric vehicles. There is a slight uptick in total road transport demand after 2035 as there is a slowdown in the rate of reductions in advanced economies and sustained growth in India, the Middle East and Africa.

Figure 3.9 ▷ Average annual change in road transport oil demand by region in the New Policies Scenario



Oil demand from road transport increases steadily in the mid-term, mainly in emerging economies in Asia, but growth levels off as efficiency measures increasingly take hold

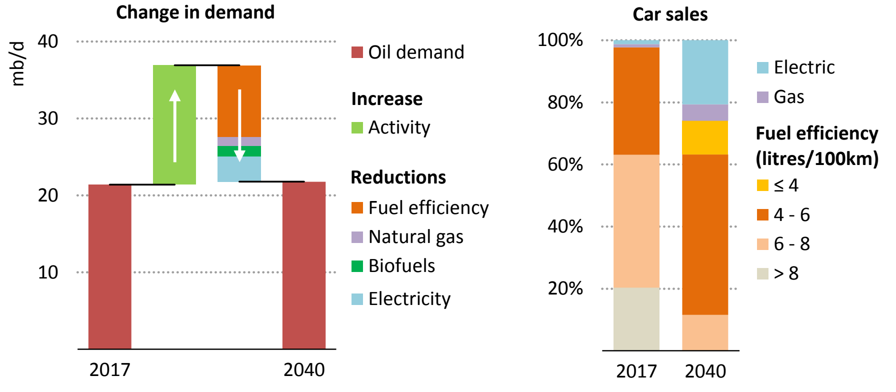
A closer look at cars in the New Policies Scenario

Some 500 million cars joined the global car fleet between 2000 and 2017. Three-quarters of these were added in developing economies, and nearly 40% were added in China alone. Today there are around 1 100 million cars on the road, nearly all fuelled by oil: electric cars account for 1% of current annual car sales and represent less than 0.3% of the global car fleet.

In the New Policies Scenario, the global car fleet grows by 80% by 2040 as the world's population becomes larger and wealthier. Every year around 40 million new cars are added to the global total: China and India account for more than 60% of these. Yet global oil demand for passenger cars barely changes, from 21.4 mb/d today to just over 23 mb/d in the late 2020s and then back to just above today's level by 2040.

Improvements in fuel efficiency of the global car fleet are the single largest contributor to moderating oil demand growth in cars in the New Policies Scenario. These measures avoid around 9 mb/d of oil demand in 2040 (Figure 3.10). A significant portion of these savings do not depend on any major technological breakthroughs. For example, bringing the fuel efficiency of the global car fleet in line with that of cars in the European Union today (7.3 litres/100 km) would reduce global oil consumption by almost 6 mb/d.

Figure 3.10 ▷ **Oil demand from cars, oil displacement and car sales globally in the New Policies Scenario**



Energy efficiency is the key mechanism that curbs oil consumption in cars. By 2040 there are no cars sold that have an efficiency worse than 6.5 litres/100 km.

Notes: Fuel efficiency refers to the efficiency of oil-fuelled cars only. Displacement in 2017: biofuels = 1.2 mb/d; natural gas = 0.5 mb/d; electricity = 0.05 mb/d.

One change in efficiency policies that has an impact on our oil outlook comes from the United States. Between 2009 and 2014, a combination of the CAFE standards and high oil prices led to an annual improvement in the average fuel efficiency of new cars sold in the United States of around 1.6%. Since the drop in the oil price in 2014, however, there has been a rise in the number of sport-utility vehicles sold and improvements in the average fuel efficiency of new cars have stagnated. In August 2018, the United States Environmental Protection Agency announced that fuel-economy and GHG emissions standards for cars and light trucks for the period 2021 to 2026 would be revised. The effect of this change is to slow the rate of improvement in fuel efficiency post-2020. As a result, oil demand for cars and light trucks in the United States in 2040 is 1.2 mb/d higher than in the *WEO-2017*.

Besides efficiency measures, biofuels offset 2.5 mb/d of oil demand in 2040 while natural gas offsets 1.6 mb/d oil demand. The 300 million electric cars on the road in 2040 displace around 3.3 mb/d of oil demand. The volume of oil avoided by electric cars is not just a function of whether they are plug-in hybrid or battery electric (of the 300 million electric cars in 2040, there are broadly equal proportions of plug-in hybrid and battery electric cars), but also of the cars they are assumed to replace. Replacing a more efficient car will displace less oil than one which is not as efficient, and this assumption varies by region and over time. In 2040, the average gasoline car is around 30% more efficient than today, which means that adding an electric car in 2040 leads to less of a reduction in oil demand than putting an extra electric car on the road today. Electric cars may also replace other non-oil based vehicles such as CNG vehicles. We estimate that 100 million electric cars in 2017 would displace around 1.7 mb/d oil demand, but the same number of electric cars in 2040 would displace around 1.1 mb/d.

A closer look at trucks in the New Policies Scenario

Trucks have been one of the main sources of oil consumption growth in recent years, with demand up by around 4 mb/d between 2000 and 2017. The vast majority of this increase has come from developing economies (a quarter of the increase came from China alone). Today trucks are the second-largest oil-consuming sector after cars, with total consumption in 2017 of almost 16 mb/d.

Translating freight activity into oil demand depends on how activity is split between light commercial vehicles, medium-duty trucks and heavy-duty trucks.[6] This in turn depends on the logistical operations required in the supply chains of different goods. Some deliveries can only be made by lighter vehicles and these have higher oil use per tonne-kilometre than heavy-duty trucks. For example, light commercial vehicles currently provide only 5% of the tonne-kilometres served by trucks, but are responsible for nearly 25% of total oil use for trucks. In contrast, heavy-duty trucks provide nearly 65% of goods transport on land but account for less than 50% of the sector's oil consumption.

In the coming years, the continued expansion of online commerce is expected to boost the amount of goods transportation undertaken by lighter vehicles, but it could also enable optimisation of routes from centralised warehouses to delivery points. Maximising vehicle utilisation is key to reducing oil consumption: options currently being explored include cross-company collaboration at warehouses, backhauling (delivering cargo on return trips) and co-loading (bundling shipments across different product categories).

In the New Policies Scenario, global road freight activity grows by 3.1% per year, with China, India and the United States accounting for nearly half of the increase.[7] In contrast to the outlook for cars, oil demand in trucks grows by 4 mb/d in the period to 2040 and is a key source of total oil demand growth in the New Policies Scenario (Figure 3.11).

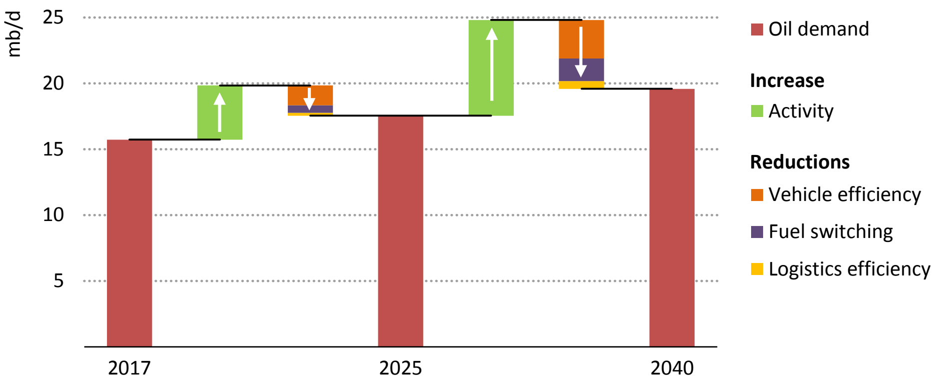
This increase would be much larger were it not for improvements in vehicle and logistics efficiency. These bring a major divergence in trends between freight activity on the one hand and oil demand on the other. For example, in advanced economies, freight activity grows by 2.1% on average each year, yet oil demand falls annually by 0.5%. This divergence is less apparent in developing economies, but there are a number of fuel-economy standards that prevent even higher growth in oil demand (e.g. recent fuel-economy standards for heavy-duty trucks in India). In total, improvements in vehicle and logistics efficiency avoid nearly 5.5 mb/d oil demand growth in 2040. There are 300 000 LNG-fuelled trucks on the road in China today and the use of natural gas grows throughout the New Policies Scenario, especially in China and the United States. The use of biofuels for trucks avoids 1.2 mb/d of

6. Light-duty trucks are vehicles with total weight lower than 3.5 tonnes, medium-duty trucks weigh between 3.5 tonnes and 16 tonnes and heavy-duty trucks weigh more than 16 tonnes.

7. Growth in the transport of goods is assumed to be constant across all scenarios modelled in this *Outlook*.

oil demand in 2040, natural gas displaces more than 1.1 mb/d of oil demand, while electric trucks avoid 0.6 mb/d.

Figure 3.11 ▷ Oil demand from trucks and oil displacement globally in the New Policies Scenario



Efficiency is instrumental in curbing the increase in oil demand for goods transportation alongside improvements in logistics and fuel switching

Note: Displacement in 2017: biofuels = 0.6 mb/d; natural gas = 0.2 mb/d.

Conclusion

Road transport remains a major consumer of oil through to 2040 and beyond but it is no longer a primary cause of demand growth in the New Policies Scenario. One reason is the rise in electrification and the digitalization of mobility services. But the more significant factor is the increase in vehicle and logistics efficiency for both cars and trucks. In total, these avoid almost 15 mb/d additional oil demand in 2040. While many of these efficiency improvements do not depend on major technological breakthroughs, they are contingent on continued policies supporting fuel-economy and emissions standards. In this area, as in others, government actions will be pivotal in determining the pathway that the world follows.

3.10 Crunching the numbers: are we heading for an oil supply shock?

In all *WEO-2018* scenarios, new sources of oil supply steadily come online at the right time to meet changes in oil demand and to keep the system in equilibrium. This smooth matching of supply and demand minimises oil price volatility and would likely be a desirable outcome for many of the world's oil consumers; it could also be better in the long run for many of the world's producers (IEA, 2018c). Yet it does not reflect the way that commodity markets often work in practice. A case where new upstream oil investments do not materialise in a timely manner and the oil price is forced ever higher to avoid a mismatch between supply and demand cannot be ruled out.

In the light of the dramatic drop in new upstream projects approved after the oil price drop in 2014 the *WEO-2016* explored the risks and implications of a future mismatch between supply and demand. We now have two more years of data on US tight oil production, on costs and project approvals elsewhere and a considerably higher starting number for global oil demand. We therefore revisit the issue: can a future oil supply "crunch" now be safely ruled out? Or are we facing an imminent risk of a rocky ride for oil markets in the coming years?

To answer these questions, we look at how oil from currently producing sources can be expected to decline in the future; we assess changes in global demand; and we examine the various ways that any gaps between supply and demand could be filled by new sources of production.

Decline rates

Many different decline rates are discussed in the context of conventional crude oil production, but some are much more useful than others when estimating how production from currently producing fields will evolve in the future. Here we explain the differences between these rates, how they can be interpreted, and what they tell us about future production prospects.[8]

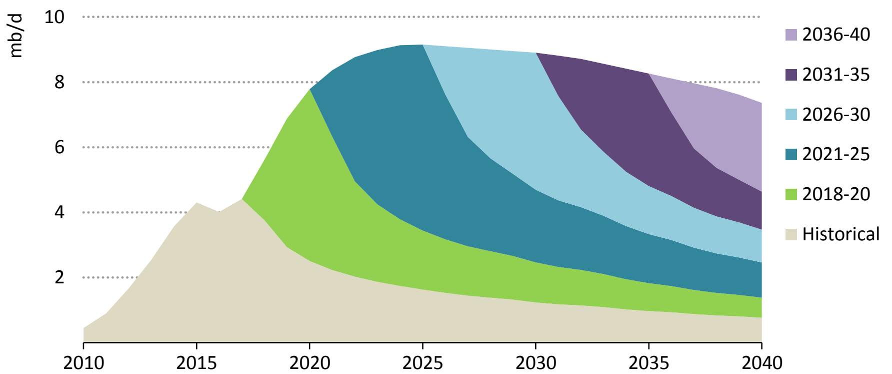
Decline rates vary depending on the location and type of oil in question. At one end of the spectrum is extra-heavy oil and bitumen. There is typically a slow ramp-up to maximum production – for example, projects in Canada approved since 2005 have taken between four and ten years after receiving development consent – but little decline in production after this until the project reaches the end of its lifetime and is shut down. At the opposite end of the spectrum is tight oil. Here there is typically a short gap between approval and maximum production, but a very rapid decline thereafter (Box 3.1). Lying between these two extremes is conventional crude oil production.

Box 3.1 ▷ Declines in tight oil production

Production from tight oil wells is characterised by an initial peak in production, followed by a sharp decline and then a long tail of low level production. New tight oil wells must therefore be drilled continuously to maintain or increase production. Nearly 70% of the 8 500 tight oil wells completed in 2017 in the United States were needed simply to compensate for declines at existing wells. If no new wells were completed after the end of 2017, then tight crude oil production would fall by around 1.8 mb/d within 12 months and by a further 0.6 mb/d during the year thereafter. However the long tail of production from wells provides an important baseload of production in the longer term. Around 80 000 tight oil wells had been completed by the end of 2017, and they will still provide around 1.6 mb/d production in 2025, even though they are all well past their production peaks (Figure 3.12).

8. This work is based on a detailed analysis of historical production in over 30 000 oil assets in the Rystad Energy UCube database.

Figure 3.12 ▷ Tight oil production according to well start-up date in the United States in the New Policies Scenario



Tight oil production drops rapidly in the absence of new well start-ups, but the large number of legacy wells provide an important base load of production

Tight oil production is a relatively new production technique and operators are continuing to make technological progress, for example in optimising the lateral length of horizontal wells and the amount of proppant used during hydraulic fracturing. Technological improvements are in a continuous battle with the effects of depletion (as is the case for all sources of production). By the mid-2020s, with the recoverable resource that we assume in the New Policies Scenario, many of the most productive areas will have been exploited. This means the average well drilled in 2025 is less productive than today and so a larger number of wells need to be completed to maintain or increase production. In 2025 over 20 000 new wells are drilled in the New Policies Scenario and production is maintained at just over 9 mb/d.

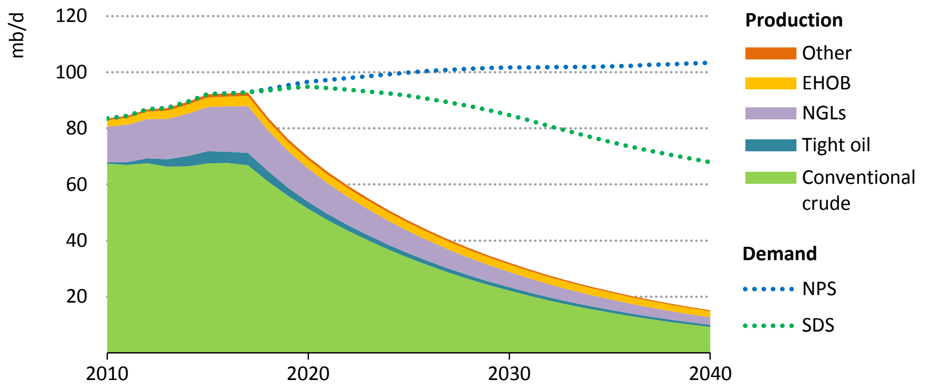
The natural decline rate is the drop in production from all currently producing fields that would occur if capital investment were to cease immediately. If there were to be no further capital expenditure, total production globally would fall by over 8% per year to 2025, an average loss of nearly 6 mb/d every year. Global production in 2040 would be just above 15 mb/d (Figure 3.13).[9] This pace of decline is significantly faster than the decline in oil demand in the Sustainable Development Scenario, highlighting the importance of continued upstream investment even during the transition away from a fossil-based energy system.

In practice, decline rates are usually lower than the natural decline rate since there is continued investment in producing fields. Another important decline rate is therefore the

9. The natural decline rate for conventional crude oil only is closer to 9%; see www.iea.org/weo/weomodel/ for further details, including how decline rates are calculated.

"observed post-peak decline rate". This is the compound annual decline in production from currently producing fields whose production has already peaked but with continued capital investment in these fields.[10] Post-peak decline rates vary according to production phase (they tend to rise as fields become more mature), field size (small fields tend to decline faster than large fields) and location (offshore fields exhibit faster decline rates than onshore fields). The global average observed post-peak decline for conventional crude oil today is 6.1% – around three percentage points lower than the global average natural decline rate.

Figure 3.13 ▷ Oil production with no new investment from 2018 and demand in the New Policies and Sustainable Development scenarios



With no new investment, global oil production would halve by 2025: an average loss of nearly 6 mb/d every year

Note: EHOB = extra-heavy oil and bitumen; NGLs = natural gas liquids; NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

However this decline rate does not correspond with the loss in production from the global oil balance. The decline rate for post-peak fields producing in 2017 will change over time as fields become more mature. Further, less than 50% of global oil production today comes from post-peak conventional crude oil fields. Other categories of fields and types of production therefore need to be considered, including:

- Ramp-up fields (13% of global production in 2017): conventional crude oil fields that were brought online since 2010 and have yet to reach peak production.
- Legacy fields (11% of global production in 2017): conventional crude oil fields that were brought on line before 2010 and have yet to reach peak production. These tend

10. Observed decline rates are often aggregated to provide an average post-peak decline rate for specific countries, regions, field sizes, etc. When aggregating post-peak declines from a set of fields, we weight by cumulative production since this incorporates information from fields that peaked some time ago and currently have a very low level of production.

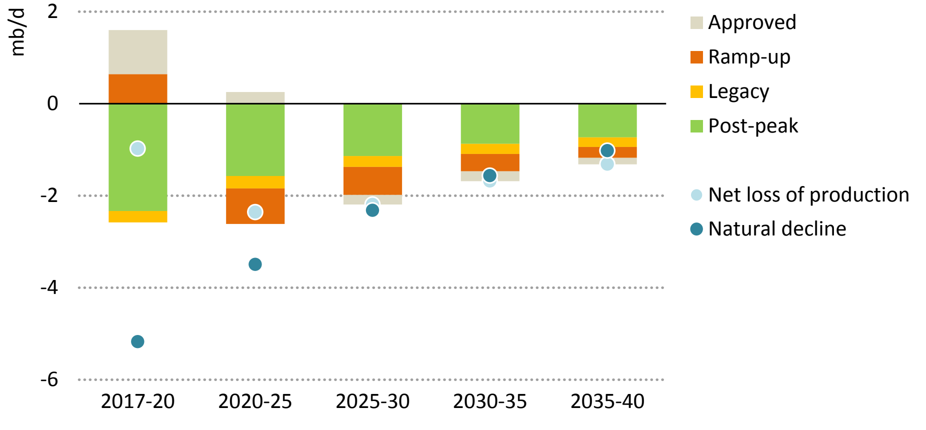
to have been subject to above-ground constraints (e.g. OPEC quota requirements) and so are hard to include in any usual post-peak field analysis. This includes a number of the "super-giant" fields in the Middle East and Russia.

- Approved fields: conventional crude oil fields that have been approved for development but have not yet started production. This includes a number of major new developments such as Johan Sverdrup in Norway and the Liza field in Guyana.
- NGLs (18% of global production in 2017), tight oil (5%), EHOB (4%) and a minor contribution from coal-to-liquids, gas-to-liquids and additives (1%).

The risk of an emerging supply-demand "gap"

How production evolves for post-peak, ramp-up, legacy, and approved conventional crude oil fields determines the annual loss of conventional crude oil production from the global oil balance (Figure 3.14). If there were to be no new fields approved after 2017, total conventional crude oil production would fall by around 1 mb/d each year to 2020 (an average annual decline rate of around 1.5%). This drop in production is smaller than the decline in post-peak fields, which fall by around 2.5 mb/d each year to 2020, given the increases in production from approved and ramp-up fields, and is much smaller than the natural decline rate (an annual loss of 5.2 mb/d conventional crude oil to 2020). Thereafter, as more fields enter decline and as the pipeline of new projects begins to dry up, the annual loss in production would accelerate to around 2.5 mb/d. This corresponds to a decline rate of around 4.5% during the 2020s, similar to the average post-peak decline of large fields.

Figure 3.14 ▷ Average annual change in production from conventional crude oil fields with no new approvals



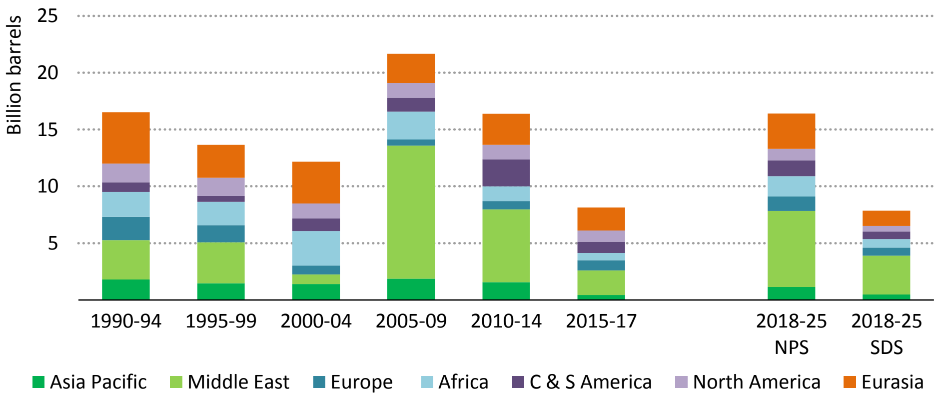
Production from ramp-up and approved fields initially offsets some of the decline in post-peak fields, but the drop in production soon escalates without new approvals

Notes: Fields are categorised as of their status in 2017. The net loss of production is the decline in conventional crude oil fields from 2017 if no new field developments are approved.

New approvals needed in the New Policies and Sustainable Development scenarios

In the New Policies Scenario, there is a 7.5 mb/d increase in demand between 2017 and 2025, and a 14.5 mb/d drop in production from currently producing and approved conventional crude oil fields (the aggregate net loss in production to 2025 shown in Figure 3.14). A 22 mb/d supply-demand gap therefore needs to be filled by new projects. Some of this gap is filled with growth in tight oil, NGLs and other unconventional sources of oil: in the New Policies Scenario these collectively grow by around 9 mb/d between 2017 and 2025. But that still leaves a gap of 13 mb/d.

Figure 3.15 ▷ Annual average conventional crude oil resources approved for development historically and volumes needed in the New Policies and Sustainable Development scenarios



Annual resource approvals in the Sustainable Development Scenario are broadly in line with approval levels since 2015; the New Policies Scenario requires double this volume

Note: C & S America = Central and South America; NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

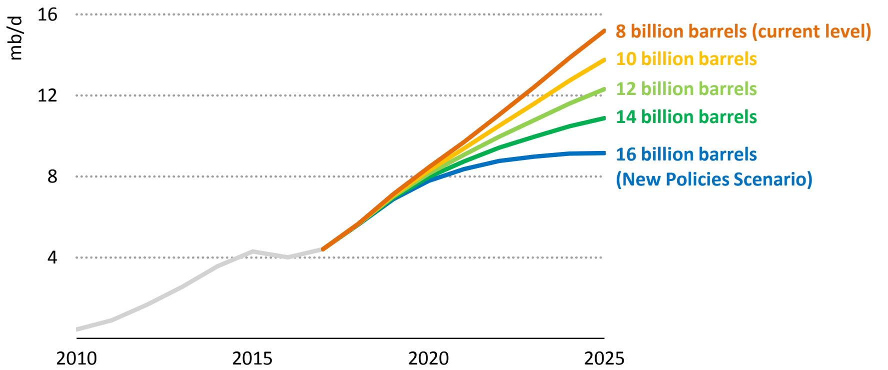
Sources: IEA analysis; Rystad Energy for historical levels.

We estimate that around 16 billion barrels of new conventional crude oil resources would need to be approved each year between now and 2025 to avoid any potential "mismatch" between supply and demand (Figure 3.15).[11] This takes into account the various locations and types of remaining conventional crude oil resources that are available, which have very different lag times between approval, first production and ramp-up. The average annual

11. This is slightly lower than the level described in the *WEO-2016* for the situation when resources approved between 2015 and 2017 remained at 6.5 billion barrels (the level of approvals projected in 2015 when the analysis was carried out). Approvals actually averaged around 8 billion barrels over this timeframe and tight oil and NGLs production in 2025 is around 4 mb/d higher than was estimated in the *WEO-2016*. However this increase is offset by a 4 mb/d increase in projected global oil demand in 2025 between the New Policies Scenario in the *WEO-2016* and in this year's *Outlook*.

level of new resources approved since the oil price crash in 2014 was around 8 billion barrels: the volumes sanctioned increased slightly in 2017, but were still well below levels in the early 2010s. The volume of conventional crude oil resources approved for development therefore needs to more than double from current levels if there is to be a smooth correspondence between supply and demand in the New Policies Scenario.

Figure 3.16 ▷ US tight oil production needed to meet demand in the New Policies Scenario at different levels of conventional resources approved each year between 2018 and 2025



If annual conventional crude oil approvals stay at the level seen since the oil price crash in 2014 (8 billion barrels), then US tight oil production would need to exceed 15 mb/d in 2025

If insufficient new conventional crude oil resources are approved for development, members of OPEC could decide to reduce their spare capacity and bring more oil to the market. This would provide something of a buffer, but it would only fill a small portion of the supply-demand gap and would weaken the ability of markets to respond to unforeseen disruptions. Another possibility is that US operators might manage to increase tight oil production at a much faster rate than is assumed in the New Policies Scenario, in which it reaches 9.2 mb/d in 2025. If the volume of resources approved globally each year were to stay at today's level of 8 billion barrels, then US tight oil would need to grow by an additional 6 mb/d between now and 2025 (Figure 3.16). With a sufficiently large resource base – much larger than we assume in the New Policies Scenario – a 1.3 mb/d annual increase in US tight oil production every year to 2025 could be possible. However distribution infrastructure bottlenecks are currently inhibiting tight oil production growth. Even if these were to be overcome as new pipelines are built, increasing production to this level would require a level of capital investment and a number of tight oil rigs that would far surpass the previous peaks in 2014. Against this backdrop, it would appear risky to rely on a tripling of US tight oil production from today's level by 2025 to offset the absence of new conventional crude oil projects.

In the Sustainable Development Scenario, there is also a 15 mb/d drop in production from currently producing fields or approved projects between 2017 and 2025 while demand falls by 1 mb/d over this period. A 14 mb/d gap therefore needs to be filled by new projects. Tight oil, NGLs and EHOB all grow from today's levels in this scenario, albeit to a lesser extent than in the New Policies Scenario given the lower oil price. A gap of around 7.5 mb/d therefore needs to be filled in the Sustainable Development Scenario in 2025 from conventional crude oil fields that have yet to be approved. Providing this level of supply would require approvals of around 8 billion barrels between now and 2025: similar to the level seen over the past few years. This places the implications of "peak oil demand" in context. Even with a near-term peak and subsequent reduction in demand of around 1 mb/d by the mid-2020s, there remains a critical need to develop new fields to fill the supply-demand gap.

Why has there been a dearth of new conventional crude oil approvals recently? Since the drop in the oil price, companies have placed greater emphasis on cost management and executing projects with shorter pay-back periods (such as tight oil), often to the detriment of investment in longer lead time conventional crude oil projects (IEA, 2018b). This could in part reflect concerns over the trajectory of future oil demand. In addition, many national oil companies are facing constrained capital budgets, limiting their ability to invest in new projects. Geopolitical events may also be discouraging an upturn in investment in some areas.

There are a number of options for policy makers to help avoid any shortfall in supply. One option is to introduce policies to reduce oil demand. Another is to provide a more attractive climate for investment, especially for projects that would have low upstream emissions intensities (see Chapter 11). With the rise in the oil price so far in 2018, companies have expressed greater interest in investing in new conventional crude oil projects, and it is possible that much higher levels of investment will materialise in the coming years without any, or much, help from governments. Depending on developments in the global economy and demand and the timeliness of project approvals and developments, it is still possible that a supply crunch will be avoided, but this pathway is a narrow one.

Conclusion

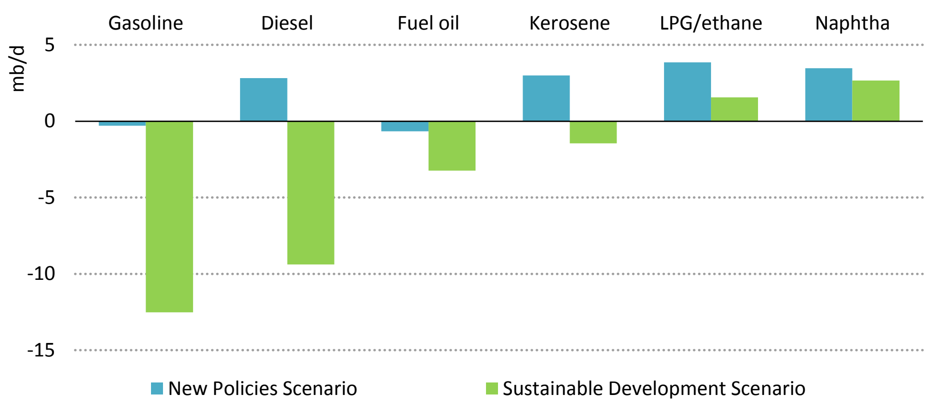
The level of new upstream oil resources approved in the years since the crash in the oil price is broadly in line with the needs of the Sustainable Development Scenario. But it is currently far from sufficient to meet the oil demand trajectory based on the policies and continued levels of economic growth in the New Policies Scenario. Current investment in demand points towards ever increasing oil consumption, while investment in oil supply appears to be geared towards a world of stagnant or even falling demand. Either demand or supply projections could yet change so as to close the gap, however the longer this dichotomy continues, the greater the risk of damaging price spikes and increased volatility.

3.11 Oil product demand: where are the winners and losers, and what could be the unintended consequences?

While global oil consumption has been on an almost unbroken rising trend for decades, there have been divergent trends for individual oil products. Demand for heavy fuel oil, for example, has been declining since the 1980s, while the pace of demand growth for lighter products (such as ethane, LPG and naphtha) has been almost triple that of total oil demand. In the New Policies Scenario, heavy fuel oil is set to face another blow when the IMO's regulation on the sulfur content of bunker fuels comes into effect from 2020 (see Spotlight). Gasoline demand also peaks in the late 2020s and is around 0.3 mb/d lower than today in 2040 as efficiency improvements, fuel switching and electrification weigh on oil demand for cars. However, there are sectors where efficiency improvements or electrification are less effective in curbing oil demand, most notably the petrochemical sector.

As a result, demand for ethane, LPG and naphtha (mainly used as petrochemical feedstocks) continues to grow much faster than total oil demand in the New Policies Scenario. Robust growth in these lighter products (also known as the "top of the barrel") means that their share of total oil consumption rises from 18% today to 23% in 2040. In contrast, the share of gasoline and heavy fuel oil declines from 33% to 28%. Refiners have coped with divergent trends for different oil products in the past, but the pace and extent of the changes envisaged in the New Policies Scenario still pose a significant test.

Figure 3.17 ▷ Change in global oil product demand by scenario, 2017-2040



The diverging sectoral oil demand outlook underpins a large-scale shift towards lighter products in the Sustainable Development Scenario

In the Sustainable Development Scenario, the share of "top of the barrel" products grows to an even greater extent. Oil demand in cars drops significantly; consumption for other transport modes – trucks, ships and aviation – also declines; but use in the petrochemical sector remains robust due to strong demand growth for chemical products in developing economies. These changes engender a major shift in the composition of oil product demand. Demand for gasoline and diesel fall by some 50% and 35% respectively between today and 2040. Demand for kerosene and fuel oil also falls. By contrast, given the growth in petrochemicals, demand for ethane, naphtha and LPG grows by around 25% (Figure 3.17). LPG is also key in this scenario to provide access to clean cooking facilities and to tackle the negative health impacts associated with the traditional use of solid biomass as a cooking fuel in many developing countries. As a result, the share of lighter products rises to over 30% by 2040 in the Sustainable Development Scenario, from 18% today.

SPOTLIGHT

Achieving the IMO regulation: plain sailing or stormy seas ahead?

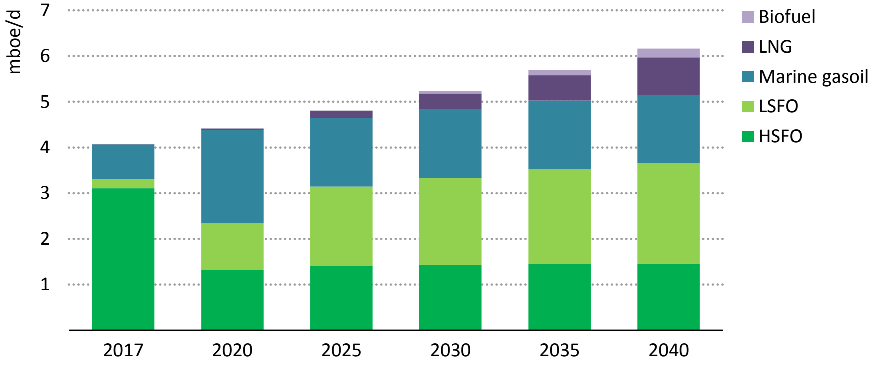
The international shipping sector has been the last large-scale refuge for high sulfur fuel oil (HSFO) in recent years. HSFO consumption in 2017 was just over 3 mb/d and the shipping industry was responsible for 12% of total energy-sector sulfur dioxide (SO_2) emissions. The IMO has now introduced a regulation to limit the sulfur content of marine fuels to no more than 0.5% (the "sulfur regulation") that will enter into force in 2020. This promises to yield substantial environmental and health benefits, but it will also have profound impacts on oil markets. In April 2018, the IMO also announced a strategy to reduce GHG emissions from the international shipping industry by at least 50% from 2008 levels by 2050 (the "GHG strategy"), which will also have major longer term implications.

There are a number of options available to the maritime industry to comply with the sulfur regulation. These include installing exhaust gas cleaning systems (known as "scrubbers"), fuel switching to LNG, or changing to use low sulfur fuel oil (LSFO) or marine gasoil (MGO).

The use of scrubbers would allow continued use of HSFO, but this is unlikely to be the main avenue for compliance: it would be capital intensive; there is a mismatch between the interests of ship owners and ship charterers; there would be loss of revenue during the idle period when the scrubber is installed; smaller ships may not easily be able to handle large scrubbers; and there is uncertainty over the cost of disposing the sludge they create. Shifting to use LNG is also likely to be relatively limited, at least in the short term, as it is expensive to convert ships to use LNG and bunkering infrastructure is not for the moment widely available. The need for eventual compliance with the GHG strategy announced in April 2018 may also militate against both scrubbers and LNG. Installing scrubbers provides no CO_2 reduction and the reduction in emissions provided by switching to LNG would not be sufficient on its own to achieve the long-term target.

The use of compliant fuels such as LSFO or MGO is therefore likely to be the most widespread option for compliance post-2020. In the New Policies Scenario, HSFO demand drops by around 2 mb/d around 2020, but filling this gap is not straightforward. The supply of LSFO from refineries is limited to around 600 kb/d, and so a large part of the remainder would need to be met by MGO (Figure 3.18). This raises the prospect of a spike in diesel prices around 2020 (IEA, 2018d). Refiners are also developing a new 0.5% sulfur bunker fuel (often called "very low sulfur fuel oil") that blends HSFO and MGO, which is likely to find a market even if there are still some technical and specification issues to be resolved. Nevertheless, many uncertainties remain that could affect this picture, including the preference of ship owners for compliant fuels over more capital-intensive options, the availability of low sulfur products, the rate of uptake of new blended products and the pace of development of new technologies.

Figure 3.18 ▷ Fuel mix for the international shipping sector in the New Policies Scenario



Low sulfur compliant fuels are the main fuels chosen in the New Policies Scenario

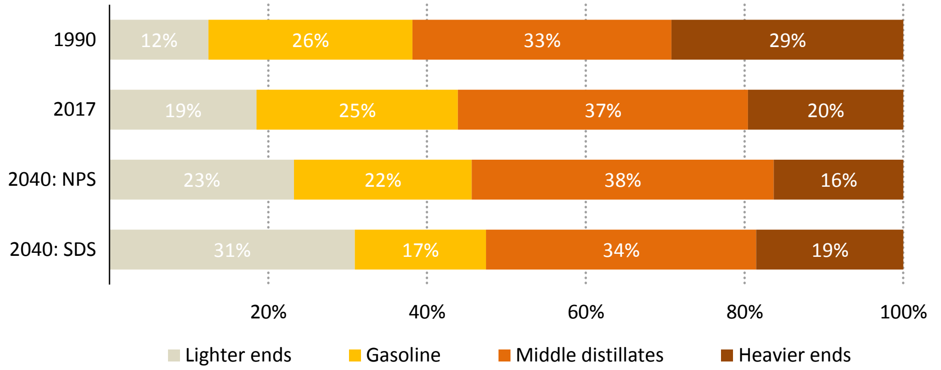
Notes: mboe/d = million barrels of oil equivalent per day; HSFO = high sulfur fuel oil; LSFO = low sulfur fuel oil. LSFO includes both straight-run LSFO and LSFO produced by blending HSFO and gasoil.

While filling the gap left by HSFO is a significant task for the shipping industry, dealing with the displaced HSFO also represents a major challenge for the refining industry. In the absence of sufficient storage capacity, the displaced HSFO could be upgraded or consumed for power generation. But this would not be sufficient to absorb all the displaced volume, implying a significant drop in HSFO prices. The sulfur regulation may therefore take a heavy toll on simple refineries that have high HSFO yields, many of which are not in a position to consider multi-billion dollar investment in upgrading units or desulphurisation units for HSFO. It could though benefit more complex refineries via higher MGO prices and cheaper HSFO feedstock. These changes could potentially add to other pressures for further restructuring of the global refining industry.

The ripple effects of the IMO sulfur regulation could spread beyond oil product markets. With elevated demand for MGO, complex refineries would increase throughput to maximise diesel outputs, which could push up prices for crude oil and sweeter crudes in particular (simpler refineries are likely to prefer to process sweet grades to minimise the yield of HSFO). This would push up fuel costs for freight across the board (both maritime and road) around 2020, which could have broader economic ramifications.

Refiners are used to coping with changing demand patterns. In the past, these efforts were mainly focused on reducing heavier yields and increasing the output of gasoline and middle distillates (diesel and kerosene). The challenge in the Sustainable Development Scenario comes from a different angle: to increase the yield of lighter products and reduce the output of traditional refined products such as gasoline and diesel (Figure 3.19). Growth in the availability of NGLs and lighter crude oil eases some of the pressure on refiners, at least in the near term. However, production of NGLs and of tight oil are both projected to fall back post-2025, while demand for lighter products continues to increase.

Figure 3.19 ▷ Change in the composition of global oil product demand



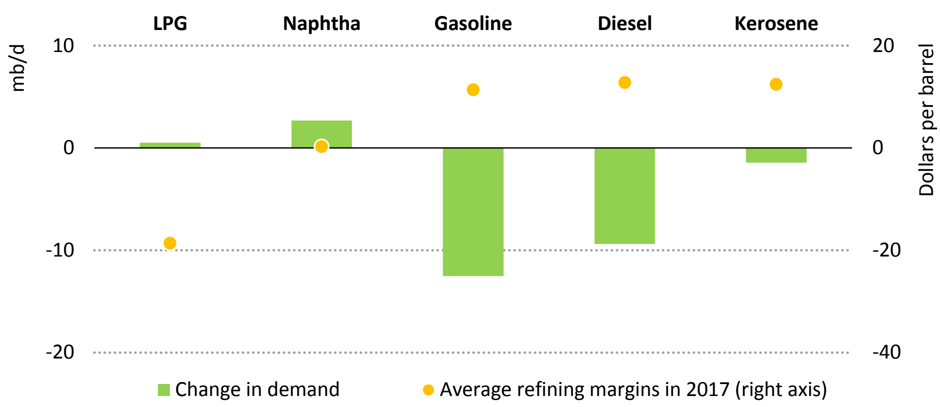
The past challenge for refiners has been reducing the "bottom of the barrel", but the future challenge comes from increasing yields of the "top of the barrel" products

Notes: NPS = New Policies Scenario; SDS = Sustainable Development Scenario. Lighter ends include ethane, LPG and naphtha. Middle distillates include diesel and kerosene. Heavier ends include fuel oil, asphalt, petroleum coke, wax, etc.

The mismatch between refinery configurations and product demand in the Sustainable Development Scenario would increase the incentives for refiners to deepen integration with petrochemical operations, and thereby boost the direct production of chemical products relative to transportation fuels. There are various technological pathways to increase chemical product yields beyond the levels that a refinery can typically produce (less than 10%). Several Asian refineries have co-located steam crackers and para-xylene facilities that provide higher chemical yields; high-severity fluid catalytic cracking technologies allow companies to achieve chemical product yields of over 30%; while companies in China are building integrated petrochemical and refining facilities that aim to have chemical yields of around 40%. There are even more ambitious schemes being pursued in the Middle East to bypass refining operations and produce chemicals directly from crude oil (IEA, 2018c).

The changes in product demand could also have profound implications for the business model of the refining industry. Today, refiners typically earn most of their profit from selling road transport fuels such as gasoline and diesel. Prices for petrochemical feedstocks – the main sources of demand growth in this scenario – often trend lower than crude oil prices. The significant reduction in road transport fuel demand in the Sustainable Development Scenario may therefore challenge this traditional pattern (Figure 3.20). In theory, foregone profits in one area would be compensated by higher prices for products in high demand such as naphtha and LPG. While it is conceivable for the prices of these products to increase to some degree, it is hard to envisage a rise that fully compensates for the reduction in road transport fuels sales. The current interest in petrochemical integration reflects a desire to hedge against this risk by seeking out new business lines and revenue streams.

Figure 3.20 ▷ Average refining margins today and change in demand in the Sustainable Development Scenario by product, 2017-2040



The product demand pattern in the Sustainable Development Scenario would pose major challenges for today's refining business models

Note: Refining margins are differentials between northwest Europe product prices versus North Sea dated prices.

Conclusion

The IMO sulfur regulation provides an illustration of how changes in product demand can send ripples through the refining industry and then through the wider energy system. Our projections highlight other possible mismatches between products demanded and refinery configurations, causing spikes or slumps in the price of individual oil products. While policy makers need to try to minimise the potential impacts of price spikes on energy consumers, they would also need to be attentive to the unintended influences of price slumps. For example, if policy action were concentrated narrowly on the passenger car segment while other sectors – such as trucks, aviation, shipping and petrochemicals – were left relatively untouched, it would be difficult to avoid a glut of gasoline on the market once demand started to fall back. Efforts to curb oil use in passenger cars would therefore face much stronger headwinds because cheap gasoline would make efficiency improvements and electrification more difficult and expensive. Avoiding such rebound effects would require removing fossil fuel subsidies or putting in place an offsetting tax or duty that maintains end-user prices at higher levels. Anticipating and mitigating these feedbacks from the supply side needs to be a central element of the discussion about orderly energy transitions.

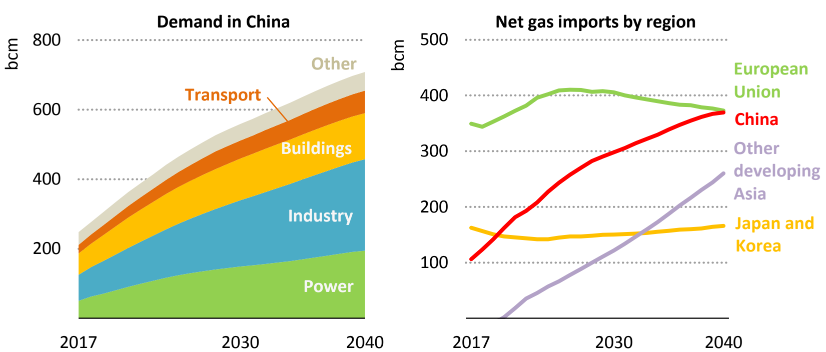
Outlook for natural gas

Blue sky thinking?

SUMMARY

- Natural gas is the fastest growing fossil fuel in the New Policies Scenario, overtaking coal by 2030 to become the second-largest source of energy after oil. With demand growing by 1.6% per year, gas consumption is almost 45% higher in 2040 than today. Industry takes over from power generation as the main sector for growth.
- China's gas demand triples to 710 billion cubic metres (bcm) by 2040, up 100 bcm compared with our *Outlook* in 2017, mainly due to a concerted coal-to-gas switch as part of the drive to "turn China's skies blue again". China's gas consumption moves from being roughly half that of the European Union today to 75% higher by 2040.
- China soon becomes the world's largest gas-importing country, with net imports approaching the level of the European Union by 2040 (Figure 4.1). It is also on track to surpass Japan as the largest liquefied natural gas (LNG) importer.

Figure 4.1 ▷ Gas demand in China and net gas imports by region in the New Policies Scenario

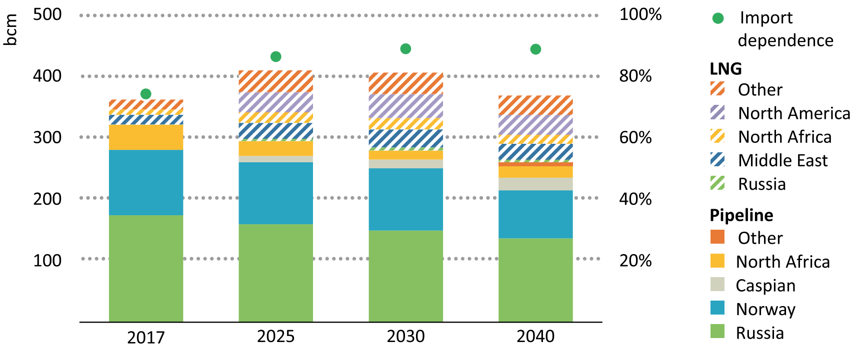


With rising gas demand in all end-use sectors, China's net gas imports approach the level of the European Union by 2040

- In other emerging Asian economies, the prospects for gas differ widely depending on the composition of domestic resources, demand and policies. Demand in India expands steadily to 170 bcm, mainly in power and industry, but the share of gas in the energy mix remains less than 10% in 2040. Demand in Southeast Asia and South Asia doubles, with growth driven largely by industry.

- Emerging economies in Asia as a whole account for around half of total global gas demand growth: their share of global LNG imports doubles to 60% by 2040.
- Unconventional gas increasingly underpins future natural gas supply. Shale gas production expands by 770 bcm in the period to 2040, which exceeds growth in conventional gas production. The United States accounts for 40% of total production growth to 2025. After 2025, additional growth comes from a more diverse range of countries including China, Mozambique and Argentina.
- Growth in global gas trade comes mostly from LNG, with its share swelling from 42% to almost 60% by 2040. LNG import flows continue to go mostly to Asia, while the export picture becomes more diverse with a new roster of suppliers.
- The global gas market comfortably absorbed a recent ramp-up in LNG liquefaction capacity; new LNG investment decisions are starting to come through, but it remains challenging to reconcile buyer expectations of greater flexibility on contractual terms with supplier needs for bankable longer term commitments.
- Gas demand in the European Union has been revised downwards on the back of new targets for efficiency and renewables, but gas infrastructure retains a strong role in ensuring security of supply – especially to meet seasonal peaks in heating demand that cannot be met cost-effectively by electricity.
- Despite lower demand, declines in indigenous production mean that the European Union's import dependence rises to 86% by 2025. Russia remains the largest single source of supply to the region and among the least-cost, but the leverage that this provides is set to wane in an increasingly integrated European gas market in which buyers have access to multiple sources of imported gas (Figure 4.2).

Figure 4.2 ▷ Natural gas imports and dependence in the European Union in the New Policies Scenario



Despite weakening demand, declining gas production suggests increased import dependence in the European Union

Introduction

Surging growth in global gas trade – underpinned by the shale revolution in the United States and the rise of liquefied natural gas (LNG) – continues to accelerate the transformation of gas markets. Although talk of a global gas market similar to that of oil is premature, LNG trade has expanded substantially in volume since 2010 and has reached previously isolated markets. Spot trading, liquidity and flexibility are all on the rise, meaning that gas is more accessible to a wider variety of market players and is more responsive to short-term changes in supply and demand across regions. Together with policy efforts to combat air pollution, these trends have supported growth in natural gas demand in emerging economies in Asia. China in particular has seen very rapid demand growth, overtaking Korea as the world's second-largest LNG importer in 2017, and well on track to surpass Japan.

Asia's emerging LNG importers are varied and are different from more mature markets in the region such as Japan and Korea. China is the closest to the traditional model, securing the bulk of its gas on a long-term basis and receiving it via onshore regasification terminals. Many other importers in Asia seek more flexible, shorter term arrangements to take advantage of current market conditions, and are more reliant on floating regasification to bring gas to market. There is some uncertainty around the position of natural gas in Asia's future energy mix, particularly since several potential new export projects do not look profitable at the price levels that have supported the recent rise in the region's gas consumption. While strong policy efforts may establish gas as a mainstream fuel in the energy system, signs of supply security risks or frequent price spikes could push gas to the margin and increase the prospect of Asian markets relying on a mix of coal and renewables. Uncertainty affects investors too, and only a handful of new liquefaction plants received the go-ahead from mid-2016 until mid-2018. Project approvals have picked up since then, but there are signs that exporters are still searching for commercial models suited to the new market order.

The first part of this chapter presents the key findings on natural gas from the various scenarios, after which we explore three crucial topics for the future of gas in detail:

- What is the outlook for natural gas demand in emerging Asian economies? There is ample scope for further growth in aggregate, but a wide variety of starting points and policy considerations make China, India, Southeast Asia and South Asia quite distinct.
- How will global gas exporters fare in a more competitive gas supply environment? We examine how changes in gas markets are creating new risks and opportunities both for the incumbents and for the burgeoning ranks of new gas exporters.
- What does the future look like for natural gas in the European Union? We explore how the European Union's ambitions for gas security and long-term decarbonisation intersect; what they mean for the future of gas infrastructure; and what the achievement of the "Energy Union" objectives might mean for the gas outlook.

Figures and tables from this chapter may be downloaded from www.iea.org/weo2018/secure/.

Scenarios

4.1 Natural gas overview by scenario

Table 4.1 ▷ Global gas demand, production and trade by scenario (bcm)

			New Policies		Current Policies		Sustainable Development	
	2000	2017	2025	2040	2025	2040	2025	2040
Power	907	1 515	1 618	1 981	1 668	2 226	1 602	1 265
Industry	631	872	1 076	1 436	1 089	1 522	1 041	1 221
Buildings	652	802	887	1 014	918	1 133	839	811
Transport	70	131	182	328	168	254	207	408
Other sectors	256	432	531	640	544	712	501	479
World natural gas demand	**2 516**	**3 752**	**4 293**	**5 399**	**4 386**	**5 847**	**4 189**	**4 184**
Share of Asia Pacific	*12%*	*21%*	*25%*	*29%*	*25%*	*29%*	*26%*	*36%*
Conventional gas	2 311	2 918	3 064	3 654	3 153	3 889	3 006	2 899
Tight gas	136	273	238	293	233	302	313	195
Shale gas	22	495	884	1 267	885	1 451	752	919
Coalbed methane	38	74	68	121	75	137	80	112
Other production	-	10	40	63	40	67	38	59
World natural gas production	**2 507**	**3 769**	**4 293**	**5 399**	**4 386**	**5 847**	**4 189**	**4 184**
Share of shale gas	*1%*	*13%*	*21%*	*23%*	*20%*	*25%*	*18%*	*22%*
Pipeline	391	447	491	532	500	657	458	452
LNG	136	323	509	757	518	807	527	627
World natural gas trade	**527**	**771**	**1 000**	**1 289**	**1 019**	**1 464**	**985**	**1 080**
Share of production that is traded	*21%*	*20%*	*23%*	*24%*	*23%*	*25%*	*24%*	*26%*
Henry Hub price ($2017/MBtu)	**6.0**	**3.0**	**3.3**	**4.9**	**3.4**	**5.3**	**3.3**	**3.6**

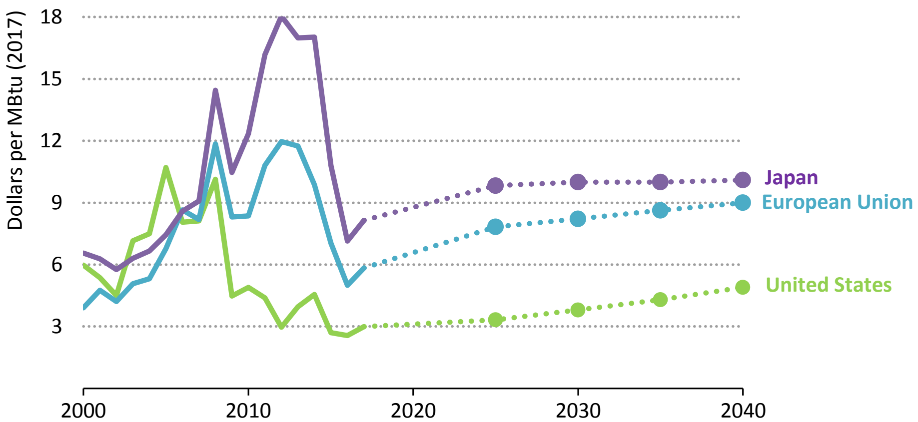
Notes: MBtu = million British thermal units. Unless otherwise stated, use of gas in industry in this chapter includes volumes also consumed in petrochemical feedstocks, own use and transformation in blast furnaces and coke ovens, and gas-to-liquids plants. Historical data for world demand differ from world production due to stock changes. Unless otherwise stated, trade figures in this chapter reflect volumes traded between regions modelled in the *WEO* and therefore do not include intra-regional trade.

In the **Current Policies Scenario**, global gas demand rises by 2% per year, resulting in almost 60% more demand in 2040 than today (Table 4.1). The largest growth in volume comes from the power sector, where gas faces less competition from renewables than in our other scenarios. With higher demand, unconventional gas resources are increasingly called upon. Shale gas production almost triples over the outlook period and increasingly takes place outside the United States, notably in China, Argentina and Canada. As the market resorts to more costly projects, the cumulative required investment in gas supply is 15% higher ($10 trillion) than in the New Policies Scenario, which explains the higher gas prices in this scenario.

In the **New Policies Scenario**, natural gas demand in 2040 has been revised up by almost 100 billion cubic metres (bcm) compared with our 2017 *Outlook*: the bulk of the revision is attributable to China, where gas demand grows rapidly reflecting strong policy efforts to improve air quality. Developing economies in Asia account for half of the total demand growth through to 2040.

The United States accounts for 40% of total gas production growth to 2025, after which sources of growth become more diverse as US shale gas production flattens and unconventional gas production from other regions picks up. Low-cost US production keeps Henry Hub prices relatively low until the mid-2020s, but increasing levels of global LNG trade eventually begin to narrow the gap between regional prices (Figure 4.3). The cumulative required investment for gas supply is about $8.4 trillion, with upstream investment representing two-thirds of the total.

Figure 4.3 ▻ Natural gas prices in key regions in the New Policies Scenario



Growing LNG trade narrows the gap in natural gas prices in key regions

In the **Sustainable Development Scenario**, gas demand continues to grow to 2025 before flattening out at around 4.2 trillion cubic metres (tcm). Gas is the only fossil fuel for which demand in 2040 is higher than today, and it becomes the largest fuel in the global energy mix. The dynamics are different from those in the other scenarios. Gas demand for power generation declines as gas increasingly provides peaking and balancing power rather than baseload generation. Instead, gas increases its share in the industry and transport sectors, where there is a strong impetus to curb the use of more emissions-intensive fuels. Lower demand translates into lower prices as well as lower investment needs for gas supply; the cumulative investment requirements amount to $6.3 trillion.

In more carbon-intensive systems where there is ample scope to displace coal, such as India, gas demand is higher than in the New Policies Scenario. In Europe and North America, demand remains stable to 2025, but declines after that reflecting improved efficiency in buildings and industry, and more rapid decarbonisation of power.

4.2 Natural gas demand in the New Policies Scenario

Table 4.2 ▷ Natural gas demand by region in the New Policies Scenario (bcm)

	2000	2017	2025	2030	2035	2040	2017-2040 Change	2017-2040 CAAGR
North America	800	969	1 078	1 101	1 136	1 170	201	0.8%
United States	669	767	853	869	890	907	140	0.7%
Central and South America	97	174	183	204	236	271	97	1.9%
Brazil	9	36	33	39	51	62	26	2.3%
Europe	606	613	622	611	601	592	- 20	-0.1%
European Union	487	482	472	450	426	408	-74	-0.7%
Africa	56	145	175	211	258	308	163	3.3%
South Africa	1	4	5	6	8	10	6	3.9%
Middle East	174	501	560	646	731	794	294	2.0%
Eurasia	471	575	592	601	617	635	60	0.4%
Russia	388	460	469	468	471	475	14	0.1%
Asia Pacific	313	775	1 073	1 248	1 413	1 579	805	3.1%
China	28	248	464	559	637	708	460	4.7%
India	28	57	94	122	147	171	113	4.9%
Japan	81	120	96	98	102	102	-18	-0.7%
Southeast Asia	88	170	205	229	258	289	119	2.3%
International bunkers	-	0	10	20	33	49	49	32.7%
World	**2 516**	**3 752**	**4 293**	**4 641**	**5 025**	**5 399**	**1 647**	**1.6%**
Current Policies			4 386	4 860	5 366	5 847	2 095	1.9%
Sustainable Development			4 189	4 318	4 298	4 184	433	0.5%

Notes: CAAGR = Compound average annual growth rate. International bunkers are LNG used as a marine fuel.

Global gas demand grew by 3% in 2017, largely driven by strong demand in China. In the New Policies Scenario, demand continues to increase by 1.6% per year, ending up some 45% higher by 2040 from current levels (Table 4.2). Two-thirds of this growth comes from developing economies in Asia and the Middle East.

China accounts for nearly 30% of total demand growth to 2040 in the New Policies Scenario. Demand grows in all end-use sectors, rising almost threefold over the outlook period. As part of the initiative to "turn China's skies blue again", the government has given a strong push to coal-to-gas switching in industry and buildings, and it plans to expand the scope beyond the original "2+26" cities (Beijing, Tianjin and 26 other cities). Gas also plays a bigger role in the power mix to meet surging electricity demand, complementing low-carbon sources. Today, natural gas consumption in China is roughly half that of the European Union, but it overtakes the EU in the mid-2020s and is almost 75% higher by 2040.

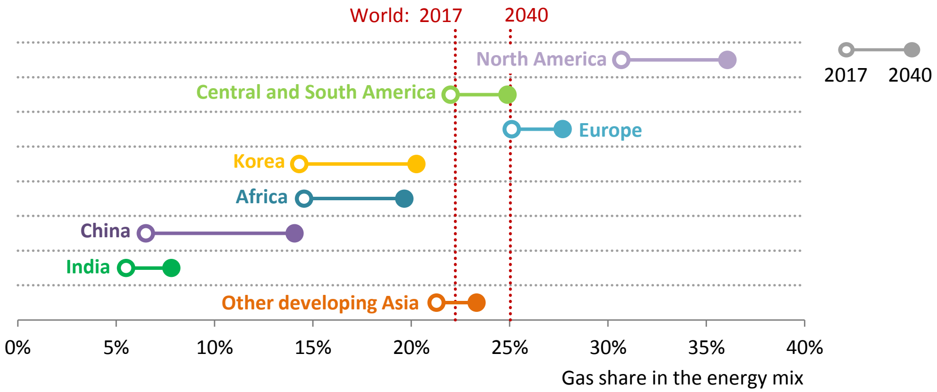
Natural gas demand in **India** expands steadily to 170 bcm, mainly due to the power and industry sectors, but the share of gas in the energy mix remains less than 10% in 2040 in the New Policies Scenario. While the low share of gas today implies huge scope for growth, strong competition from coal and renewables for power generation, the lack of policy measures to push out coal and challenges around infrastructure developments all hamper this potential from being fully realised.

In **Southeast Asia** and **South Asia**, where natural gas already occupies a relatively large share in the energy system, renewables and coal gain shares in the power mix, although gas demand still grows in absolute terms. In particular, demand for gas in industry pushes up overall gas consumption, resulting in gas demand in 2040 almost doubling from today's level (see section 4.5).

The **Middle East** sees growth in gas consumption over the outlook period that is second only to China. A combination of surging electricity demand and scope to displace oil makes the power sector the main source of rising gas demand. There is also substantial growth for desalination and industrial uses. Overall gas demand is 60% higher in 2040 than today.

Natural gas demand in **Africa** more than doubles in the period to 2040. The primary driver is gas use for power generation, followed by desalination and industrial uses.

Figure 4.4 ▷ Share of gas in the energy mix by region in the New Policies Scenario



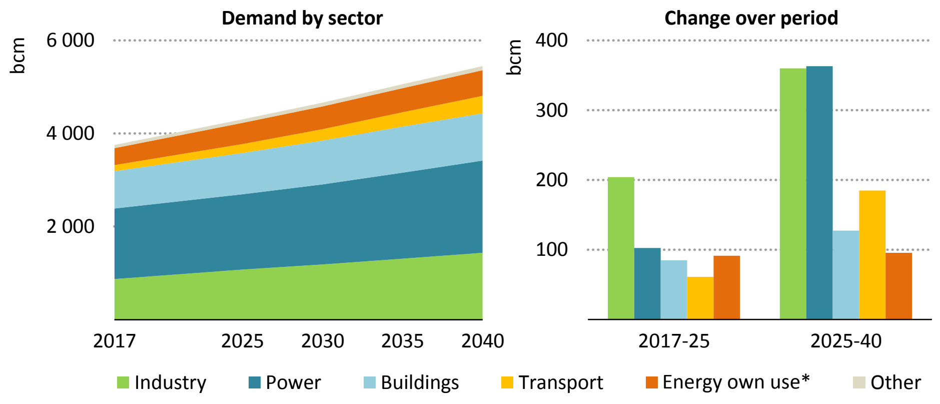
Gas continues to gain share in the energy mix in most regions, boosted by its versatility and environmental advantages

Unlike other fossil fuels, natural gas continues to make inroads in almost all **advanced economies**; the impacts of stagnant or declining primary energy demand are muted by the growing share of gas in the energy mix (Figure 4.4). In the United States, ample availability of gas at affordable prices fosters gas demand growth. In Korea, gas demand increases as the use of nuclear and coal in the power mix declines.

In 2017, over 60% of the global increase in gas demand was in the industry and buildings sectors. This is in contrast to the prevailing trend of the past where the power sector accounted for most of the increase in natural gas consumption (IEA, 2018a).

The **industry** sector is the main source of growth in natural gas demand in the New Policies Scenario, accounting for a third of the total (Figure 4.5). The chemical industry is the largest contributor: it uses gas to generate heat and steam as well as a feedstock to produce ammonia and methanol. Today gas is mainly used in energy-intensive industries that require high-temperature heat. In the New Policies Scenario, it is increasingly also used in light industries where there is strengthening policy impetus to curb emissions.

Figure 4.5 ▷ Global gas demand by sector in the New Policies Scenario



Industry remains the largest contributor to total gas demand growth, although the power sector contributes similarly in the latter part of the outlook period

* Includes energy used in oil and gas extraction, liquefaction, and refining processes.

The **power** sector is the second-largest contributor to increasing natural gas demand in the period to 2040. Prospects vary widely by region, but retirements of coal-fired capacity and strong demand for electricity create space for gas-fired power generation to expand in many developing economies in the latter part of the period. In some power systems, gas also has a role in providing flexibility to facilitate the deployment of variable renewable sources.

Outside China, there is only modest growth in demand for natural gas in the **buildings** sector in the New Policies Scenario. Gas use in this sector in advanced economies is curbed by increasing end-use efficiency and electrification, and – outside China – most developing economies do not have large seasonal heating needs.

Natural gas demand for **transport** nearly triples in the period to 2040, a result of policy-driven efforts to promote compressed natural gas (CNG) and LNG fuelled vehicles, especially in China. LNG use in shipping grows due to International Maritime Organization regulations to reduce the sulfur content in marine fuels, though its share in the overall fuel mix for shipping is modest (see Chapter 3).

4.3 Natural gas production in the New Policies Scenario

Table 4.3 ▹ Natural gas production by region in the New Policies Scenario (bcm)

	2000	2017	2025	2030	2035	2040	2017-2040	
							Change	CAAGR
North America	763	976	1 185	1 225	1 274	1 328	351	1.3%
Canada	182	184	181	173	175	194	10	0.2%
Mexico	37	32	33	38	50	60	28	2.8%
United States	544	760	971	1 014	1 049	1 074	314	1.5%
Central and South America	102	183	189	212	251	293	109	2.1%
Argentina	41	45	57	77	99	117	72	4.3%
Brazil	7	27	28	39	60	80	54	4.9%
Europe	338	291	227	207	205	203	-88	-1.6%
European Union	265	132	65	49	46	45	-87	-4.6%
Norway	53	128	128	109	107	105	-23	-0.9%
Africa	124	216	280	354	422	498	282	3.7%
Algeria	82	94	99	104	114	128	33	1.3%
Mozambique	0	5	15	42	55	69	64	12.2%
Nigeria	12	43	45	47	63	80	37	2.7%
Middle East	198	620	709	817	925	1 025	405	2.2%
Iran	59	214	241	275	302	315	101	1.7%
Qatar	25	169	188	219	244	264	95	2.0%
Saudi Arabia	38	94	106	121	139	157	63	2.3%
Eurasia	691	886	974	1 016	1 069	1 104	217	1.0%
Azerbaijan	6	18	32	39	44	46	28	4.1%
Russia	573	694	757	767	789	805	111	0.6%
Turkmenistan	47	80	90	114	136	154	74	2.9%
Asia Pacific	290	596	730	810	877	950	353	2.0%
Australia	33	105	158	178	191	208	103	3.0%
China	27	142	222	263	301	343	202	3.9%
India	28	32	41	58	71	85	53	4.4%
Indonesia	70	74	80	82	89	100	26	1.3%
Rest of Southeast Asia	89	151	152	155	154	146	-5	-0.1%
World	**2 507**	**3 769**	**4 293**	**4 641**	**5 025**	**5 399**	**1 630**	**1.6%**
Current Policies			4 386	4 860	5 366	5 847	2 078	1.9%
Sustainable Development			4 189	4 318	4 298	4 184	415	0.5%

Note: CAAGR = Compound average annual growth rate.

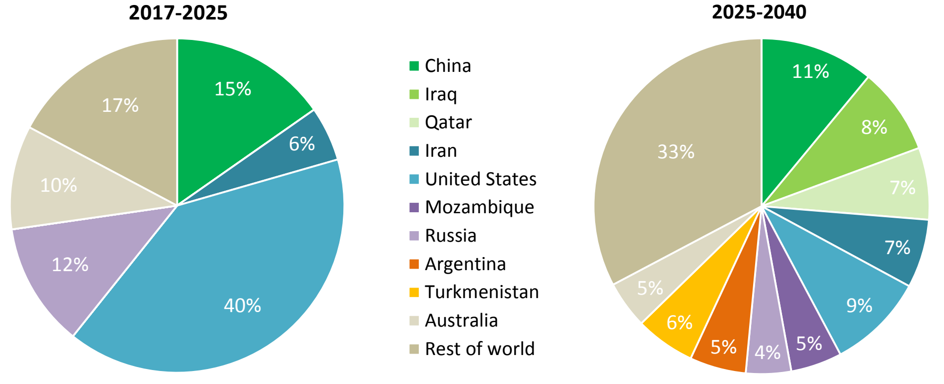
The natural gas supply projection in the New Policies Scenario is increasingly underpinned by unconventional gas production, which provides over half of the production growth in the period to 2040. Shale gas production expands by 770 bcm. The United States accounts for most of the growth to 2025, but other countries come into the picture thereafter, notably Canada, China and Argentina.

Conventional gas represents the majority of current gas production, but its share declines from 80% today to under 70% by 2040. Almost two thirds of production growth comes from the Middle East and Russia. Offshore production, deepwater in particular, accounts for an increasing share of conventional production, rising to almost half by 2040.

The share of associated gas in total gas output stays in a range between 10-15%. The United States remains the largest producer, although output begins to decline after US tight oil production reaches a plateau in the mid-2020s.

Today's major producers dominate production growth to 2025, with the United States taking the lion's share: five countries account for over 80% of total production growth. After 2025, there is a more diverse range of producer countries, with the top-five contributors accounting for less than 40% of the production growth (Figure 4.6).

Figure 4.6 ▷ Share by region in gas production growth in the New Policies Scenario



The supply picture becomes increasingly diverse after 2025; the top-ten contributors share around two-thirds of the production growth

The **United States** is the largest gas producer today and remains so throughout the outlook period. In the late 2020s, the country produces a third more gas than the next largest producer (Russia). Remaining resources of shale gas have been revised up to 34 tcm, a 5.5 tcm increase compared with our 2017 projection, in line with new estimates from the US Energy Information Administration: production in 2025 is now 70 bcm higher than in the *World Energy Outlook-2017 (WEO-2017)*. Today shale gas accounts for 63% of total US gas production; within five years this share reaches 80%. Shale gas production reaches its highest level in the early 2030s, and then declines slowly.

Shale gas production in **Canada** accelerates and by 2040 it accounts for around 70% of Canada's total gas production, compared with less than 5% today.

There have been promising signs from drilling activity in **Argentina**'s resource-rich Vaca Muerta Basin. Argentina also has a well-established gas market and improving conditions for investment. Today shale gas production is less than 3 bcm: after 2025, it expands by over 10% every year to more than 60 bcm in 2040, necessitating a search for new export outlets.

Natural gas production in **Russia** grows steadily through to 2040, maintaining its position as the world's second-largest gas producer. Today nearly all production in Russia comes from fields in Western Siberia and the Yamal peninsula, but the opening of new routes to China leads to production also expanding in Eastern Siberia and in Russia's Far East. Domestic consumption in Russia remains broadly flat, meaning that the rise in output has to find export markets.

Norway remains Europe's largest gas producer. Production is broadly constant until 2025 and then declines by around 1.5% per year due to waning North Sea production. In the **Netherlands**, the decision to restrict further gas production from the giant onshore Groningen field leads to a major decline in production. Groningen produces around 25 bcm today: this will be roughly halved in the next five years and reduced to zero by 2030. By 2040, production in the Netherlands falls to just under 10 bcm.

Natural gas production in **Iran** grew by almost 15 bcm in 2017, but the re-imposition of US sanctions has cast uncertainty over further substantive increases in the near term. The New Policies Scenario sees production expand to over 320 bcm after 2025, most of which is needed to meet growing domestic needs. Most of **Iraq**'s gas is associated with oil in its southern super-giant fields, although an estimated 18 bcm is currently flared. This situation changes in the New Policies Scenario as infrastructure is put in place, with the power sector the main beneficiary. The recent lifting of the moratorium on the North Field in **Qatar** will take some time to feed through into any substantial new gas volumes, and the New Policies Scenario sees production growth remain subdued until the mid-2020s. After 2025, production grows by nearly 80 bcm. The majority of this increase is exported as LNG.

Egypt is emerging as an important gas producer with development of its Zohr and Nooros gas fields and plans to evaluate the Noor gas fields. These lead to a jump in production of over 25 bcm by 2025. In **Mozambique**, the Coral floating LNG project was recently approved. While it does not make a material impact in the near term, production expands nearly fivefold after 2025 as onshore liquefaction plants are added.

China possesses vast shale and tight gas resources, but it faces substantial challenges in developing them, and the government's production projections have been consistently revised downwards. Substantial growth in demand acts as a stimulant to push shale gas production up by around 90 bcm between 2017 and 2040, along with other unconventional sources. China becomes the world's third-largest gas producer by 2040, surpassing Iran.

4.4 Trade and investment

Table 4.4 ▷ Natural gas trade by region in the New Policies Scenario

Net importer in 2040	Net imports (bcm)				As a share of demand			
	2000	2017	2025	2040	2000	2017	2025	2040
European Union	221	349	409	373	45%	73%	86%	89%
China	1	106	243	369	5%	43%	52%	52%
Other Asia Pacific	-65	-56	12	174	n.a.	n.a.	4%	36%
Japan and Korea	97	162	145	166	97%	98%	98%	99%
India	0	26	54	86	0%	45%	57%	50%
Rest of world	46	-27	-11	31	37%	n.a.	n.a.	16%
Net exporter in 2040	**Net exports (bcm)**				**As a share of production**			
	2000	2017	2025	2040	2000	2017	2025	2040
Russia	185	234	288	328	32%	34%	38%	41%
Middle East	24	119	148	224	12%	19%	21%	22%
North America	-37	7	106	154	n.a.	1%	9%	12%
Australia	10	60	107	149	31%	57%	68%	71%
Caspian	36	78	94	138	30%	40%	43%	46%
Sub-Saharan Africa	6	33	56	125	35%	51%	60%	53%
North Africa	62	37	48	63	58%	25%	26%	24%
Central and South America	5	9	5	19	5%	5%	3%	6%
World	**Trade (bcm)**				**As a share of production**			
	2000	2017	2025	2040	2000	2017	2025	2040
Pipeline	391	447	491	532	16%	16%	11%	10%
LNG	136	323	509	757	5%	5%	12%	14%
New Policies	**527**	**771**	**1 000**	**1 289**	**21%**	**20%**	**23%**	**24%**
Current Policies			1 019	1 464			23%	25%
Sustainable Development			985	1 080			24%	26%

Notes: n.a. = not applicable.

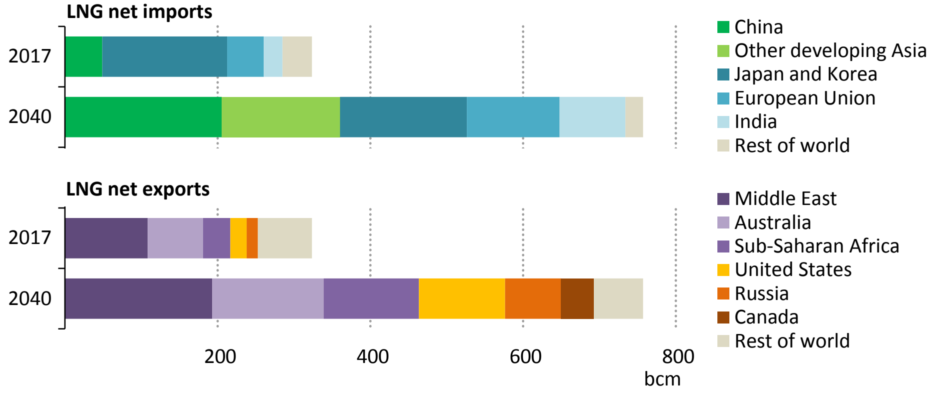
Global gas trade expands at an annual average rate of 2.3% over the course of the New Policies Scenario, much faster than the pace of demand growth (1.6% per year). This outlook underpins a major shift in the importer/exporter landscape. With rapidly increasing demand, China soon becomes the world's largest gas-importing country, and its net imports approach those of the European Union by 2040. With growing import needs in other Asian economies, over 60% of the world's gas trade finds a home in Asia. Russia and the Middle East remain the world's largest gas exporters throughout the outlook period, but their share in global exports gradually reduces with the rise of new exporters.

The growth in trade comes mainly from LNG, lifting its share in global gas trade from 42% today to almost 60% by 2040. Global LNG trade more than doubles to 760 bcm by 2040, making the gas market much more global and interconnected. China is the only region that shows a noticeable growth in trade via pipeline, mostly from Eurasia.

Asia is the primary destination for rising LNG imports. China and India account for over half of the growth in net LNG imports in the period to 2040. With waning production in Malaysia, Bangladesh and Pakistan, other developing countries in Asia increase their import volumes considerably. The Asia Pacific region accounts for around 80% of global LNG imports by 2040.

While the import picture concentrates on Asia, the export one becomes more diverse with a roster of new suppliers later in the outlook period. Today about 60% of LNG exports are from Qatar and Australia. Over the outlook period, first the United States and then sub-Saharan Africa each add some 90 bcm of export volumes and Russia increases LNG exports by 60 bcm. These three regions collectively take up larger stakes in global LNG exports, doubling their share from 23% today to over 40% by 2040 (Figure 4.7).

Figure 4.7 ▷ LNG net trade by region in the New Policies Scenario



Global LNG trade flows show contrasting trends; imports concentrate in Asia and export supply sources diversify

In the New Policies Scenario, around $380 billion of investment is needed each year for natural gas supply: upstream investment accounts for two-thirds, with unconventional plays taking an increasing share. The required investment for LNG infrastructure amounts to $35 billion per year on average. Since its peak in 2014-15, investment in LNG has declined to $20 billion in 2017 (IEA, 2018b). Although there are signs of a pick-up in new project approvals, the lack of final investment decisions in recent years still points to a possible risk of market tightening in the 2020s (IEA, 2018c).

Key themes

4.5 The future of gas demand in emerging Asian economies[1]

In the aftermath of the shale boom in the United States and the parallel LNG investment rush in Australia, there was a general expectation of structural oversupply in global gas markets that has not materialised at the anticipated scale. The rapid growth of gas demand in emerging Asian economies – led by China – has played a central role in challenging this expectation. Emerging Asian economies accounted for most of the increase in global LNG imports in recent years, with their share growing from 13% in 2010 to almost 30% in 2017. China and India accounted for the lion's share of this growth, but other countries were also substantial contributors. A number of countries, notably Indonesia, Malaysia and Pakistan, initiated LNG imports in recent years: Pakistan in particular emerged as the third-largest LNG importer among emerging Asian economies as it faced gas shortages. The share of emerging Asian economies in global LNG imports is set to grow further with additional countries – Bangladesh and potentially Myanmar, Viet Nam and the Philippines – joining the ranks of importers of LNG.

Where does gas demand in emerging Asian economies go from here? There appears to be plenty of room for further growth: the share of gas in the region's energy mix is less than 10%, considerably lower than the global average of 22%. Gas is also a good fit for a rapidly urbanising region with a population that is increasingly concerned about qualitative aspects of economic development, including air quality. However, the considerations vary widely by country:

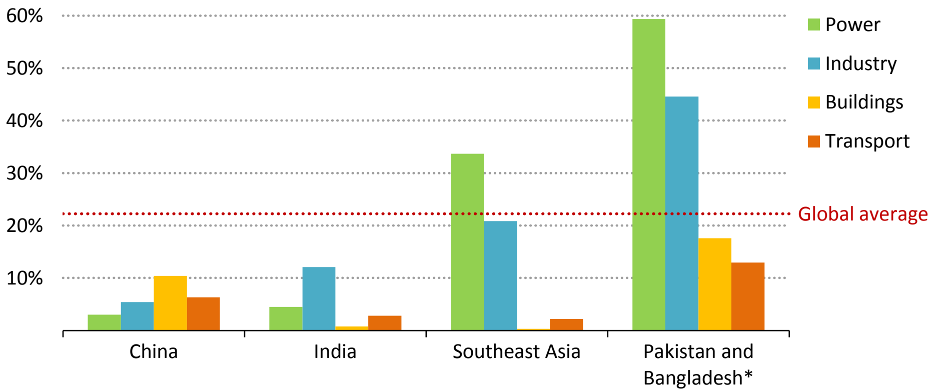
- The price of natural gas, of course, is a key variable and the structure of gas demand in each importing country affects the way in which it responds to changing market conditions. Price sensitivity varies by sector. Demand for gas for use in power generation can be more volatile; depending on relative prices and levels of variable renewable output, the role of gas can oscillate between baseload, mid-merit and peak load, leading to variations in consumption patterns. Demand from industry and transport is generally less sensitive to price, at least in the short term, as natural gas faces less immediate pressure from competing fuels and industrial processes may not be conducive to fuel switching. Natural gas demand in the buildings sector is also less sensitive to prices on an annual basis, but can show large swings in seasonal load.
- Policy measures to promote the use of gas (or to limit the use of competing fuels such as coal) can significantly influence demand levels. For example, in China the government is pushing coal-to-gas switching in industry and buildings to address environmental concerns. The introduction of similar policy measures in other Asian countries would translate into higher gas use; any retreat from policies favouring gas would have the opposite effect.

1. Emerging Asian economies include China, India, Southeast Asia, South Asia and other developing countries in the region.

- Security of supply is a concern. While some markets may have a basket of supply options that include indigenous production and imports via pipeline and LNG, others may rely solely on a limited number of supply sources. Confidence in the reliable operation of international gas markets is an important variable for the future.
- The availability of infrastructure is critical: in markets where gas networks are already well developed, there is an incentive to support their continued use as long as gas is reasonably reliable and affordable. The prospects for gas elsewhere are highly dependent on a readiness to expand gas networks.

Although the region is often dubbed "emerging Asia" as a whole, it is difficult to generalise about its gas demand. Gas has been a niche fuel in some markets (such as India) while it is well established in some others (parts of Southeast Asia, Pakistan and Bangladesh). Understanding the outlook for gas in emerging Asia requires a much more granular approach (Figure 4.8). It also requires a close look at the emerging gas giant – China.

Figure 4.8 ▷ Share of natural gas in the energy mix by sector in emerging Asian economies, 2017



Gas plays a different role and faces varying prospects in emerging Asian markets

* Shares in 2016.

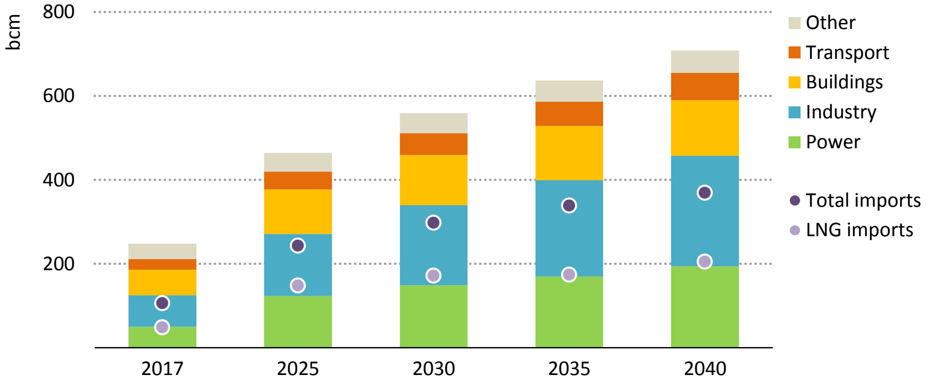
China shakes up global gas markets

Natural gas accounts for only around 7% of China's primary energy mix today, but demand expanded by a notable 16% in 2017 and the indications for 2018 look similarly strong. This is mainly attributable to the strong policy push for coal-to-gas switching in industry and buildings as part of the drive to "turn China's skies blue again" and improve air quality. In 2017, the government set targets for "clean" winter heating in Beijing, Tianjin and 26 other cities (the "2+26" cities) and announced a medium-term target for the whole of northern China to reach 70% of clean heating rates by 2021 (up from 34% in 2016).[2]

The continued push for clean heating is likely to have huge impacts on demand for gas and electricity. So far, coal-to-gas switching has been the main option to meet the target, but winter gas shortages in 2017 suggest that the future pathway is likely to be more diverse. While some regions continue to push coal-to-gas switching (e.g. the "2+26" cities), other regions may pursue electrification (or coal-to-electricity) or cleaner coal-burning technologies (coal-fired boilers retrofitted for low emissions), depending on resources and infrastructure availability. In the New Policies Scenario, we expect strong demand growth for both natural gas and electricity for heating at the expense of direct coal use, especially during the period to 2025.

Partly for this reason, and because of the broader shift towards a consumer oriented economy, electricity demand in China is set to increase by 30% in the years to 2025. Although growing electricity demand is primarily met by renewables and nuclear in our projections, there is scope for gas to contribute. China has also introduced incentives to use CNG for passenger vehicles and LNG for trucks. In the New Policies Scenario, gas makes strong inroads in every sector, taking total demand to 710 bcm by 2040 (three-times higher than today, and accounting for 14% of total energy demand in 2040) (Figure 4.9).

Figure 4.9 ▷ China's natural gas demand by sector and import needs in the New Policies Scenario

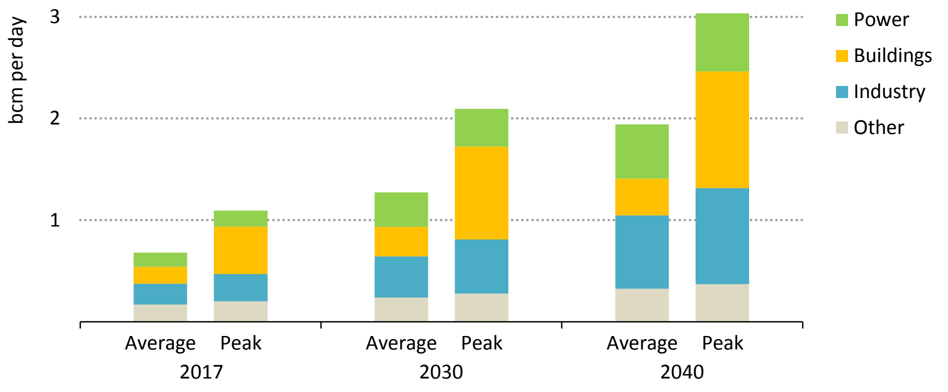


With rising gas demand in all end-use sectors, China's import needs more than triple in the period to 2040, and it becomes the world's largest gas-importing country

2. China's latest Clean Winter Heating Plan defines clean heating rates as the share of natural gas, electricity, geothermal, biomass, solar energy, industrial waste heat, nuclear energy and cleaner coal-burning technologies in total heating demand. In 2016, cleaner coal represented half of the clean heating demand in northern China.

By displacing more polluting fuels, rising gas demand helps to meet important Chinese policy objectives that target a high quality of development. However, it also brings challenges for security of supply as well as infrastructure development. Today, indigenous production meets around 60% of China's gas needs. In our projections, China's gas production increases by 4% per year (almost entirely driven by unconventional gas), but this is insufficient to satisfy soaring gas demand. Increasing volumes of imports are therefore required to fill the gap, especially via LNG. In the New Policies Scenario, China's needs for LNG more than quadruple in the period to 2040, becoming the largest LNG importing country in the world. Securing affordable and reliable gas supply, ensuring supplier diversification and building infrastructure in a timely way are becoming important challenges for Chinese policy makers.

Figure 4.10 ▷ Average and peak daily gas demand in China in the New Policies Scenario



China's peak daily gas demand is almost 60% higher than average daily demand

Infrastructure availability is a major potential constraint, and the recent winter gas shortage highlighted China's limited storage capacity. China's gas demand for buildings and power generation has a large seasonal swing, resulting in a large gap between average daily demand and peak day demand (Figure 4.10). China's current storage capacity, at around 12 bcm, can only cover around ten days of peak demand. In the New Policies Scenario, a significant expansion of storage capacity is required to balance the seasonality of demand. Pipeline capacity constraints and limited interconnectivity – the connection between existing trunk lines and pipelines and LNG import terminals – also hinder the expansion of gas, although small-scale LNG trucks are filling the gap to some extent. In recent years, the government has made serious efforts to expand gas storage and the pipeline network. In 2018, China's State Council issued an order to mandate gas suppliers, city gas distributors and local governments respectively to have storage capacity equal to 10% of supply, 5% of demand and three days of average daily demand by 2020, although there are challenges such as finding suitable sites for storage and addressing pricing issues.

Looking beyond China; Asia's other major gas markets

Although China is the largest, there are many other sizeable markets for gas across emerging Asia with huge room for growth. For instance, in **India**, the penetration of gas is low today (around 5% of the total energy mix), but this does not necessarily mean that it is poised to follow the path that China is taking.

The Indian government is keen to boost the use of gas to combat air pollution and is promoting the expansion of gas infrastructure: four additional LNG receiving terminals are under construction and a number of pipelines are being built to bring imported LNG to new consumers. The government has also made it a priority to expand city gas networks to stimulate demand in urban areas, alongside efforts to promote third-party access to infrastructure and liberalise the domestic gas market. The example of Gujarat state in the northwest shows what can be done: it has an extensive pipeline network and with only around 5% of the country's population, it accounts for almost one-third of national gas consumption. For the moment, though, Gujarat is an outlier. Elsewhere, particularly in states close to the main coal-producing areas, gas has struggled to gain ground.

Gas consumption in India's power sector (with less than a 5% share today) faces strong competition from coal and renewables, and the value of gas-fired plants as a source of peaking power is often not recognised or remunerated by cash-strapped electricity distribution companies. In the industrial sector, gas consumption today is concentrated in subsectors with potential for growth, notably the fertiliser, refinery and chemical industries. Gas might also be an economically attractive option for industries that use oil products for heat. However, the prospects for gas being used on a much larger scale as an industrial fuel depend on a helping hand from policy, without which it is likely to struggle to displace coal. Supportive policies can create an opening for gas as a residential fuel in some major urban areas, primarily for cooking, with the aim of freeing up liquefied petroleum gas (LPG) to replace solid biomass for use as a cleaner fuel outside the cities. Yet the absence of major heating requirements in India limits the potential for gas use in the buildings sector.

The result in our New Policies Scenario is steady, rather than spectacular, growth in gas use in India, with an expansion of around 5% per year bringing consumption to 170 bcm by 2040, mostly driven by the power and industry sectors. LNG imports take most of the strain on the supply side, reflecting slower domestic production growth and the limited scope for pipeline imports (for the moment, we do not see the proposed Turkmenistan-Afghanistan-Pakistan-India pipeline coming to fruition).

Infrastructure will be a crucial determinant of the future role of gas in India. If there is sufficient confidence in the LNG market, one approach to gas market development could be to focus infrastructure development on specific areas near the coast, where there is easy access for LNG and a relatively dense concentration of urban and industrial users.[3] Gas-fired power could then be made more widely available via the electricity grid (the so-called "gas-by-wire" model) if distance, cost and planning issues mitigate against the extension of gas pipeline networks.

Price reforms are also crucial for gas to expand its role in India. Regulated prices for domestic gas are dampening investment in upstream activities while creating distortions in consumption patterns. Sectors with priority access to domestic gas may not be incentivised to use it as efficiently as possible, meaning that other sectors without priority access have to pay more for their gas than they otherwise would, which undermines the potential for demand growth (Boersma, Losz and Ummat, 2017). Several steps have been taken to improve gas pricing in recent years and the direction and pace of further reforms is likely to have a significant impact on the outlook for natural gas.

At the other end of the spectrum from China and India, there are markets in Southeast and South Asia where natural gas already occupies a much higher share in the energy mix. In **Southeast Asia**, a number of countries are highly dependent on gas for electricity: today around one-third of the region's power is generated by gas, and this share is 53% in Thailand and over 90% in Singapore. The question in Southeast Asia is therefore quite different from that in China and India: can gas retain its current position in the mix?

It will be challenging. In many parts of Southeast Asia, domestic gas production is failing to keep pace with demand, leading to a rise in imported gas. In these circumstances, countries may turn to readily available alternatives to gas in order to meet surging electricity demand. In the New Policies Scenario, gas use for power increases in absolute terms but loses share to renewables and coal in the overall mix. The largest growth of gas demand instead comes from industry, as the region adds a host of manufacturing facilities. Gas has fewer opportunities to penetrate into the buildings sector given scattered demand centres, low levels of demand for heating and the absence of distribution networks.

Although Southeast Asia contains major current LNG exporters like Malaysia, Indonesia and Brunei Darussalam, the New Policies Scenario sees the region becoming increasingly dependent on LNG imports over the period to 2040. The rise of 90 bcm in LNG imports is much higher than the growth in India over the same period. Security of supply is therefore a critical variable in shaping the prospects for gas in this region. If policy makers perceive future supplies as secure, gas is set to sustain a large share in the energy mix, but frequent price spikes or perceived security of supply risks could change the picture.

The outlook in parts of **South Asia**, notably in Pakistan and Bangladesh, is different again. The energy mix in both of these countries is highly reliant on gas; growth in indigenous production has helped to push the share of gas in the energy mix up to over 25% in

3. Natural gas compares favourably to other energy carriers as a clean urban energy solution when demand is reasonably concentrated and the region's power system depends on emissions-intensive fuels such as coal. With higher conversion efficiencies, gas boilers require less primary energy to produce heat, thereby incurring less carbon and air pollutant emissions.

Pakistan and almost 60% in Bangladesh. Gas use is highest in the power sector, but (in contrast to Southeast Asia) is also prominent across all end-use sectors. Here too, more limited availability of domestic gas is putting pressure on the system: subdued production in recent years has caused severe gas shortages, which have triggered fuel switching in an unconventional direction, from gas-to-coal and even to oil, alongside the initiation of LNG imports. As in Southeast Asia, confidence in the reliability and affordability of supply will be important in shaping the future prospects of gas. While domestic infrastructure favours continued use of gas, there is an emerging need for additional imports to feed the existing network. In our projections, these supplies arrive in the form of LNG, although an alternative possibility for Pakistan in particular is to source pipeline imports from Iran or from Turkmenistan (both of these routes face sizeable political obstacles, at least in the near term). If either of these projects were to be realised, they would anchor a significant part of Pakistan's gas demand.[4]

Countries in South Asia pursue a diverse set of power generation options in the New Policies Scenario, gradually reducing the share of gas in the power mix and increasing the share of renewables and coal (and nuclear in Pakistan). However, there are still opportunities for gas to displace fuel oil and diesel in the power mix and to meet increasing electricity demand: these put gas demand for power generation on a moderately rising trajectory through to 2040. Gas also continues to make inroads into the expanding industry sector and demand also grows in buildings: unlike in India and Southeast Asia, there is demand for winter heating in parts of Pakistan.

Implications for global LNG markets

In the New Policies Scenario, gas faces varying prospects in each of the emerging Asian economies. Gas makes a rapid transition from a niche fuel to a mainstream fuel in certain markets, while in others it faces intense competition to defend its prime position. Nevertheless, a common feature is their growing need for LNG imports. Emerging Asian economies account for over 80% of the growth in global LNG imports in the period to 2040, and their share in LNG imports more than doubles from less than 30% to 60% in 2040.

The consumers driving the increase of LNG imports have differing demand profiles, which means that their interactions with global LNG markets may vary substantially. To give a sense of these variations, we consider this import demand in three indicative categories.

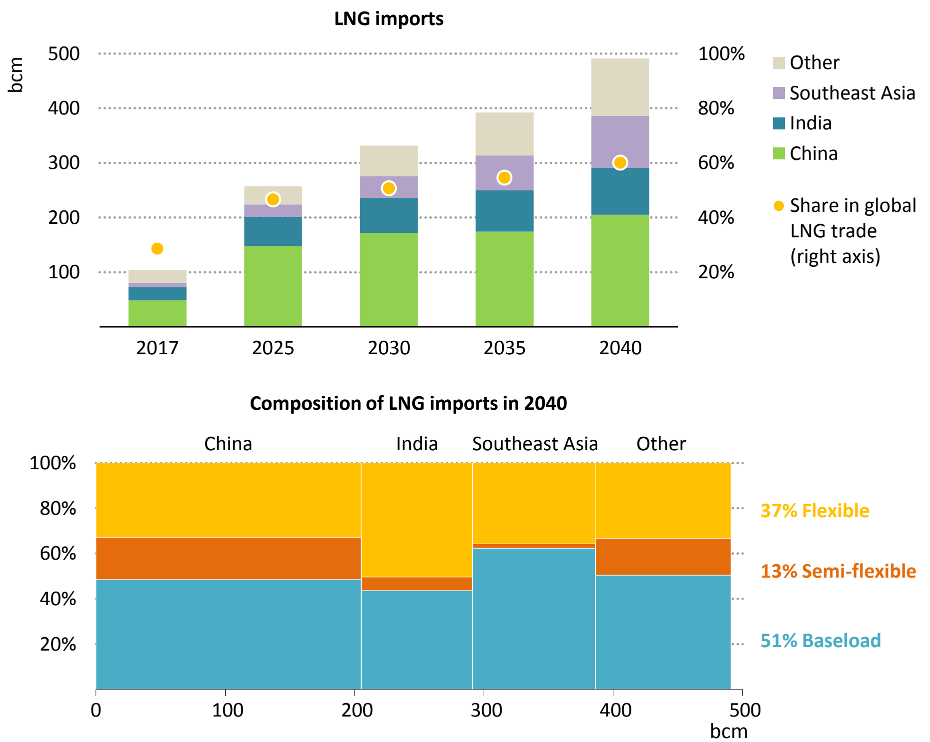
- "Baseload" LNG imports: these include natural gas demand in industry, particularly the energy-intensive segments, and transport which tends to be relatively constant throughout the year. In addition, where gas provides baseload power generation or there is not much excess capacity in the market, demand for gas in power generation could also be well suited to regular shipments of imported gas.

4. For example, the proposed Turkmenistan-Afghanistan-Pakistan-India pipeline has planned total capacity of 33 bcm/year, of which 14 bcm/year is for Pakistan. This volume corresponds to over 40% of today's gas demand in Pakistan.

- "Semi-flexible" LNG imports: include demand in the buildings sector, which can have significant seasonal load variations. When there is insufficient storage capacity to balance seasonality (as in most emerging Asian countries), LNG is an option for dealing with seasonal demand variation, providing flexibility to ramp up and down as needed.
- "Flexible" LNG imports: demand in power generation (especially peak or mid-load demand) is likely to depend on price competition with other available fuels on an annual basis as well as over the long term. This segment is more opportunistic and is likely to value contractual terms that offer flexibility and have shorter duration.

In the New Policies Scenario, the largest increment in LNG consumption between today and 2040 comes from the baseload segment, underpinned by demand growth in industry: this is the largest source of demand growth in all major countries except for India. The baseload segment represents around half of total LNG demand in 2040 (Figure 4.11).

Figure 4.11 ▷ LNG imports in emerging Asian economies in the New Policies Scenario



Emerging Asian economies become heavyweights in global LNG markets, with their share of global LNG trade more than doubling to 60% by 2040

The importance of the baseload segment suggests that Asian importers could provide the sort of longer term offtake commitments that might underpin new upstream and infrastructure developments elsewhere in the world. At the same time, the more price-sensitive flexible segments that may vary their purchases depending on the price of gas, stand to benefit from movement towards a more liquid and competitive LNG market. Aggregators (or "portfolio players") that can provide shorter term volumes on demand promise to be an important source of gas for these more opportunistic consumers.

The way that this market evolves will have implications far beyond Asia. A more flexible LNG market, combined with a price-responsive segment of gas demand in Asia's power sector that can switch away from gas if prices rise too high, would be an important contributor to overall gas security. Such a market could potentially serve as a buffer to absorb any supply or demand shocks to the system, compensating for a loss of flexibility in Europe and the United States as coal-fired capacity falls and reduces fuel-switching capabilities in these regions. This though would depend critically on the progress made in developing well-functioning gas and electricity markets in Asia that allow price signals in international markets to feed into decisions throughout the value chain.

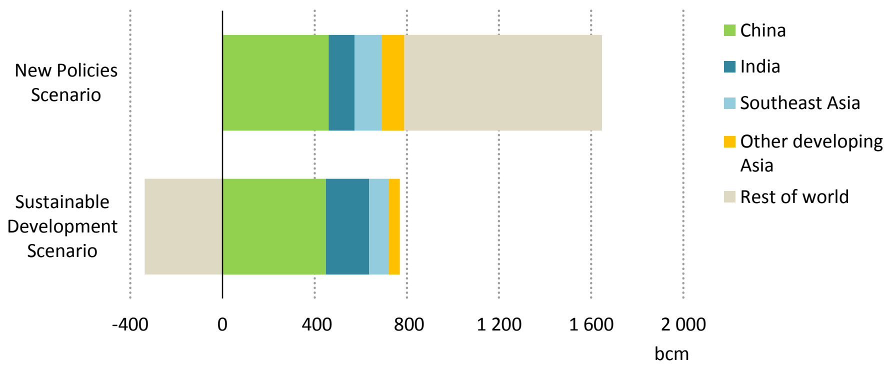
To the extent that policy makers in Asia feel that gas represents a reliable, affordable option that helps to meet their economic and environmental objectives, they will be ready to commit to the policies and the infrastructure necessary for its growth – as China is demonstrating. For exporters and suppliers, this creates an imperative to keep the cost gap with competing fuels as narrow as possible and to develop commercial strategies that are adapted to the demands of Asia's new consumers (see section 4.6). The development of a liquid and competitive LNG market is therefore closely linked with the prospects of gas demand in emerging Asian economies and vice versa.

Box 4.1 ▻ Emerging Asian gas demand in the Sustainable Development Scenario

Gas demand grows in most parts of the world in the New Policies Scenario, but there are strong regional variations in the Sustainable Development Scenario. While gas use comes under pressure from the expansion of renewables and from strong energy efficiency policies in many advanced economies, emerging Asia remains a key source of demand growth to 2040 as gas plays a prominent role – alongside renewables – in displacing more carbon-intensive fuels. In the Sustainable Development Scenario, the share of gas in the energy mix rises to almost 20% in China and 16% in India by 2040, compared with 14% and 8% in the New Policies Scenario. Gas demand also grows in Southeast and South Asia, but less robustly, reflecting its already strong position in the energy mix.

There is a striking similarity in outcomes (in volume terms) for natural gas between the New Policies Scenario and the Sustainable Development Scenario in emerging Asian economies (Figure 4.12). However, this does not mean that a positive role for gas in the region can be taken for granted. If the price, policy, security of supply and infrastructure issues are not overcome, most of the alternative pathways would involve greater reliance on a combination of indigenous renewables and coal, the latter coming with a range of local and global environmental hazards.

Figure 4.12 ▷ Changes in gas demand by region and scenario, 2017-2040



Owing to China and India, growth in emerging Asian gas demand in the Sustainable Development Scenario is largely the same as the New Policies Scenario

4.6 Exporter strategies in a changing gas market order

Global gas markets, business models and pricing arrangements are all in a state of flux. Thus far, increasing LNG supply is being absorbed by robust demand, particularly in Asia. However, an additional 100 bcm of liquefaction capacity is expected to come online by 2023, as the expansion of export capacity continues in Australia and the United States. With a host of new players positioning themselves between buyers and sellers, the market itself is becoming more contestable, with signs of more flexibility in contractual provisions on destination and re-sale, more gas-on-gas competition and a greater share of gas being sold on a spot or short-term basis. However, it is not clear that buyers' expectations of new, more flexible contractual terms are a good match for what sellers will need to underpin major new infrastructure projects, which continue to require long-term commitments. In this section, we examine the implications of changes in the market for suppliers, consumers, and for business models and investment.

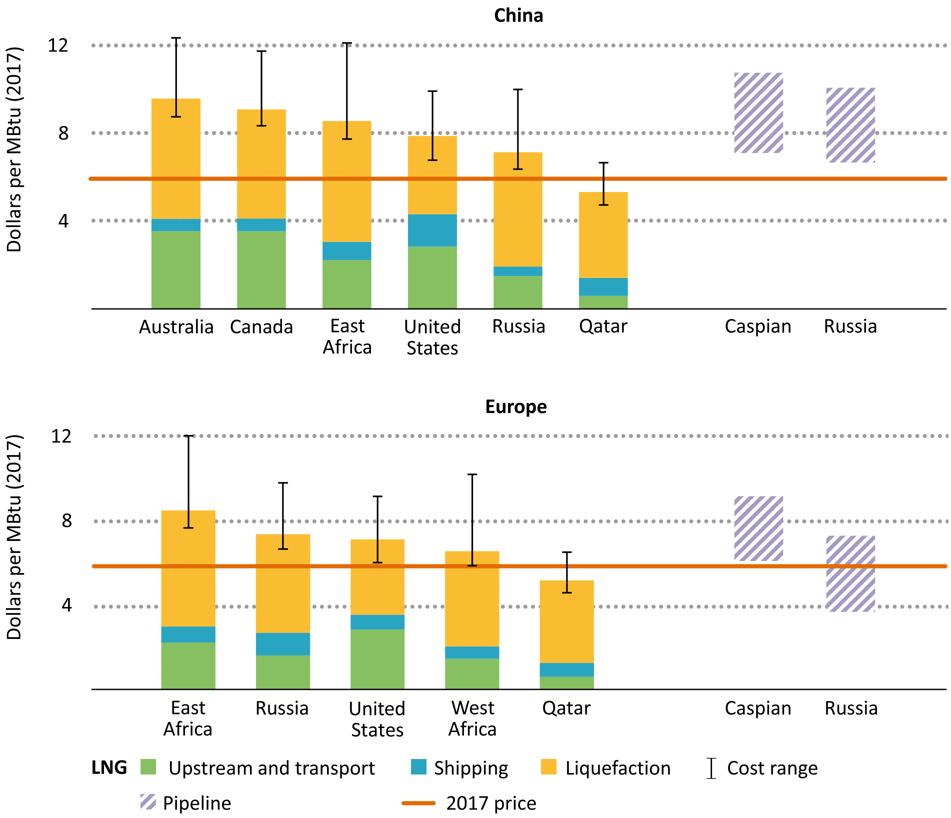
Qatar's plans to expand its LNG capacity are an important test of market sentiment. With a geographical position ideally situated to serve both Asian and European markets, Qatar is in a strong position to develop a sizeable part of new LNG liquefaction projects scheduled to come on stream in the mid-2020s. Its potential to tap into liquids-rich gas and leverage its vast existing infrastructure complex at Ras Laffan means that it sits firmly at the bottom of the cost curve for new supply. Following the lifting of a self-imposed moratorium on further development of the vast North Field, Qatargas announced its intention to add around 45 bcm to its supply portfolio by constructing four new liquefaction trains. The eventual pricing and contracting structures underpinning these future volumes will give some indication of whether traditional exporters are willing to countenance changes to the way the market works. The early indications are that there is still an appetite for longer term arrangements: ten years after its last contracts with Chinese buyers, Qatargas recently announced a new 22-year oil-linked contract with PetroChina, which would follow a 15-year contract signed in 2017 by Qatargas with Bangladesh (IEA, 2018c).

Many other countries are looking to expand or announce their presence in international gas markets. The commissioning of Yamal LNG in Russia on time and on budget in 2017 – against market expectations – has reignited discussions about future prospects in the Arctic, and the Russian government's exemption of Yamal LNG from mineral extraction and export taxes may provide the template for further projects. Mozambique has long been exporting gas via pipeline to South Africa, but its horizons expanded with major discoveries in the offshore Rovuma Basin: the Coral floating LNG project was approved in 2017, and there is now the prospect of larger onshore liquefaction investment to develop these resources at scale. The decision in October 2018 to move ahead with the LNG Canada project in British Columbia is Canada's first large-scale move into LNG, allowing the country to look beyond its regional role as a pipeline supplier to the United States. In West Africa, the gas discovered on the maritime border between Mauritania and Senegal looks destined for export. Although Argentina has no current plans for LNG, it too may well be drawn towards this market as and when it needs to find outlets for expanding production from the Vaca Muerta play.

The likelihood of a second wave of LNG investment in the United States looms large in the investment calculations facing projects elsewhere in the world. New US LNG projects are not the least expensive option for incremental gas delivery into either European or Asian markets; it is highly unlikely that any project will be able to undercut Qatar on this score (Figure 4.13). However the size of US resources, the large number of proposed LNG export projects, the scope for production flexibility, together with an LNG export industry actively seeking arbitrage opportunities, combine to put a ceiling price in the market – a deterrent for any project that requires a gas price higher than the delivered cost of US supply.

The long shadow of US LNG adds to the complexity facing other projects as potential sellers try to align their interests with those of potential buyers. There is, for the moment, little consensus on the appropriate choice of pricing mechanisms, contract durations and degree of flexibility, or on whether the world is still in a buyers' market or is seeing bargaining power gradually shifting back towards sellers. In addition, LNG projects in different parts of the world all carry their own unique challenges. The recently approved LNG Canada project, for example, will require 670 kilometres of new pipeline infrastructure to transport gas to the LNG facility on the coast. In sub-Saharan Africa, the lack of a developed governance framework and undercapitalised market players could lead to delays and financing problems (the latter having already affected Fortuna LNG's deepwater project in Equatorial Guinea).

Figure 4.13 ▷ Indicative delivered cost of selected new gas supplies to China and Europe in the New Policies Scenario, 2025



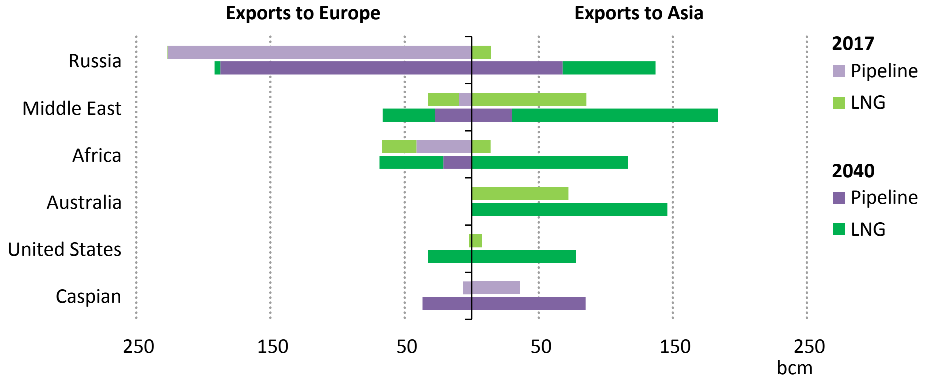
There are up to 1 300 bcm/y of potential new gas export projects; managing costs and securing financing without committed buyers is key to future capacity

Notes: Upstream and transport includes the cost of new infrastructure to deliver feedgas to a LNG plant. Shipping excludes the cost of regasification. LNG cost stacks are indicative benchmarks using generic capital and operating cost assumptions, while the ranges reflect the project- and location-specific uncertainties related to upstream finding and developing, liquefaction and pipeline costs.

For pipeline exporters, which are even more reliant on minimum capacities and firm delivery commitments to justify the considerable upfront costs of construction, the new gas order may create an enduring disadvantage relative to LNG. The Caspian region is emblematic of the current strategic dilemma for landlocked gas exporters. For Turkmenistan, for example, potential export markets are limited by its geographical position between Russia and Iran, both of which are themselves large gas producers and therefore have few incentives to provide transit. Partnership with China has enabled the financing and construction of the first three lines of the 55 bcm/y Turkmenistan-China Gas Pipeline, but reaching other large gas-consuming markets is proving challenging. The most advanced of the current diversification projects is the 33 bcm/y Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline, but its viability is compromised by transit risk through Taliban-held areas of Afghanistan, as well as by Pakistan and India's access to LNG.

In Russia, the vast majority of exports take the form of pipeline supply to Europe, where long-term demand reduction is partially offset by declines in indigenous production (see section 4.7). Russia therefore continues to pursue further large-scale pipeline projects into Europe such as the 55 bcm/y Nord Stream II project and the two-string Turkstream link through the Black Sea (each with a capacity of 15.75 bcm/y). The Power of Siberia opens up a direct route to China, with the possibility of further expansion linked to China's import needs. However, it may become increasingly difficult for a rigid pipeline gas strategy based on exclusive rights for Gazprom to coexist with flexible LNG supplies marketed by competing Russian players. LNG could therefore gradually force changes in Russia's overall approach to gas export.

Figure 4.14 ▷ Selected LNG and pipeline gas exports to Europe and Asia in the New Policies Scenario



Most of the additional growth in gas trade to 2040 is to satisfy demand in Asia

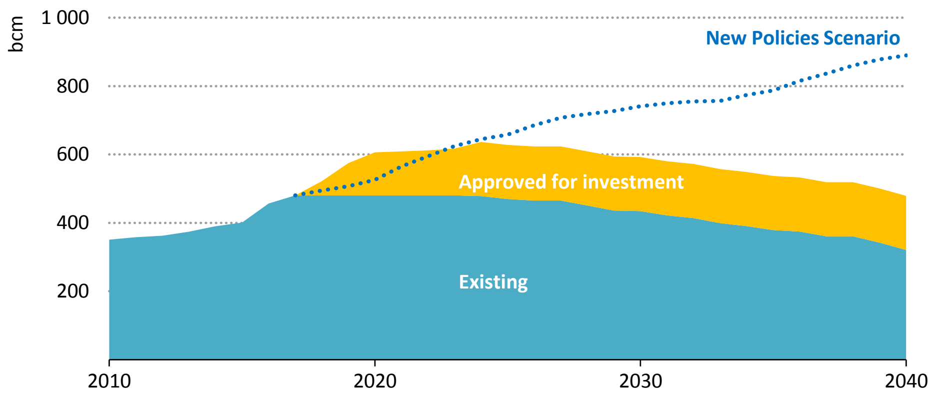
In this *Outlook*, Russia and the Middle East – led by Qatar – retain their position as the top-two net exporters of gas, with a combined market share of 43% of total global gas trade by 2040. However, the overall picture is one of increased diversity and competition. In a globalising LNG market where destination-flexible US volumes provide an upper bound on price in each region, competing exporters sell into markets where they have a competitive geographical advantage. The Middle East, Russia and East Africa in particular benefit from favourable access to the two key importing regions of Europe and Asia; Australian and US LNG exports gravitate towards Asia (Figure 4.14).

Buyers and sellers – never the twain shall meet?

The pickup in new LNG project approvals in the second half of 2018 suggests that the risk of an abrupt tightening in gas markets around the mid-2020s may be easing, although a steady flow of additional projects would still be required to meet demand in the New Policies Scenario (Figure 4.15).

However, there is still considerable uncertainty about what kind of business models and contracting structures will underpin new investment decisions. Projects that can come to market relatively quickly and at relatively low cost are the ones most amenable to the industry's current focus on capital discipline and short-cycle investments. This works in favour of established low-cost exporters such as Qatar. It is likely to work in favour of brownfield projects elsewhere, notably in the United States, where there is already a queue of new projects and expansions with regulatory approvals that are waiting for the right market conditions to move ahead. However, our analysis suggests that large-scale greenfield projects can also find a place in the new gas order. The creditworthiness and risk-sharing arrangements among the players involved in a given project can overcome uncertainty about future market conditions and the need for bankable guarantees for capital-intensive gas supply projects.

Figure 4.15 ▷ Global liquefaction capacity, existing and approved, compared with requirements in the New Policies Scenario



Recent project approvals have narrowed the gap between expected liquefaction capacity and projected demand in 2025

With growth in flexible and spot volumes and the increasing diversity of global LNG supplies, new market players are emerging and starting to challenge the traditional bilateral relationship between buyers and sellers that has underpinned investment in new capacity. Various utilities, national and international oil companies, independent developers and trading houses are increasingly seeking to manage risk or create value from greater optimisation and trading.

The result is an increasingly blurred distinction between buyers and sellers. Larger portfolio players (also known as aggregators) contract capacity at liquefaction and regasification terminals around the world (paying for the upfront fixed costs of doing so) without a specific destination for these volumes. Smaller independents and trading houses take open positions in the market, buying and selling single cargoes to take advantage of arbitrage opportunities. European and Asian utilities have meanwhile developed their own trading capabilities, evolving away from their traditional role as passive off-takers. Their increased ability to access both short- and long-term contract gas in a flexible way widens the opportunities for arbitrage, with the growing spot market providing a handy backstop for contract surpluses. Some have entered into joint venture partnerships with one another for this purpose, such as the recent agreement between EDF, a French utility, and JERA, a LNG buyer in Japan, created from a merger of long-term contracts of Chubu and Tepco, both Japanese electric utilities. The expanding middle ground has helped to underpin the growth of spot LNG sales, allowing for the re-selling, swapping or redirecting of cargoes, utilising a wide variety of short- and long-term contracts.

While this has helped accommodate buyer preferences for greater flexibility around existing supplies, several new projects continue to require long-term commitments to secure the funding necessary to build new liquefaction projects. This is where the mismatch between buyers and sellers is most pronounced.

New solutions for this impasse are beginning to emerge. By leveraging their supply chain presence, large creditworthy portfolio players such as integrated oil and gas majors can underpin new supply capacity on the strength of their balance sheets without necessarily locking in significant long-term volume commitments from buyers. These companies can then break up their contracted output from large-scale projects to match the volume, tenure and flexibility requirements of smaller buyers across multiple markets. Their investment decisions may be driven not just by the stand-alone economics of single projects but also by the value that a project might add to an integrated portfolio of assets (for example by opening up optionality and hedging opportunities). For players with less easy access to credit, LNG developers in the United States are offering prospective buyers equity stakes in new liquefaction terminals in exchange for bearing some of the market risk associated with the commissioning of new capacity. Mid-sized independent players are also experimenting with multiple small-volume, short-term contracts with buyers of various credit ratings, which together can attract enough financing for a larger project, while mid-stream players are adding power generation capabilities to floating storage and regasification units, tempting buyers to sign up to integrated, “plug-and-play” options to use LNG for electricity.

In aggregate, these multiple strategies, which in various ways leverage the expanding middle ground and the opportunities to spread market risks more evenly along the value chain, offer scope to ensure the health of the global gas balance. The final investment decision for LNG Canada in late 2018 is a case in point: a joint venture partnership between Shell, Petronas, PetroChina, Mitsubishi and Kogas, the project is not backed by any long-term contracts. Rather, its partners are responsible for their own gas supply and marketing strategies, implying a greater spread of risk among a diversified, creditworthy ownership pool. Strong government support has also been essential to overcome exceptionally complex land use, regulatory and social issues.

The changes that are taking place should not, however, lead to the conclusion that the old order has ceased to exist, or that every buyer is looking to maximise the flexibility of their contracts. Some buyers, especially in large growth markets such as China, remain keen on firm delivery. Volume flexibility may be useful in an oversupplied market, but the value of firm, guaranteed deliveries will go up if the balance tightens. Market players who have a portion of their supply locked-in with long-term contracts would stand to benefit in such an environment, while buyers relying primarily on short-term contracts would find themselves exposed to price floors set by the relative willingness of competing regions to pay for gas. A buyer's import portfolio is therefore likely to feature a balance of firm, flexible and uncontracted gas in order to match the price and volume sensitivity of their demand profile.

4.7 Natural gas in Europe's Energy Union

Gas is a major element in the European Union's energy mix, and is particularly important for the provision of power and heat to both buildings and industrial processes. Over at least the next decade, many of the European Union's climate and environmental policies provide important indirect support for gas: for example, reforms to the emissions trading scheme, which will become operational in 2019, have the potential to increase the price of carbon emissions, thereby further encouraging fuel switching from coal-to-gas. Other EU policies encourage more gas infrastructure to support competition and security of supply, thus reinforcing the use of gas. In the long term, however, the prospects for gas are less certain in the face of EU policies that support energy efficiency and renewable energy.

The European Union is currently the world's largest importer of natural gas, and continued declines in domestic production mean that reliance on imports is set to increase. The evolution of Europe's gas infrastructure and the operation of its internal gas market have a strong bearing on how these import needs are going to be met, and its implications for the security and diversity of gas supplies. Although there are many moving parts, much of this boils down to a battle for market share between Europe's largest gas supplier, Russia, which is currently setting records for pipeline gas exports to Europe, and the rising international supply of LNG.

The EU's Energy Union Strategy[5] depicts a long-term vision for a more secure, sustainable, competitive EU energy market, one in which gas can flow freely across borders and

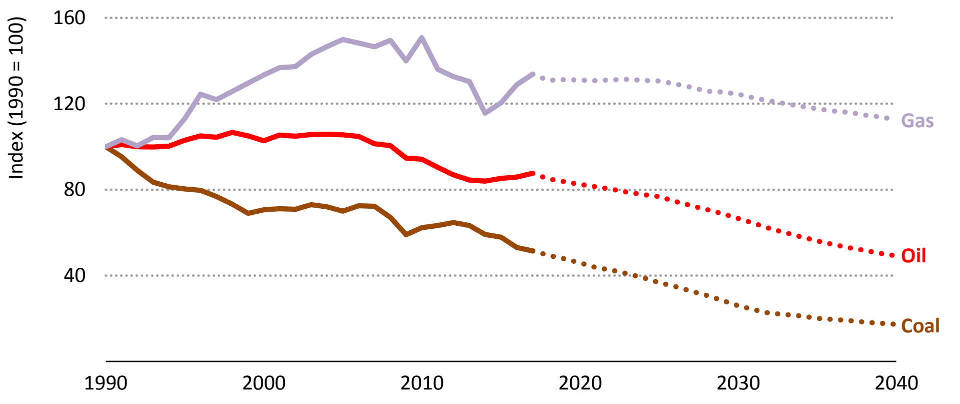
5. A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, presented in 2015. Our projections for the European Union are for its composition as of 2018, i.e. including the United Kingdom.

member states have access to a diversified portfolio of supply options. This builds on the achievements of the Third Energy Package agreed in 2009, which has sought to remove physical and regulatory barriers to a fully functioning internal market. We analyse gas demand, supply and infrastructure in the European Union in this context, employing our scenario projections and a new model of the EU's gas infrastructure to investigate how the EU's policy choices, as it strives for an "Energy Union", might shape the outlook.

Demand – is gas running out of steam in Europe?

There is considerable uncertainty about future gas demand in the European Union. After reaching a peak in 2010 of 545 bcm, gas demand declined for four consecutive years, mainly as a result of falling electricity demand and of competition from renewables and lower cost coal. However, since 2014, lower gas prices have underpinned a partial reversal of fortune in power generation, and the EU's gas consumption has grown by 4-7% per year.

Figure 4.16 ▷ Demand for gas, oil and coal in the European Union in the New Policies Scenario



Gas demand grew substantially in the 1990s and 2000s. As a cleaner burning fossil fuel, its prospects in a decarbonising European energy system are better than those of oil and coal.

In 2018, the European Union reached a political agreement on new, binding renewable energy and efficiency targets: the agreement stipulates a 32.5% increase in energy efficiency across the European Union and a 32% share of renewable energy by 2030. These revised targets have the potential to affect the outlook for gas demand in the European Union, although the effects will not be uniform because the profile and role of gas varies widely across European countries (Box 4.2); moreover, the effects are unlikely to be felt until later in the outlook period. For the next decade, at least, the prospects for gas demand in the European Union look relatively upbeat, compared with other fossil fuels (Figure 4.16).

Box 4.2 ▷ Europe's diversity of gas consumers

The role of gas varies widely across the countries of today's European Union. The six largest consumers of gas are responsible for 75% of total EU demand for natural gas (although in the New Policies Scenario, this share declines to two-thirds). Gas plays a particularly important role in the energy mix of Italy, the Netherlands and the United Kingdom, whereas in other countries, such as Sweden and Finland, the gas share is well below 10% (Table 4.5). Gas is an important fuel for industry in most EU countries, but its role for heating buildings and for power generation varies significantly from country to country. As examined in more detail in the following section, the various consumption patterns in different countries have implications for the utilisation of gas infrastructure: sectors are subject to varying policy pressures and they have varying seasonal characteristics, meaning that they contribute differently to the periods of peak load on the system.

Table 4.5 ▷ Share of gas in overall energy demand by country in the European Union (averages for 2010-2016)

Size of market	Country	Share of gas in TPED	Share of gas in sectoral demand		
			Power	Industry	Buildings
>20 bcm	Germany	20%	13%	35%	35%
	United Kingdom	31%	31%	33%	57%
	Italy	32%	41%	33%	50%
	France	12%	4%	37%	30%
	Netherlands	38%	48%	35%	64%
	Spain	18%	20%	40%	21%
10-20 bcm	Belgium	24%	22%	35%	40%
	Poland	11%	3%	23%	18%
	Romania	25%	20%	40%	33%
5-10 bcm	Hungary	29%	24%	32%	48%
	Austria	19%	21%	34%	19%
	Czech Republic	14%	5%	30%	31%
	Slovak Republic	23%	11%	26%	48%
<5 bcm	Ireland	26%	51%	28%	25%
	Portugal	15%	27%	23%	10%
	Greece	11%	17%	16%	7%
	Denmark	13%	16%	30%	13%
	Bulgaria	11%	8%	31%	4%
	Finland	6%	10%	6%	1%
	Lithuania	31%	58%	31%	10%
	Croatia	22%	29%	34%	20%
	Latvia	22%	58%	20%	11%
	Sweden	2%	1%	3%	1%
	Luxembourg	22%	82%	42%	37%
	Slovenia	9%	4%	34%	9%
	Estonia	7%	7%	20%	8%

Notes: TPED = total primary energy demand. Cyprus and Malta excluded.

The resilience of gas in the **power sector** is primarily a result of the closure of 50% of coal-fired capacity by 2030, and of reductions in nuclear power in European Union member countries. Installed gas capacity in the European Union increases by some 70 gigawatts (GW) to reach over 280 GW by 2040. Despite these capacity additions, gas consumption in power plants declines by 0.5% per year to 2040. With renewables-based capacity set to almost double by 2040, the business case for building new gas-fired power plants in Europe relies less on high load factors and more on the value attached to the firm capacity that gas can provide to electricity systems with high shares of variable renewable sources (see Chapter 10, section 10.4).

Buildings are the single largest consumers of gas in Europe, accounting for 38% of the EU's gas consumption in 2017 (Table 4.6). In our projections, gas demand in this sector declines by an average of 1.2% per year. Overall floor space in most countries increases, and gas benefits from fuel switching in some countries that still have a large number of oil-fired boilers. However, new policies are set to push up the efficiency of the buildings stock, plus new condensing boilers lead to higher efficiency gains. There is also an increase in the use of electricity in buildings, spurred by increased investment in electric heat pumps. These effects vary by region: northwest Europe sees a significant decrease in gas use in buildings, while in central and eastern Europe this drop is not as pronounced, as efficiency gains are offset by increased demand from the growth in floor space.

Table 4.6 ▷ Natural gas demand in the European Union in the New Policies Scenario (bcm)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
Power generation	127	151	153	147	138	135	-16	-0.5%
Buildings	183	185	176	165	153	140	-45	-1.2%
Industry	145	116	114	109	104	101	-14	-0.6%
Transport	1	4	5	6	8	10	6	3.9%
Other	31	26	24	23	22	22	-4	-0.8%
Total	**487**	**482**	**472**	**450**	**426**	**408**	**-74**	**-0.7%**

Notes: CAAGR = Compound average annual growth rate. Other includes agriculture, fishing, transformation and other non-energy use.

Gas demand in the EU **industry** sector peaked in 2000, at 145 bcm. A 20% decline since then can largely be attributed to declines in energy intensity following a shift from heavy to light industry and from industry to services. In the New Policies Scenario, industrial gas demand declines by a further 12% to around 100 bcm in 2040. All energy-intensive branches of industry see their gas demand decline slightly, largely because of economic restructuring and efficiency improvements rather than a shift to other fuels and technologies. Remaining gas demand in industry by 2040 is mainly for light industry (such as food and manufacturing) and for process heat above 400 °C (for example in the chemical industry), where there are fewer readily available low-carbon options. Outputs from energy-intensive industries remain sensitive to global macroeconomic conditions and the industrial competitiveness of Europe in relation to other regions.

Transport is a minor natural gas-consuming sector in the European Union, accounting for less than 1% of demand, but it grows at a rate of 4% per year in the New Policies Scenario. The bulk of the increase in gas use comes from passenger cars, for which promotion programs are already in place today in some EU member states. There is also growth in LNG bunkering for domestic and international shipping, stemming from the implementation of new International Maritime Organization standards on sulfur content of marine fuels in 2020.

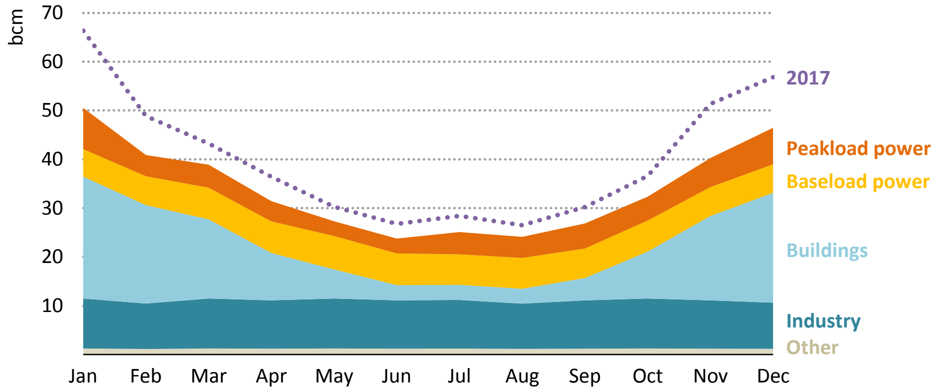
European peak gas demand

The gas infrastructure that is in place today in the European Union was designed to handle marked seasonal swings. The EU's winter gas consumption (October-March) is almost double that of summer (April-September), with the majority of additional demand required for heating buildings. Power generation forms a relatively small part of overall peak demand: deliveries to power plants made up only about one-fifth of the EU's peak daily gas demand in 2017. Whether Europe's gas infrastructure is sufficient to handle seasonal and short-term swings in the future depends to a large extent on the evolution and composition of peak demand.

Examining the evolution of peak demand requires much greater granularity in demand modelling, especially for the power and buildings sectors. For this analysis, we constructed individual peak gas load outlooks for all EU countries, using the results of our hourly power sector model (see Box 8.6) as well as detailed analysis of the outlook for the buildings sector. The results at EU level suggest that the peak in gas demand in the electricity sector increases by an additional 50% in 2040 compared with today. This is the result of a more significant role for gas in balancing an increasing share of variable renewables-based electricity generation (although the peak in gas demand does not necessarily occur during peak load power generation, meaning the contribution of gas to peak power demand declines over the projection period). The increased flexibility requirements, however, are offset by a drop in the role of gas in providing baseload power supply, and the net effect is a modest reduction in overall gas demand for electricity. Meanwhile, the drop in gas consumption in buildings, largely as a consequence of improved efficiency, has a significant effect on the seasonality of gas consumption. By 2040, monthly peak demand for gas overall is a third lower than in 2017 (Figure 4.17).

This trajectory of gas demand has significant commercial implications. The slow erosion of peak demand for heating implies an even more pronounced flattening of the spread between summer and winter gas prices, further challenging the economics of seasonal gas storage. With the anticipated phasing out of coal-fired power plants, there is less potential for commercially driven gas-to-coal switching, and increased need for gas to maintain power system stability, thereby favouring short-term storage. The demand remaining on the distribution grid (for example from households and small businesses) is largely weather dependent and therefore far less responsive to changes in price. Nevertheless, higher operating costs for ageing infrastructure will need to be recovered from a diminished customer base, further reinforcing longer-term fuel switching.

Figure 4.17 ▷ Seasonal gas demand in the European Union in the New Policies Scenario, 2040



Despite a 50% increase in the peak of gas demand in the electricity sector, the efficiency-driven drop in consumption for space heating leads to an overall decline in peak demand

The dilemma for policy makers is that, while the utilisation and profitability of Europe's gas infrastructure might decline, it still fulfils an indispensable role in ensuring security of supply. It might be needed less in aggregate, but when it is needed during the winter months there is – for the moment – no obvious, cost-effective alternative to ensure that homes are kept warm and lights kept on: the amount of energy that gas delivers to the European energy system in winter is around double the current consumption of electricity. Moreover, the importance of this function and the difficulty of maintaining it both increase as Europe proceeds with decarbonisation: that is why options to decarbonise the gas supply itself are gaining traction (notably with biomethane and hydrogen). Further electrification of space heating would naturally reduce direct gas use in buildings, but would transfer that seasonality to the electricity sector, where gas-fired power would again be the fallback option (see Chapters 7 and 8).

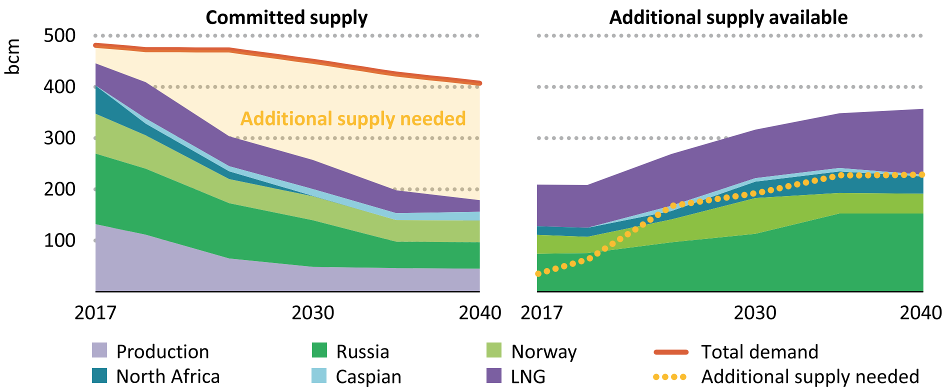
Supply: falling EU gas production keeps imports strong

Natural gas production in the European Union has been on a declining trajectory since 2000. This trend is mainly a result of resource depletion (most notably in the North Sea) and policies to tackle the problem of seismic activity at the Groningen gas field in the Netherlands. Some countries take considerable efforts to counter or decelerate the decline of their domestic gas production. However, the prospects for a significant expansion of domestic production are remote: the maturity of existing offshore fields in the North Sea limits the upside to marginal production additions, and many European countries have decided against pursuing onshore shale gas. Overall, gas production within the European Union is projected to fall from 132 bcm today to 45 bcm in 2040.

This means a high level of reliance on imported gas. The European Union is the largest gas-importing region in the world, and Russia is its largest supplier. In 2017, Russia exported a record level of 174 bcm to the EU countries, nearly half of the EU's total imported gas. The second-largest supplier, Norway, also set a record level of exports to the EU countries at 107 bcm; together, the two countries provided 75% of the EU's total gas imports. Other sources of piped imports into Europe have been limited by supply-side constraints. Algeria's export potential is expected to stagnate owing to robust demand growth and the uncertainty around the depletion of its largest gas field, Hassi R'Mel, while political unrest continues to cast a shadow over gas exports from Libya.

European gas supplies are broadly split between committed volumes and those for which choices remain. Committed volumes are those that flow more or less regardless of changes in natural gas prices. This category includes domestic production, which tends to run at full capacity, as well as the minimum volumes of gas required under long-term take-or-pay import contracts (for both piped gas and LNG). As shown in the left-hand side of Figure 4.18, the vast majority of gas consumed in Europe in 2017 falls into this category. Over time, however, as long-term contracts expire and domestic production declines, Europe requires additional supplies that are either uncontracted or above take-or-pay levels.

Figure 4.18 ▷ European Union committed gas supply and options to supply remaining import demand in the New Policies Scenario



The European gas market can choose from a range of available LNG and pipeline gas supplies to satisfy its remaining import demand

Notes: Additional supply available is: Russian, Norwegian and Algerian contracted volumes above take-or-pay levels, plus remaining export capacity through existing entry points (subject to production constraints); uncontracted capacity on the Caspian route; uncontracted LNG capacity available to the EU internal gas market.

The additional need for imports can mainly be met through a combination of LNG and piped gas from Russia (right-hand chart of Figure 4.18). Other imported pipeline sources are unlikely to be able to offer much optional supply. Norwegian gas supplies to Europe typically run at full capacity and look set to remain relatively stable until the early 2030s, after which declines in the North Sea reduce the volumes available for export. In North Africa, high levels of demand growth and geopolitical instability raise questions over its future export potential. Though strategically important, the Southern Gas Corridor[6] adds only modest volumes to Europe's overall import balance, while potential options to reinforce this corridor are not yet sufficiently advanced to be included here.

Given that the most significant spare import capacity to satisfy Europe's incremental import requirement lies with Russian piped gas and LNG, the stage is set for competition between these sources. In the New Policies Scenario, Russia remains the largest single source of supply to the European Union: even though the volumes supplied decrease from today's record highs, Russia is still projected to supply 140 bcm to the European Union in 2040, or 37% of the total 385 bcm imported in that year.

Nevertheless, there are uncertainties about how this will play out. To a degree, this is simply a question of relative costs: which suppliers can most profitably bring gas to consumers in different parts of the continent? Closely linked to this is the question of world market conditions, especially for LNG: in an increasingly flexible and liquid global market for gas, exporters are not going to look to Europe as a market if there are more lucrative opportunities elsewhere. But strategic considerations also come into play on both sides: these could include pricing and marketing strategies on the part of the sellers, such as a willingness to sell pipeline gas at a level below the long-run marginal cost of most LNG exporters, and strategies on the part of buyers to ensure a diverse mix of import sources. In addition, there are questions of physical infrastructure and regulations across Europe, including the question that we return to in the analysis below: could a poorly functioning internal market and/or infrastructure bottlenecks leave some consumers without much choice when it comes to gas supply?

Gas infrastructure in Europe's Energy Union

Allowing gas to flow more efficiently within the European Union and ensuring that member states have access to a diverse portfolio of supplies requires a fully functioning internal EU gas market, and much effort has been devoted to this objective. Wholesale markets are gradually improving, with an increasing number of buyers and sellers freely trading gas across borders. The Title Transfer Facility in the Netherlands is emerging as Europe's most liquid hub and relevant price benchmark, offering forward trading and hedging options to a growing pool of market participants. Spot trading is growing in other hubs in Europe, leading to prices that increasingly reflect short-term fundamentals across markets. This is supported by shared rules, known as network codes, which set out the conditions for the use of infrastructure, and ongoing efforts to harmonise national approaches to transmission tariffs. Since the early 2010s, there have also been a number of investments in bidirectional pipelines, regasification terminals and pipeline import infrastructure. In addition to

6. The Southern Gas Corridor refers to the set of planned infrastructure projects to diversify the EU's supply mix, by opening up a route for Caspian gas to reach EU markets via Turkey.

improving market liquidity, this infrastructure has reduced Europe's vulnerability to gas supply disruptions.

Improvements in EU market operation are also partly a consequence of market and regulatory pressure on Gazprom, Russia's sole pipeline gas exporter to Europe. A succession of arbitration cases and anti-trust investigations has seen Gazprom's pricing and contracting structures adjusted to the demands of liberalising European gas markets. Gazprom now integrates European spot market benchmarks in its pricing formulas for the majority of its contracts with EU buyers. Controversial elements in its supply agreements, such as destination clause restrictions, have been removed and fixed delivery points have been revised.

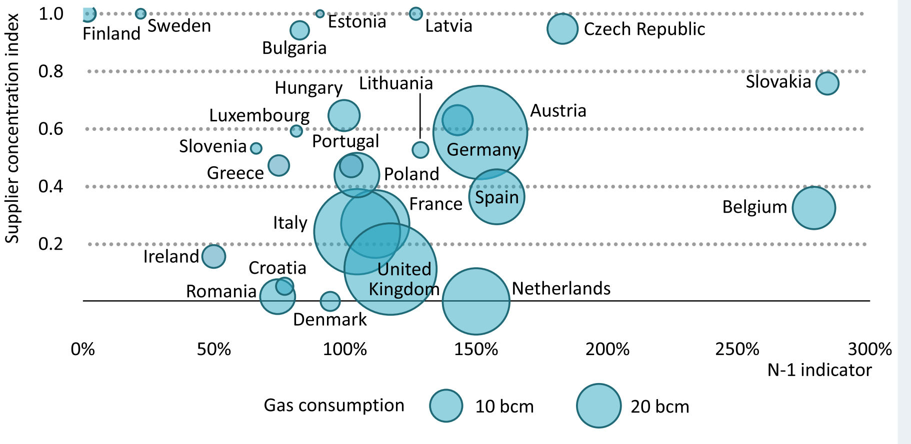
However, despite improvements over the past years, several countries in Europe are isolated from gas hubs and remain sensitive to dependence on single gas suppliers. Persistent wholesale price differences exist between northwest Europe, where liquid gas hubs provide robust price formation that reflects short-term market fundamentals, and central and southeast Europe, where gas flows continue to be largely underpinned by traditional long-term oil-indexed contracts with single suppliers. Tariff "pancaking" – whereby traders incur multiple charges to transport gas across markets – as well as the hoarding of long-term capacity rights remain barriers to the efficient utilisation of existing infrastructure. Meanwhile, regional co-operation related to gas security remains challenging. Political sensitivities and commercial constraints may render member states unwilling or unable to pool their resources with neighbours and, in practice, responsibility for security of supply still rests with national operators and regulators. Many gas infrastructure projects in Europe, particularly those designed to better insulate member states from supply shocks, are either uneconomic or may only provide benefits to a subset of stakeholders; moreover, third-party access rules challenge the way such large-scale infrastructure in Europe is typically financed, i.e. through long-term bilateral commitments between buyers and sellers of gas.

To address the difficulties of implementing projects with wider benefits, the European Commission, supported by pan-European bodies such as the European Network of Transmission System Operators for Gas (ENTSOG) and the Agency for the Cooperation of Energy Regulators, promotes regional initiatives and platforms encouraging gas market actors to work together to identify projects that enhance collective security. Through the Projects of Common Interest (PCI) list and a focus on a number of "priority corridors", the European Union has offered to financially support an additional 10 000 km of gas transmission pipelines, five LNG terminals and five underground storage sites. According to ENTSOG, EU gas infrastructure projects are expected to involve a combined investment cost of nearly $100 billion up to 2030 (ENTSOG, 2017).

Box 4.3 ▷ Measuring Europe's gas security

Two indicators are often used to measure the security and diversity of gas supply in European countries. The first is a supplier concentration index, where lower values indicate higher supply source diversity. The second is an "N-1" value that calculates the capacity available to the market area in case of the loss of the single largest gas supplying infrastructure, with a figure above 100% indicating sufficient alternative capacity to meet peak demand. As shown in Figure 4.19, several EU member states – particularly those on the EU's periphery – rely on only one source of gas and do not possess sufficient infrastructure to remedy this. In some cases, vulnerabilities are partly alleviated by hosting transit pipelines, which are sized to accommodate onward deliveries to consumers with larger gas requirements, though this is not without its own difficulties during periods of supply disruption.

Figure 4.19 ▷ Indicators of gas supplier diversity and infrastructure resilience in EU countries, 2016



Secure, liquid wholesale gas markets in Europe need multiple sources of gas; a number of EU countries rely on a limited number of suppliers

In the New Policies Scenario, the N-1 values for most EU member states comfortably exceed 100%: assuming full implementation of planned infrastructure measures, the N-1 value for the European Union as a whole rises from 130% in 2017 to 170% by 2040, suggesting far stronger resilience. The EU's supplier concentration index, which was 0.33 in 2017, remains broadly flat in the New Policies Scenario, as higher import dependence is offset by increased import diversity. The caveat is that both aggregated values, which notionally suggest sufficient gas security, rely on a fully functioning internal market that is able to efficiently utilise infrastructure to allow gas to be redirected to where it is needed.

The achievement of the EU's efficiency and renewable targets may appear to challenge the idea of further investment in gas-based infrastructure. However, the majority of PCI projects are not aimed directly at meeting growth in demand, but rather at removing physical bottlenecks to the completion of an internal gas market and at enhancing the security and diversity of gas supply (Box 4.3). Moreover, the additional infrastructure could put downward pressure on wholesale gas prices by giving member states stronger bargaining power as a result of their enhanced access to alternative sources of gas supplies, thus also improving the affordability of gas.

As shown previously, EU member countries have a range of potential supply options in the face of dwindling domestic production (see Figure 4.18). The projections in the New Policies Scenario suggest that Russian gas is well placed to maintain a strong position in the European gas import mix: even though LNG imports grow, Russia remains the largest single supplier, capturing over half of the European Union's additional supply requirements in the period from 2017-2040 (defined in Figure 4.18) and maintaining a market share of more than 30% of total EU gas demand. But what matters in practice, both for security of supply and price, is whether consumers – especially in eastern and southeast Europe – are choosing Russian gas as the most competitive among a range of import options, or because they have little choice.

To consider this issue we developed a new European gas infrastructure model, which allows us to examine trade flows and potential bottlenecks on a disaggregated country-by-country basis across the entire European single market.[7] To test the ability of consumers across Europe to access alternative sources of supply, we constructed two contrasting cases, both of which are based on the same supply and demand projections as those in the New Policies Scenario. We consider:

- An "Energy Union" case, where the vast majority of PCI projects are successfully implemented[8], there are no regulatory impediments to the free flow of gas across the single market and solidarity principles are broadly applied during supply interruptions. This applies as well to Contracting Parties to the Energy Community in southeast Europe.
- A "Counterfactual" case, where the majority of PCI projects are not constructed, flows of gas outside northwest Europe continue to suffer from contractual and regulatory congestion, and EU countries do not co-operate with one another, nor with the Energy Community countries, during periods of system stress.

7. EU-28, plus Switzerland and countries of southeast Europe that are contracting parties to the Energy Community Treaty: Albania, Bosnia and Herzegovina, the former Yugoslav Republic of Macedonia, Kosovo, Moldova, Montenegro, Serbia and Ukraine. Georgia is not included in this analysis, although part of the Energy Community, it is not contiguous with the single market; Turkey and Belarus, Iceland and Norway are the only countries in our "Europe" aggregate that are not included.

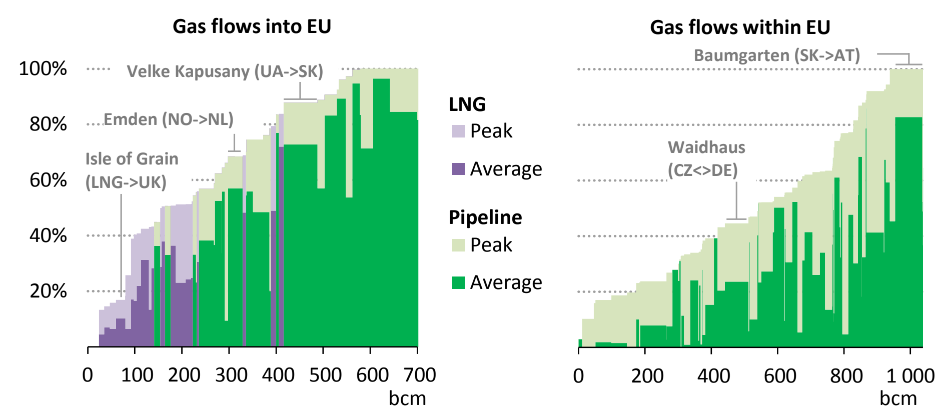
8. We assessed infrastructure development from a bottom-up, project-by-project perspective. Some PCI projects, particularly those competing with one another, are assumed not to go ahead in the analysis. Others had their commissioning dates adjusted to better reflect current market and political conditions.

European gas infrastructure and gas import options

At present, import infrastructure in the European Union is utilised very unevenly (Figure 4.20). Pipeline gas continues to be cost-competitive with LNG, meaning high overall utilisation rates – over half of the EU's import pipelines operate at peaks above 80%. By contrast, the EU's LNG import infrastructure is almost all on the left-hand side of the graph, much of it with utilisation rates well under 50%.

Once inside the European Union, there are few bottlenecks to impede gas travelling through cross-border pipelines, with less than a fifth of volumes running at a peak greater than 80%. Moreover, the spread between peak and average utilisation of infrastructure is wider than for imports, implying more slack in the market. This suggests that much of the EU's gas infrastructure is often under-utilised, with considerable spare capacity across storage and intra-EU transmission pipelines, even when taking into account peak monthly demand requirements.[9] However, there are both physical and contractual constraints within the European Union that prevent some import capacity from being fully utilised: roughly 80 bcm, or 40%, of the EU's LNG regasification capacity cannot be accessed by neighbouring states.

Figure 4.20 ▷ Utilisation of main European Union gas import and internal cross-border capacity, 2017



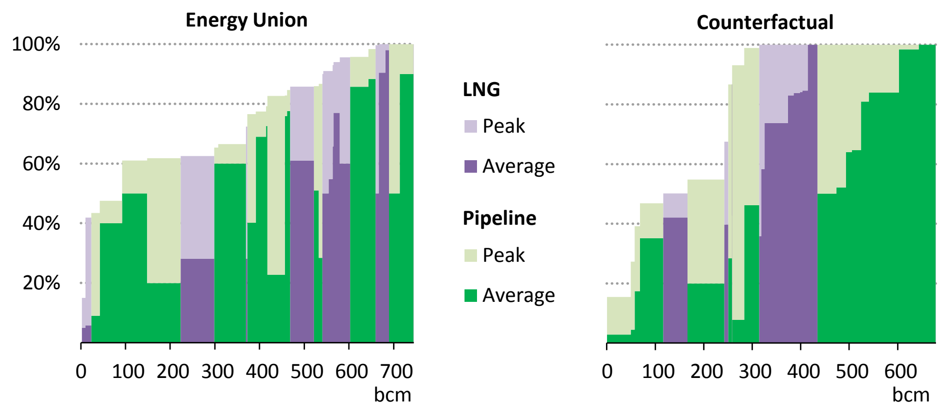
Many import pipelines run at full capacity during peak months, while LNG terminals are underused. Overall, there is ample capacity for gas transmission between EU countries.

Notes: Figure shows average and peak utilisation levels for cross-border infrastructure in 2017, using monthly flow data. "Gas flows into EU" include all entry points from non-EU to EU countries, split between pipeline and LNG terminals. "Gas flows within EU" are those between EU countries and include interconnection points largely reserved for transit pipelines crossing multiple borders. Highlighted interconnection points shown for illustration purposes. <> denotes bidirectional capacity, with flows calculated as the weighted average utilisation in both directions.

9. It is worth noting that more granular stresses may appear when analysing daily demand, as well as significant peak periods (such as those with a 1-in-20 year probability of occurring, as applied in EU regulations on security of supply).

Pursuing additional infrastructure, and maintaining what already exists, may appear to run against the reality that low-cost pipeline gas via traditional supply routes stands ready to satisfy Europe's incremental import requirements. Figure 4.21 shows how the completion of the internal market helps reduce the congestion that would otherwise arise in a Counterfactual case: almost half of the EU's pipeline import infrastructure runs at nearly full capacity in 2040 in the Counterfactual case, compared with only 22% in the Energy Union case. Without planned regasification terminals in Croatia, Greece and Poland, the EU's LNG import capacity can only operate at a peak utilisation rate of 85% before bottlenecks begin to emerge: congestion on north-south interconnections prevents northwest European LNG terminals from transmitting onwards all the gas needed elsewhere, and the resulting congestion rent amounts to almost $40 billion over the period 2017-40.

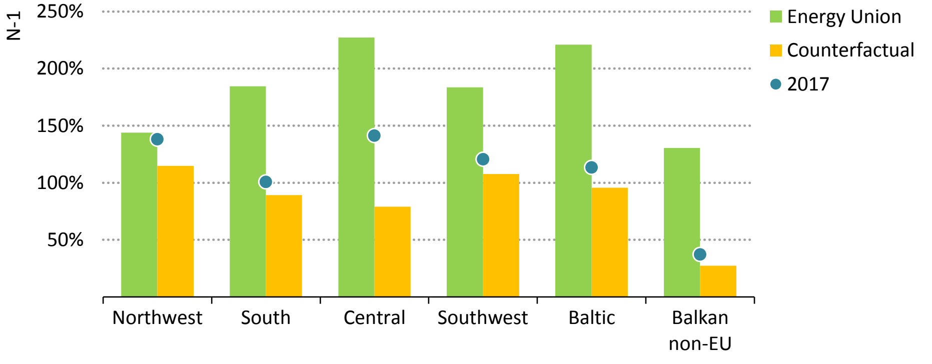
Figure 4.21 ▷ Utilisation of import infrastructure in 2040, Energy Union case versus Counterfactual case



A well-functioning market which allows gas to flow freely within the European Union significantly reduces the risk of congestion and supply problems

Moreover, in the Counterfactual case – with restricted trade and insufficient infrastructure between regions – the N-1 value falls below 100% in 2040 in some regions, as a consequence of reduced domestic production and less intra-EU transmission capacity (Figure 4.22). The Baltics, central and southern European countries in particular show a higher degree of exposure. By contrast, in the Energy Union case, with additional LNG terminals in southeast Europe as well as transmission lines crossing multiple borders (e.g. the Baltic Connector linking Estonia and Finland; Gas Interconnection Poland-Lithuania; Interconnector Greece-Bulgaria and Bulgaria-Romania-Hungary-Austria) the N-1 values significantly increase, and the majority of countries in the region are able to access at least three other sources of gas.

Figure 4.22 ▷ Regional N-1 values in 2040, Energy Union case versus Counterfactual case



Congestion on existing infrastructure and insufficient new capacity could lead to an inability to access alternative supply sources in some European regions

Notes: *Northwest:* Belgium, Denmark, France, Germany, Ireland, Luxembourg, Netherlands, United Kingdom, Switzerland (exceptionally, Switzerland is included among the EU countries for this analysis), United Kingdom; *South:* Bulgaria, Croatia, Greece, Italy, Romania, Slovenia; *Central:* Austria, Czech Republic, Hungary, Poland, Slovakia; *Southwest:* Portugal, Spain; *Baltic:* Estonia, Finland, Latvia, Lithuania, Sweden; *Balkan non-EU:* Albania, Bosnia-Herzegovina, Kosovo, Former Yugoslav Republic of Macedonia, Montenegro, Serbia. Excluded from the figure: Cyprus and Malta.

This suggests that there may be a way to ensure a secure, diversified supply mix while also allowing choices about sources of gas in a competitive internal market based on their relative costs. Both objectives can be addressed by robust infrastructure and liberalised trading of gas across borders. In the Energy Union case, the value of additional LNG and pipeline infrastructure derives less from the absolute volumes imported than from their contribution to diversification, the benefits of which include not just security of supply, but the ability to negotiate better deals with suppliers as a result of having a choice of alternatives. Our modelling shows that actual utilisation of several intra-EU pipelines only arises during security of supply crises or when alternative sources are able to outcompete Russian gas. Nevertheless, their presence, along with transparent and liquid spot markets, is what counts. Moreover, the cost of maintaining volume optionality is lower across a larger market, implying that a functioning EU internal market can reduce the per-unit costs of insurance against future supply disruptions.

That said, being on the PCI list is not a prerequisite for, or a guarantee of, eventual construction, and there are other projects on the horizon that are not on the list that could very plausibly change the picture. The completion of Nord Stream 2 is the obvious example. The debate over Nord Stream 2 underscores the tension between different visions of where the European market is today and where it might go in the future, a tension that is encapsulated in our two cases. The Energy Union case is one in which a well-functioning European market becomes part of a globalising gas market, meaning that European consumers – wherever they are – get enhanced access to competitive supply options. In this case, the physical location where gas enters Europe, and even the identity of the supplier, becomes less important. The Counterfactual case represents a concern that Europe's gas market may remain relatively fragmented and less efficient, an environment in which geography, suppliers and supply routes matter – especially in central and eastern Europe – and price differentials and bargaining power continue to vary widely across the continent.

Conclusion

The gradual projected decline in gas demand in the European Union means lower utilisation rates for cross-border transmission pipelines over time. However, gas infrastructure will remain a crucial security of supply asset for Europe, accommodating seasonal variations in both demand and supply, while alleviating the effects of extreme weather events. It will also become increasingly important for the electricity system, implying a higher degree of interdependence between gas and electricity security.

Our analysis indicates that the EU's current gas infrastructure can accommodate a wide range of supply configurations. However, this is only the case if gas is able to flow freely across borders, unencumbered by physical and regulatory constraints. Our Counterfactual case, in which infrastructure constraints persist and barriers to trade across Europe remain high, shows a Europe where access to alternative supplies of gas is constrained across many parts of central and southeast Europe. Under these circumstances, gas remains a more "political" commodity in these regions, with buyers remaining vulnerable during tight supply conditions.

Our analysis also indicates that a strong internal market can make better use of existing infrastructure. Hubs enable the marketing of gas futures, swap deals and virtual reverse flows, and thus remove the physical component from gas trade and allow molecules to be bought and sold several times before being delivered to end-users. This precludes much of the need for costly physical gas infrastructure and, in time, enables gas deliveries to be increasingly de-linked from specific suppliers. This puts greater emphasis on the efficient auctioning of available gas capacity between EU countries and the ability of liberalised markets to transport gas flexibly: short-term price signals rather than destination-inflexible delivery commitments become the main factor in determining whether flows can be directed to areas experiencing supply constraints. There are encouraging signs in this respect. Short-term and spot trading is increasing while planned infrastructure projects, if realised, will put all parts of Europe within plausible reach of multiple suppliers. Despite declining demand, therefore, there remains a case for new gas infrastructure. However, each project will require careful cost-benefit analysis, particularly as the debate about the pace of decarbonisation in Europe intensifies.

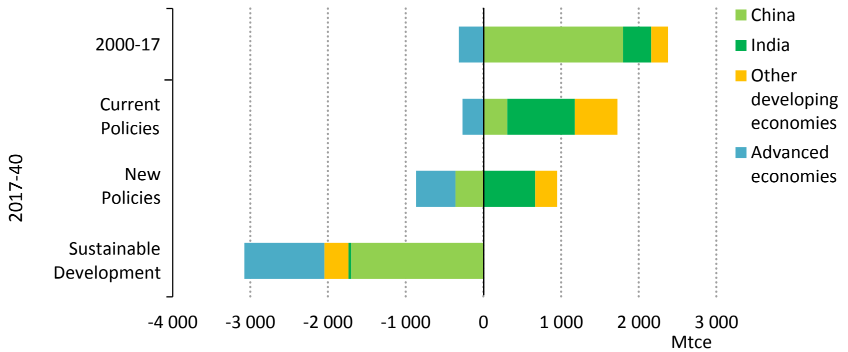
Outlook for coal

Too soon for goodbyes?

SUMMARY

- After two years of decline, global coal demand rebounded in 2017, reflecting an uptick in demand in China and India. In the New Policies Scenario, coal demand flattens at around 5 400 million tonnes of coal equivalent (Mtce), as falling consumption in China (-15%), European Union (-65%) and United States (-30%) is balanced by rising demand in India (+120%) and Southeast Asia (+120%) (Figure 5.1).

Figure 5.1 ▷ Change in global coal demand by region and scenario



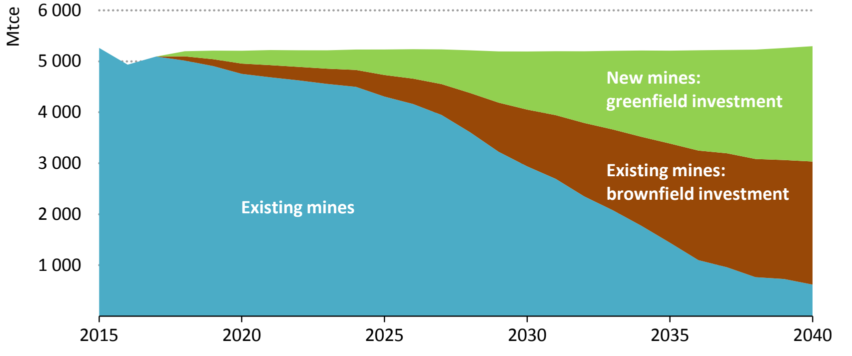
The outlook for coal is heavily dependent on the policies that governments decide to follow

- The 2017 increase in coal-fired electricity generation in China, by far the world's largest coal consumer, has continued into 2018, but coal demand comes under pressure in our projections from the policy priority to improve urban air quality, supported by coal-to-gas switching in the industrial and residential sectors, a push for renewables in power generation and ongoing restructuring of the economy.

- India, which became the world's second-largest coal consumer in 2015, is the single largest source of global demand growth in the New Policies Scenario. India is pushing strongly to expand the role of renewables in its power mix, yet robust growth in electricity demand still means a near-doubling in coal-fired power output to 2040. India has set ambitious targets for domestic coal production, but imports nonetheless rise, especially for coking coal as India's domestic resources are insufficient to meet growing demand from the iron and steel industries.

- Coal prices have soared since early 2016 due to strong import demand and efforts to limit and restructure supply in China. Despite the resulting boost in profits for mining companies, investment in coal mining remains subdued, particularly among export-oriented companies. The New Policies Scenario implies $1 trillion of investment to offset decreasing production from existing mines (Figure 5.2) and to build new coal infrastructure, the majority of which is in China and India.

Figure 5.2 ▻ Global coal production by type in the New Policies Scenario



Global coal production from existing mines drops markedly by 2030. More than 40% of coal production in 2040 is from new mines.

- Coal trade remains close to today's levels through to 2040 in the New Policies Scenario, but even small changes in the supply-demand balance in China or India could have substantial implications for traded coal, underlining the policy and market uncertainty facing coal producers worldwide. Over the outlook period, some new coal importers emerge in Asia, Africa and Middle East, even as import needs decline elsewhere. Australia continues to be well positioned to serve demand in Asia in a growing international coking coal market.

- Technology choices are vital to the outlook for coal in power generation: alongside a shift towards higher efficiencies, coal plants are also adapting to the need for more flexibility in power systems in order to accommodate rising shares of wind and solar photovoltaics (PV). Whether coal can provide flexibility in a cost-effective way depends very much on the specific circumstances of particular power systems.

- Carbon capture, utilisation and storage (CCUS) needs to play an important role in meeting climate goals, but there are very few projects operating or planned. There are some signs of positive momentum: the 2018 US budget bill which raised the 45Q tax credits is expected to provide a boost for CCUS and other countries such as Canada, China, Norway and United Kingdom are also stepping up efforts.

Introduction

Coal demand made a comeback in 2017. Declines in coal demand and prices after 2014 led some observers to conclude that coal had already entered terminal decline. But in 2016, coal prices started to rebound, demand increased in 2017 and prices continued to rise into 2018, leading to sustained profits for coal producers. In Europe and North America, coal demand remains under pressure due to low electricity demand growth, strong uptake of renewables-based capacity and, in the United States, the availability of inexpensive natural gas. Nonetheless, recent trends provide a reminder that coal demand could be more resilient than some expect, especially among developing economies in Asia.

Looking ahead, the updated projections in this *World Energy Outlook-2018 (WEO-2018)* confirm that the longer term outlook for coal is highly contingent on how policies evolve. Coal demand has been revised down in the New Policies Scenario, our main scenario, reflecting not only strong competition in some markets but also an increasing focus on policy measures that either penalise coal directly or give a helping hand to its competitors. Such policies become much more stringent in the Sustainable Development Scenario. But the Current Policies Scenario underscores that coal use could be higher than projected in the New Policies Scenario if the measures which the latter scenario incorporates fail to materialise or are scaled back.

The key findings on the outlook for coal are described in the next section. In the second part of the chapter, we look in more detail at two questions:

- Does coal have a role in the transformation of the power sector? As described in detail in Part B, power systems are changing rapidly with the growth in renewable energy generation, yet coal use in power generation remains robust in many parts of the world. Is it inevitable that, as the share of renewables goes up, the share of coal goes down? Or is it possible that they work in a complementary fashion in some cases, with coal providing a source of flexibility to power systems? The answers vary by country and scenario. We examine the technical, economic and environmental challenges of flexible coal plant operation as well as the potential role of plants equipped with CCUS in the Sustainable Development Scenario.
- What are the prospects for coal exporters in a demand-constrained world? Investment in export-oriented coal mining remains subdued, as coal companies are cautious about investing in an uncertain market and policy environment. We look at some of the key uncertainties facing exporters, including the effects of coal market restructuring in China, the variability in India's potential import needs, the prospects of import demand in Southeast Asia, and the plans of some countries in the Middle East and Africa to introduce coal use in power generation.

Figures and tables from this chapter may be downloaded from www.iea.org/weo2018/secure/.

Scenarios

5.1 Coal overview by scenario

Coal demand in 2040 in the **New Policies Scenario** has been revised down by some 3% (170 Mtce) compared with *WEO-2017*. Downward revisions have been made for industrial coal use, as the shift from coal to alternative fuels in industry speeds up, and in the buildings sector where coal use almost disappears.

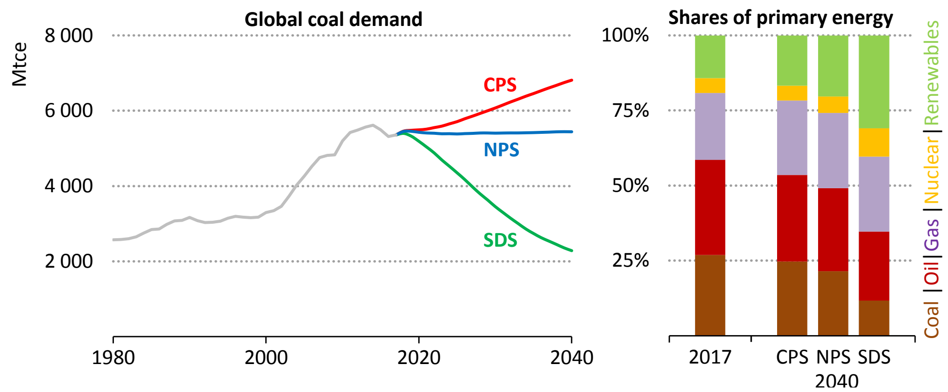
Overall coal demand for power generation declines slightly in the New Policies Scenario as moderate growth in coal-fired generation is offset by improvements in plant efficiencies. Modest growth in industrial coal consumption is due in part to rising use of coal as a feedstock for a range of conversion processes, notably coal-to-gas and coal-to-liquids projects in China. Overall coal consumption flattens around 5 400 Mtce and does not regain the peak seen in 2014 (Table 5.1).

Table 5.1 ▷ Global coal demand, production and trade by scenario (Mtce)

			New Policies		Current Policies		Sustainable Development	
	2000	2017	2025	2040	2025	2040	2025	2040
Power	2 235	3 415	3 341	3 361	3 593	4 485	2 448	732
Industry	857	1 716	1 867	2 005	1 906	2 178	1 744	1 530
Other sectors	205	227	175	74	212	150	159	19
World coal demand	**3 298**	**5 357**	**5 383**	**5 441**	**5 711**	**6 813**	**4 350**	**2 282**
Share of Asia Pacific	*47%*	*74%*	*78%*	*82%*	*77%*	*81%*	*81%*	*83%*
Steam coal	2 504	4 134	4 201	4 412	4 486	5 655	3 313	1 609
Coking coal	449	960	918	806	937	869	837	579
Lignite	302	265	264	224	288	289	201	93
World coal production	**3 255**	**5 360**	**5 383**	**5 441**	**5 711**	**6 813**	**4 350**	**2 282**
Share of Asia Pacific	*48%*	*72%*	*75%*	*78%*	*75%*	*77%*	*76%*	*79%*
Steam coal	310	805	736	760	803	1 066	538	281
Coking coal	175	302	320	346	340	378	287	250
World coal trade	**471**	**1 102**	**1 044**	**1 089**	**1 121**	**1 422**	**815**	**518**
Share of production that is traded	*14%*	*21%*	*19%*	*20%*	*20%*	*21%*	*19%*	*23%*
Coastal China steam coal price ($2017/tonne adjusted to 6 000 kcal/kg)	**35**	**102**	**91**	**94**	**95**	**106**	**81**	**79**

Notes: kcal/kg = kilocalories per kilogramme. Unless otherwise stated, use of coal in industry in this chapter reflects volumes also consumed in own use and transformation in blast furnaces and coke ovens, petrochemical feedstocks, coal-to-liquids and coal-to-gas plants. Historical data for world demand differ from world production due to stock changes. Lignite production includes peat. Unless otherwise stated, trade figures in this chapter reflect volumes of coking and steam coal traded between regions modelled in the *WEO* and therefore do not include intra-regional trade. World coal trade is the sum of net exports for all *WEO* regions and may not match the sum of steam and coking coal trade as a region could be a net exporter of one coal type but a net importer of another.

Figure 5.3 ▷ Global coal demand and share of coal in global primary energy demand by scenario



Stringency of environmental policies determines coal's fortunes in the scenarios

Note: CPS = Current Policies Scenario; NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

In the New Policies Scenario, the share of coal in global primary energy demand declines from 27% today to 22% in 2040, falling behind gas in the late 2020s. The growth picture looks very different in the other two scenarios, reflecting the extent to which the prospects for coal are dependent on the way that policies evolve. In the **Current Policies Scenario**, coal demand increases at 1% per year over the outlook period, but coal still falls behind gas by 2040. In the **Sustainable Development Scenario**, coal consumption decreases steeply (-3.6% per year) and coal's share in primary energy falls below 12% by 2040.

Coal prices increase slightly in the New Policies and Current Policies scenarios from 2025 onward, reflecting upward cost pressure caused by the need to tap more remote coal deposits, increasingly challenging geological conditions and rising costs for consumables such as fuel. Coal prices decrease in the Sustainable Development Scenario as lower demand forces the closures of high cost mines in a market where only the most productive, least-cost mines can survive.

CCUS provides a technology option to reduce emissions of the existing coal-fired power plant fleet through retrofits in the Sustainable Development Scenario. Some 210 gigawatts (GW) of coal plants are fitted with carbon removal technology by 2040, of which 170 GW are retrofits to existing plants. However, progress in CCUS deployment and investment remains limited in practice and lags well behind the pace that would be needed in this scenario.

5.2 Coal demand by region and sector

There are strong regional variations in the outlook for coal (Table 5.2). Many **advanced economies**, such as Canada, Germany and United Kingdom are considering how to phase out coal use in power generation as part of their plans to reduce carbon dioxide (CO_2) emissions, or have already pledged to do so.

Many **developing economies** view coal as important to their economic development because of its ready availability and relatively low cost. India and Southeast Asia are the growth centres for coal use in the New Policies Scenario, with demand more than doubling over the period to 2040. Demand is also projected to increase in some African countries (South Africa, a major current coal consumer, is an exception).

Table 5.2 ▹ Coal demand by region in the New Policies Scenario (Mtce)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
North America	818	513	396	372	356	341	-172	-1.8%
United States	763	472	379	359	345	330	-142	-1.5%
Central and South America	29	48	52	53	52	54	6	0.5%
Brazil	19	24	23	23	23	24	-1	-0.1%
Europe	578	475	363	290	251	240	-234	-2.9%
European Union	459	334	239	169	131	113	-222	-4.6%
Africa	117	145	150	149	146	142	-2	-0.1%
South Africa	106	129	123	110	99	86	-43	-1.8%
Middle East	2	5	8	9	11	13	8	4.5%
Eurasia	202	224	228	219	214	211	-13	-0.3%
Russia	171	167	165	153	147	141	-27	-0.7%
Asia Pacific	1 551	3 948	4 186	4 312	4 388	4 439	492	0.5%
China	955	2 753	2 735	2 659	2 536	2 395	-358	-0.6%
India	208	572	801	955	1 104	1 240	668	3.4%
Japan	138	164	134	129	119	111	-53	-1.7%
Southeast Asia	45	180	251	297	348	398	218	3.5%
World	**3 298**	**5 357**	**5 383**	**5 405**	**5 419**	**5 441**	**84**	**0.1%**
Current Policies			5 711	6 074	6 457	6 813	1 456	1.1%
Sustainable Development			4 350	3 452	2 738	2 282	-3 076	-3.6%

Note: CAAGR = Compound average annual growth rate.

Increasing attention to air quality, efforts to diversify the energy mix away from coal in power generation and the buildings sector, plus a strong push for gas use in industry have led to a downwards revision of more than 40 Mtce in 2040 of coal demand in China in the New Policies Scenario, compared with the *WEO-2017*.

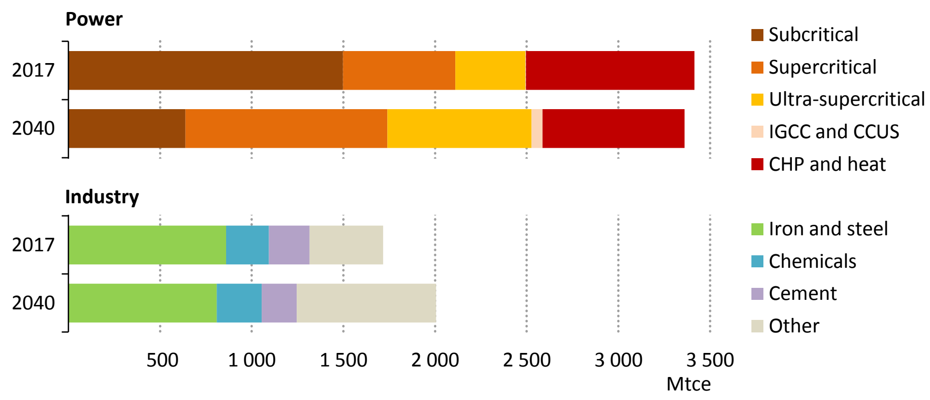
Ample inexpensive natural gas and increasingly competitive renewable options for power generation in the United States have contributed to a downward revision of US coal demand by some 95 Mtce in 2040 compared with the *WEO-2017*.

Investment in new coal-fired power plants in 2017 was at its lowest level in a decade, not least because of a drop of more than 50% in such investment in China, which has pledged to reach a peak in CO_2 emissions by 2030 or earlier. The projection for coal-fired power generation is essentially flat over the period to 2040, putting related investment on a downward trajectory in the New Policies Scenario.

The efficiency of the coal fleet gradually increases as supercritical and ultra-supercritical coal plants become the technologies of choice (Figure 5.4). The share of subcritical plants, which make up just less than half of global coal-fired capacity today at an average plant age of about 25 years, drops to just below one-third by 2040 in the New Policies Scenario.

5

Figure 5.4 ▷ **Global coal demand by sector in the New Policies Scenario**



More efficient and flexible technologies change the demand structure for coal in the power sector

Notes: IGCC = integrated gasification combined-cycle; CCUS = carbon capture, utilisation and storage; CHP = combined heat and power. Iron and steel includes volumes consumed also in own use and transformation in blast furnaces and coke ovens. Chemicals includes petrochemical feedstocks. Other includes coal-to-liquids and coal-to-gas plants.

Investment in new steel capacity has slowed dramatically since 2013 and coal-based capacity additions now trail gas- and electricity-based additions for the first time in several decades. Over the outlook period, electricity-based routes account for the majority of steel production growth. Alongside efficiency improvements, this means that coal use in the iron and steel industry declines by around 50 Mtce by 2040. Coal use as a feedstock for coal-to-gas and coal-to-liquids projects grows by almost 180 Mtce in the New Policies Scenario, largely due to anticipated project start-ups in China.

5.3 Coal production by region

The projections in the New Policies Scenario imply that coal production peaked in 2014, mirroring trends on the demand side. However, there are stark regional differences in coal production prospects to 2040 (Table 5.3).

India overtakes Australia and the United States in the early 2020s to become the world's second-largest coal producer behind China (in energy terms; considered by mass, India is already the second-largest coal producer). Steam coal accounts for the majority of coal production growth in India as coking coal output is limited by coal quality, i.e. the high ash content of Indian coal. Commercial mining was recently opened to the private sector in India, a policy shift we are monitoring for its potential effect on production from the mid-2020s.

Table 5.3 ▷ Coal production by region in the New Policies Scenario (Mtce)

							2017-2040	
	2000	2017	2025	2030	2035	2040	Change	CAAGR
North America	824	582	465	433	417	406	-177	-1.6%
United States	767	530	432	403	386	374	-156	-1.5%
Central and South America	48	88	85	86	87	88	-0	-0.0%
Colombia	36	83	80	82	83	84	1	0.0%
Europe	397	237	176	133	102	93	-144	-4.0%
European Union	307	170	120	81	55	43	-127	-5.8%
Africa	187	224	218	222	217	228	4	0.1%
South Africa	181	208	194	192	177	175	-33	-0.7%
Middle East	1	1	1	1	1	1	0	1.0%
Eurasia	234	384	390	390	403	408	24	0.3%
Russia	184	314	312	311	325	330	16	0.2%
Asia Pacific	1 564	3 844	4 049	4 140	4 192	4 217	374	0.4%
Australia	235	416	417	425	445	474	58	0.6%
China	1 019	2 538	2 576	2 567	2 457	2 314	-224	-0.4%
India	187	395	583	712	842	955	561	3.9%
Indonesia	65	374	350	308	317	338	-36	-0.4%
World	**3 255**	**5 360**	**5 383**	**5 405**	**5 419**	**5 441**	**82**	**0.1%**
Current Policies			5 711	6 074	6 457	6 813	1 454	1.0%
Sustainable Development			4 350	3 452	2 738	2 282	-3 078	-3.6%

Note: CAAGR = Compound average annual growth rate.

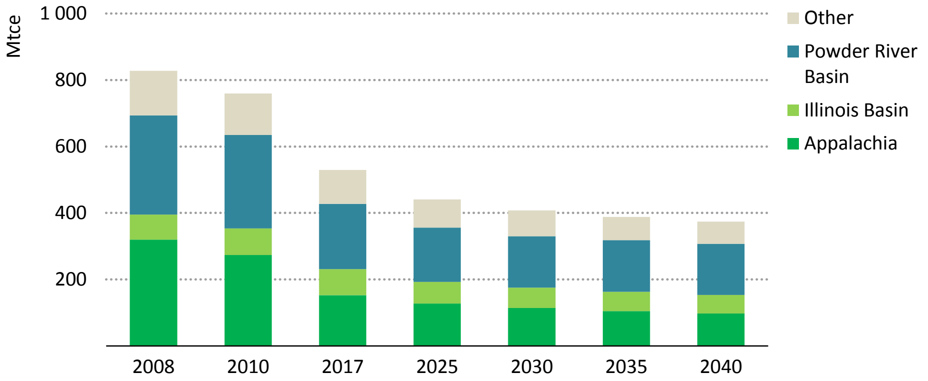
Coal production in **China**, by far the world's largest coal producer, declines at an average rate of 0.4% per year over the outlook period. This is a downward revision for coal production in China compared with the *WEO-2017*, reflecting lower steam coal demand. Coking coal production in China declines by around 40% to 2040 as domestic steel manufacturing decreases and more of it is made in electric arc furnaces.

Even though the New Policies Scenario projects a decline in coal production in China, investment needs in coal mining increase between the mid-2020s and mid-2030s. In that period, China would face strategic choices as the mines built during the coal boom of the first decade of the 2000s reach the end of their operational life. Meeting projected demand would mean expanding these mines or replacing them with new mining capacity.

Coal production in the **United States** has fallen by 35% since peaking in 2008 (Figure 5.5). While output increased strongly in 2017, US coal production is projected to drop another 30% over the period to 2040, reflecting declining domestic demand and limited opportunities to tap into export markets (see section 5.7).

5

Figure 5.5 ▷ United States coal production by basin in the New Policies Scenario



US coal production declines to levels half of the 2008 peak in the period to 2040

Coal production in the **European Union** declines sharply from about 170 Mtce today to around 45 Mtce in 2040 in the New Policies Scenario. Hard coal production is mainly concentrated in Poland. Lignite production, revised downwards from the *WEO-2017* to some 25 Mtce in 2040, continues at least in the near to medium term in Germany, as well as in various countries in eastern and south-eastern Europe.

The outlook for coal trade is uncertain in the New Policies Scenario (see section 5.7), but **Australia** is the only export-oriented country projected to significantly ramp up coal production over the period to 2040. Benefiting from its strong resource base and its proximity to growing markets in Asia, Australia's production exceeds that of the United States by the late-2020s.

Coal production in **Indonesia** drops by 10% to 340 Mtce in 2040 due to depletion of the best resource sites. The share of production serving growing domestic coal demand increases from 18% in 2017 to around 46% in 2040, at the expense of exports.

5.4 Trade

Traded coal, which accounts for around one-fifth of global coal production, remains broadly at today's levels of around 1 100 Mtce in the New Policies Scenario (Table 5.4). Steam coal trade declines, most notably over the period to 2025, as declining import demand in China and advanced economies outweighs rising demand in India and other Asia Pacific. Coking coal trade, supported by a diversification of steel production centres, increases at an annual average of 0.6% to 2040.

Table 5.4 ▷ Coal trade by region in the New Policies Scenario

Net importer in 2040	Net imports (Mtce)				As a share of demand			
	2000	2017	2025	2040	2000	2017	2025	2040
India	20	172	218	285	10%	30%	27%	23%
Other Asia Pacific	53	112	141	270	52%	55%	54%	67%
Japan and Korea	192	291	241	196	97%	100%	100%	100%
China	-58	209	159	81	n.a.	8%	6%	3%
European Union	140	158	119	70	31%	47%	50%	62%
Rest of world	22	88	86	101	9%	29%	30%	31%
Net exporter in 2040	**Net exports (Mtce)**				**As a share of production**			
	2000	2017	2025	2040	2000	2017	2025	2040
Australia	173	350	366	428	74%	84%	88%	90%
Russia	14	144	147	189	8%	46%	47%	57%
Indonesia	48	308	255	182	74%	82%	73%	54%
South Africa	66	68	71	89	36%	33%	37%	51%
Colombia	33	79	71	71	93%	95%	88%	84%
United States	40	76	53	44	5%	14%	12%	12%
World	**Trade (Mtce)**				**As a share of production**			
	2000	2017	2025	2040	2000	2017	2025	2040
Steam coal	310	805	736	760	12%	19%	18%	17%
Coking coal	175	302	320	346	39%	31%	35%	43%
New Policies	**471**	**1 102**	**1 044**	**1 089**	**14%**	**21%**	**19%**	**20%**
Current Policies			1 121	1 422			20%	21%
Sustainable Development			815	518			19%	23%

Note: n.a. = not applicable.

In the New Policies Scenario, India becomes the largest coal importer, overtaking China. As discussed in section 5.7, there is considerable uncertainty regarding the import requirements of both these countries. In our projections, exports from Indonesia decrease by more than 40% over the outlook period as production goes to satisfy increasing domestic demand. Australia, Russia and South Africa are able to fill this gap.

5.5 Investment

Investment in the coal supply chain peaked in 2012. It has nearly halved since then as investment activity in export-oriented mining has largely dried up. Russia is the notable exception among coal exporters.

Coal mining investment in China and India remains robust for the moment, with China aiming to increase average mine size, productivity levels and safety standards in line with broader industrial restructuring goals, and India targeting ambitious production growth.

5

Table 5.5 ▷ Cumulative coal supply investment by region in the New Policies Scenario, 2018-2040 ($2017 billion)

	Total	Mining			Ports and rail	Total annual average
		Capacity additions	Maintenance	Total		
North America	59	19	29	48	11	3
Central and South America	22	11	8	19	3	1
Europe	24	5	6	11	12	1
Africa	44	18	19	37	7	2
Middle East	1	0	0	0	1	0
Eurasia	72	23	28	50	22	3
Asia Pacific	706	299	278	578	129	31
Shipping	54	n.a.	n.a.	n.a.	54	2
World	**983**	**376**	**367**	**743**	**240**	**43**
Current Policies	1 228	457	408	865	364	53
Sustainable Development	590	179	257	436	154	26

Note: n.a. = not applicable.

Investment requirements vary widely by scenario: in the New Policies Scenario, cumulative capital spending in the coal supply chain amounts to $1 trillion over the period to 2040, or $43 billion per year on average (Table 5.5). The Asia Pacific region (most notably China and India) accounts for around three-quarters of annual investment expenditures.

Current high price levels in coal markets and the associated surge in profitability have not resulted in an uptick of coal investment (see Spotlight), although a supply shortage in the coal industry seems much less likely than for oil and gas. Capital expenditure to support operations at existing mines comes to roughly $370 billion over the period to 2040, a sum almost equal to greenfield and brownfield mining expenditures.

Key themes

5.6 A role for coal in the transformation of the power sector?

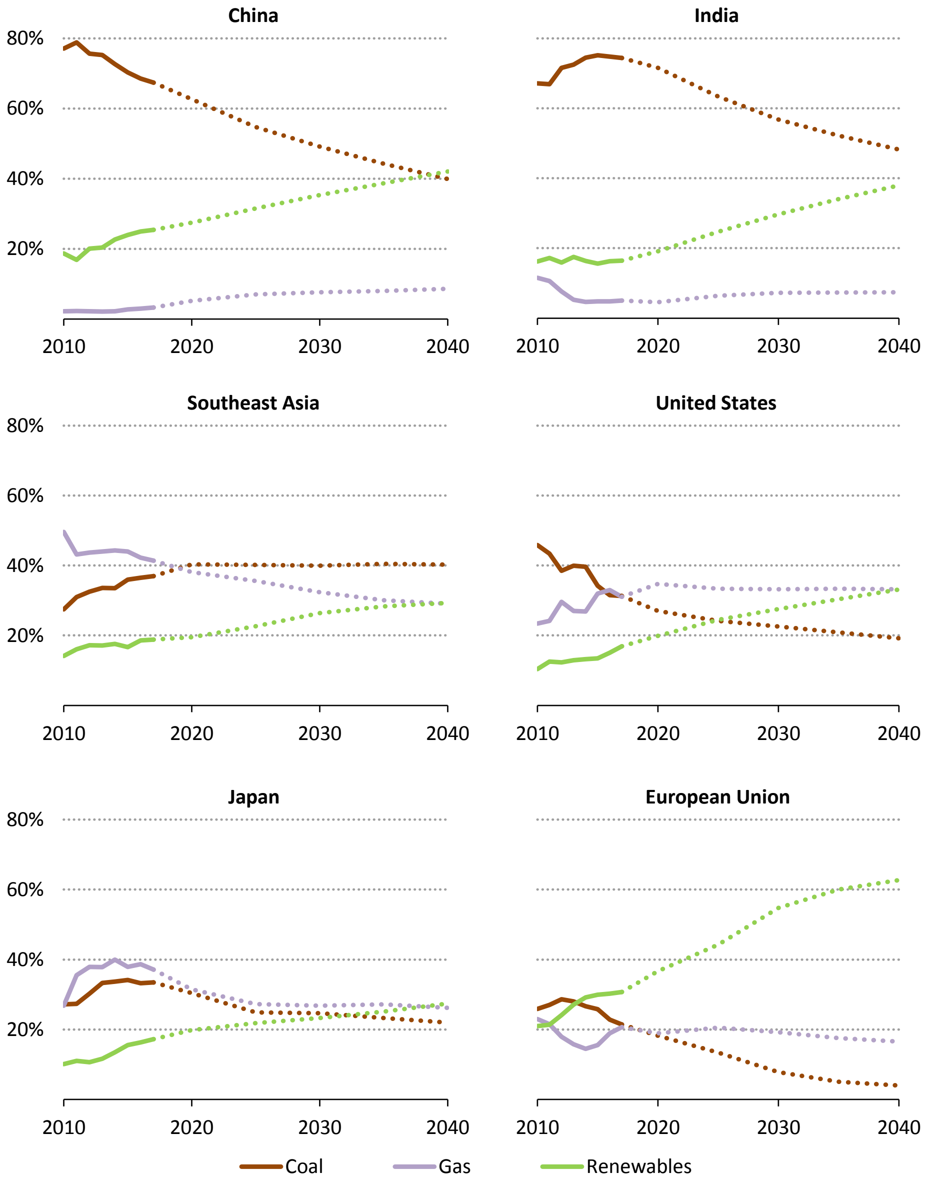
Despite all the changes in the global power sector, coal-fired generation is still the largest source of electricity production worldwide with a share of around 40%. Power generation from variable renewable energy sources, such as wind and solar photovoltaics (PV), are delivering new features to power systems. These challenge the investment case for new coal-fired generation capacity and the traditional operating regimes of the existing fleet (see the focus on electricity in Part B). Coal-fired power plants have typically been designed for baseload operation, whereas today in many regions power plants that can operate flexibly are at a premium. Even if it is technically feasible for coal plants to ramp their output up and down according to the needs of the system, would a reduction in operating hours still allow plants to recover their investment costs and operate profitably, especially in markets where remuneration is based solely on power dispatched? And what are the implications of flexible operation for the plants themselves and their emissions performance?

The answers to these questions vary by scenario. In the Sustainable Development Scenario, unabated coal-fired generation is increasingly incompatible with the required emissions reductions, so the future of coal ultimately boils down to the feasibility of CCUS for new and existing plants (through retrofits) in a power system dominated by renewables. In the New Policies Scenario, however, the share of coal-fired generation declines more gradually and the size of the operating coal fleet remains substantial. So, in some countries, the coal-fired fleet needs to find accommodation with the transformation of the power sector and vice versa. Over the outlook period, many coal-fired plants are retired, especially in Europe and North America, where the average age of the fleet is already around 40 years. But the average age of the coal-fired fleet in Asia is less than 15 years, so the co-existence of coal and renewables becomes an important element of power system operation and electricity security.

Outlook for coal-fired power to 2040

The share of coal in global power generation is almost unchanged today compared with 1977 or 1997, but this picture is set to change (Figure 5.6). The boom years for coal-fired power investment, driven by an extraordinary expansion of capacity in China in the 2000s, are over. Capacity additions, although still larger than retirements, have slowed dramatically. Once plants currently under construction enter into service, the rate of capacity additions slows sharply in the New Policies Scenario. There is also a marked shift in the technologies being deployed in favour of more efficient options which also have lower emissions characteristics.

Figure 5.6 ▷ Shares of electricity generation by fuel and selected regions in the New Policies Scenario

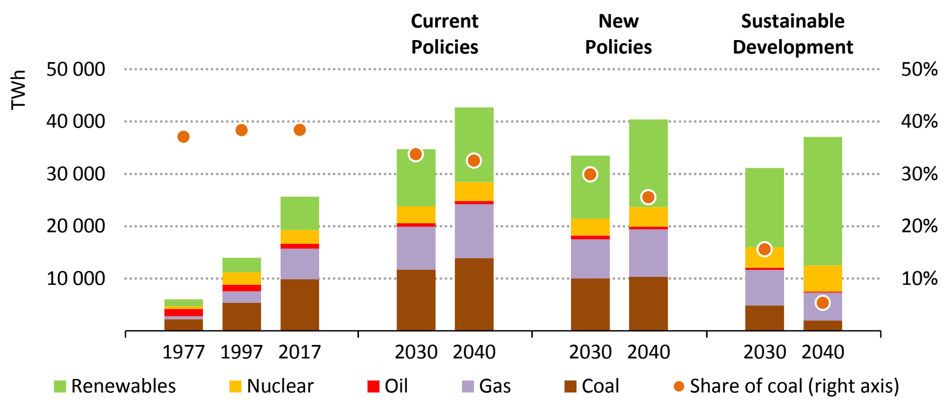


The levels of coal-fired power generation vary widely across regions, reflecting their demand and policy landscapes, and market competitiveness

Coal plant development faces challenges from public opposition, policies to limit greenhouse gas emissions, and the fight against air pollution. While generation levels slightly increase over the outlook period, the share of coal in global power generation drops to 30% by 2030 and 26% by 2040 (Figure 5.7). The coal fleet falls behind natural gas and solar PV to become the third-largest source of power generation capacity at about 2 200 GW by 2040.

The efficiency of the coal fleet increases markedly as subcritical capacity falls from above 900 GW today to below 700 GW by 2040. High-efficiency plants are commissioned once the remaining subcritical coal plants in the investment pipeline have come online, leading to a fall in the average emission intensity of the coal plant fleet from around 920 grammes of carbon dioxide per kilowatt-hour (g CO_2/kWh) today to some 860 g CO_2/kWh in 2040.

Figure 5.7 ▷ Global electricity generation by source and scenario



The higher the climate ambition, the lower the level of coal in the power mix

Note: TWh = terawatt-hours.

In the Sustainable Development Scenario, coal is almost squeezed out of the power mix. Renewables account for two-thirds of power generation by 2040 in this scenario and the share of coal falls to around 5%. Unabated coal plants operate far less often, providing power primarily when low-carbon sources (e.g. wind and solar PV) are not available. High load factors of 60-70% are confined to plants equipped with CCUS: by 2040, roughly 20% of coal capacity is equipped with carbon capture technology.

The picture for coal on a regional level is more nuanced. In the New Policies Scenario, coal remains an important pillar of electricity generation in many regions. In India, coal remains the main fuel in power generation in 2040 with a share of around 50% (solar PV overtakes coal in the late-2030s in terms of capacity, but not in terms of electricity generation).

Coal accounts for around 40% of power generation in 2040 in China and Southeast Asia. In Southeast Asia it becomes the primary fuel for power generation over the period, as the share of gas decreases. By contrast, coal generation is in retreat in many advanced economies such as Japan, Korea and the United States, and almost vanishes from power generation in the European Union over the period.

Flexibility needs in the power system: can coal adapt?

The rising share of renewables in the New Policies Scenario mainly displaces coal and gas generation and in some cases oil. While the expansion of variable renewable generation (thus far) is comparable in magnitude to that of nuclear power in the 1970s and 1980s, the implications for the power system are distinctly different.[1] At higher levels of deployment, the properties of variable renewable generation (most notably variability, stochastic feed-in and near-zero operating costs) have some profound implications for the operation of power systems and markets. The variable nature of wind and solar increase the need for flexibility in power system operation on all timescales from sub-seconds and seconds (inertia, grid stability) to minutes and hours (frequency reserve requirements, real-time markets), days (day-ahead planning), plus longer term that spans months and years (i.e. hydro-thermal co-ordination).

Most coal plants operating today were not designed with flexibility needs in mind. Adapting them to a different mode of operation typically requires modifications and upgrades. Changes to plant operation schedules and procedures, and additions of digital technology for real-time monitoring and other forms of smart technology can be low-cost options to increase the flexibility of existing coal plants. Retrofits to the boiler, turbine and water-steam systems typically go deeper into the plant architecture, but have the potential to raise flexibility by some 30-50% for ramp rates and turndowns depending on the measure (NREL, 2013). Costs for retrofits are plant specific and can vary substantially. State-of-the-art coal technology achieves ramp rates of 3-8% of full load per minute (% FL/min) and minimum stable load levels of 20% of full load (FL), a range comparable to the performance of combined-cycle gas turbines at 4-8% FL/min and 30-40% FL (IEA, 2018).

Operational flexibility from coal plants becomes most relevant in cases where there is a significant existing coal plant fleet. In practice, the existing coal fleet has been a significant source of flexibility in countries that took the lead in adopting variable renewable sources, such as Germany and Denmark, even though the coal plants were designed to serve as baseload. In China and India, coal plants have contributed to the integration of rising shares of renewables (see Spotlight). Coal power plants in these systems have helped balance seasonal generation (e.g. hydro in China), smoothed renewables feed-in on a daily and hourly basis (e.g. PV and wind power generation in Germany) and provided important system services on shorter time scales.

1. Nuclear power generation increased by around 1 500 TWh between 1973 and 1987; an amount almost equal to the rise in power generation from solar PV and wind, the main sources of variable renewables-based power, between 2003 and 2017.

SPOTLIGHT

Can India's coal-fired fleet be turned into a flexible asset?

Flexibility in the power system can come from generation assets, transmission networks, energy storage systems and demand-side response (see Chapter 8). For the special focus on electricity in this year's *Outlook*, India's power sector has been modelled as five interconnected regions with pre-defined transmission capacity, allowing for deeper analysis of the roles played by different forms of flexibility. Results for the New Policies Scenario in 2040 show that generation assets contribute a substantial share of the (considerable) flexibility requirements of a solar-rich system in India. Within this, the role of coal-fired plants is important, as the outlook for gas in power generation in India is not promising and only limited hydro assets are amenable to be made load-following.

Coal plants in India have operated at relatively low load factors over the last few years. Utilisation of the coal-fired fleet dropped from above 70% in 2010 to around 60% in 2017, largely because capacity additions ran ahead of actual demand growth. In the last five years, growth in generation from variable renewables has already resulted in some requirement for balancing services using traditional resources such as spinning reserves in thermal power plants. With a dispatchable capacity of 330 GW and a peak demand of around 200 GW, there is a significant reserve margin in the system to provide flexibility, provided that the right regulations, implementation mechanisms and incentives (or penalties) are in place.

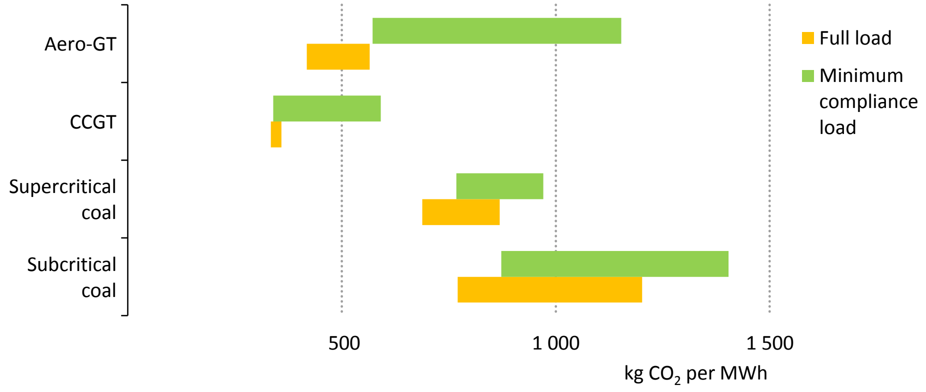
India formally introduced regulations for the provision of ancillary services in August 2015, and detailed provisions for compensation were made in April 2016. Given the challenges of co-ordinating among multiple regions, participation in ancillary services provision in India is limited to generating stations that provide supply to more than one state and where the tariff is determined by the Central Electricity Regulatory Commission. Around 50 GW of coal-based capacity meets these criteria. There are also mechanisms for compensating generation stations for degradation in efficiency and performance due to load-cycling requirements.

There are still questions to resolve. Some states in India have pushed back at the imposition of central regulations on coal-fired power plants, citing technical difficulties and uncertainties on cost recovery. The focus of regulation has been on the technical minimum that plants must achieve, but there has been little attention to ramp rates and impacts on plants beyond efficiency deterioration. Additional detailed analysis is needed to assess the costs of achieving these ramp rates or, alternatively, reducing the need for rapid flexing via higher reliance on storage and demand-side response.

Flexibility in the existing fleet can be augmented only if there are appropriate incentives to do so. For example, the northeast region of China introduced a remuneration scheme that provides compensation, in defined circumstances, for thermal plants that are called upon to reduce output. The increased flexibility in the power system has allowed for a significant increase in output from renewables: annual generation from renewables in the northeast region increased by 22% in 2017 with only a 2% increase in capacity. The scheme has now been extended to five more provinces in China.

Expanding flexible operation has implications for emissions (Figure 5.8). Operating a coal plant flexibly rather than as baseload generally reduces overall emissions because it is operating for less time. However, flexible operation increases emissions per unit of generation because emission intensity is higher during start-ups and during periods when the plant is operating at low load levels (as with other fossil fuel generation technologies). For coal plants, CO_2 emissions per unit of generation at minimum load are 5-15% higher than at full load. Sulfur oxide (SO_X) emissions of coal plants are hardly impacted at minimum load, while nitrogen oxide (NO_X) emissions are largely proportional to the load level, i.e. lower at lower load levels (Gonzales-Salazar, Kirsten and Prchlik, 2018). Technical interventions to the NO_X system, the flue-gas desulfurisation system and the particulate removal system can help reduce the negative impact of cycling on emission performance as well as limit the negative impact on the systems themselves (IEACCC, 2014).

Figure 5.8 ▷ Specific emission factors of various generation technologies at full and minimum compliance load



Emissions performance of fossil fuel generation technologies generally is negatively impacted by flexible operation

Note: MWh = megawatt-hour; GT = gas turbine; CCGT = combined-cycle gas turbine.

Sources: Gonzales-Salazar, Kirsten and Prchlik (2018); IEA analysis.

Box 5.1 ▷ Coal and CCUS in the Sustainable Development Scenario

Unabated coal generation is incompatible with the long-term emissions requirements of the Sustainable Development Scenario. In this scenario, only 5% of global electricity generation is based on coal by 2040, of which around two-thirds comes from plants equipped with CCUS. The share of renewables in power generation is 66% compared to 41% in the New Policies Scenario, increasing the need for flexibility.

Two CCUS projects are operating today as baseload capacity applying post-combustion capture technology: the Boundary Dam project in Saskatchewan, Canada and the Petra Nova Carbon Capture project in Texas, United States, with annual capture capacities of 1.0 million tonnes of carbon dioxide (Mt CO_2) and 1.4 Mt CO_2, respectively. There are no projects to date that provide experience of large-scale coal plants equipped with CCUS operating flexibly.

Retrofitting thermal power plants with one of the three main carbon capture routes – post-, pre- and oxyfuel combustion – appears to have only a small impact on their operational flexibility, provided that the capture systems are designed properly. In fact, post- and pre-combustion capture applications, which account for the vast majority of projected CCUS applications in the Sustainable Development Scenario, could potentially increase the ramp rate and lower the minimum stable operating load if the capture system and power block are operated independently. There are also several techniques to enhance flexibility involving storage of oxygen (oxyfuel combustion), hydrogen (pre-combustion) or solvents (post-combustion).

The technical difficulties of flexible operation of CCUS plants are small compared with the economic consequences. High-efficiency CCUS plants are costly to build and it is questionable whether newly built plants would be able to recover costs if required to operate flexibly. But perhaps the question should not really arise. At high capture rates, CCUS plants could generate near-zero or (if co-firing with bioenergy) even negative-emissions electricity, thereby helping to offset emissions in sectors where little or only very costly carbon reduction is possible. In this case there might be better options for flexibility.

Learnings from the two retrofit plants in operation indicate that substantive cost reductions are possible, suggesting that CCUS could provide an important strategic hedge for the existing coal fleet in a carbon constrained world. Market and policy design as well as technological progress will ultimately determine the viability of CCUS in power generation. The current lack of progress implies that, if it is to be part of the solution, efforts to help CCUS become commercially viable need to be stepped up.

Whether coal plant flexibility makes sense from an economic perspective is another question. Coal-fired plants are relatively capital intensive. Operating a plant flexibly reduces full load hours and therefore lowers revenues in energy-only markets, making cost recovery of retrofits and investment costs substantially more difficult. Flexible operation also leads to additional costs due to increased wear and tear of plant components.[2] In general, there is no business case for constructing large efficient coal plants with the sole purpose of providing flexibility (in practice, the economic calculation in such a case would favour inefficient coal plants with lower investment costs).

The extent to which existing coal plants can provide flexibility in a cost-effective way to the system is context dependent. Coal-fired capacity does play a part in meeting the increasing demand for flexibility in the New Policies Scenario (see Part B). The existing fleet is valuable in some countries where electricity storage is not available at cost and scale, grid interconnection between regions is not yet well developed, and demand response is not fully utilised. In these cases, coal plant flexibility retrofits are among the least-cost ways to bring additional flexibility to the system. The possibility of flexible operation can also be taken into account in the design of coal-fired power plants under construction or in planning stages, thereby reducing additional costs in the future. A trade-off for coal plant design remains: large boiler sizes typically imply higher efficiencies and lower CO_2 emissions, but also higher capital expenditure and more financial risks. New technologies such as small modular coal plants are being investigated that could potentially reduce capital needs while providing the flexibility and electricity security requirements of future power systems.

In the long run, competition among flexibility providers is set to intensify as grids are strengthened and energy storage and demand-side measures become increasingly prevalent. In our projections, decisions to build new coal-fired capacity are set to diminish in any policy environment that prizes reductions in the emissions intensity of power generation, even if supercritical or ultra-supercritical technology are capable of providing flexibility services to the system (Box 5.1).

5.7 What are the prospects for the world's coal exporters?

The volume of coal traded internationally nearly doubled between 2000 and 2011, underpinned by the rapid rise in demand in Asia, especially in China. Then, amid growing oversupply and declining prices, this expansion came to a halt, a painful reversal of fortune for many of the world's coal exporters who were forced into a period of retrenchment and cost-cutting. Leaner and in many cases newly profitable in 2017, these exporters are ready to take advantage of any increase in import demand, whether from existing or new coal consuming regions. But is such a rise in prospect in an increasingly demand-constrained coal outlook? And who, in a very competitive coal export market, is now best positioned to serve the world's coal import needs?

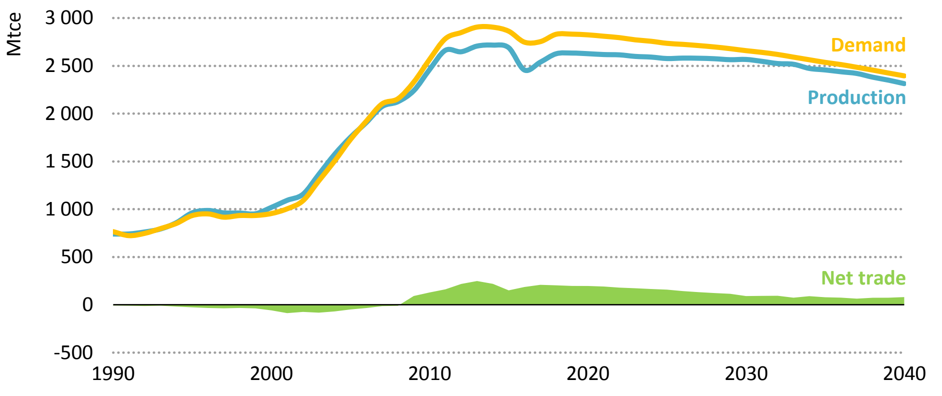
2. Several coal-fired plants, e.g. the Litoral Coal Power plant in Spain, have installed batteries to reduce wear and tear of components, thereby reducing maintenance costs and increasing the lifetime of components.

Where is coal import demand coming from?

Asia remains the main source of import demand in our projections, but there are significant uncertainties over the outlook in the New Policies Scenario, particularly in the two largest coal markets, China and India. Even minor changes in the supply-demand balance in either would have major repercussions on import demand and global coal trade. There are also smaller, emerging coal importers in Asia, Africa and the Middle East: their needs could have an effect on volumes and the direction of coal trade flows. In addition, even though coal demand is in structural decline in most advanced economies, the uncertain prospects for nuclear and renewables in power generation in Japan and Korea, in particular, provide some potential for upward or downward adjustments to our trade projections.

China is the largest coal importer, though its imports are small compared to the overall size of its coal market, and have fluctuated substantially in the past. The south-eastern coastal area, which takes delivery of more than 500 Mtce of coal from both international markets and China's northern regions, is one of the main determinants of steam coal prices globally. Coal buyers in that region arbitrage between domestic and imported coal, and thereby effectively determine a reference price for steam coal worldwide.

Figure 5.9 ▷ China's coal balance in the New Policies Scenario



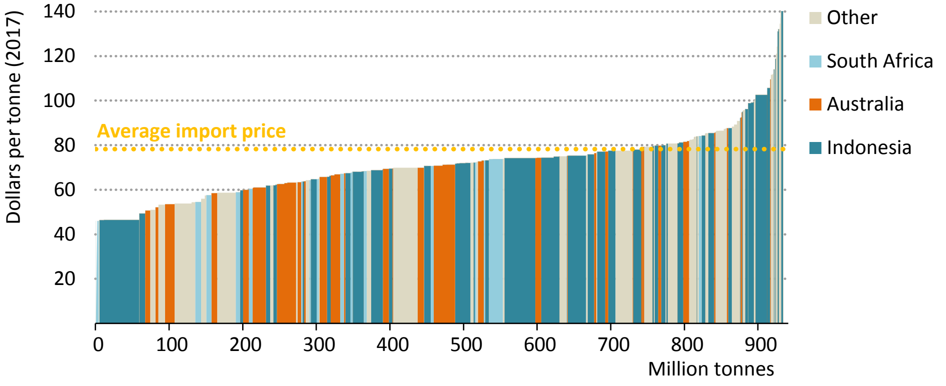
China's trade position is the balance between two very large numbers for production and demand: a relatively small shift in either could have large implications for trade

In the New Policies Scenario, China's coal consumption falls to 2 395 Mtce by 2040 with imports decreasing gradually from 210 Mtce in 2017 to around 80 Mtce in 2040 (Figure 5.9). Policy makers in China are actively engaged in managing production levels and cutting inefficient mining capacity, but the experience in recent years highlights the difficulties involved: in response to overcapacity, mine closure and labour hour limits were implemented in 2016 which curbed output but drove up prices above the range sought by policy makers of $80-90/tonne. The authorities in China introduced temporary price caps in early 2018 to bring prices back within the targeted price range and subsequently announced a series of policy measures to stimulate coal production. Further adjustments to policy could lead to fluctuations in prices and import levels.

Our projections for Chinese coal demand have been revised downwards since last year's *Outlook*, and it is not automatic that the pace of restructuring in the coal mining sector will align smoothly with any decline in consumption. Given the difficulties of reducing mining employment and the likelihood of an increase in mining productivity from its current low levels, a return to a net export position (as in the early 2000s) cannot be ruled out. Even if such a case were only temporary, it could have far reaching implications for coal exporters worldwide.

India's coal consumption continues to grow in the New Policies Scenario, even with ambitious targets to boost the share of clean energy technologies in its energy system. Power generation from coal in India nearly doubles over the outlook period and industrial demand more than triples. But there are major uncertainties about the size of this increase (especially in the power sector) and also about the extent to which it might translate into rising demand for imports (Figure 5.10). In practice, coal imports have fallen since 2014 and they could fall further as a result of efforts to boost domestic output. In 2015, Coal India Limited, which accounts for around 80% of domestic production, was set a target of producing 1 billion tonnes by 2020 (PIB, 2015), with a view to reducing reliance on imported coal.[3]

Figure 5.10 ▷ Delivered costs of steam coal from various sources to India, 2017



Coal exporters are eager to benefit from a growing steam coal market in India, but the ultimate scale of import growth is uncertain

Sources: CRU (2018); IEA analysis.

3. The target is measured in physical volumes and has been moved to 2026, keeping in mind the economics and the ability of newly launched production sites to ramp up production. But the policy preference for domestic coal remains firmly in place.

In the New Policies Scenario, coal demand in India reaches 955 Mtce by 2030 and 1 240 Mtce by 2040. The pace of demand growth slows steadily over the outlook period. Overall import dependence also declines and returns to levels observed before the boom in imports from 2010. However, dependence on coking coal imports rises significantly, as domestic output is constrained by resource limitations.

There are a number of potential bottlenecks in India that could affect the pace of coal production capacity expansion and the delivery of adequate quantities to various users. Some of India's coalfields are in relatively inaccessible parts of the country making it difficult to connect new mines to the rail network. An overhaul of the coal allocation system in India has reduced the distance that coal needs to travel on the rail network: on average, coal haulage distance was cut 30% in the last five years from 640 km to 460 km (Indian Railways, 2017). Nonetheless, as of April 2018 more than 50 million tonnes (Mt) of coal was stockpiled at mines awaiting transportation, augmenting the need for imports (CIL, 2018a).

Around 90% of domestic coal in India is allocated through long-term fuel supply agreements to end-users at notified prices. Auctions and short-term purchases are typically only used by small consumers or those who are unable to access coal on long-term contracts. The logistics system is often slow to respond to fluctuations in demand and, with bottlenecks in the rail network, there is often a shortfall in supply in critical months, meaning that plants resort to imports. A recent order passed by the Maharashtra state electricity regulator, which does not allow the power generation utility to pass on the costs of expensive imported coal when domestic coal could have been planned for and made available, may prove to be a landmark ruling which sets a precedent for more accountability on the part of regulated players in India's coal sector.

Domestic coal in India is of variable quality. Over the last two decades, official data suggest a continuous decline in the quality of indigenously produced coals in terms of calorific values and high mineral-ash content. In total, there are 17 grades of non-coking coal allocated to the various sectors (CIL, 2016). There are frequent disagreements between end-users and suppliers on the quality (and quantity) of coal delivered. Coal "grade-slippage", as it is commonly referred to, is the difference between the stated quality of coal dispatched and that which is received by the purchaser. This can be as high as 10-20% of the declared calorific value. In recent years, with mandated third-party verifications of coal quality, there have been efforts to increase transparency in the system, which has resulted in a narrowing of the range between coal quality "as declared" and "as received" (CIL, 2018b).

Coal demand in **Southeast Asia** is set to more than double in the New Policies Scenario in the period to 2040. The electricity sector, where demand rises by almost 4% per year to 2040, is the main source of increasing coal demand, as the projected uptake of renewables does not keep pace with electricity demand growth and imported liquefied natural gas (LNG) is relatively expensive. However, coal-fired power plant development in Southeast Asia is facing increasing public opposition, for instance in Thailand and the Philippines, which poses some downside risk to our coal outlook. Import demand in Southeast Asia (excluding Indonesia) increases to some 180 Mtce by 2040 as there is only limited domestic mining outside Indonesia. With Indonesia included, the Southeast Asia region only just remains a net exporter, as an increasing share of coal production in Indonesia serves domestic demand. Elsewhere in Asia, Bangladesh and Pakistan are targeting a significant ramp up of coal in power generation. While Pakistan is endowed with domestic lignite resources in the Thar field in Sindh province, coal imports to both countries are set to increase over the outlook period.

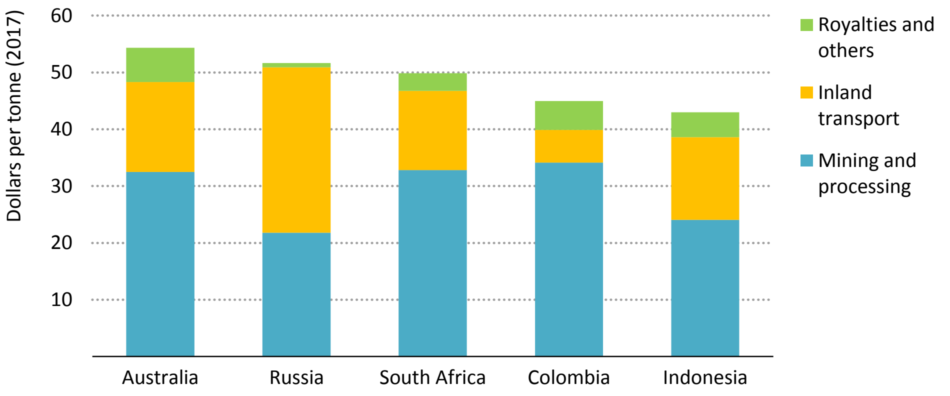
In the **Middle East** and **Africa,** several countries plan to start using imported coal in power generation. Construction of new coal-fired power plants has already started in the United Arab Emirates, Iran and Jordan. Oman plans to build its first coal-fired power plant in Duqm to diversify its power generation mix. Coal imports to the Middle East are projected to reach 12 Mtce by 2040. Egypt plans to build its first coal-fired power plants in Ayoun Moussa and Hamrawein. However, our overall coal demand projections for Africa have been revised downward in light of a more favourable outlook for renewables.

In **advanced economies,** coal demand and imports are in structural decline. Finland, France, Italy, Netherlands and United Kingdom have announced plans to phase out coal. Germany, Europe's largest coal consumer, has set up a commission to report by the end of 2018 on the future of coal in the country; it is preparing a roadmap for the phase-out of coal-fired power generation, which will ensure that Germany's climate targets are achieved, while also submitting proposals for structural development in the affected regions. Korea and Japan, which both have limited domestic coal reserves, are the main sources of uncertainty for our projections in advanced economies. With electricity demand growth remaining sluggish, the primary question for Japan remains the speed at which nuclear power plants restart. In our projections, Japanese coal imports decrease by 32% to 2040, as nuclear power generation reaches some 230 TWh.

How do the world's coal exporters line up?

Relative positioning on the supply cost curve is crucial for coal exporters. An in-depth look at the cost structure of the individual coal exporters forms the basis of the *WEO's* analysis when mapping coal trade developments. Mining cash cost and their components provide a first indication of the relative competitiveness of producers (Figure 5.11). Infrastructure availability is crucial for exporters to bring coal to international markets, as constraints and bottlenecks in infrastructure can limit coal exports from otherwise viable coal basins. Shipping costs are a major determinant of whether coal can be competitively supplied to import markets. Coal quality considerations are increasingly important.

Figure 5.11 ▷ **FOB cash cost components of major steam coal exporters, 2017**



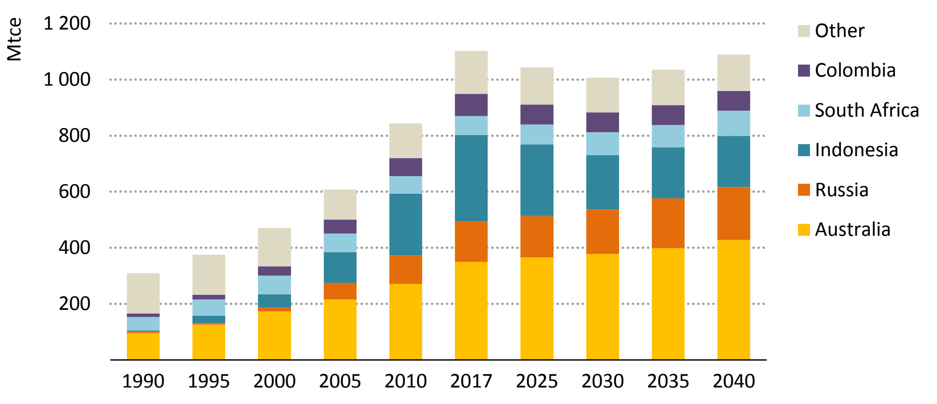
Coal exporters' cost structures shape their relative competitiveness

Note: FOB = free on board.

Sources: CRU (2018); IEA analysis.

Many coal exporters have emerged leaner and fitter from the recent coal market downturn, and competition promises to be strong in the uncertain import demand environment of the New Policies Scenario, in which overall coal trade remains largely flat (Figure 5.12). Australia, the world's largest exporter continues to be well positioned to serve coal import needs in the Pacific Basin while Indonesian exports decline over the outlook period due to increasing domestic coal demand in power generation. The fundamentals suggest that Russia has the potential to expand market share; it becomes the second-largest coal exporter in our projections, overtaking Indonesia by the mid-2030s.

Figure 5.12 ▷ **Major coal exporters in the New Policies Scenario**

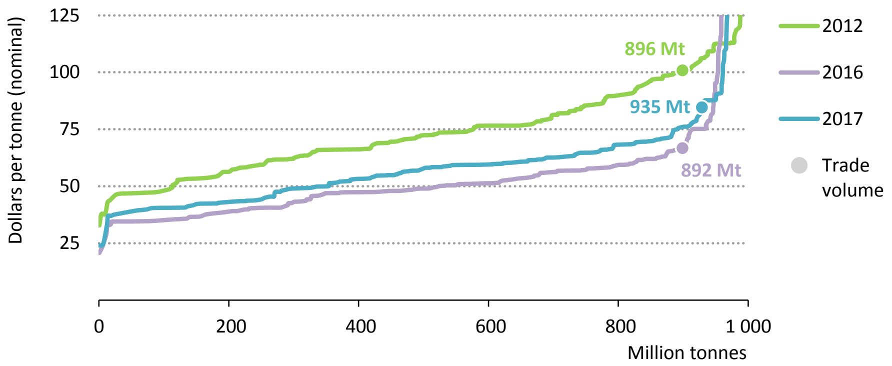


Coal exporters vie for market share in a stagnant trade market

Investment in coal mining is lagging: has it gone for good?

Although much less capital intensive than the upstream oil and gas industries, coal mining still requires substantial spending. The New Policies Scenario has a flat coal production profile over the period to 2040, but capital expenditures are needed along the value chain to sustain existing and to establish new mining operations, as well as to build railway and port infrastructure to connect new or expanding mining regions to coal importers.

Figure 5.13 ▷ The seaborne steam coal cost curve and trade volumes



After years of stringent cost-cutting, production costs increased slightly in 2017 driven mainly by macroeconomic factors

Sources: CRU (2018); IEA analysis.

A round of cost-cutting, followed by the subsequent run-up in prices, has helped the financial situation of many coal suppliers (although production costs rose slightly in 2017 due to macroeconomic factors and the general commodity price environment) (Figure 5.13). But the return to financial health has not been accompanied by a renewed appetite for investment in the coal supply chain. There are a few new projects in Australia and Russia, and some continuing coal investments in China and India.[4] However, in most coal exporting countries, there has been no noticeable pick-up in investment. There are competing explanations for this continued slowdown in investment:

- Market participants may see the recent increase in price not as a sign of scarcity, but rather as a product of China's domestic coal market restructuring. Chinese

4. In India, tailored contracts are supporting coal mining. Long-term power purchase agreements tied to the allocation of coal mines assures guaranteed offtake of coal at agreed prices.

policies have been adjusted on several occasions over the last few years to balance price, demand and supply, and there may be uncertainty regarding future policy interventions in the world's largest coal market.

- Coal companies may be holding back because they remember the previous upswing, when many producers invested in expanded operations and then were faced with declining prices. In the United States, some of the largest coal producers went into bankruptcy protection and have just recently re-emerged.
- Uncertainty is underscored by climate policies, energy efficiency improvements and declining costs for renewable sources and storage, which may be seen as posing a big risk for future coal demand.
- The fossil fuel divestment movement may have made market entry and access to capital more difficult for some coal producers.

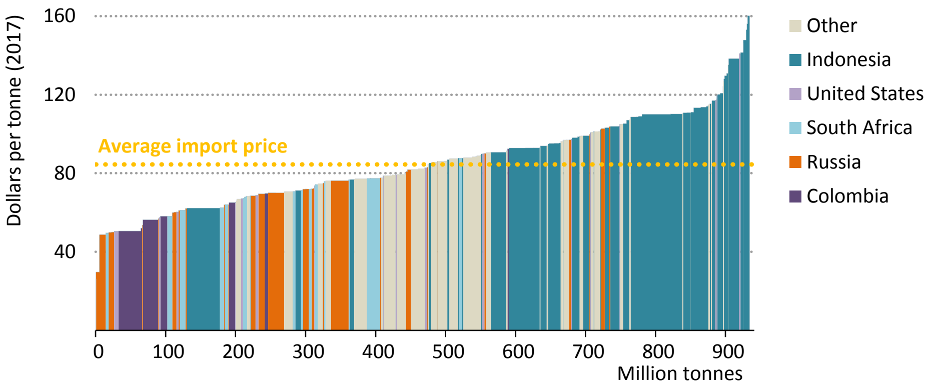
Australia is the world's largest coal exporter. It benefits from a large high quality resource base (in particular low cost/high quality coking coal) and from a formidable mining industry which has successfully cut costs in recent years. In order to expand export volumes in the future, new basins and new transport infrastructure would need to be developed, including railway connections between new mines in the Galilee Basin in Queensland, like Adani's Carmichael mine, and export ports. Our projections in the New Policies Scenario see Australia increasing its exports to around 430 Mtce by 2040, roughly half of which is coking coal. This is consistent with some mining development in the Galilee Basin, albeit subject to all the caveats regarding import demand discussed above.

Indonesia has a diverse coal mining industry. Although there are higher quality deposits, much of Indonesian coal has a relatively low calorific value, which means it trades at a discount to its competitors in the international coal trade market. Some mines have been pushed to the higher end of the supply curve by the increase in oil prices, especially mines relying on truck-and-shovel methods to develop complex seams and river barges for inland transportation. A growing share of Indonesian production is destined to serve domestic demand over the outlook period. The speed at which domestic demand picks up will be a major determinant for Indonesian export potential. Our projections in the New Policies Scenario see coal exports to drop to some 180 Mtce by 2040. However, in the past, Indonesian exporters have shown they can mobilise production and exports rapidly when the market and price environments are favourable. This means that there is some upside potential for exports from Indonesia.

Russia has some of the lowest mining costs in the world, but transportation costs are more than twice as high as in its main competitors and account for more than 50% of Russian FOB costs. Russian coal has to be transported over long distances from mining regions to export ports. The depreciation of the rouble has helped to expand exports in recent years, and investment in mining and ports is under way to serve growing demand in Asia, as demand in Europe declines. In our projections, Russia is able to increase exports to some 190 Mtce by 2040.

Colombia currently sends some 60% of its steam coal exports to Europe, where coal demand is in steep decline (Figure 5.14). In the New Policies Scenario, Colombia continues to provide coal to the Mediterranean area and also to supply some emerging coal markets in the Middle East and Africa. However, distance from the main markets in Asia limits Colombia's ability to diversify further, and Colombian exports are projected to decrease by more than 10% over the period to 2040.

Figure 5.14 ▷ Delivered costs of steam coal from various sources to Europe, 2017



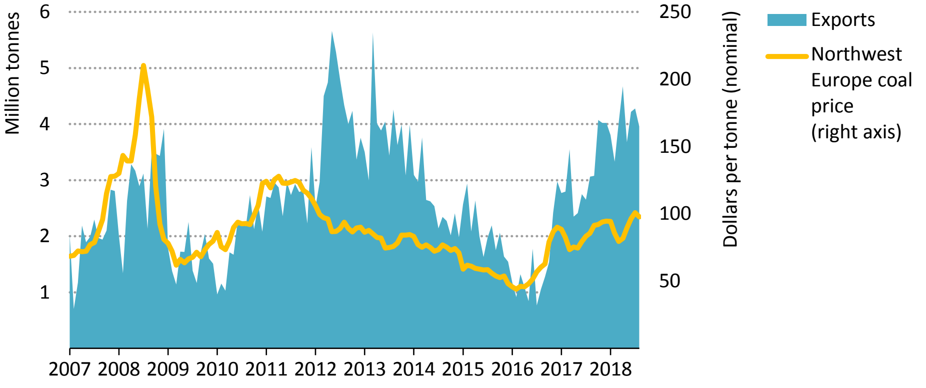
Colombian exporters provide some of the lowest cost coal to the European market

Sources: CRU (2018); IEA analysis.

South Africa has increased coal exports to India in recent years and shifted exports to the Pacific Basin away from the Atlantic Basin. Its mining industry is approaching the "2020 coal-cliff", an expression coined to describe a drop in capacity around 2020 when several existing mines, in particular in the Mpumalanga province, are expected to be depleted. Mining in the remote Waterberg region as well as associated transport infrastructure (e.g. rail lines) would need to expand to sustain production levels. Domestic coal demand is set to fall substantially over the outlook period as nuclear power and renewables challenge coal in power generation. South African exports gradually increase over the period to some 90 Mtce, largely destined for South Asia and Southeast Asia.

United States coal exports increased by some 70% in 2017, but exporters are facing the challenge of being a high cost swing supplier in a stagnating trade market (Figure 5.15). Coking coal suppliers accounted for nearly two-thirds of coal exports in 2017 and have generally fared better than steam coal suppliers. Over the outlook period, US coal exports decline by more than 40% to around 45 Mtce, reflecting the challenges that exporters face in matching the prices of other suppliers due to high production costs, high transport costs, or both, in the various production basins.

Figure 5.15 ▷ Monthly US steam coal exports and northwest Europe coal price



US coal has been a swing supplier to the international coal market

Sources: IHS Energy (2018); IEA analysis.

Canada, Mozambique and **Mongolia** are important players in international coking coal trade. While Canada increases export volumes over the period, Mongolian exports shrink as its landlocked position means that its export opportunities are restricted to the Chinese market. Mozambique increases exports from 7 Mtce in 2017 to around 20 Mtce by 2040.

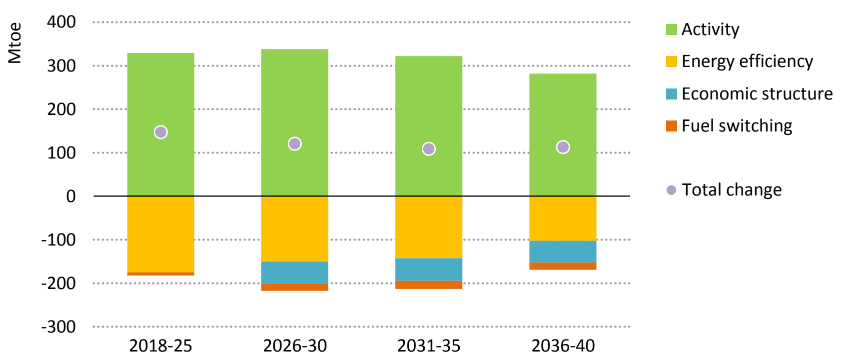
Energy efficiency and renewable energy

Driving investment and technology change

SUMMARY

- Global total final consumption was almost 9 700 million tonnes of oil equivalent (Mtoe) in 2017, an increase of 1.7% compared with 2016. In the New Policies Scenario, this rises to almost 12 600 Mtoe by 2040, an increase of 1.1% per year on average, while global energy intensity improves by 2.3% per year. Government policies and measures, including mandatory energy efficiency regulations, drive much of the improvement in energy intensity which curbs growth in energy consumption.

Figure 6.1 ▷ Average annual change in total final consumption by driver in the New Policies Scenario, 2018-2040



The increase in total final consumption would be around twice as large, if it was not for continued improvement in energy efficiency

- In the buildings sector – with 31% of total final consumption, the largest energy consuming end-use sector today – consumption increases by an average of 0.9% per year in the New Policies Scenario. The industry sector, which accounted for around 29% of total final energy consumption in 2017, sees growth of 1.3% per year, the fastest among the end-use sectors. Transport energy consumption increases by 1.1% on average over the period to 2040, maintaining a 29% share in total final consumption.

- In 2017, around $236 billion was invested in energy efficiency across the buildings, transport and industry sectors. In the New Policies Scenario, investment expands and reaches around $770 billion by 2040. The transport sector accounts for more than half of this investment (54%), followed by buildings (39%) and industry (7%).

- Already a major global industry, renewable energy technologies supply 45% of incremental primary energy demand to 2040 in the New Policies Scenario. China becomes the world leader in renewable energy use, followed by the European Union, the United States and India. Renewables overtake coal for power generation in the 2020s and supply 40% of electricity by 2040. Investment in renewables-based electricity rises from $300 billion in 2017 to around $410 billion in 2040. Solar photovoltaic (PV) accounts for around 35% of power generation investment.

- The use of renewables to meet demand for both heat and in transport increases in the New Policies Scenario. Renewables for heat rises by around 85% over the outlook to about 875 Mtoe in 2040. The share of renewables in transport energy demand increases steadily to reach 8% in 2040 compared with 3.5% today. Owing to energy efficiency improvements in combustion engines, biofuels deliver more useful energy over time. The contribution of renewables-based electricity increases with electric vehicle (EV) deployment and the growing share of renewables in electricity generation.

- The United Nations Agenda for Sustainable Development (2030 Agenda) includes targets to increase the share of renewables in energy supply (Sustainable Development Goal [SDG] 7.2) and improve energy efficiency (SDG 7.3). Our analysis shows energy efficiency improving by an annual average of 2.4% to 2030: this represents a near 50% improvement on recent progress, but remains below the 2.7% required to meet the SDG 7.3 target. The share of modern renewables in total final energy consumption grows to 15% by 2030 in the New Policies Scenario, well below the 22% achieved in the Sustainable Development Scenario.

- Transport is the largest oil-consuming sector today, accounting for a fifth of global energy demand and a quarter of energy-related CO_2 emissions. The car fleet increases by 80% over the outlook period, but fuel needs are less than 20% higher than today. This is a result of energy efficiency gains, and to a lesser extent, the uptake of electric cars. Higher efficiency leads to better use of biofuels, for which sustainable feedstock is limited.

- Heat demand in the buildings sector worldwide accounts for almost 75% of total final consumption in buildings, mostly for space heating. In the European Union, energy efficiency measures such as insulation and retrofitting play an important role in curbing energy demand for heating. In the New Policies Scenario, which includes a buildings retrofit rate of 2% a year, energy demand for heating in the buildings sector in European Union falls by 0.95% per year to 2040 or an overall reduction in buildings energy demand of just over 60 Mtoe.

Introduction

This chapter examines current trends in renewable energy and energy efficiency. Recent years have been characterised by strong growth in the deployment of renewable energy technologies, with the power sector leading the way. While the power sector is regularly breaking records for levels of investment and deployment, the uptake of renewables has been slower in the industry, buildings and transport sectors. Some renewable energy technologies are already competitive in existing markets; others teeter on the line between needing support and being competitive, while others clearly cannot compete today without financial support.

Along with renewables, energy efficiency needs to be one of the cornerstones of any strategy to guarantee sustainable and inclusive economic growth. It remains one of the most cost-effective ways to enhance security of energy supply, to boost competitiveness and welfare, and to reduce the environmental footprint of the energy system. Not only can the growth of carbon-dioxide (CO_2) emissions be tempered by the more efficient use of energy but energy efficiency can also improve global air quality and contribute to reducing the millions of air-pollution related premature deaths each year (IEA, 2018a).

While governments recognise the significant contributions and remaining potential of both renewables and energy efficiency gains, generally their policy approaches follow distinct paths and support measures. As the scale and pace of the deployment of each grows, the case for an integrated approach becomes more compelling. This chapter focuses on three key themes:

- The first builds on the analysis on tracking progress towards energy-related Sustainable Development Goals (SDGs) in Chapter 2 and extends this framework to the two targets aimed at increasing the share of renewables in the energy mix (SDG 7.2) and improving energy efficiency (SDG 7.3), and assesses whether the energy system is on track to meeting them.
- The role of efficiency improvements and renewables in the transport sector is the second thematic focus. Significant energy efficiency improvements have been achieved, or are in sight, thanks to new technologies, strengthened fuel-economy standards for road vehicles and new policies for the aviation and shipping sectors. Biofuel blending obligations have been the key driver for the growth of renewables in transport.
- The third theme examines the impact of recent changes to the European Union's Energy Performance of Buildings Directive (EPBD). In the European Union (EU) today, the buildings sector is the largest consumer of energy and is a major contributor to carbon dioxide (CO_2) emissions. Of the residential buildings that will be in use in 2040, it is estimated that around 60% have already been built. This underscores the important role of retrofits in EU residential buildings to go hand-in-hand with effective efficiency standards for new buildings.

Figures and tables from this chapter may be downloaded from www.iea.org/weo2018/secure/.

Scenarios

6.1 *Energy efficiency by scenario*

Global energy intensity, defined as the ratio of primary energy supply to gross domestic product (GDP), continued to improve in 2017, reaching 110 tonnes of oil equivalent (toe) per $1 million of GDP.[1] This favourable trend stretches back two decades. Improved energy intensity is primarily the result of efficiency gains in the power and end-use sectors, together with a gradual restructuring in many regions from energy-intensive to lighter industries. Worryingly, the annual average rate of energy intensity improvement slowed to 1.7% in 2017 from 2.5% in the last three previous years. This is only half of the annual improvement required in the Sustainable Development Scenario (Table 6.1).

Table 6.1 ▷ Key energy indicators by scenario

		New Policies		Current Policies		Sustainable Development	
	2017	2025	2040	2025	2040	2025	2040
TPED (Mtoe)	13 972	15 388	17 715	15 782	19 328	14 146	13 715
Share of fossil fuels (%)	81%	78%	74%	79%	78%	77%	60%
TFC (Mtoe)	9 696	10 871	12 581	11 103	13 510	10 126	9 958
Energy intensity of GDP (2017=100)	100	82	58	84	64	75	45

Notes: TPED = total primary energy demand; Mtoe = million tonnes of oil equivalent; TFC = total final consumption.

In the absence of existing and announced efficiency measures, global energy consumption in 2040 would be almost 3 400 Mtoe higher than projected in the **New Policies Scenario**. Energy efficiency policies in developing economies account for 60% of the reduction in global energy consumption in 2040 in the New Policies Scenario, but only in the European Union, Japan, and Korea do energy efficiency gains fully offset the increase in energy demand.

The worldwide trend of enhanced energy intensity masks regional variations. In China, energy intensity improved by 3.9% in 2017, but the rate of improvement was only half that of 2016. In the United States, energy intensity improved by almost 3% in 2017 (Table 6.2).

Despite progress in many countries and regions, significant energy efficiency potential remains untapped (IEA, 2018a). In the **Sustainable Development Scenario**, the systematic pursuit of economically viable opportunities to improve efficiency keeps the increase in global final energy consumption to around 250 Mtoe in the period to 2040, compared with nearly 2 900 Mtoe in the New Policies Scenario.[2] In the Sustainable Development Scenario, energy intensity declines by 3.4% a year, compared with 2.3% in the New Policies Scenario.

1. In the *World Energy Outlook-2018*, energy intensity is calculated using GDP in purchasing power parity (PPP) terms to enable differences in price levels among countries to be taken into account. In our scenarios, PPP factors are adjusted as developing countries become richer.

2. A measure to improve energy efficiency is defined as being economically viable if the payback period is shorter than the economic lifetime of the technology or piece of equipment.

Table 6.2 ▷ Energy intensity of GDP by scenario (toe/$1 000, PPP)

		New Policies		Current Policies		Sustainable Development	
	2017	2025	2040	2025	2040	2025	2040
North America	0.11	0.10	0.07	0.10	0.08	0.09	0.06
United States	0.11	0.10	0.07	0.10	0.07	0.09	0.06
Central and South America	0.09	0.08	0.06	0.08	0.07	0.07	0.05
Brazil	0.09	0.08	0.06	0.08	0.07	0.08	0.05
Europe	0.08	0.07	0.05	0.07	0.05	0.06	0.04
European Union	0.08	0.06	0.04	0.06	0.05	0.06	0.04
Africa	0.13	0.11	0.08	0.09	0.07	0.09	0.05
South Africa	0.17	0.15	0.10	0.16	0.12	0.14	0.07
Middle East	0.12	0.11	0.09	0.11	0.10	0.10	0.07
Eurasia	0.18	0.16	0.12	0.16	0.12	0.15	0.10
Russia	0.18	0.16	0.12	0.17	0.13	0.16	0.11
Asia Pacific	0.11	0.08	0.06	0.09	0.06	0.08	0.04
China	0.13	0.09	0.06	0.10	0.07	0.09	0.05
India	0.09	0.07	0.05	0.07	0.05	0.06	0.03
Japan	0.08	0.07	0.06	0.07	0.06	0.07	0.05
Southeast Asia	0.08	0.07	0.05	0.07	0.06	0.06	0.04
World	**0.11**	**0.09**	**0.06**	**0.09**	**0.07**	**0.08**	**0.05**

6

S P O T L I G H T

Efficient World Scenario: pulling the energy efficiency lever

In the 2012 edition of the *World Energy Outlook*, the International Energy Agency (IEA) produced an Efficient World Scenario, quantifying the implications for global energy use of pursuing all economically viable opportunities to improve energy efficiency, based on the technologies then available. In 2018, we updated our modelling of the Efficient World Scenario, again to show how tackling the barriers to energy efficiency investment can unleash this potential and bring significant gains for energy security, economic development and the environment (IEA, 2018a).

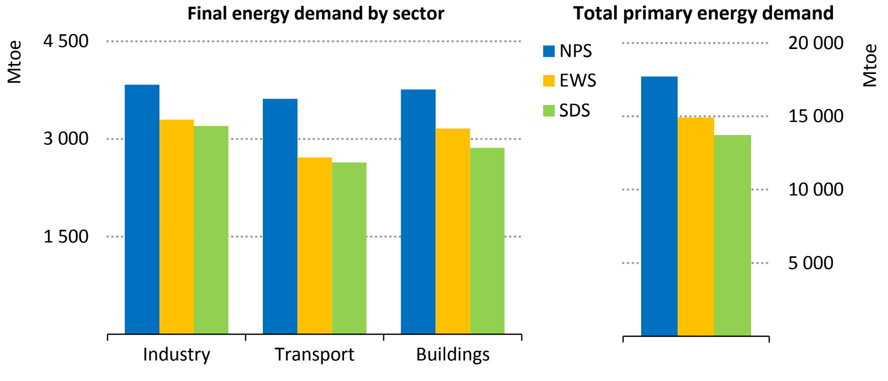
In the new Efficient World Scenario, a 3% annual rate of improvement means that the primary energy intensity of GDP is halved by 2040. This is a considerable step up from the average rate of intensity improvement of 2.3% seen in the New Policies Scenario. It has major impacts on energy consumption of every end-use sector:

- In transport, road passenger vehicles use 40% less fuel per vehicle-kilometre (vkm) travelled in 2040 compared to today. Thanks to hybridisation, and logistics efficiency improvements, road freight uses 46% less energy per tonne-kilometre (tkm) moved.

- In industry, the average energy needed to produce a tonne of crude steel in 2040 decreases by 25% from today's levels, with similar improvements in pulp and paper, thanks largely to increases in recycling rates and equipment efficiency. The most significant gains are in less energy-intensive sectors, however, largely thanks to improvements in electric motor systems and deployment of heat pumps.
- In buildings, a typical square metre of residential floor space uses 26% less energy in 2040 than today, as residential space heating is 43% and lighting around 50% less energy intensive. Average energy intensity of non-residential buildings is 37% lower in 2040 than today.

Implementation of the additional energy efficiency measures assumed in the Efficient World Scenario reduces final energy consumption by 14% in industry, 25% in transport and 16% in buildings in 2040 compared with the New Policies Scenario in 2040, driving down total primary energy demand by nearly 2 800 Mtoe.[3] While pulling the energy efficiency lever is a cornerstone of decarbonisation, alone it is not sufficient to achieve the targets of the Sustainable Development Scenario: this Scenario needs a holistic approach which goes wider than energy efficiency.

Figure 6.2 ▷ Final energy demand by sector and total primary energy demand in each scenario in 2040



The Efficient World Scenario highlights the untapped potential of energy efficiency, taking the world a long way towards the Sustainable Development Scenario

Note: NPS = New Policies Scenario; EWS = Efficient World Scenario; SDS = Sustainable Development Scenario.

3. Latest results from *WEO-2018* scenarios are used for comparison with the Efficient World Scenario. This may lead to some relatively small differences with Energy Efficiency 2018 (IEA, 2018a) which uses *WEO-2017* scenarios as a basis for comparison.

6.2 Renewables by scenario

Electricity generation from renewables has grown very rapidly in recent years, mainly owing to hydropower, wind and solar photovoltaic (PV). In 2000, solar PV accounted for only 1 TWh of electricity generation, by 2017 this had increased to 435 TWh. Wind power accounted for 31 TWh of electricity generation in 2000; by 2017 this had increased to almost 1 100 TWh. The use of renewables in heating and in the transport sector has also grown: for example, biodiesel demand in 2000 was less than 1.0 Mtoe but reached 29 Mtoe by 2017.

Today, hydropower is the largest source of renewables-based power generation, though its rate of deployment slowed somewhat in 2017 with only 25 GW of new capacity added (compared with 36 GW in 2016 and 35 GW in 2015). Wind power holds the second spot: overall wind power capacity additions declined in 2017 even though investment in offshore wind is picking up. Solar PV capacity additions expanded to 97 GW in 2017, led by China, which accounted for more than half of the increase. Electricity output from wind and solar PV combined was almost 20% higher in 2017 than in 2016. In 2017, renewable energy technologies accounted for a quarter of all electricity generation. The perspectives for growth vary considerably, depending on the policies assumed to be in place, ranging from a one-third share in 2040 in generation in the Current Policies Scenario to a two-thirds share in the Sustainable Development Scenario (Table 6.3).

In the **New Policies Scenario**, indirect use of renewables grows faster in the period to 2040 than its direct use in both heat and transport applications. In the **Sustainable Development Scenario**, additional measures to incentivise investment in renewables-based electricity, biofuels, solar heat, geothermal heat and electrification push the share of renewables to two-thirds of the power mix, 25% in heat and 22% in transport in 2040 (including indirect use in transport and heat).

The supply of heat accounted for more than half of total final consumption (almost 5 000 Mtoe) in 2017. The vast majority of heat supply today is produced from fossil fuels, with only 10% coming from renewable energy sources. Bioenergy dominates the renewable contribution to heat supply, accounting for almost 90% of the direct use of renewables-based heat in 2017, as well as almost all of its contribution in district heating systems.

The share of renewables in global heat supply increases in the New Policies Scenario by five percentage points, reaching 875 Mtoe in 2040. Around 60% of this increase is expected to take place in China, the European Union, India and the United States, which are today's largest consumers of renewables-based heat. In the Sustainable Development Scenario, the contribution of renewables to heat supply grows at a much faster rate, reaching 1 100 Mtoe and representing a quarter of overall heat demand by 2040.

The transport sector accounted for almost 8% of direct consumption of renewables in 2017. Around 1.8 mboe/d (86 Mtoe) of biofuels, the only renewable energy source used directly in the sector, were consumed in 2017; some two-thirds of this was ethanol, followed by biodiesel (one-third) and biofuels for aviation and shipping (less than 1%).

Table 6.3 ▷ World renewable energy consumption by scenario

		New Policies		Current Policies		Sustainable Development	
	2017	2025	2040	2025	2040	2025	2040
Primary demand (Mtoe)	**1 334**	**1 855**	**3 014**	**1 798**	**2 642**	**2 056**	**4 159**
Share of global TPED	*10%*	*12%*	*17%*	*11%*	*14%*	*15%*	*30%*
Traditional use of solid biomass (Mtoe)	**658**	**666**	**591**	**666**	**591**	**396**	**77**
Share of total bioenergy	*48%*	*42%*	*32%*	*42%*	*33%*	*29%*	*5%*
Electricity generation (TWh)	**6 351**	**9 645**	**16 753**	**9 316**	**14 261**	**10 917**	**24 585**
Bioenergy	623	890	1 427	873	1 228	1 039	1 968
Hydro	4 109	4 821	6 179	4 801	5 973	5 012	6 990
Wind	1 085	2 304	4 690	2 151	3 679	2 707	7 730
Geothermal	87	129	343	125	277	162	555
Solar PV	435	1 463	3 839	1 334	2 956	1 940	6 409
Concentrating solar power	11	34	222	30	119	54	855
Marine	1	3	52	2	29	4	78
Share of total generation	*25%*	*32%*	*41%*	*30%*	*33%*	*38%*	*66%*
Final consumption (Mtoe)*	**930**	**1 309**	**2 113**	**1 259**	**1 838**	**1 510**	**2 977**
United States	141	186	271	178	245	226	408
European Union	186	245	326	237	290	269	366
China	158	261	473	246	378	304	671
India	57	99	200	96	179	116	277
Share of global TFC	*10%*	*12%*	*17%*	*11%*	*14%*	*15%*	*30%*
Heat consumption (Mtoe)*	**478**	**606**	**874**	**594**	**820**	**653**	**1 090**
Industry**	236	288	395	289	395	302	460
Buildings and other***	242	318	478	304	425	351	630
Share of total heat demand	*10%*	*11%*	*15%*	*11%*	*13%*	*13%*	*25%*
Biofuels (mboe/d)****	**1.8**	**2.8**	**4.7**	**2.5**	**3.5**	**4.4**	**7.3**
Road transport	1.8	2.6	4.0	2.4	3.4	3.9	4.9
Aviation and shipping*****	0.0	0.1	0.7	0.0	0.1	0.5	2.3
Share of total transport demand	*3%*	*4%*	*6%*	*4%*	*4%*	*7%*	*15%*

* Includes indirect renewables contribution, but excludes environmental heat contribution and traditional use of solid biomass. ** Coke ovens and blast furnaces are included in the industry sector. *** Other refers to desalination and agriculture. **** In energy-equivalent volumes of gasoline and diesel. ***** Includes international aviation and marine bunkers.

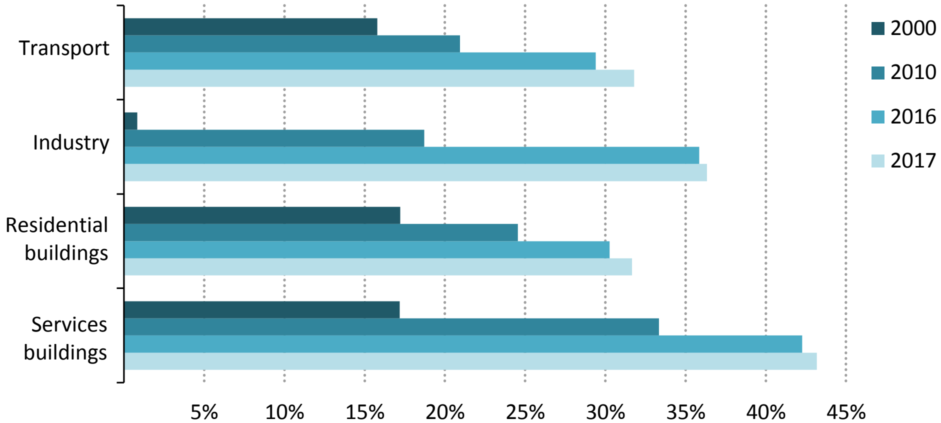
Note: TPED = total primary energy demand; TWh = terawatt-hours; Mtoe = million tonnes of oil equivalent; TFC = total final consumption; mboe/d = million barrels of oil equivalent per day.

The United States is by far the largest market for biofuels with almost half of global demand, followed by Brazil (20%) and the European Union (18%). Demand for biofuels is projected to increase in both the New Policies Scenario and the Sustainable Development Scenario (the outlook for the use of biofuels in examined in more detail in section 6.7).

6.3 Energy efficiency policies and investments

The coverage and strength of energy efficiency policies have increased in recent years (Figure 6.3). Energy efficiency policies covered one-third of final energy consumption worldwide in 2017. Almost all of the increase in coverage is attributable to more goods being covered by existing standards, rather than new standards (IEA, 2018a).

Figure 6.3 ▹ Share of global final energy consumption covered by mandatory efficiency standards by selected end-uses



Mandatory energy efficiency standards have been increasingly adopted in recent years, though the coverage varies among end-use categories

Different assumptions about efficiency policies, and consequent changes in investment flows, underpin the variations in final consumption between scenarios. Energy demand in **buildings** increases by just under 1% per year on average in the New Policies Scenario: this rise reflects growing demand for space cooling alongside increasing ownership of electric appliances and connected devices. In the Sustainable Development Scenario, thanks to strong efficiency policies including performance standards and building codes, energy consumption in the buildings sector falls by around 190 Mtoe over the outlook period.

In **industry**, the average annual increase in consumption of 2.5% since 2000 is projected to slow to 1.3% per year in the New Policies Scenario as a result of energy efficiency gains and significantly lower growth rates for output from energy-intensive industries. For example, on an average annual basis since 1990, the amount of steel produced worldwide has expanded by 3.0% and that of cement by 4.8%, but these rates slow to 0.8% per year for steel and 0.2% per year for cement in our projections. A significant contributing factor is that production of both steel and cement in China in 2040 is projected to be lower than today. Growth in industrial energy demand in the Sustainable Development Scenario slows even further, to an annual average of 0.5%.

In the **transport** sector, efficiency measures help to constrain growth in demand to around 30% in the New Policies Scenario; in the Sustainable Development Scenario it decreases by 6%, despite a large increase in demand for mobility (see section 6.7).

In 2017, $236 billion was invested in energy efficiency across the buildings, industry and transport sectors – an increase of $8 billion (or 3%) from the previous year (Table 6.4).[4] The increase was largely attributable to spending on heating, cooling and lighting in buildings (IEA, 2018b). Spending in the buildings sector is the main area for energy efficiency expenditure, which at $140 billion in 2017 accounted for 59% of total investment in energy efficiency. Spending on building envelopes (insulation, walls, roofs and windows) represented almost half of this investment in the sector.

Table 6.4 ▷ Global annual average investment in energy efficiency in selected regions by scenario ($2017 billion)

		New Policies		Current Policies		Sustainable Development	
	2017	2018-25	2026-40	2018-25	2026-40	2018-25	2026-40
United States	42	62	85	55	72	92	156
European Union	n.a.	121	174	84	112	128	134
China	65	66	108	45	89	84	120
India	8	17	36	16	36	21	56
World	**236**	**397**	**666**	**299**	**496**	**505**	**828**
World – Cumulative		*3 173*	*9 983*	*2 391*	*7 447*	*4 038*	*12 425*

Source: 2017 data from IEA (2018b).

Spending on improved efficiency in the transport sector increased by 11% to $60 billion in 2017 compared to the previous year with expenditure on light-duty vehicles (LDVs) representing just over half of this total ($33 billion). Conversely investment in energy efficiency in the industry sector fell by 8% to $35 billion (IEA, 2018b). Worldwide, current investment in energy efficiency in the industry sector was directed more to manufacturing such as food and beverage than to energy-intensive production such as iron and steel.

In the New Policies Scenario, energy efficiency investment increases in all end-use sectors, especially in transport and buildings. Buildings account for almost 40% of the cumulative investment in energy efficiency to 2040, around 60% of which is in the residential sector. Almost 45% of this amount is for improved insulation and some 30% is for more efficient appliances. In transport, around 60% of the investment is for efficiency improvements in LDVs, and most of the rest is for other forms of road transport, though only about a quarter of this is for medium- and heavy-duty trucks. The corollary is that medium- and heavy-duty trucks remain one of the main drivers of oil demand growth by 2040.

4. An energy efficiency investment is defined as the incremental spending on new energy-efficient equipment or the full cost of refurbishments that reduce energy use. The intention is to capture spending that leads to reduced energy consumption.

6.4 Renewables policies and investments

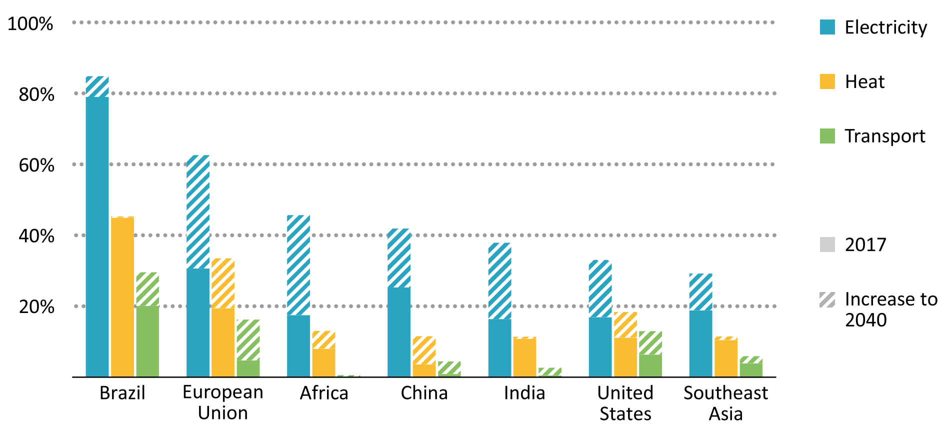
The future of renewables remains heavily dependent on the policy frameworks put in place. To date, policies that deal with the direct use of renewables in end-use sectors have received much less focus than policies for the power sector.

In 2017, targets for the renewable share of primary and final energy were in place in 87 countries, while sector-specific targets for renewable power were in place in 146 countries, for renewable heating and cooling in 48 countries, and for renewable transport in 42 countries (REN21, 2018). Furthermore, the number of countries with renewable heating targets has remained fairly constant over recent years, while the number of countries introducing renewable electricity targets has continued to grow.

In 2017, the power sector accounted for the largest share of investment in renewables, followed by heating for buildings and by biofuels for transport. Overall investment in renewables-based power was 7% less than the previous year, but lower unit costs facilitated the addition of almost 180 GW of new capacity, up 6 GW from 2016 and a new record. Investment in solar PV brought 97 GW of new capacity, a record amount, with deployment levels in China and India continuing to rise. Investment in offshore wind also rose to record levels, while investment in onshore wind fell by nearly 15% (IEA, 2018c).

In most major countries and regions, low-carbon generation investment in 2017 exceeded that for fossil fuel-based power. The main exceptions to this trend are Southeast Asia, the Middle East and North Africa.

Figure 6.4 ▷ Renewable energy share by category and region in the New Policies Scenario, 2017 and 2040*



Renewable energy contributions increase in all sectors in the main regions, dominated by the power sector

* Excludes traditional use of biomass.

In China, where renewables already account for a quarter of electricity production (largely from hydropower), the share of renewables in electricity production rises to over 40% by 2040, reflecting large investments in wind and solar PV. In India, renewables-based electricity generation increases by almost 1 500 TWh over the outlook period, also reflecting significant investment in solar PV and wind power.

Table 6.5 ▷ Global annual average renewables investment by scenario ($2017 billion)

		New Policies		Current Policies		Sustainable Development	
	2017	**2018-25**	**2026-40**	**2018-25**	**2026-40**	**2018-25**	**2026-40**
Renewables-based power generation	298	322	361	286	278	441	616
Wind	85	98	119	85	87	134	218
Solar PV	144	127	116	111	89	177	186
Transport biofuels	2	9	18	8	18	25	47
Renewable heat	109	116	127	103	111	134	154
Total	**407**	**437**	**488**	**390**	**389**	**576**	**770**
Cumulative		*3 574*	*7 600*	*3 183*	*6 110*	*4 807*	*12 246*

Note: Renewable heat includes only the direct use of renewables for heat in end-use sectors.

Source: 2017 data for renewables-based power generation from IEA (2018b).

In the **New Policies Scenario**, investment in renewable electricity generation continues to increase over the outlook period, rising from almost $300 billion in 2017 to $413 billion in 2040 (Table 6.5). Wind power and solar PV account for two-thirds of the $8 trillion cumulative global spend on renewable electricity energy generation over the outlook. Hydropower accounts for 20% of the remaining renewables-based power investment, with bioenergy and concentrating solar power (CSP) making up the balance. China, the European Union, the United States and India account for more than 60% of total investment in renewable power generation. Investments in renewable heat increase from $109 billion in 2017 to around $150 billion in 2040, a cumulative total of around $2.8 trillion. The buildings sector accounts for the majority of renewable heat investment (85%).

In the **Sustainable Development Scenario**, which includes additional policy measures to support increased deployment of renewable-based electricity across all regions, cumulative investment in renewables-based power generation is $12.8 trillion over the outlook period, with wind accounting for 34%, followed by solar PV (33%), and hydropower (18%). Investments in renewable heat rise to nearly $180 billion by 2040, a cumulative total of $3.4 trillion. The buildings sector accounts for the largest share, boosted by the introduction of mandatory energy conservation building codes, including net-zero emissions requirements for all new buildings and increased support for solar thermal and geothermal heating.

6.5 Renewables support

Key drivers of the rise in renewables include policy support and associated government financial commitments (such as feed-in tariffs and long-term power purchase agreements awarded through auctions) and cost reductions. Stable support policy frameworks, cost reductions and renewables deployment are strongly interlinked. Based on a survey of established national policies and on the known deployment of new renewable energy projects, we estimate that the cost of the support mechanisms on a global basis in 2017 for renewables-based electricity was $143 billion, 2% higher than in 2016.

Wind power and solar PV accounted for majority of non-hydro renewables output (70% of the total) and were the primary recipients of support for renewables, accruing more than 80% of the total in 2017. Bioenergy-based power plants were the third-most supported renewable energy technology, receiving more than $20 billion in 2017. After a record year of solar PV capacity additions, China became the leading provider of renewables support for the first time, ahead of Germany, United States, Japan, and Italy. Together, these five countries accounted for almost two-thirds of total financial support for renewables in 2017.

The costs of renewables support mechanisms increased only marginally relative to the rate of new generation in 2017, largely because of increases in average wholesale electricity prices in many countries, and because of declining technology costs of solar PV and wind power. Recognising these factors led some governments to scale back the unit rate of support provided.

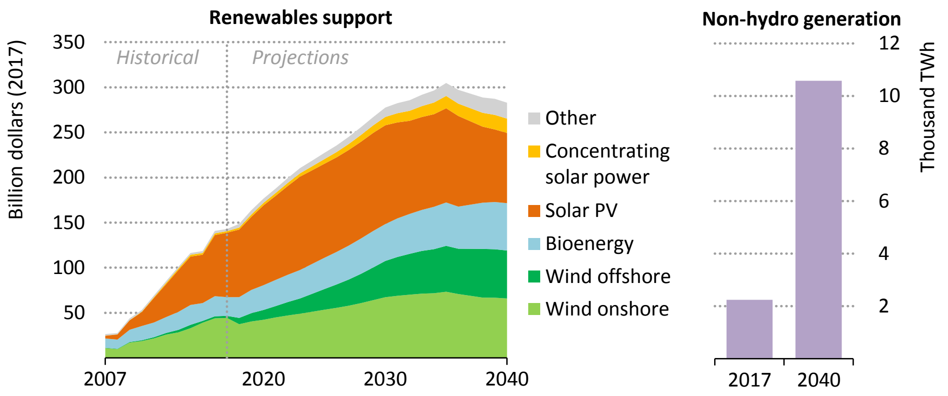
In many markets, there has been a shift to auctions for renewable energy projects and other means of awarding support on the basis of competition. In 2017, more than 20% of new solar projects that received support were selected on the basis of competition, together with about 30% of onshore wind and 50% of offshore wind projects.

Other mechanisms used to provide support for the deployment of renewables included FiTs, market premiums, green certificates and investment tax credits. Supportive frameworks may lower total project costs by enabling low-cost financing (see Chapter 7, section 7.3.2) or making available low-cost land or grid access. Renewable energy use in the transport sector is mostly supported by various biofuel mandates, greenhouse gas (GHG) reduction policies and fiscal benefits. Support for renewable heat includes feed-in tariffs and premiums, capital grants, subsidies, soft loans and tax incentives.

In the New Policies Scenario, support provided to renewables-based electricity generation peaks at around $300 billion in 2035 and then declines to about $280 billion by 2040 (Figure 6.5). Of the total cumulative support over the period from 2017 to 2040, more than three-quarters goes to solar PV and wind power, and more than 15% goes to bioenergy. By 2040, the share going to solar PV and wind decreases to 70%, while the shares going to bioenergy and concentrating solar power increase to just below 20% and just above 5% respectively.

The average support per unit of electricity generated by renewables declines dramatically in most regions to 2040, largely as a result of technology cost reductions and rising wholesale electricity prices (see Chapter 10, section 5). By 2040, the global average support per unit of output for new solar PV projects declines almost 90%, and for new wind power projects it declines by almost 70%.

Figure 6.5 ▷ Global renewables-based electricity support and non-hydro generation in the New Policies Scenario



Globally, support to renewables for power generation increases from $143 billion today to $280 billion in 2040, with generation from non-hydro renewables more than quadrupling

Key themes

In the following sections we examine in detail three key themes, each of which provide examples of the interaction between energy efficiency and renewables, and indicate the value of considering them in an integrated way.

6.6 Tracking progress in meeting sustainable development goals

The United Nations (UN) Agenda for Sustainable Development (2030 Agenda), adopted in 2015, includes the goal to "ensure access to affordable, reliable, sustainable and modern energy for all" (SDG 7). It includes a target to increase the share of renewables in the energy mix (SDG 7.2) and another that aims to improve energy efficiency (SDG 7.3). Both make a contribution to SDG 7.1 (ensuring universal access to modern energy). This section elaborates on the role of renewables and energy efficiency in the 2030 Agenda, and assesses whether the energy system is on track to meeting SDG 7.2 and SDG 7.3.

As a co-custodian agency for SDG targets 7.2 and 7.3, the IEA has a key role in providing the methodological basis and data for the indicators used to track annual country-by-country progress, and is mandated to report country-level progress each year to the United Nations.[5] In support of the first UN review of SDG 7 at its High-level Political Forum in July 2018, the IEA made country-by-country data and projections for all SDG 7 targets available for free online.[6] The IEA also co-leads the *Tracking SDG 7* report, a joint report of the SDG 7 custodian agencies, which provides a consolidated benchmark tracking annual progress on the targets of SDG 7.

Table 6.6 ▷ SDG 7 targets for energy access, renewable energy and energy efficiency

Goal 7: Ensure access to affordable, reliable, sustainable and modern energy for all			
Target		**Indicator**	
7.1	By 2030, ensure universal access to affordable, reliable and modern energy services.	7.1.1	Proportion of population with access to electricity.
		7.1.2	Proportion of population with primary reliance on clean fuels and technologies.
7.2	By 2030, increase substantially the share of renewable energy in the global energy mix.	7.2.1	Renewable energy share in total final energy consumption.
7.3	By 2030, double the global rate of improvement in energy efficiency.	7.3.1	Energy intensity measured in terms of primary energy and gross domestic product.

It is important to note that the indicators used to track progress towards the SDGs differ from the usual WEO definitions. For SDG 7.2.1, the share of renewables in total final energy consumption is calculated as the direct and indirect renewable energy consumed over total final energy consumption, excluding non-energy uses. It, however, includes the traditional use of biomass, which the IEA usually does not consider as renewable. In the remainder of this section, modern renewables is used when the traditional use of biomass is not included. For SDG 7.3.1, energy intensity is calculated against a GDP expressed in 2010 dollars.

Renewables and energy efficiency targets on the 2030 Agenda

SDG 7.2 and 7.3 are integral components of the UN 2030 Agenda. They reflect the way in which the SDGs were formed to include root factors rather than headline indicators of sustainable development. Energy efficiency and renewable energy together contribute more widely to the SDGs in a number of ways:

- Both help to reduce greenhouse gas (GHG) and air pollutants, and therefore contribute to climate (SDG 13) and air pollution (SDG 3) goals (See Chapter 2).
- Both are essential for modern energy access. Renewables are set to deliver many new electricity access connections by 2030 (in the Sustainable Development Scenario, they

5. The SDG 7 custodian agencies are the IEA, IRENA, United Nations Statistics Division, the World Bank and the World Health Organization.

6. See www.iea.org/sdg.

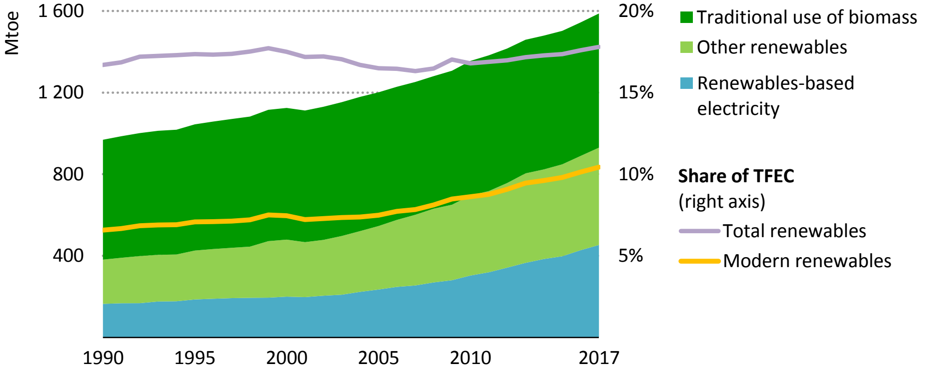
deliver more than three-quarters of new electricity access connections), and energy-efficient appliances help people to make the most of their electricity access. Energy access in turn supports other development priorities, including poverty reduction, provision of health facilities and gender equality (IEA, 2017a).

- Beyond the SDGs, both increased energy efficiency and use of renewable energy can also provide other benefits, for example, by reducing fuel imports, improving energy security, and providing local employment.

Progress and policy efforts towards meeting the renewable energy target (SDG 7.2)

The share of modern renewables in total final energy consumption has been growing since the 1990s, reaching 10% in 2017 (Figure 6.6). Renewables-based electricity generation (now a quarter of total generation) accounts for just over 55% of the increase in renewables energy use since 2000. Hydro, wind and bioenergy account for most of this, but solar has contributed one-quarter of the growth in electricity generation from renewables in the last three years. Bioenergy accounted for nearly 90% of the direct use of renewables in 2017, with 50% of it consumed in North America and Europe.

Figure 6.6 ▷ Renewables in total final energy consumption



The growth of renewables has outpaced the rate of increase of energy consumption but traditional use of biomass still accounts for 7% of global final energy consumption

Note: Mtoe = million tonnes of oil equivalent; TFEC = total final energy consumption, which excludes non-energy use.

These figures exclude the traditional use of biomass (fuelwood, charcoal and organic waste used as the main cooking fuel for 2.3 billion people), most of which is used in developing Asia and sub-Saharan Africa (see Chapter 2). This solid biomass is consumed primarily in inefficient and poorly ventilated cookstoves in developing countries, and is a major contributor to air pollution and premature deaths worldwide. Although the traditional use of biomass has been growing in absolute terms, its growth has been slower than that of modern renewables and it now accounts for 7% of total final consumption, down from 9% in 2000.

Although lagging behind policies promoting electricity (see Chapter 8, section 3), there have been some notable recent policy developments related to renewable energy in transport and heating in selected countries (Table 6.7).

Table 6.7 ▷ Selected policies for renewable energy in transport and heat announced or introduced since mid-2017

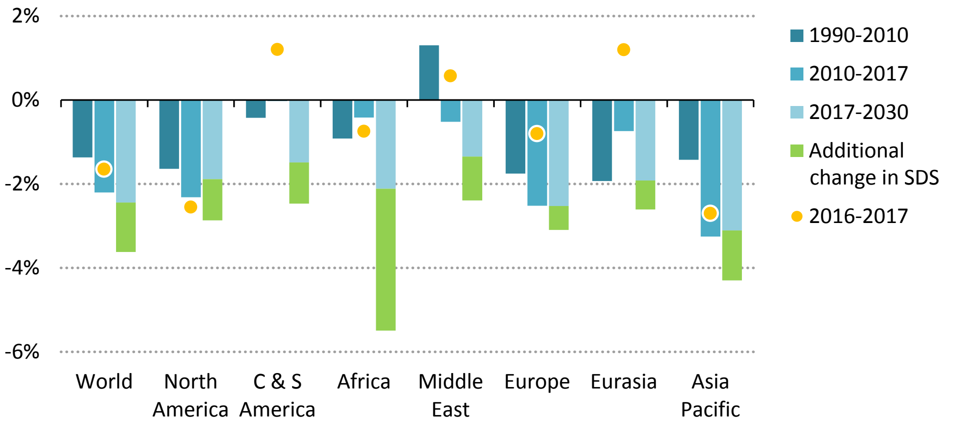
Region	Sector	Policy
Brazil	Transport	RenovaBio introduces a target for the overall decarbonisation of the transport sector by 2028, and includes sub-targets for fuel distributors.
Canada	Transport	Phases 1 and 2 of the Electric Vehicle and Alternative Fuel Infrastructure Initiative allocates $140 million over six years (2016-2022) to support infrastructure deployment and demonstrations in the areas of electric vehicles and alternative fuels (e.g. natural gas, hydrogen).
China	Transport	Implementation of the Expansion of Ethanol Production and Promotion for Transportation Fuel plan, jointly announced by a number of government agencies and ministries, sets a goal to achieve the use of 10% ethanol (E10) nationwide by 2020.
European Union	Heating/ cooling	The European Union established a new, binding renewable energy target of 32% of gross final consumption of energy by 2030, including a review clause by 2023. The 2030 goal includes a target of 1.3 percentage point increase each year in heating and cooling from renewable sources.
India	Transport	A new national biofuels policy was approved in 2018. It includes several measures to support biofuel production and to widen the permitted feedstock base for ethanol production, including additional tax incentives and investment support of around $700 million over six years.
	Heating	The National Biogas and Manure Management Programme established an annual target of launching around 65 000 biogas plants in 2018.
United Kingdom	Transport	The Renewable Transport Fuel Obligation, which regulates biofuels used for transport and non-road mobile machinery, was amended to require suppliers to ensure the fuel mix is at least 12.4% renewables by 2032, up from 4.75% and with an interim target of 9.75% by 2020.

Progress and policy efforts towards increasing energy efficiency (SDG 7.3)

Global energy intensity, defined as the ratio of primary energy supply to GDP, is the indicator used to track progress on global energy efficiency (SDG 7.3). The original target was an annual reduction of 2.6% although the world has fallen short of this goal since it was announced: the annual reduction in 2017 was only 1.7% (Figure 6.7). This shortfall means that the required rate of intensity improvement has risen to 2.7% for the remaining years to 2030.

Energy efficiency gains in recent years have largely been achieved through measures introduced by governments. These have included fiscal measures (such as tax relief on residential renovations and electric vehicle purchases) and mandatory energy efficiency regulations (such as minimum performance standards, fuel-economy standards, building energy codes and industry targets), as well as public financing and the use of market-based instruments, such as tradable certificates linked to energy saving obligations for utilities. Price effects, technological change and advances in energy management in the industrial and buildings sectors are also delivering efficiency improvements. Table 6.8 highlights some recent energy efficiency policy measures.

Figure 6.7 ▷ Annual average change in energy intensity by region



Recent improvements in energy intensity have been strong, yet are not sufficient to meet the 2030 SDG target

Notes: SDS = Sustainable Development Scenario; C & S America = Central and South America. The 2017-2030 projections are based on the New Policies Scenario.

Table 6.8 ▷ Selected energy efficiency policies announced or introduced since mid-2017

Region	Sector	Policy
Brazil	Cross-sector	New standards adopted for electric motors and ceiling fans. Consultations held on stronger minimum energy performance standards for refrigerators, freezers, air conditioners and distribution transformers; adoption likely in 2018.
Canada	Buildings	The Buildings Strategy was endorsed by federal and provincial First Ministers in August 2017 and efforts to support its implementation are underway. The Energy Efficient Buildings RD&D programme was launched in 2017: it supports the development and implementation of building codes for existing buildings and new net-zero buildings.
	Transport	The Pan-Canadian Framework on Clean Growth and Climate Change outlines a strategy to reduce emissions from the transportation sector by setting and updating vehicle emissions standards and improving the efficiency of vehicles, using cleaner fuels, shifting towards lower emitting types of transportation, and increasing the uptake of zero-emission vehicles.

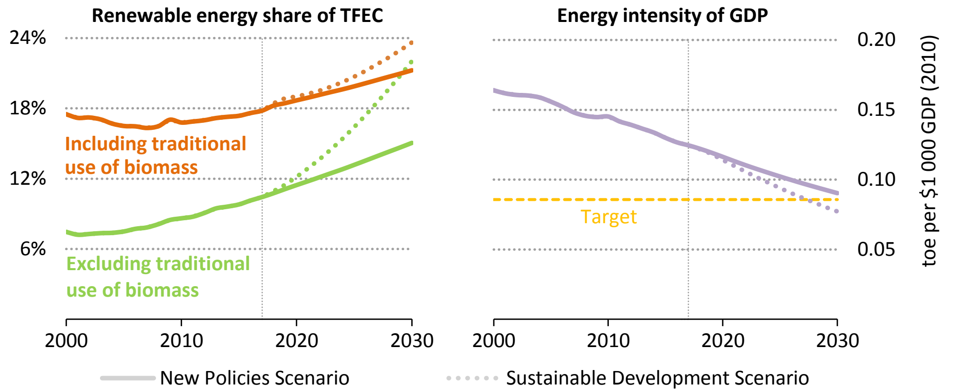
Table 6.8 ▷ Selected energy efficiency policies announced or introduced since mid-2017 (continued)

Region	Sector	Policy
China	Cross-sector	Development of the "100, 1 000, 10 000" programme, building on the Top 10 000 initiative, which mandates energy savings across a range of sectors. In parallel, ongoing expansion in coverage and scope of minimum energy performance standards for appliances.
European Union	Cross-sector	Energy efficiency measures agreed as part of the EU Clean Energy Package, notably revision of the EU Energy Efficiency Directive with binding target for 32.5% EU-wide energy efficiency improvement relative to current projected values by 2030.
	Buildings	The Revised Energy Performance of Buildings Directive (EPBD) includes an obligation for member states to develop long-term renovation strategies and "smart readiness" measures including at least one electric vehicle charging point for buildings with more than ten parking spaces.
	Transport	14% share of renewables in total transport energy consumption.
India	Cross-sector	Development of the National Energy Plan links efficiency to energy security and aligns with its Nationally Determined Contributions under the Paris Agreement. In parallel, revision of building codes and appliance standards to improve energy efficiency, as well as continuation and broadening of the Perform, Achieve, Trade (PAT) efficiency certificate trading scheme for energy-intensive industries.
Indonesia	Transport	Full tax relief for vehicles under the low-cost green car programme, which covers small cars with 20 km/litre fuel economy for spark ignition engines up to 1 200 cc or compression ignition engines up to 1 500 cc.
	Appliances & equipment	New minimum energy performance standards as well as progressive updates, alongside a labelling system for residential air conditioners.
Italy	Cross-sector	Target of 10 Mtoe reduction in final energy consumption by 2030, featuring tax breaks and loan guarantees for residential energy efficiency investments.
Malaysia	Cross-sector	National Energy Efficiency Action Plan 2016-2025 featuring sectoral targets including government-building retrofits, ISO 50001 energy management standards for companies and smart meters in industry.
Mexico	Cross-sector	Additional instruments in energy transition law, including consumption monitoring for high energy consumers, mandating regular evaluation of energy efficiency standards every three years, and voluntary agreements coupled with energy efficiency excellence awards.
United Kingdom	Cross-sector	UK Clean Growth Strategy, featuring a target of 20% efficiency improvement in business and industry by 2030, alongside energy efficiency obligations for utilities as well as funds for innovation in low-carbon heating and public sector efficiency improvements.
United States	Buildings	California introduced new building codes featuring tighter efficiency standards, requirements for solar photovoltaic systems and measures to promote building electrification through heat pumps and battery storage.

Are we on track to meet the renewables and energy efficiency SDG targets?

In the New Policies Scenario, the share of modern renewables increases to 15% of total final energy consumption in 2030. Electricity generation from renewables overtakes coal in the 2020s and supplies around 36% of electricity by 2030. Growth is not confined to the power sector: the direct use of renewables for heating and transport also increases significantly. In our Sustainable Development Scenario, modern renewables reach 22% of final energy consumption in 2030. In some countries and regions the rate of progress is far from the substantial increase required to meet the SDG (Figure 6.8).

Figure 6.8 ▻ Progress towards SDG 7.2 and 7.3 in the New Policies and Sustainable Development scenarios



Renewables and efficiency are cornerstones of the Sustainable Development Scenario

Note: TFEC = total final energy consumption, which excludes non-energy use.

While intensity improvements accelerate in most regions in the New Policies Scenario, they accelerate fastest in developing economies. In Developing Asia, for example, energy intensity improves at an annual rate of 3.3%. A number of significant energy efficiency policies, which have recently been agreed or are currently under development, are expected to boost energy intensity reduction. These include new policy packages announced by the European Union and China, and plans to strengthen mandatory energy performance regulations in various regions. As a result, overall global energy intensity in the New Policies Scenario is expected to decrease by 2.4% per year on average between 2017 and 2030. This is a faster rate than has been achieved in recent years, but falls short of the 2.7% annual improvement required in the SDG 7.3 target, and the 3.6% annual improvement needed to achieve the Sustainable Development Scenario.

6.7 Efficiency and use of renewables in the transport sector

Transport accounts for a fifth of global energy demand today and is responsible for a quarter of energy-related carbon dioxide (CO_2) emissions. More than 95% of today's transport sector emissions are from oil. Demand for the transport of people and of goods is projected to increase significantly through to 2040 as a result of both population and economic growth. There remains large untapped potential for energy efficiency improvements in transport – e.g. via increased efficiency of internal combustion engines (ICEs), friction reduction or hybridisation – and to switch to alternative renewable fuels, which have been fostered in many countries.

Policies promoting energy efficiency are the main lever in place for reducing vehicle fuel consumption and to minimise related pollution (Table 6.9). These generally take the form of efficiency or GHG emissions performance standards that establish targets for maximum fuel consumption for cars and other vehicles, and efforts to promote greater use of public transportation and better urban planning.

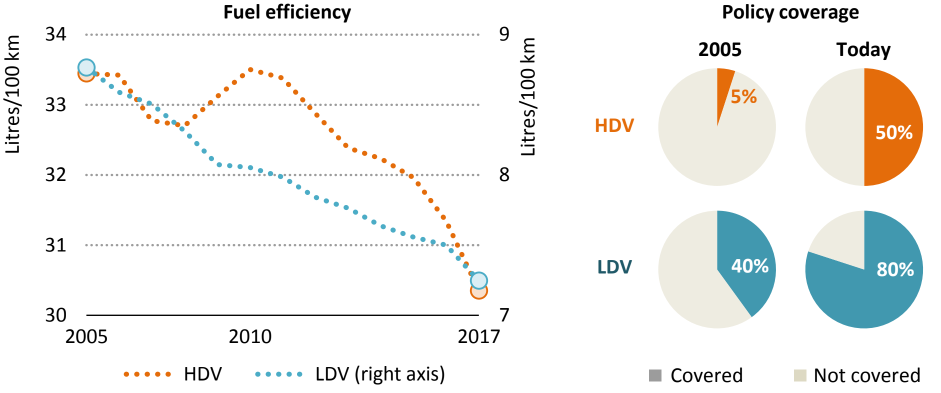
Table 6.9 ▷ Recent policy developments related to efficiency and biofuels in transport by selected region

Region	Energy efficiency policy
China	Update of passenger car fuel-economy standards to include the new energy vehicle mandate.
European Union	Political agreement about the extension of CO_2 standards to LDVs. Plans for implementation of CO_2 emission standards for HDVs.
India	Entry into force of HDV fuel-economy standards in April 2018.
United States	Revision of Corporate average fuel-economy standards (CAFE) for model years 2022-2025.
Region	**Biofuels policy**
Canada	Clean Fuel Standard: target of abating 30 million tonnes of carbon emissions by 2030. Biojet fuel challenge launched in August 2018.
Brazil	RenovaBio, a new national biofuel policy, includes sub-targets for fuel distributors to increase the supply of biofuels.
Colombia	Increase in ethanol and biodiesel blending mandates to 10% for most of the country.
European Union	14% share of renewable energy in the transport sector by 2030, with a non-food based biofuels target of 3.5% by 2030. Implementation of additional sustainability criteria for biofuels limiting imports of feedstock with risk of deforestation.
India	Ambition for a 20% ethanol blend in gasoline and 5% blend of biodiesel in diesel by 2030. Promotion of industrial development of advanced biofuels.
United Kingdom	Long-term framework for growth of renewable energy in transport: 12.4% in 2032 of which 2.8% must come from advanced biofuels.
United States	Renewable Fuel Standard update: 73 billion litres of renewable fuels in 2018 and 136 billion litres by 2022.

Notes: LDVs = light-duty vehicles; HDVs = heavy-duty vehicles. See Chapter 8 for recent electric vehicles policy developments.

Mandatory fuel-economy standards for light-duty vehicles (LDVs), which account for almost 45% of all transport energy use, are now in force in 38 countries. Mandatory fuel efficiency standards for LDVs apply to over 80% of new LDV sales worldwide: the number of new LDVs covered by standards quadrupled from 2005 to 2017.[7] Fuel-efficiency standards for heavy-duty vehicles[8] (HDVs) currently are in place in only five countries, although they cover around half of new HDV sales today.[9] Coverage of fuel-efficiency standards for HDVs will jump by up to 8% when the new European Union CO_2 emissions standards currently under discussion enter into force. These standards will first apply to heavy-duty trucks and then be extended to smaller trucks, buses, coaches and semi-trailers.

Figure 6.9 ▷ Evolution of average fuel efficiency and efficiency standards coverage of new sales by selected modes



The average fuel efficiency of new vehicles has improved substantially due to wider policy coverage and more stringent performance requirements

Note: Litres/100 km = litres of gasoline equivalent per 100 km driven; HDV = heavy-duty vehicles; LDV = light-duty vehicles.

The average fuel efficiency of new vehicles has improved significantly in recent years, although there are signs that progress is now slowing (Figure 6.9). Existing policies have delivered important improvements in the average fuel economy of LDVs, with an average 1.5% annual rate of improvement over the 2005 and 2015 decade. Between 2005 and 2008, the global average annual rate of improvement was 1.8%, but it fell to 1.1% between 2014 and 2015, then to 0.5% in 2016.

7. Light-duty vehicles include passenger and commercial cars, sports utility vehicles and light-duty trucks.

8. Heavy-duty vehicles include buses, coaches, medium- and heavy-duty trucks and account for around 30% of transport energy demand.

9. Canada, China, India, Japan and United States.

Meanwhile, the average test-cycle CO_2 emissions of new cars sold in 2017 in the European Union deteriorated for the first time to 118.5 grammes of carbon dioxide per kilometre (g CO_2/km), compared with the 2021 target of 95 g CO_2/km (European Environment Agency, 2018). The main reason is a shift from diesel to gasoline cars: the latter accounted for more than half of the new cars sold for the first time since 2010. In the United States, fuel economy also degraded in 2017, reflecting a surge in sales of light truck and sports utility vehicle (SUVs) and a slide in the sales of lighter cars. SUVs have quickly gained market share in China and India as well, where they account for around 42% and 33% respectively of new car sales.

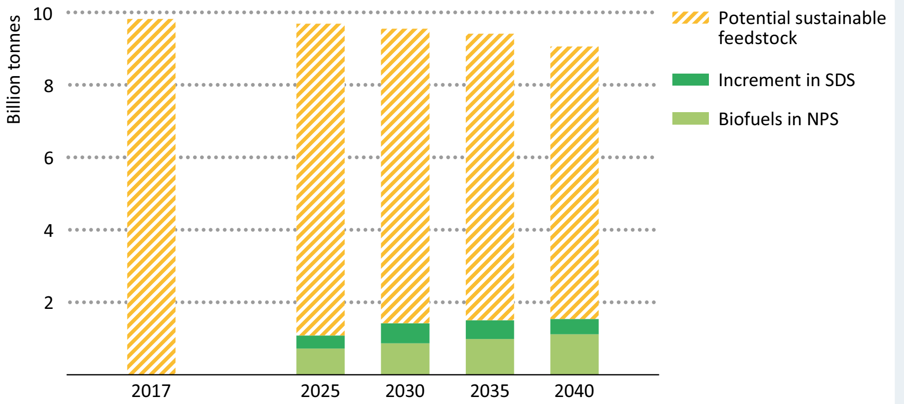
Box 6.1 ▷ Advancing advanced biofuels

Currently around 1.8 million barrels of oil equivalent per day (mboe/d) of biofuels are produced globally, predominantly using "conventional" methods of production. Concerns have been raised about its sustainability in some countries: the feedstocks required can compete with food production for agricultural land and there can be a large increase in CO_2 emission intensity associated with land clearing and cultivation. As a result, there is increased interest in advanced biofuels, which can avoid these concerns. Various materials can be used: waste oils, animal fats, lignocellulosic material such as agricultural and forestry residues and municipal wastes, and all are the subject of current research programmes. If successful, the results of these research programmes could lead to huge potential increases in biofuel production. We estimate that today there are around 10 billion tonnes of lignocellulosic "sustainable" feedstock that could be used for biofuels production worldwide (Figure 6.10).[10] The 4.7 mboe/d of biofuel production in the New Policies Scenario in 2040 would need around 12% of the available feedstock (if it were to be produced entirely using advanced technologies). Even the 7.3 mboe/d of biofuel production in the Sustainable Development Scenario would need 14% of the available feedstock.

While large volumes of advanced biofuels could be produced sustainably, their development and deployment has been slowed by their costs (relative both to conventional biofuels and oil). Conventional biofuel feedstocks can often be harvested close to production centres; they have a higher energy content, and they often have a low level of contaminants so handling and treatment can be relatively inexpensive and simple. In contrast, advanced biofuel feedstock tends to be spread over a larger geographic area and of variable quality. Producing a barrel of advanced biodiesel costs around $140/barrel today. Assuming that these results in no net CO_2 emissions, a carbon tax above $150 per tonne of CO_2 would be required for such a biodiesel to be cost-competitive with diesel refined from crude oil. The future of advanced biofuels therefore will depend critically on continued technological innovation to reduce production costs as well as stable and long-term policy support.

10. Sustainable in this context means that the feedstock has near-zero life-cycle GHG emissions, that it does not compete with food for agricultural land, and that it does not have other adverse sustainability impacts (such as reducing biodiversity). The sustainable level of wood feedstock estimated here is below annual forest growth rates to ensure that forest levels are preserved.

Figure 6.10 ▷ Sustainable feedstock available and levels needed to cover total biofuel consumption by scenario



The availability of sustainable feedstock using advanced processes is much higher than the levels required for biofuel production in the New Policies Scenario

Note: Feedstock consumption levels shown would cover conventional and advanced biofuel production.

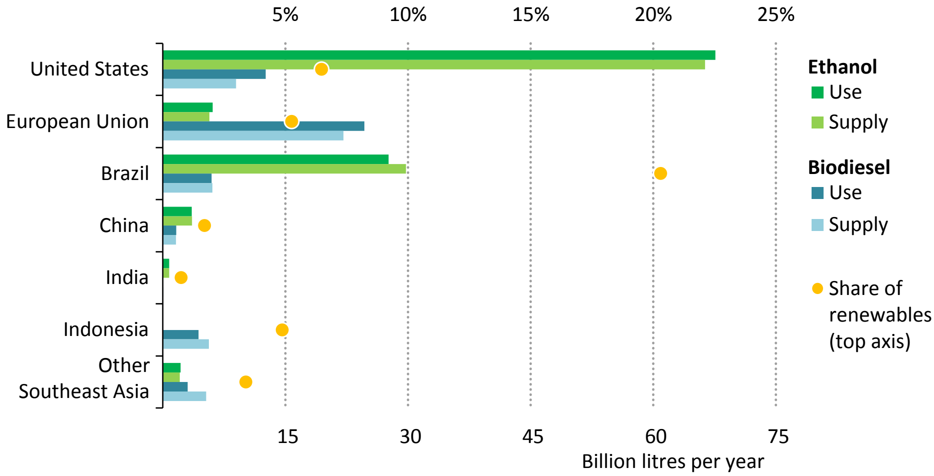
Global transport biofuel consumption increased by more than 5% in 2017 to reach 150 billion litres, of which three-quarters is ethanol.[11] Biofuel promotion policies are now in place in 68 countries. The United States is the only country to set absolute consumption targets through its Renewable Fuel Standard II, with an overall target of 73 billion litres in 2018 and 136 billion litres in 2022. Most other countries have set objectives in the form of blending mandates. The United States remains the leader in ethanol use and supply, followed by Brazil, the country with the highest blending rate. The European Union is the third-largest producer of ethanol and is the leading biodiesel producer and consumer.

A proposed EU Renewables Energy Directive, which is currently under discussion, would set a specific target of a 14% share of renewable energy in the transport sector, and a 3.5% sub-target for advanced biofuels by 2030. In Brazil, the RenovaBio policy, which is similar to California's Low-Carbon Fuel Standard, sets GHG emissions reduction targets for fuel distributors and may lead to the doubling of Brazilian ethanol production capacity by 2030 (Empresa de Pesquisa Energética, 2017). It also aims to revitalise the domestic ethanol industry by assigning carbon intensity to transportation fuels.

From 2000 to 2017, the deployment of fuel-economy standards helped to offset around 1.2 mb/d of oil, and 1.8 mboe/d of biofuels were consumed, mainly in road vehicles. Government policies were largely responsible for these advances, and policy development will inevitably have an important bearing on future developments.

11. In energy terms, biofuel consumption is 86 Mtoe, of which two-thirds is ethanol.

Figure 6.11 ▷ Biofuels production, consumption and share of renewable energy in transport energy use in selected regions, 2017



The United States leads the ethanol market while the European Union is the biodiesel leader. Brazil surpasses 20% of renewable energy use in the transport sector.

Outlook for energy efficiency and renewables in transport

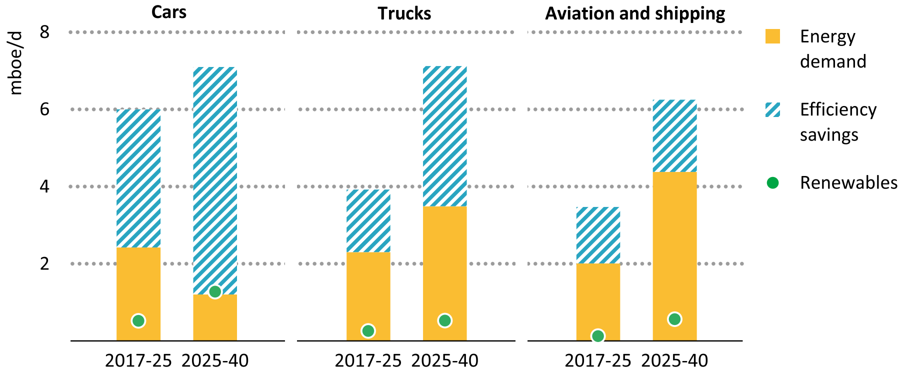
In the New Policies Scenario, energy efficiency improvements in vehicles come from technical improvements such as a downsizing of the engine or reducing tyre friction. Efficiency gains in the transport sector also derive from structural change such as shifts to electric vehicles, and from system enhancements such as better logistics management that optimise the use of the variety of truck types to achieve a higher energy efficiency per unit of transport activity (Figure 6.12).[12]

In the New Policies Scenario, the efficiency of the global average gasoline car is 8.3 litres per 100 kilometres (L/100 km) in real-driving conditions in 2025 and 6.6 L/100 km in 2040, compared to 9.9 L/100 km today. Energy efficiency, and to a lesser extent the uptake of electric vehicles, mean that an increase of 80% in the size of the car fleet between now and 2040 leads to an increase in energy use of less than 20%. Energy savings in trucks come both from improvements in logistics – higher reliance on heavy-duty vehicles together with increased load per vehicle – and engine enhancements (see Chapter 3 for the impact on oil demand). Logistics improvements are driven by cost minimisation, including from more efficient use of central warehouses and backhauling. The energy efficiency of the global average heavy-duty truck sold in 2040 improves by 15% compared with today, but overall

12. Modal shift, e.g. switching from a private vehicle to public transportation is also an important driver for energy efficiency in transport and is included in the Sustainable Development Scenario.

freight efficiency increases by a third. Aviation and shipping efficiency improvements lead to energy savings of more than 3 mboe/d by 2040: there are few fuel substitution options for oil in aviation and shipping.

Figure 6.12 ▷ Change in energy demand and energy efficiency savings for selected transportation modes in the New Policies Scenario



Energy efficiency is key to curbing transport energy demand in the New Policies Scenario

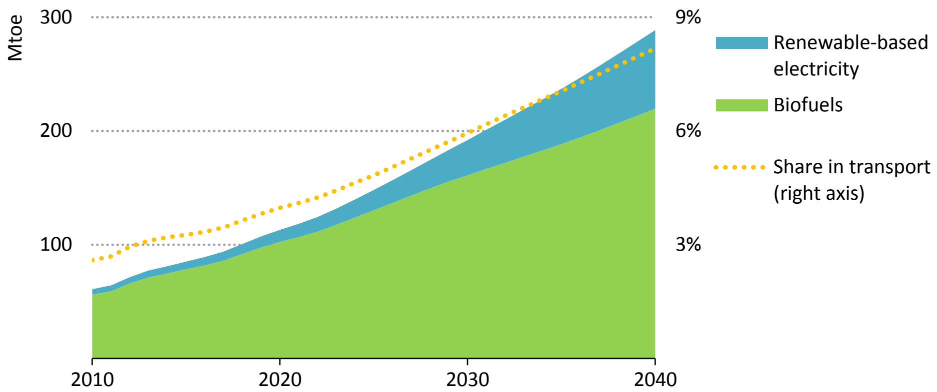
Note: Energy efficiency improvements are calculated compared with the efficiency level in the first year of the period.

The use of renewable energy in the transport sector increases in the New Policies Scenario. From 2017 to 2025, biofuel use worldwide increases at a rate of 5% each year, influenced by the extension to 2030 of the Renewable Energy Directive in the European Union[13] and policies to promote biofuels in transport in Latin America, the United States and China. The annual rate of growth of biofuels use slows to 3.5% between 2025 and 2040 as the use of gasoline and diesel levels off. This is particularly true in the European Union, where transport biofuel consumption plateaus after 2030. An increase in the use of advanced biofuels in aviation and shipping is not enough to offset the slowdown in consumption from road transport (see Box 6.1).

As electric vehicles and the share of renewables in electricity generation expand, the contribution of renewables in transport grows strongly. Today, electricity generated from renewable sources accounts for less than a tenth of renewable energy use in the total transport sector, including rail and road. This share barely increases to 2025, but then rises to reach 25% by 2040 (Figure 6.13). China accounts for 40% of the growth in renewables-based electricity in transport between now and 2040 in the New Policies Scenario, with the European Union accounting for 25%, and India and the United States just below 10% each.

13. For the EU target of 14% of renewable energy share in transport to be achieved, it will require a quick ramp up of advanced biofuel production, owing to the cap on conventional biofuel blending rate.

Figure 6.13 ▷ **Renewable energy consumption in the transport sector by source and share in the New Policies Scenario**



Renewable energy meets 8% of demand in the transport sector in 2040 with renewables-based electricity accounting for a quarter of renewables use in transport

In the New Policies Scenario, road vehicles powered by renewables – cars, trucks, buses and two/three wheelers – account for almost 15% of the total distance driven in 2040, of which over half is attributable to renewables-based electricity. This may seem surprising given that the share of direct and indirect renewables in transport fuel consumption in 2040 is around 8% (Figure 6.13). It reflects the importance of electric bikes and scooters in China and their low energy consumption. Even when cars alone are considered, renewable energy represents 11% of car fuel consumption, but 14% of kilometres driven. This is largely thanks to the higher efficiency of electric engines relative to conventional ICEs: electricity represents a quarter of the total renewable energy used in transport in 2040, but accounts for more than a third of kilometres travelled.

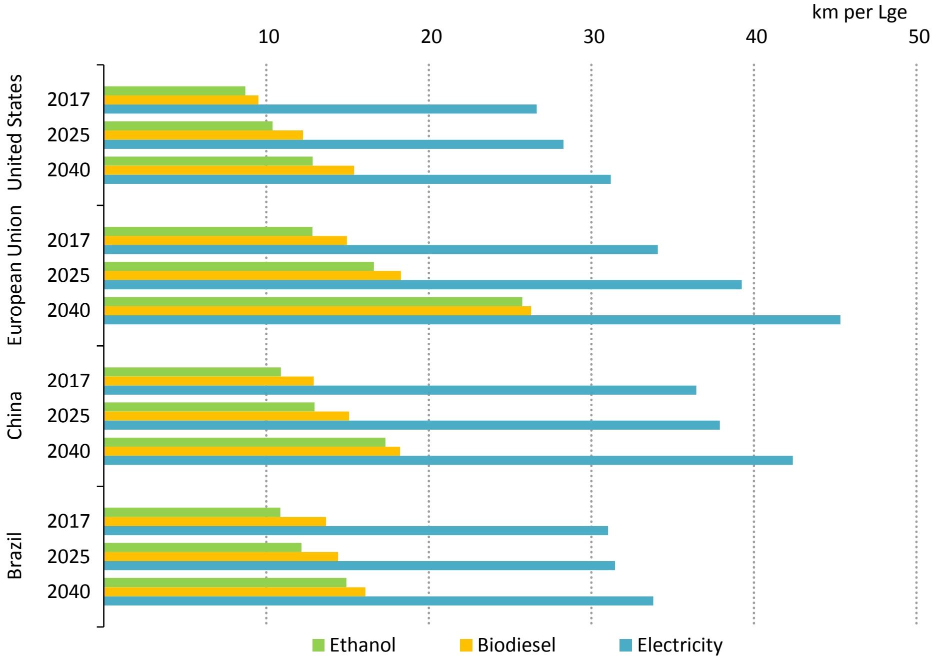
When discussing the comparative advantage of biofuels and electricity, energy efficiency is an important benchmark, expressed as the number of kilometres driven per unit of energy used by the car engine (Figure 6.14). In the New Policies Scenario, the gap in energy efficiency between gasoline and biodiesel narrows over time owing to the higher efficiency potential of gasoline ICEs.[14] Electric engines are about twice as efficient as conventional engines today. Regional differences are also important in the New Policies Scenario, especially for conventional ICEs. The European Union does well in terms of ICE energy efficiency, as it is characterised by a market of relatively small cars and stringent fuel-economy standards.

Even though electric engines are more efficient than conventional ones, there are also energy efficiency improvements in the use of biofuels in transport in the New Policies Scenario. This is important, not least because sustainable feedstock for advanced biofuel production is limited and is in competition with other uses, such as biochemistry, power

14. Gasoline ICE refers to spark ignition engine, and diesel ICE refers to compression ignition engine.

generation or heat production (see Chapter 11). Energy efficiency improvements in the European Union mean that drivers in 2040 use 20% less ethanol or biodiesel per kilometre than in 2025.

Figure 6.14 ▷ Kilometres driven on ethanol, biodiesel and electricity by an average car with the energy equivalent of one litre of gasoline



Energy efficiency improvements help to make the best of biofuels use. Electric cars are more efficient than an internal combustion energy run on renewables.

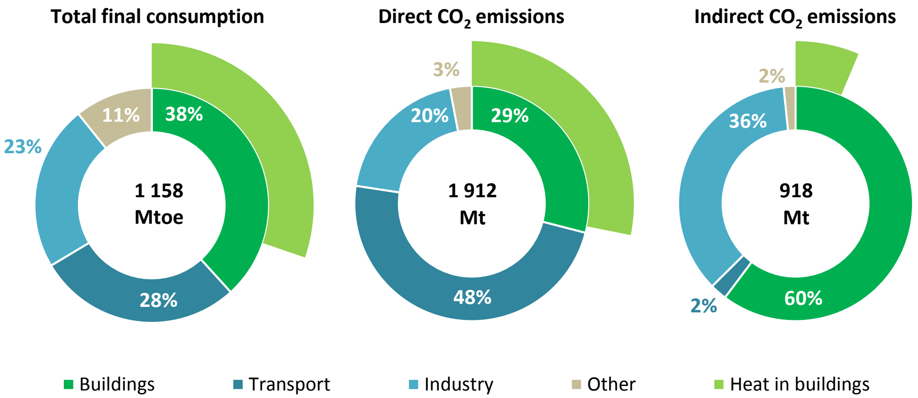
Notes: Lge = litre of gasoline equivalent. For ethanol, the average is determined for conventional and hybrid gasoline cars. For biodiesel, the average is determined for conventional and hybrid diesel cars. For electric vehicles, the average is determined for battery electric and for plug-in hybrid electric (for the latter, only the share that drives on electricity). Projection numbers are based on the New Policies Scenario.

6.8 Buildings: a key component of the energy transition in Europe

In the European Union, the buildings sector is responsible for a particularly large share of final energy demand today compared with other regions. The European Union (EU) has adopted a range of targets to facilitate a clean energy transition. This section explores the key role that efficiency measures and renewable heat in the buildings sector will play in order to achieve these targets.

Buildings represent almost 40% of total final consumption in the European Union, with transport accounting for 28% and industry for 23% (Figure 6.15). Heat demand in the buildings sector accounts for almost 80% of this, mostly in the form of space heating and generally using fossil fuels. Two-thirds of energy consumption in buildings sector is in the residential sector. Buildings account for almost 30% of direct CO_2 emissions in the European Union (i.e. not including indirect emissions from the use of electricity and district heating) compared with a worldwide figure of 17%. As the buildings sector also accounts for almost 60% of EU electricity consumption, it is also responsible for an important share of indirect CO_2 emissions.

Figure 6.15 ▷ Total final consumption and related emissions in the European Union by sector in 2017



Buildings, and in particular heating in buildings, account for the biggest sectoral share of final consumption and related carbon emissions in the European Union

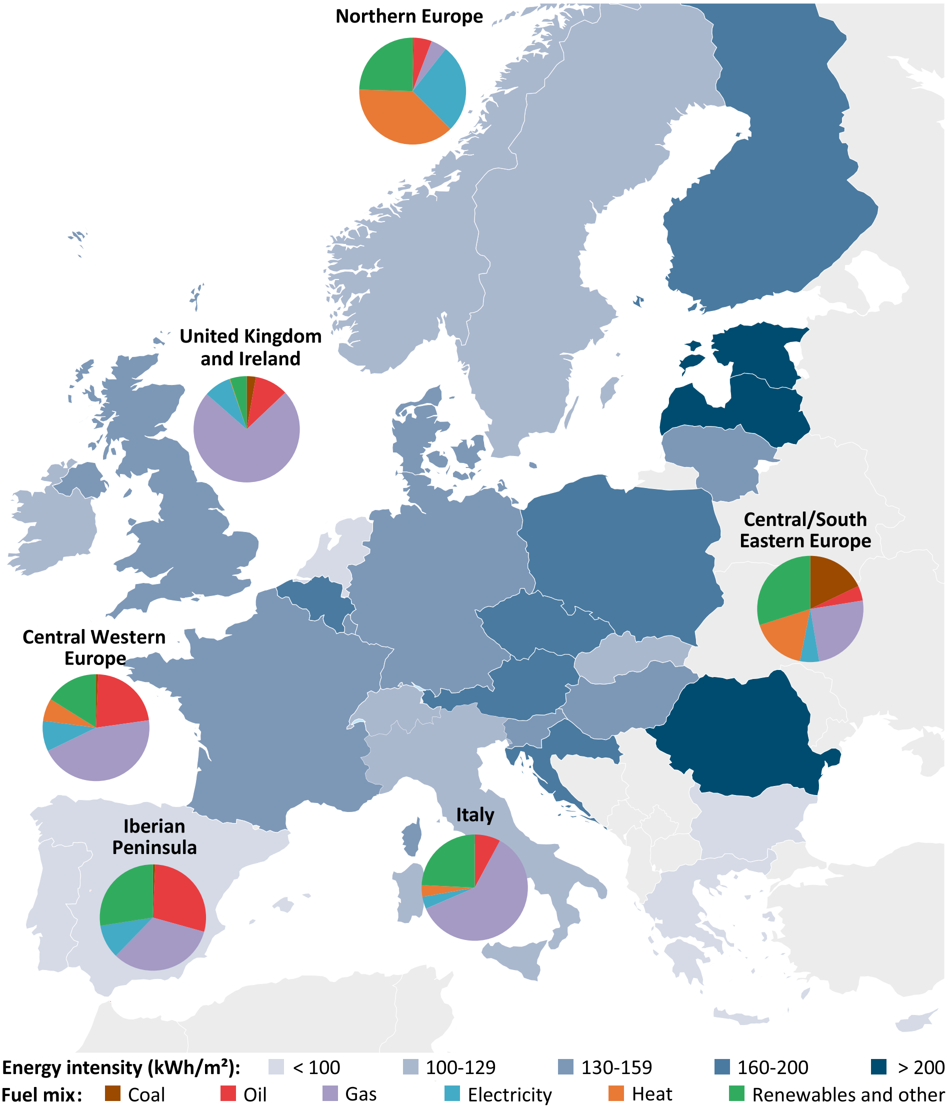
Note: Mtoe = million tonnes of oil equivalent; Mt = million tonnes.

There are a range of policies and measures in place in different European Union countries to control energy demand in buildings. Nordic countries in particular place strong emphasis on high insulation standards in new buildings, and they have also made a strong push in recent decades to improve insulation levels in existing buildings, especially in Sweden and Denmark (Figure 6.16). As a result, they consume less energy per unit of floor area to meet their heating needs than some countries with warmer climates. Finland has the highest number of heating degree days (HDD) among EU countries, but its energy consumption for heating per floor area is equivalent to Belgium which has half the number of HDD.[15, 16] Some Central European and Mediterranean countries, for example Austria and Croatia, consume more energy per unit of floor area than the Nordic nations, despite their relatively milder climates.

15. Heating degree days measure the deviation of temperatures from a reference point in a given location over a specified period. The more extreme the outside temperature, the higher the number of degree days.

16. The building stock of Finland is much younger than in Belgium: around a third of residential buildings in Belgium were built before 1945, this share is only 12% in Finland.

Figure 6.16 ▷ **Energy use for residential heating, 2017**



Energy intensity for heating varies widely from less than 100 kWh/m² to above 200 kWh/m² as a result of different climates and levels of buildings insulation

Notes: kWh = kilowatt-hours. Energy use for heating includes both space and water heating. The six regional groupings are defined in Annex C.

Cost-effective efficiency gains can be achieved by improving both the energy efficiency of buildings and end-use equipment. Building codes are the preferred tool for ensuring that efficiency is incorporated in new construction and building retrofits. Mandatory energy performance standards play an important role by establishing performance requirements for the equipment used to meet space and water heating demand. Energy labels for buildings and equipment help to raise consumer awareness of the energy efficiency characteristics of their purchasing decisions.

Nearly zero-energy buildings – how much energy do they consume?

Today all of the EU countries have building codes that contribute to reducing energy consumption in new construction. As from 2021, all new building construction will be required to meet "nearly zero-energy buildings" (NZEB) standards.[17] While the standards differ from country to country, most require that total buildings energy consumption should be around 50 kilowatt-hours per square metre per year (kWh/m²/year) in primary energy terms (Table 6.10). This represents a 70% reduction relative to the current average energy intensity of the EU residential buildings stock, which is around 170 kWh/m²/year (in primary energy terms).

6

In addition, in many countries, NZEB standards also require that energy demand be met by renewable energy, either directly (by using solar thermal or geothermal) or indirectly (using electricity or district heating that are produced from renewable sources). A switch to electric or district heating options and to direct use of renewable options such as biomass boilers or solar thermal are other options which may reduce energy demand and carbon emissions.

Table 6.10 ▷ NZEB requirements for selected European Union countries

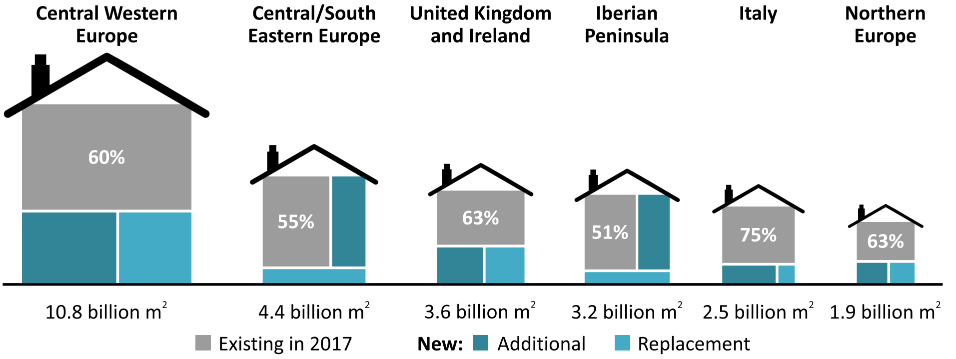
	Year of enforcement		NZEB definition for buildings (kWh/m²/year)			
	Public	Private	New buildings		Existing buildings	
			Residential	Non-residential	Residential	Non-residential
Austria	2019	2021	160	170	200	250
Czech Republic	2016-18	2018-20	75-80%*	90%*	75-80%*	90%*
Denmark	2019	2021	20	25	20	25
France	2011	2013	40-65	70-110	80	60%*
Germany	2019	2021	40%*		55%*	
Hungary	2019	2021	50-72	60-115		
Italy	2019	2021				
Netherlands	2019	2021	25	25		
Poland	2019	2021	60-75	45-70		
Sweden	2019	2021	30-75	30-105		
United Kingdom	2016-18	2016-19	40-45			

* Primary energy maximum measured against that of the building stock.

17. For public buildings, they need to meet NZEB requirements by end of 2018.

New buildings represent an important opportunity to achieve lower heating intensity, but 60% of the residential buildings that will be in use in the European Union in 2040 have already been built (Figure 6.17). A key policy challenge is therefore to improve energy efficiency of the existing building stock.

Figure 6.17 ▷ Residential floor area by region in the European Union in 2040



Around 60% of the residential buildings stock in the European Union in 2040 exists today

Notes: m^2 = square metres. The size of the house figure is relative to the total buildings stock in terms of floor area.

Retrofitting ageing building stock and equipment is a key element

Addressing efficiency improvements in existing buildings is essential to achieving the European Union's energy efficiency targets. Much of the existing building stock across the region is more than 50 years old. In 2018, the European Union updated the EPBD (Energy Performance of Buildings Directive), which focuses on efforts to both decarbonise and reduce energy demand in buildings and will require an acceleration of deep-retrofits.[18] The EPBD instructs member states to develop and implement strategies to make all buildings NZEBs by 2050, whilst also decarbonising building energy demand. Policies for energy efficiency in buildings in EU countries have largely focused on codes for new construction because of the practical difficulties associated with retrofitting existing buildings and the high upfront costs of deep retrofit options. One notable policy challenge is the "split incentive" issue wherein building owners may not have incentive to retrofit properties that are rented. Moving towards a more modular retrofit industry with fewer disturbances for building occupants is likely to be critically important to improve retrofit rates.

Unlocking the energy efficiency potential of existing buildings is especially important in countries with slow turnover of the building stock. In Italy and Hungary, for example, more than 70% of the residential building stock in 2040 is already in place. Retrofitting existing buildings, including the improvement of insulation and replacing inefficient equipment, can

18. See http://europa.eu/rapid/press-release_IP-18-3374_en.htm.

provide significant efficiency gains. Retrofits are most effective in terms of efficiency and cost when a suite of different measures, for example greater insulation and air sealing, as well as the replacement of electric resistance heaters with heat pumps, are implemented in parallel (IEA, 2013). This is known as a deep retrofit, which can often achieve reductions in space heating energy demand on the order of 50% or more.[19] The EU's EPBD focuses on efforts to both decarbonise and reduce energy demand in buildings and will require an acceleration of deep retrofits.

Moving towards near-zero emissions for the overall buildings stock

Building retrofits also provide the opportunity to move towards near-zero emissions by combining energy efficiency measures with a switch to renewable energy options for heating (direct or indirect). Today, 1.5% of European households use solar thermal for water heating purposes, and biomass boilers represent 15% of energy consumption for residential space and water heating. There is scope to increase this and also to increase the use of renewables indirectly through the development of district heating networks that are powered by renewables (currently 10% of EU energy demand for heating in buildings is met through district systems, of which 30% of the heat supplied comes from renewable sources) or through the use of heat pumps (currently 3% of EU energy demand for heating in buildings is from heat pumps).

Heat pumps offer significant benefits. The efficiency of a heat pump can be more than three-times that of a conventional gas boiler at the end-use level. Even after allowing for losses in the generation, transmission and distribution of electricity, a heat pump can reduce primary energy use by an average of more than 35% relative to a conventional gas boiler. The high upfront costs of heat pumps and associated work (for example to replace pipes) constitute a barrier for many households to invest, but costs are expected to decline with increasing heat pump deployment, leading to the technology becoming competitive with gas boilers by around 2025 (see Chapter 9).

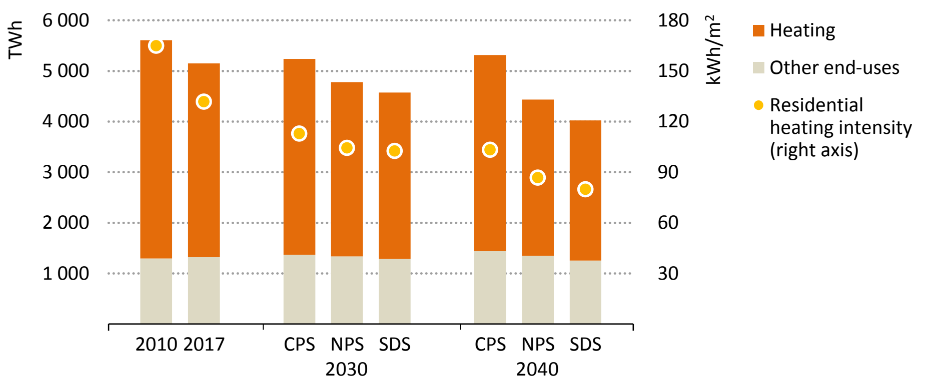
There are already some useful examples of good practice, such as the minimum level of building energy performance of rentals in Germany or the *Crédit d'impôts* (up to 30% of the investment made prior to year-end 2018 in improving the energy performance of a home are eligible for a tax credit) in France. Generally it makes sense to couple a building retrofit with installation of a heat pump, so as to obtain the maximum benefit from the efficiency of the heat pump by connecting it to a low temperature heating system in a well-insulated building. Further deployment of electricity for heating though the use of heat pumps or district heating systems needs to be planned in line with the evolution of the electricity system to make sure that the electrification of heating does not negatively impact system operations and costs.

19. There is no formal definition for deep retrofit but it generally encompasses only high levels of insulation such as roof and wall insulation and at least double-glazed windows.

Correct implementation of the EPBD can lead to long-term savings

In the New Policies Scenario, energy demand in the buildings sector in the Europe Union falls by 0.65% annually to 2040, despite an increase in the number of households and building floor area (Figure 6.18). Most of the savings are achieved through the annual renovation of 2% of the buildings stock from 2020 onwards. Additional savings come from the turnover of old equipment, the switch to other fuels such as solar thermal for water heating and the increased penetration of heat pumps. Energy demand for heating in the European Union declines by 0.95% a year in the New Policies Scenario and the average energy intensity of space and water heating equipment reduces by 35% in the period to 2040.

Figure 6.18 ▷ Energy consumption in buildings by end-use and residential heating intensity by scenario in the European Union



A retrofit rate of 2% could deliver large savings in energy for heating in buildings

Notes: TWh = terawatt-hour; kWh/m² = kilowatt-hour per square metre. The Current Policies Scenario (CPS) assumes a 0.8% retrofit rate; the New Policies Scenario (NPS) assumes a 2% retrofit rate after 2021 and the Sustainable Development Scenario (SDS) assumes a 2.5% retrofit rate from 2021 to 2025 and 4% afterwards. All the scenarios include measures other than retrofit, but retrofit has the highest impact on energy use in buildings between the scenarios.

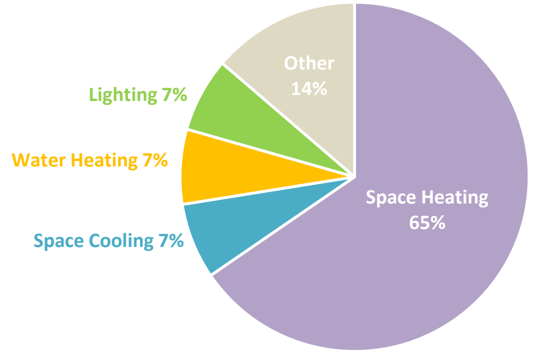
Coal and oil use in buildings in the European Union has declined by 23% and 21% respectively since 2010. This trend accelerates the New Policies Scenario, with demand for coal and oil combined falling to around 10 Mtoe by 2040 compared to over 60 Mtoe today. Natural gas has a prominent role in heating demand in the European Union, and is affected by the new regulatory requirements in the revised EPBD. In the New Policies Scenario, demand for gas in the buildings sector is 140 billion cubic metres (bcm), 45 bcm lower than today.

The Current Policies Scenario, which does not include any new policies and assumes a 0.8% retrofit rate (this rate varies from 0.4 to 1.2% depending on the country), sees a small increase in energy consumption in the buildings sector in 2030 compared to today's level. This increase continues to 2040, with energy demand in the buildings sector being 3% higher compared with today's level. The Sustainable Development Scenario assumes a retrofit rate of around 4% and energy demand in buildings declines by more than 20% over the period to 2040. Most of the savings come from heating, as high efficiency standards are assumed for appliances.

Box 6.2 ▷ Digitalization – an opportunity to further increase energy savings

The new Energy Performance of Buildings Directive in the European Union includes provisions on digitalization and smart buildings, alongside an initiative for rating the "smart readiness" of buildings. The directive points to the potential value of smart technologies for buildings, such as the installation (where economically viable) of building automation and control systems and devices that regulate temperature at room level. Active controls in the different end-uses within buildings can result in large energy savings; sensors and smart meters have a key role to play in monitoring energy use and identifying the most cost-effective opportunities (Figure 6.19). According to the current EU Energy Label legislation (Regulation 811/2013), temperature controls can add up to five percentage points to the efficiency of a space heater.

Figure 6.19 ▷ Energy savings by end-use from smart controls in the European Union in the New Policies Scenario, 2040



Smart controls could help to avoid more than 50 Mtoe of energy demand in buildings in the European Union by 2040, or around 15% of energy consumption in buildings

Note: Other includes appliances, cooking and other services.

Source: IEA (2017b).

PART B
SPECIAL FOCUS ON ELECTRICITY

2018 is the year of electricity at the IEA. Electricity has been the fastest growing element of final demand, and is set to grow much faster than energy consumption as a whole over the next 25 years.

The power sector now attracts more investment than oil and gas combined – a major change for the energy sector, which was traditionally dominated by upstream spending on oil and gas.

Global electricity supply is being transformed by the rise of variable renewable sources of generation, putting electricity at the centre of the response to a range of environmental challenges.

Changes in the electricity sector are also requiring a fresh look at how power systems are designed and how they operate. Electricity security is rising up the policy agenda in many countries.

It is thus fitting that the World Energy Outlook includes, for the first time, a Special Focus on Electricity.

OUTLINE

This special focus looks at different aspects of electricity in turn.

Chapter 7 presents an overview of electricity in the global energy system today, covering key electricity demand and supply developments. It describes the current state and range of options for flexibility in energy systems; analyses the latest investment trends, players and implications on market security; and takes stock of power sector pollutant emissions.

Chapter 8 looks at how the current electricity trends discussed in Chapter 7 might develop in the future. It focuses on the results of the New Policies Scenario, which looks at the outlook for electricity demand and supply to 2040 on the basis of currently announced policies and plans. It also discusses the outlook for flexibility solutions such as storage, demand-side response and smart grids to meet growing needs. It includes two regional deep dives into the European Union and India.

Chapter 9 starts from the recognition that electricity demand growth is uncertain and could be accelerated by policy actions beyond those in the New Policies Scenario. It explores, for the first time, a Future is Electric Scenario – an alternative future for electricity to complement the IEA's central electricity outlook by exploring key policy uncertainties – which looks at what might happen if demand for electricity was indeed to grow faster than in the New Policies Scenario, with a focus on what it might mean for different end-use sectors and regions, and on the possible implications for electricity supply and energy systems. It also draws on key results from the Sustainable Development Scenario to investigate the role of electricity in achieving long-term sustainability.

Chapter 10 stands back and looks at the wider implications of the expanding role of electricity as discussed in the preceding chapters. It focuses on three crucial topics: security, affordability and environmental impact. It considers the role of electricity in achieving environmental goals. It analyses ways to enable efficient power sector investment in competitive markets, and highlights key uncertainties resulting from the pace of deployment of new technologies that may necessitate change to business models. It concludes by looking at the affordability of electricity for consumers.

Electricity today

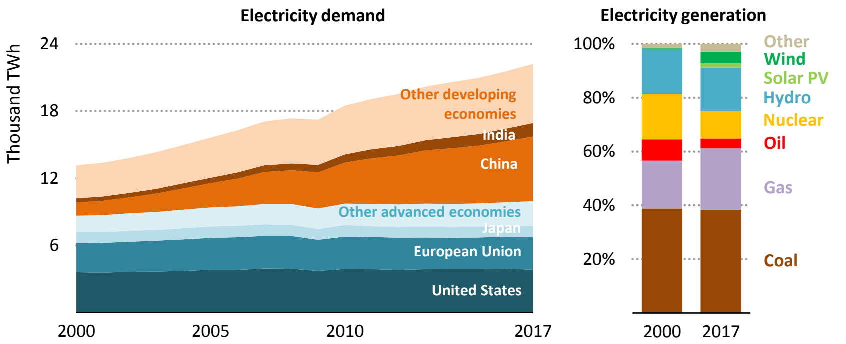
Power to change?

SUMMARY

- Electricity is increasingly the "fuel" of choice for society, but a dramatic transformation of the power sector is underway. Innovative technologies are disrupting traditional ways of producing, transporting and storing electricity, creating opportunities for new actors and business models. Ensuring the reliable and secure provision of affordable electricity, while meeting environmental goals, is at the heart of the 21st century economy and is increasingly a central pillar of energy policy making.

- Electricity accounts for 19% of total final consumption today compared to just over 15% in 2000. Since 2000, global electricity demand has grown by 3% a year, around two-thirds faster than total final consumption. Developing economies account for around 85% of this increase. China is now the largest and India is the third-largest electricity market in the world.

Figure 7.1 ▹ Global electricity demand by region and generation by source, 2000-2017



Electricity demand has increased by around 70% from 2000 to 2017, while the power mix remains dominated by coal and gas, even with growth in renewables

Note: TWh = terawatt-hours.

- Demand for electricity continues to grow in developing economies whereas demand in advanced economies is flattening and in places is declining. Strong growth in India and China provides a stark contrast with relatively stagnant demand in Japan, the European Union and United States. While electricity demand expands in developing economies, universal access to electricity remains elusive: nearly one billion people remain without access today.

- A number of transformations are re-defining the nature of electricity supply. Wind and solar photovoltaics (PV) are growing fast: together they now provide 6% of global electricity generation compared to 0.2% in 2000, whereas coal's share has remained flat. This expansion has been accompanied by growth in flexible natural gas-fired generation as gas becomes more readily available. The expansion of renewables has not yet dented the overall share of fossil fuels in the generation mix, which remains stable at 65% (Figure 7.1).
- As the share of wind and solar increases, so too does the need for flexibility to maintain reliability of power systems. Thermal power makes the biggest contribution to flexibility worldwide, as interconnections and pumped storage hydro each provide further flexibility of around 150 gigawatts (GW). Batteries are starting to contribute too, including behind-the-meter. Digitalization is unlocking new, smaller and more distributed sources of flexibility, especially demand-side response, which today accounts for around 40 GW.
- In 2017, power sector investment was $750 billion, down 6% from 2016 but higher than investment in oil and gas for the second consecutive year. Wind and solar PV counted for nearly half of global capacity additions as they outpaced fossil fuels in 2017. Investment in electricity networks rose to more than $300 billion (accounting for 40% of power sector investment) its highest level in nearly a decade. By 2020, more than 150 GW of new coal-fired capacity is set to start operation compared with around 160 GW of wind power capacity and almost 230 GW of solar PV capacity. Highly regulated markets and market segments, where many investors are sheltered from revenue risk, accounted for over 95% of power sector investment in 2017.
- Today's regulation is not always up to the task of ensuring timely and adequate investment. Some highly regulated markets stimulate over-investment, estimated at around $350 billion, leading to excess capacity, lower profitability for generators and higher costs to the system.
- In contrast, price signals in some liberalised markets are failing to attract investment in capacity and flexibility at the levels required. Without action by policy makers and regulators, this will put the security of power systems under greater pressure in the medium term.
- Since 2000, carbon dioxide (CO_2) emissions from the power sector have grown by an annual average of 2.3%. Coal-fired power plants remain the largest single source of energy-related greenhouse gas emissions, and account for the majority of the sector's total emissions of sulfur dioxide, nitrogen oxides and particulate matter. Nonetheless, power sector emissions are increasing at a lower rate than electricity production as renewables expand and as the average efficiency of fossil fuel power generation fleets improves.

7.1 Introduction: electricity in the global energy system

Increasing digitalization of the global economy is going hand-in-hand with electrification, making the need for electricity for daily living more essential than ever. Electricity is increasingly the "fuel" of choice for meeting the energy needs of households and companies resulting in rapidly rising electricity demand.[1] Since 2000, global electricity demand has grown two-thirds faster than total final consumption, mostly stemming from growth in China and India. This trend looks set to continue.

As the role of electricity in total final consumption has increased, so too has the importance of the power sector in global energy markets. Power generation accounts for 64% of coal use and 40% of natural gas use. Worldwide investment in electricity generation, networks and storage of $750 billion in 2017 was higher than combined investment in oil and gas supply while renewables accounted for two-thirds of investment in generation assets. China was the largest destination for power sector investment.

The cost of variable renewables is continuing to fall, challenging the well-established role of traditional dispatchable generation.[2] Revenues from wholesale electricity sales in many markets are shrinking, while new services – such as providing the flexible capability needed to ensure security of electricity supply – are becoming more valuable, attracting new types of companies to the sector. These factors are contributing to the most significant transformation that the power sector has experienced since its formation over a century ago.

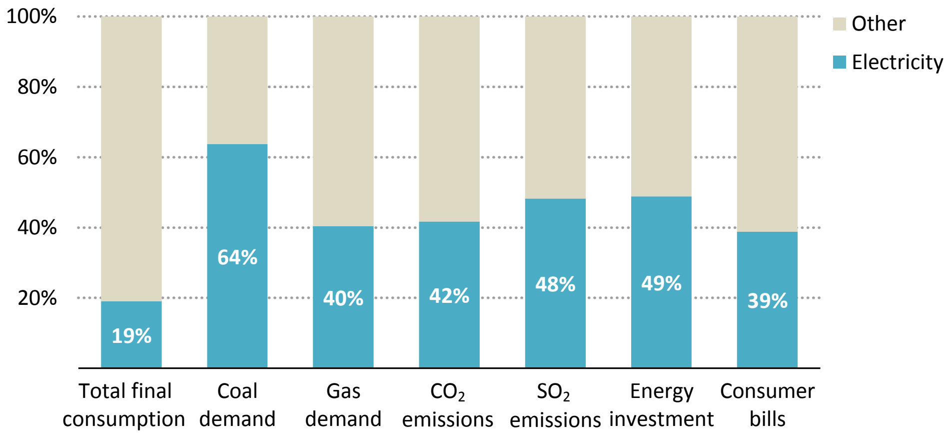
Global consumer expenditure on electricity now stands at $2.5 trillion, almost double what it was in 2000. Consumers are spending almost 40% of their energy expenditures on electricity today, up from 32% in 2000, while the share of spending on oil products is now below 50%. High levels of investment in the power sector and spending on electricity contrast with the relatively poor financial performance of major utilities, reflecting low wholesale electricity prices in many markets that depress revenue from selling electricity. The bulk of investment going into the electricity sector is in heavily regulated markets or market segments, that provide some guarantee of revenue certainty.

The power sector is also the largest source of global energy-related CO_2 emissions and sulfur dioxide (SO_2) emissions, a major air pollutant (Figure 7.2). The power sector is at the heart of efforts to mitigate climate change and fight air pollution.

1. Electricity is a carrier of energy rather than a fuel, but it is referred to on occasion as a "fuel" in this special focus insofar as it competes with other fuels to provide energy services.

2. Variable renewable energy (VRE) refers to technologies whose maximum output at any time depends on the availability of fluctuating renewable energy resources. It includes a broad array of technologies such as wind power, solar PV, run-of-river hydro, concentrating solar power (without thermal storage) and marine.

Figure 7.2 ▷ Share of electricity in the global energy system, 2017



The electricity sector is a key pillar of global energy demand, investment and emissions

Note: CO_2 and SO_2 emissions refer to the share of the power sector in total energy-related emissions.

This chapter examines today's changing electricity sector:

- It starts by highlighting recent trends in **electricity demand** by region and sector.
- It goes on to examine recent trends in **electricity supply**, noting that variable renewable energy (VRE) sources now account for around half of all capacity additions. It discusses the consequent need for increased system flexibility in order to ensure the security of electricity supply. It identifies power plants, grid infrastructure, demand-side response and storage as the four key potential mechanisms for providing this **flexibility**, and analyses recent trends affecting each of them.
- It looks in detail at **electricity markets, investments and regulatory frameworks**, and the greenhouse gas (GHG) and pollutant emissions produced by the power generation sector.

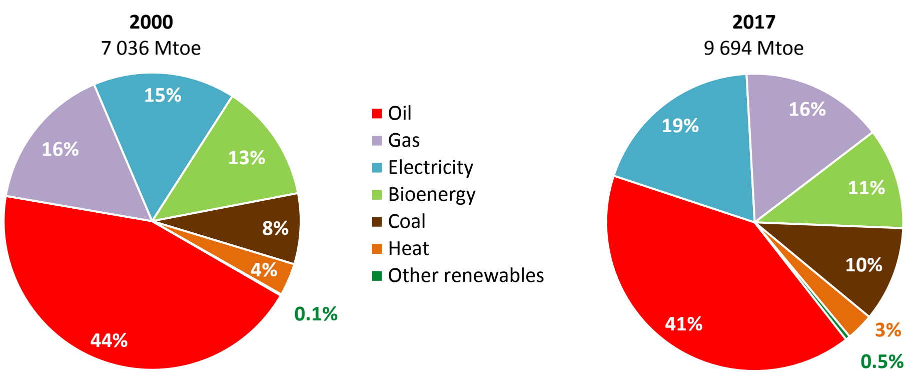
7.2 Electricity demand

In 2017, global electricity demand grew by 3%, more than any other major fuel, reaching 22 200 terawatt-hours (TWh).[3] Global electricity consumption has increased by around 70% since 2000, and it accounts for 19% of total final consumption today compared to just over 15% in 2000. The steady rise in demand for electricity means that it is now the second-largest fuel by end-use, but the level of electricity consumption remains less than half the level of oil consumption (Figure 7.3).

3. Electricity consumption refers to the electricity consumed by end-use sectors (agriculture, buildings, industry and transport), while electricity demand also includes onsite electricity consumed by power plants, refineries, blast furnaces, coke ovens, oil and gas extraction, and heat and boiler transformation.

Although electricity demand has increased at more than two-and-a-half times the rate of population growth since 2000, universal access to electricity remains elusive. Nearly one billion people remain without access to electricity, most of whom are in sub-Saharan Africa and in developing Asia. There is cause for optimism, however, as new policies implemented in India and Southeast Asia are boosting the number of people gaining access to electricity. From 2010 to 2017, an average of almost 50 million people gained access to electricity every year, compared to around 35 million per year during the period 2000-09. India in particular is making unprecedented progress in extending access, with nearly 550 million people gaining electricity access since 2000 (see Chapter 2).

Figure 7.3 ▷ Total final consumption, 2000 and 2017



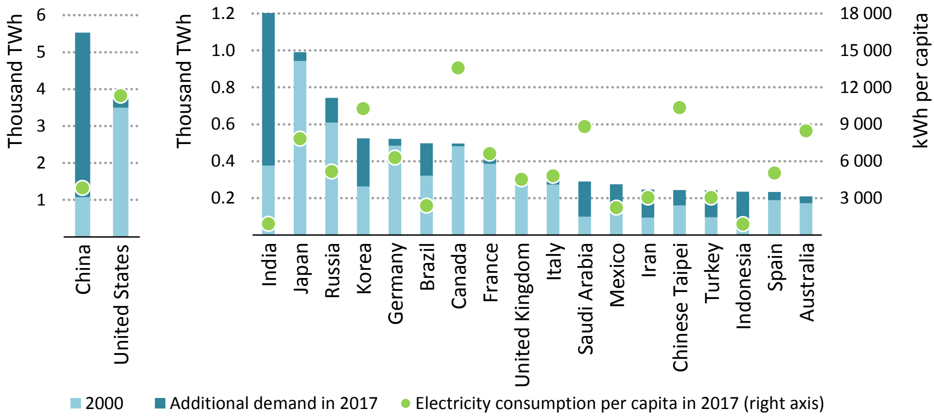
The share of electricity in total final consumption has grown rapidly since 2000, increasing from just over 15% to 19% today

7.2.1 Electricity demand by region

Electricity demand varies widely by region and country. China is by far the world's largest electricity market: electricity demand has grown five-fold since 2000 and now accounts for around 25% of global electricity demand. The United States is the second-largest market, and India, where demand has more than tripled since 2000, is the third-largest market, followed by Japan. Growth in India and China contrasts starkly with relatively stagnant demand in Japan, European Union and United States.

Levels of electricity use per capita also vary widely by region and country, in part reflecting differences in the structures of energy markets and economies. Annual per-capita electricity demand was relatively high in Canada (around 15 000 kilowatt-hours [kWh] per capita) and the United States (around 11 750 kWh per capita) in 2017 (Figure 7.4). In contrast, an individual in China consumes around one-third of the electricity of an average American. While the level of electricity consumption per capita in the industry sector is very similar in the United States and China, per-capita consumption in the buildings sector is seven-times higher in the United States. This reflects that the services sector is a smaller portion of the economy in China and households have fewer electric appliances, as well as the fact that appliances in US households tend to be bigger on average and so require more electricity. Electricity demand per capita in China (4 150 kWh per capita in 2017) is closer to the levels of large European economies, such as Italy, Spain and the United Kingdom (with a range of 4 500 and 5 000 kWh per capita).

Figure 7.4 ▷ Top-20 countries by electricity consumption, 2000-2017, and per-capita electricity consumption in 2017



China consumes a quarter of global electricity, but its per-capita electricity consumption is well below many advanced economies

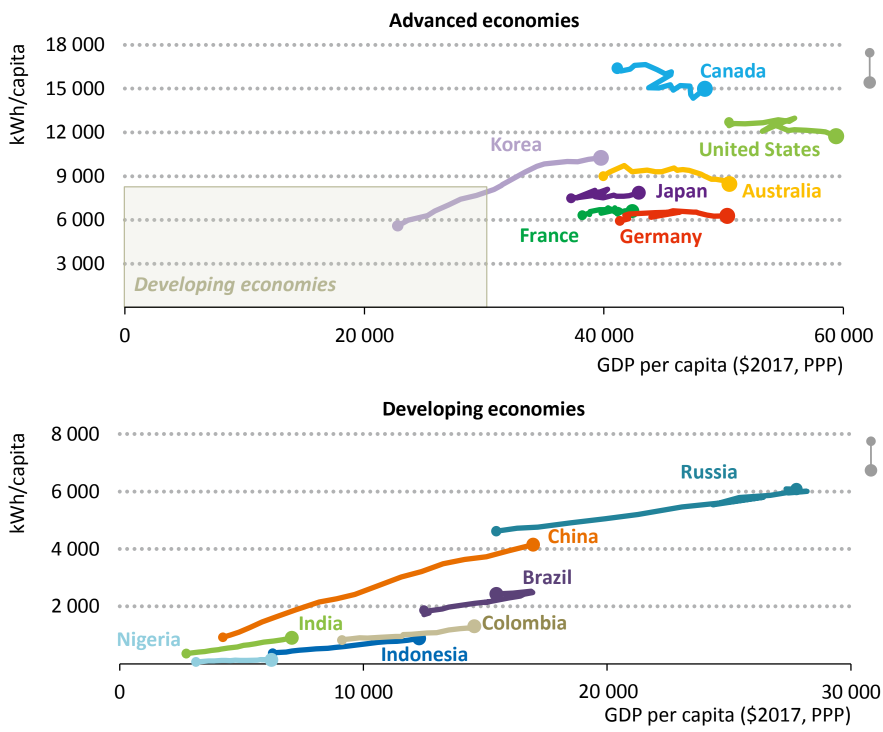
Note: TWh = terawatt-hours; kWh = kilowatt-hours.

Overall electricity demand is rapidly increasing in India, though the per-capita consumption at 910 kWh is less than a third of the global average. This reflects lower per-capita electricity consumption in industry, partially attributable to the continuing importance of coal use in the sector, and appliance ownership rates that are among the lowest in the world.

In **advanced economies**, electricity demand has started to flatten or decline in recent years. In many advanced economies, the link between gross domestic product (GDP) growth and electricity demand growth has weakened considerably in the past decade (Figure 7.5). Electricity demand has fallen in 18 out of 30 International Energy Agency (IEA) member countries since 2010. Several factors have slowed growth in electricity demand in advanced economies, but the key reason is energy efficiency.

New sources of electricity demand growth (digitalization and electrification of heat and mobility) have been outpaced by savings from energy efficiency in advanced economies. Energy efficiency measures adopted since 2000 saved almost 1 800 TWh in 2017 (around 20% of overall current electricity use) (Figure 7.6). Over 40% of the slowdown in electricity demand was attributable to energy efficiency in industry, largely a result of strict minimum energy performance standards for electric motors, now covering almost a half of their electricity use.[4] By the end of 2017, 98% of electricity use for refrigerators, freezers and almost 95% for air conditioners was subject to minimum energy performance standards in advanced economies. Electricity demand for lighting in households peaked in 2001, and demand related to refrigerators and cleaning appliances is down relative to the peak in 2007. In the absence of energy efficiency improvements, electricity demand would have grown at 1.6% per year since 2010, instead of 0.3%.

Figure 7.5 ▷ Relationship between electricity consumption and GDP per capita

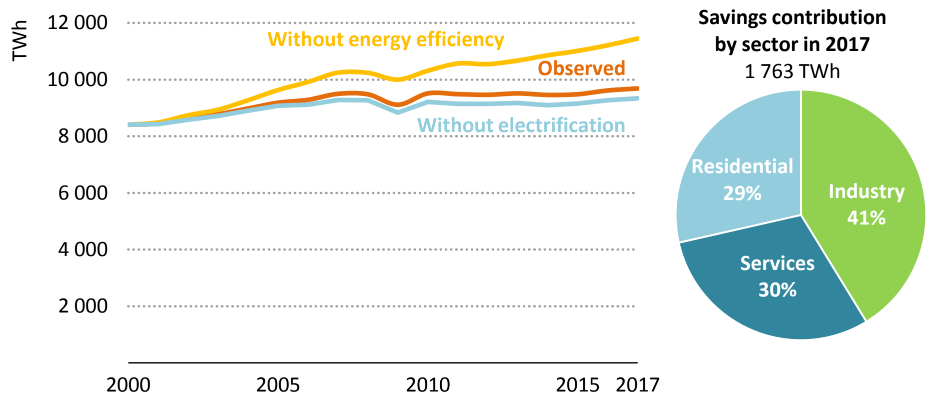


As income increases in developing economies so does electricity consumption, while the correlation has weakened in advanced economies

Note: GDP = gross domestic product; PPP = purchasing power parity.

4. The average strength of those standards is equivalent to the IE3 standard of the International Electro-technical Commission standards, which range from low (IE0) to super premium (IE4). For more information on the energy implications for electric motor systems, see Chapter 8.

Figure 7.6 ▷ **Electricity consumption in advanced economies and efficiency savings by sector, 2000-2017**



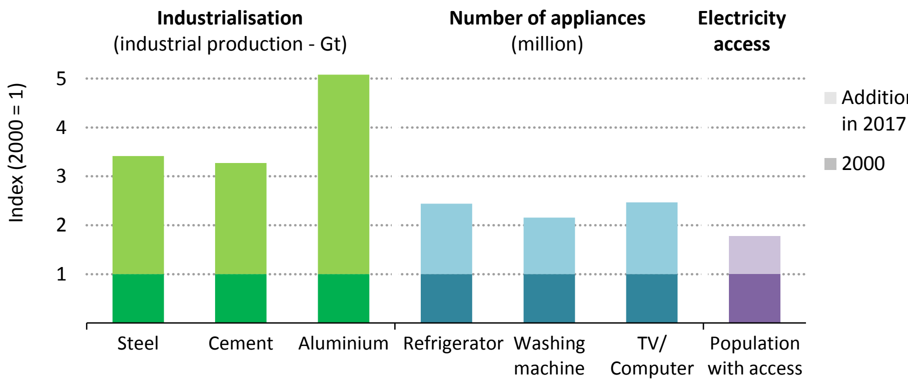
Efficiency measures have moderated growth in electricity demand in advanced economies

Changes in economic structure in advanced economies also contributed to lower demand growth: in 2017 more than 55% of electricity demand in the industrial sector came from light industry, e.g. textiles and food processing. The equivalent figure in 2000 was 47%. Advanced economies now account for 30% of global steel production, for example, down from 60% in 2000; and for 25% of aluminium production, also down from around 60% in 2000. Although the electrification of heat and mobility holds great promise for the future, these sources increased demand by only 350 TWh between 2000 and 2017. Today, electric cars represent only 1.2% of all passenger vehicle sales in advanced economies and account for less than 0.5% of the passenger vehicle stock. Since 2000, around 7% of households have switched from fossil fuels (mainly gas) to electricity for space and water heating purposes, and electricity satisfies 3.6% of heat demand in the industrial sector. In many regions, the price of electricity relative to fossil fuels limits its competitiveness for heating end-uses.

In developing economies, electricity demand has almost tripled since 2000,[5] even though energy efficiency measures implemented over this period helped to avoid an additional 1 400 TWh of electricity demand in 2017. Industrialisation, rising incomes and access to electricity have been key factors behind the growth in demand (Figure 7.7). The industry sector accounts for around 50% of electricity use in developing countries. Industrial production has boomed, and developing economies now produce more than two-thirds of the world's industrial products, compared with about 40% in 2000.

5. Developing economies refers to all other countries not included in the advanced economies regional grouping (see Annex C).

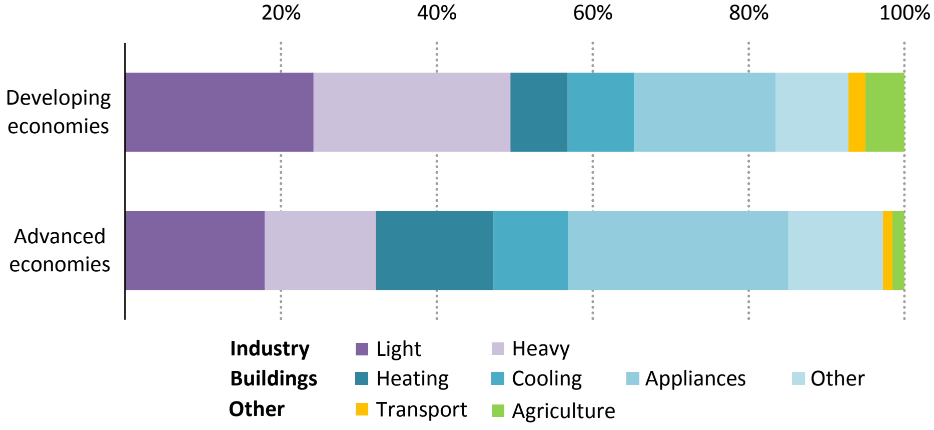
Figure 7.7 ▻ Key drivers of electricity demand growth in developing economies, 2000-2017



Industrialisation, middle class growth and access to electricity have led to a near tripling of electricity demand since 2000 in developing economies

A doubling of average incomes and increasing purchasing power of an emerging middle class have doubled electricity use per capita in the residential sector in the span of twenty years in most developing countries. For the poorest, access to electricity has been on the upswing since 2000: with the proportion of the population lacking access declining and 1.2 billion people gaining access to electricity.

Figure 7.8 ▻ Share of electricity demand by sector and end-use, 2017



Industry is the number one source of electricity demand in developing economies, whereas in advanced economies, the buildings sector is the largest source of demand

There are some clear differences in the composition of electricity demand in advanced economies and in developing economies. First, in advanced economies, electricity demand is split relatively evenly between industry, the services sector and residential buildings, while in developing economies, the industry sector tends to dominate electricity demand. Even excluding China, the industry sector in developing economies accounts for around 35% of electricity demand, compared with around 30% in advanced economies (Figure 7.8).

Second, large differences in appliance ownership rates underpin the differences in building sector electricity demand. Heating accounts for a much higher share of electricity demand in advanced economies. The share of cooling is broadly similar for the moment, but this is an area of tremendous potential growth in developing economies, many of which have relatively hot climates but low ownership rates for air conditioners. Sales of electric vehicles are brisk in some countries, but the use of electricity in rail still dominates transport electricity demand.

7.2.2 Electricity use by sector

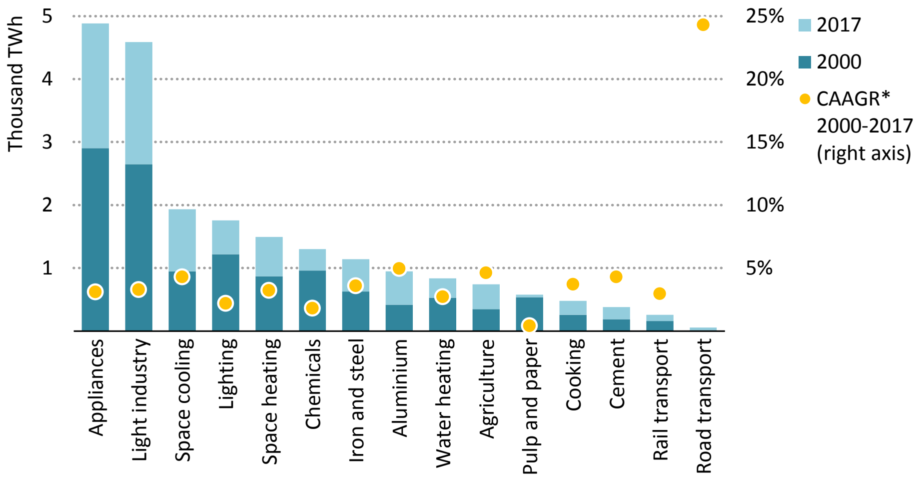
Today, electricity consumption accounts for 19% of total final consumption. Its high conversion efficiency means that electricity provides more useful energy per unit than other fuels, and as a result it meets 27% of useful energy demand.[6] Electricity powers a multitude of end-uses (Figure 7.9). The share of electricity is largest in the **buildings** sector, accounting for 32% of buildings energy demand and 47% of useful energy demand (Figure 7.10). Appliances alone account for over 20% of total global electricity demand. Cooling accounts for a further 9%, and has been propelled higher by 4.3% per year since 2000 by an expanding middle-income population living in hot and humid regions. (For more information on historical and future electricity demand for cooling see *The Future of Cooling* [IEA, 2018a]).

End-use applications in **industry** account for 40% of global electricity demand. Non energy-intensive industries account for around 20%, mostly for motor-driven systems (including fans, compressors and drives). Chemicals, iron and steel, and aluminium production together account for around 15% of electricity use worldwide. Aluminium production grew at 6% per year since 2000, leading to a 5% electricity growth in that sector – the fastest rate among end-uses in industry.

The **transport** sector only accounts for around 2% of electricity demand. Currently, rail is responsible for more than two-thirds of this. It is the road component, however, that is the fastest growing as the sales of electric vehicles swell, albeit from a very low base.

6. Useful energy refers to the energy that is available to end-users to satisfy their needs. This is also referred to as energy services demand. As a result of transformation losses at the point of use, the amount of useful energy is lower than the corresponding final energy demand for most technologies. Equipment using electricity often has higher conversion efficiency than equipment using other fuels, meaning that for a unit of energy consumed electricity can provide more energy services.

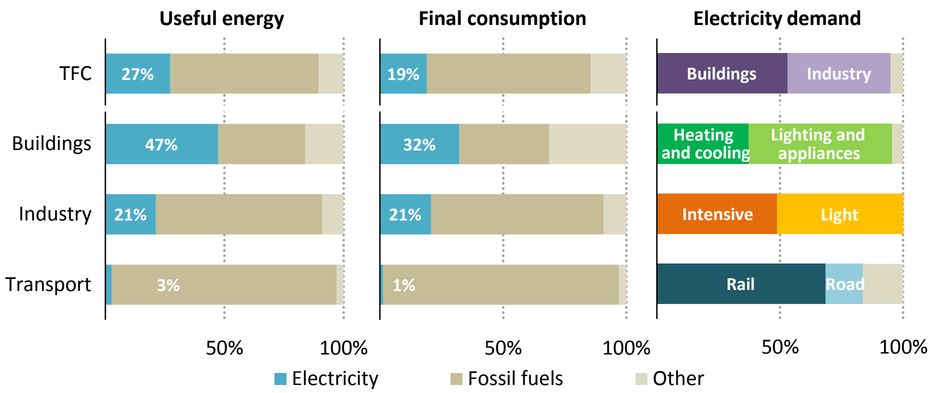
Figure 7.9 ▻ **Electricity demand growth by end-use, 2000-2017**



Appliances and light industry grew the most in absolute terms, while road transport had the highest growth rate, albeit from a low base

* Compound average annual growth rate.

Figure 7.10 ▻ **Share of electricity measured in terms of useful energy delivered and total final consumption, 2017**



Electricity represents 19% of final energy consumption, but thanks to higher average conversion efficiency it meets 27% of useful energy demand

7.3 Electricity supply

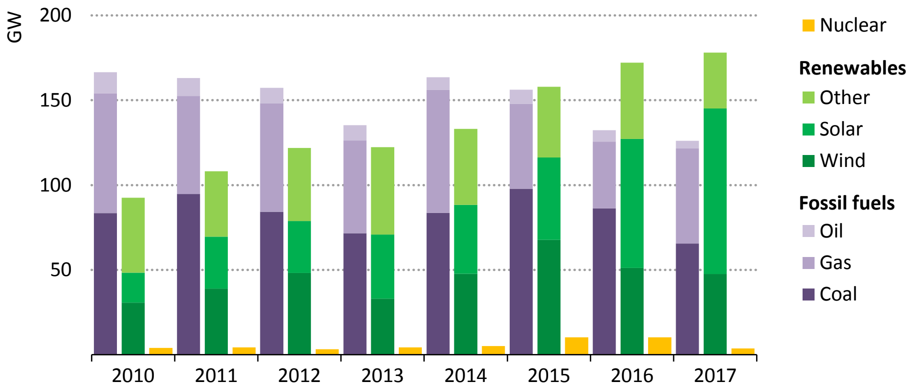
The nature of electricity supply has been remarkably stable for decades in several important respects. Fossil fuels have long dominated the global fuel mix, providing about two-thirds of electricity supply every year over the past two decades. Coal has been the largest source of electricity, holding steady at around 40% of global generation. Large centralised power plants – typically coal-fired, gas-fired, nuclear or hydropower – have provided the vast majority of electricity supply, with individual units able to meet the demand of hundreds of thousands of households. Networks have transmitted power over long distances to demand centres and distributed it directly to individual connected households, businesses and industries. These sources of electricity have been central to accommodate consumer needs, dispatched to match demand.

Today there are a number of transformations underway that are re-defining the nature of electricity supply. The market for new wind power projects increased ninefold from 2000 to 2017, while the solar PV market expanded aggressively. As a result, wind and solar PV now provide 6% of electricity generation worldwide, up from just 0.2% in 2000. The rise of wind and solar PV and their inherent variability have significant implications for the design and operation of power systems, and for the need for flexibility from other electricity sources to ensure security of supply. This is one factor that has contributed to the growth of flexible natural gas-fired generation in some markets, with its share of electricity supply rising five percentage points since 2000. Electricity generated from nuclear, the second-largest source of low-carbon electricity after hydro power, has stagnated over the past two decades, with its share of generation declining from 17% in 2000 to 10% in 2017. The spreading of rooftop solar PV and the falling costs of digital technologies, combined with affordable wind and solar power options, are creating a host of new opportunities that enable consumers to take a more active role in meeting their own energy needs, and supporting new business models to provide affordable access to electricity for the nearly 1 billion people without it today.

7.3.1 Recent market developments

New wind and solar PV generation capacity accounted for nearly half of the 310 gigawatts (GW) of capacity additions worldwide in 2017. Wind and solar PV additions outpaced those of fossil fuels in 2017, driven by policy support and declining costs (Figure 7.11). The global solar PV market had a record-setting year in 2017, with 97 GW of new capacity additions, almost 30% higher than the previous year. China experienced a boom, adding some 53 GW in 2017 and accounting for 60% of both global PV demand and cell manufacturing capacity (IEA, 2018b). Global wind power additions fell to 48 GW in 2017, 7% below the 2016 level and 30% below the peak in 2015: the offshore wind market however added a record 3.8 GW of new capacity in 2017. With the exception of geothermal, capacity additions of other renewable energy technologies declined, mainly owing to a slowdown in hydropower development. Nuclear capacity additions fell to 3.3 GW in 2017, with only China and Pakistan bringing new reactors online.

Figure 7.11 ▷ Annual power generation capacity additions, 2010-2017



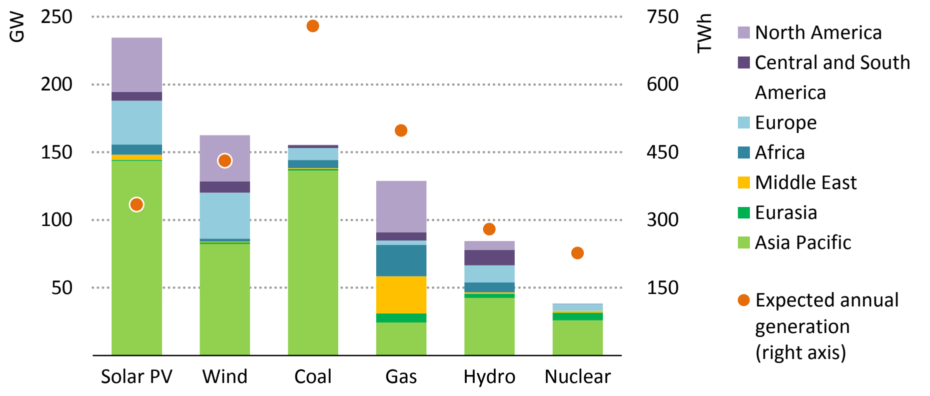
Wind and solar are on the rise, having overtaken fossil fuels in 2017 in terms of capacity additions

Fossil-fuelled capacity additions worldwide fell for the second consecutive year, to the lowest level in over a decade. Coal-fired capacity additions led the way (65 GW), followed by gas (56 GW) and oil (5 GW). Coal-fired capacity additions slowed substantially to around one-quarter below the level in 2016 and to the lowest level in a decade.

Market conditions continued to evolve in 2017, bringing with them implications for the future. Natural gas prices remained relatively low in most markets, particularly in the United States; growing US resource estimates for natural gas are bringing down our long-term gas price trajectories in many markets (see Chapter 4). International coal prices increased substantially while the cost of renewable energy continued to fall (see section 7.3.2). The nuclear power industry continues to face significant challenges, notably in advanced economies, linked to low gas and wholesale electricity prices as well as their costs of construction. It was announced that several reactors in the United States will be retired before their operating licences expire, citing financial hardship as the primary cause.

Looking to the near term, as indicated by recent final investment decisions (FIDs), there is a further shift away from large dispatchable power plants (IEA, 2018c). Total FIDs for coal-fired power plants dropped to a ten-year low in 2017 (32 GW), around one-third of the average rate of the previous decade, mainly owing to sharp reductions in China and India. Decisions to build gas-fired power plants have also slowed in recent years, dropping to 52 GW in 2017, 30% lower than the average of the previous decade. Hydropower is also set for slower growth: the last five years averaged just 22 GW of FIDs per year, 23% lower than the preceding five-year average.

Figure 7.12 ▷ Power plants under construction or expected to 2020 and expected annual generation in 2020 by source



Solar PV and wind power continue to lead near-term capacity additions, although around 300 GW of fossil-fuelled power plants are also expected to start operation by 2020

Note: For comparative purposes, renewables include all capacity additions in the period 2018-20 from the main case projections in the *Renewables 2018, Market Report Series* (IEA, 2018b).

Sources: S&P Global Platts (2018); IEA (2018b).

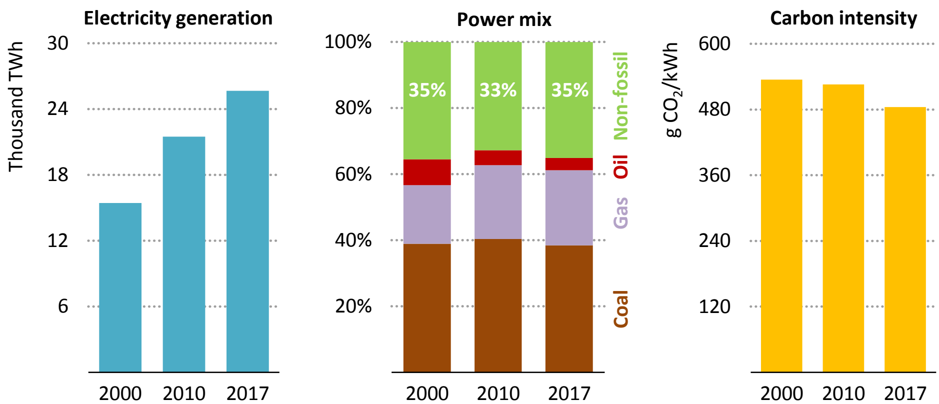
Of the 870 GW worldwide that are currently under construction or are expected to come online by the end of 2020, almost 60% will use renewables-based technologies (Figure 7.12). China is set to remain the clear leader in renewables deployment, with strong growth also taking place in Europe and North America. About two-thirds of the 60 GW of nuclear power capacity currently under construction are completed by 2020, of which two-thirds is in Asia Pacific (almost half is in China alone). In advanced economies, nuclear construction activities are limited relative to developing economies.

The growth of renewables should not obscure the fact that about 330 GW of new fossil-fuelled power plants are also under construction (approximately 300 GW of which is anticipated to start operation by 2020). Coal additions represent the largest share, about 90% of new coal-fired capacity under construction worldwide are deployed in Asia Pacific, including 62 GW in China, 50 GW in India and 30 GW in Southeast Asia. Gas-fired capacity under construction is spread evenly throughout the world. The Middle East is the main location for investment in new oil-fired capacity, often based on subsidised provision of oil for the power generation sector (see Chapter 3).

While electricity generation has increased by two-thirds since 2000, the share of fossil fuels has remained constant, and they still account for two-thirds of total electricity generation. Coal's share of total electricity generation has remained stable throughout the period at around 40% of the electricity mix. Gas-fired generation has more than doubled and today represents almost one-quarter of global generation, more than offsetting the reduction in oil both in absolute and percentage terms (Figure 7.13).

The share of low-carbon electricity production has remained stable over the past two decades in a fast growing overall market. Renewables have offset the decline in the share of nuclear (nuclear generation has remained more or less stable in absolute terms). Wind and solar PV have grown around 50-times compared to 2000 when globally wind produced only 30 TWh and generation from solar PV was only 1 TWh.

Figure 7.13 ▹ Electricity generation, power mix and carbon intensity, 2000, 2010 and 2017



Electricity generation has increased by 10 000 TWh since 2000 with a constant share from fossil fuels while the average carbon intensity of power generation steadily improves

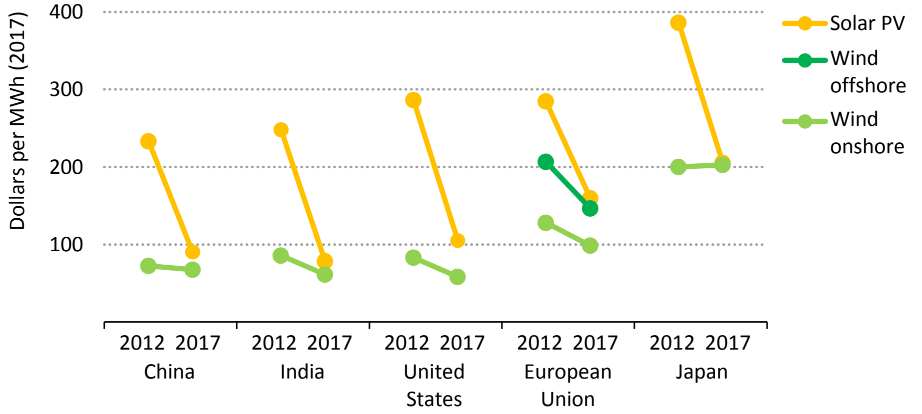
7.3.2 Renewable energy technology costs

The levelised cost of electricity (LCOE) is a commonly used metric to assess the costs of power generation technologies, including renewables. The LCOE takes account of the direct costs specific to each technology – including the upfront capital investment, financing costs, fuel costs, operation and maintenance costs, and CO_2 prices when applicable – combining (and discounting as appropriate) them into an estimate of the average cost incurred to produce one unit of electricity over the life of a project.

The LCOE has limitations. In its standard form, for example, an LCOE does not include indirect costs to the system, including network integration costs, and nor does it take account of the overall value that different technologies provide in terms of meeting demand, contributing to system adequacy and providing flexibility. This has led the IEA to examine the case for a new metric (see Chapter 8, section 8.3). Nonetheless, the LCOE still has value, and it remains the most commonly used metric in assessing cost competitiveness across technologies as it is straightforward to calculate and provides a useful high-level comparison.

The global average LCOE of solar PV and wind power has declined substantially over the last five years – by an estimated 65% for solar PV and 15% for onshore wind.[7] Not all renewables have experienced such pronounced cost reductions, in some cases because they are mature technologies (e.g. hydropower and bioenergy) and in other cases because more limited deployment has presented fewer opportunities for learning-by-doing, as for example with marine energy technologies. The average costs for offshore wind have started to come down, by 25% from 2012 to 2017, though cost reductions were limited as continued development in Europe has pushed projects into deeper water further from shore, offsetting direct gains from turbine development. However, continued technology improvements point to likely cost reductions in the near term (IEA, 2018d).

Figure 7.14 ▹ Levelised costs of electricity by selected technologies and regions, 2012-2017



Solar PV has seen the biggest cost reductions in utility-scale renewables with cost cuts up to 70% in major markets

Sources: IRENA Renewable Cost Database; Bolinger and Seel (2018); IEA analysis.

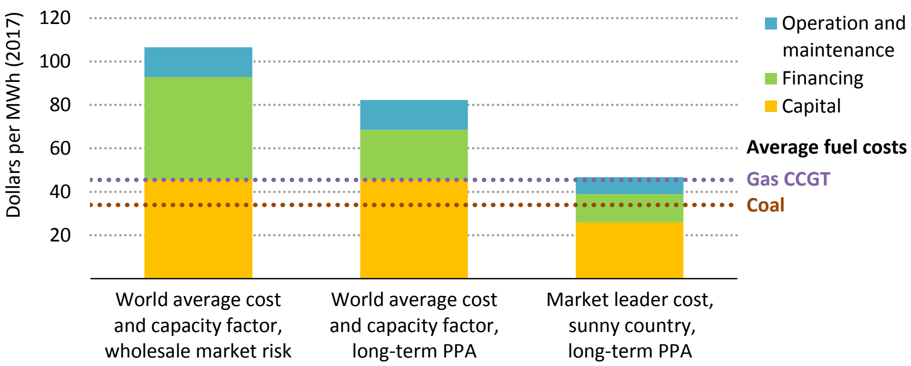
The costs of renewable energy technologies vary by region, depending on many factors including the quality of renewable energy resources, the experience of the industry, labour costs, availability and cost of land, and licensing and permitting processes. For solar PV, China and India are the two lowest cost regions, combining best-in-class average capital costs with good resources, while the European Union has a higher average levelised cost because of its relatively poor solar resources (Figure 7.14). The United States and Japan both have notably higher average capital costs for new projects, but these are moderated

7. Historical LCOEs for solar PV and wind power technologies are based on historical capital costs and capacity factors provided by IRENA through direct communication in March 2018, complemented by other sources, and combined with uniform financing terms by region (8% weighted average cost of capital in real terms in advanced economies and 7% in developing economies), and assumed economic lifetimes by technology. LCOEs presented do not incorporate available subsidies or other support measures.

in the United States by high quality resources. The United States has exceptional wind resources and a well-developed wind industry, making for some of the lowest LCOEs onshore projects in the world. Moderate wind conditions in China, India, the European Union and Japan lead to higher average levelised costs.

Recent auctions for solar PV offered some record-low prices – such as $24 per megawatt-hour (MWh) in the United Arab Emirates, $27/MWh in India, $20/MWh in Mexico and $18/MWh in Saudi Arabia – but they are not directly comparable to LCOEs. The LCOEs represent the average of a range of project-level costs, while auction prices, by their nature, reflect the costs for best-in-class projects. Auction prices may also often benefit from advantageous financing terms; applicable when long-term power purchase contracts are awarded. Additional support measures and financial incentives can further divide auction prices from the full underlying costs.[8] Best-in class projects with low financing costs can achieve up to 60% lower costs than the global average LCOE (Figure 7.15).

Figure 7.15 ▷ Solar PV levelised cost of electricity, 2017



Best-in-class projects that obtain low-cost financing can achieve costs that approach the fuel costs of gas-fired power plants

Notes: PPA = power purchase agreement; CCGT = combined-cycle gas turbine. Fuel costs reflect 2017 global averages and assume a natural gas price of $6/MBtu with 50% efficiency for existing CCGTs, a coal price of $90/tonne with 39% efficiency for supercritical plant.

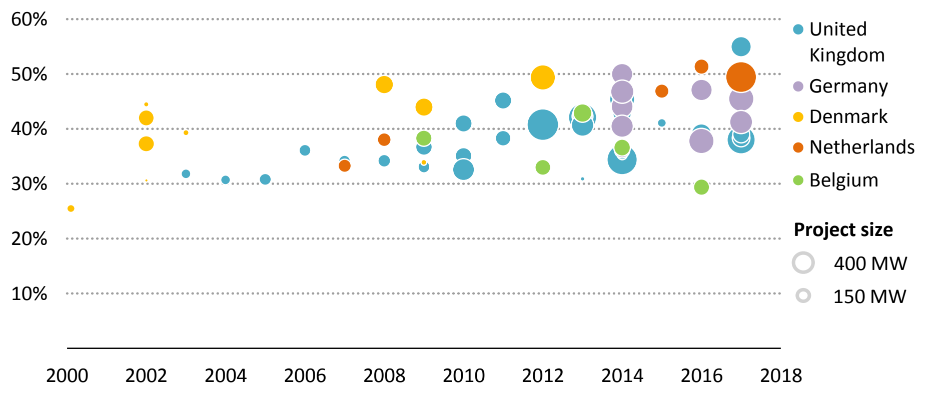
The main driver of cost reductions for solar PV has been declining upfront investment costs, global average capital costs have fallen by almost 70% since 2010 to $1 300 per kilowatt (kW) for the average utility-scale project in 2017. The lowest upfront capital costs were in Germany ($1 090/kW), India ($1 125/kW) and China ($1 130/kW). Technology innovation has driven down the costs of solar panels, while also enhancing their performance, and learning-by-doing has reduced the balance-of-system costs (IRENA, 2018).

8. Available support measures may include the provision of low cost or free land and grid connections, as well as direct financial support through tax incentives, premiums or green certificates.

At the same time, the performance of solar PV has also improved thanks to the increasing efficiency of solar panels deployed and wider adoption of single- and dual-axis-tracking in utility-scale projects. The average cost of smaller scale solar PV, such as rooftop projects has declined by 40-80% since 2010, though they remain 20-60% more expensive than utility-scale projects in most regions.

Performance improvements have been the primary reason for cost reductions for wind power, including offshore projects. Advances in wind turbine designs have supported higher performance in a wide range of conditions, notably including low wind speed environments, raising the global average capacity factor of wind power from less than 22% in 2010 to over 24% in 2017. The expansion of offshore wind power has also contributed to these gains, with new projects achieving higher capacity factors, edging towards 50% (Figure 7.16). The global average capital costs for onshore wind power have decreased by about 20% since 2010.

Figure 7.16 ▷ Average load factors and size of offshore wind installations by year of construction in top-five European producers



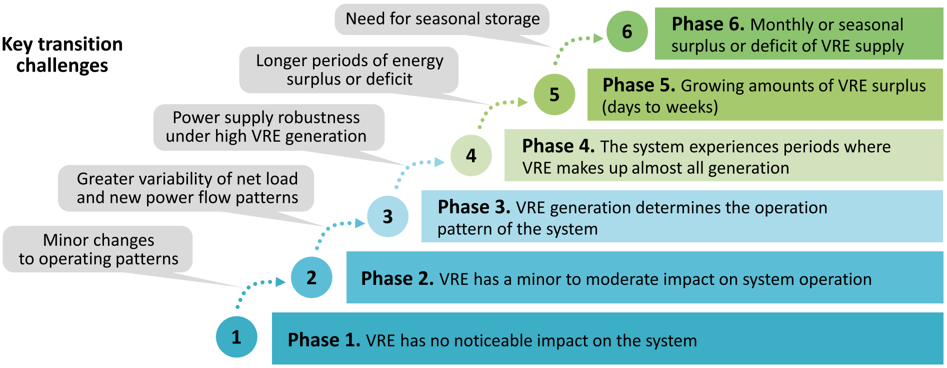
Opportunities for offshore wind developments are being transformed by higher capacity factors that offset rising capital costs

Sources: IEA analysis; Danish Energy Agency; Energynumbers.info; Platts; UK Balancing Mechanism Reporting Service complemented by public data from operators; WindEurope (2018).

7.3.3 State of renewables integration

Continued cost reductions and policy support are driving sustained uptake of wind power and solar PV across the world. The integration of variable renewable energy sources (VRE) into electricity systems can be categorised into six distinct phases, which can help to identify relevant challenges and integration measures (IEA, 2017) (Figure 7.17). The categorisation not only depends on the share of VRE, but also on technical and other characteristics of the systems.

Figure 7.17 ▷ Characteristics and key transition challenges in different phases of integration of renewables



Key challenges by phase in moving to higher levels of integrating variable renewables in power systems

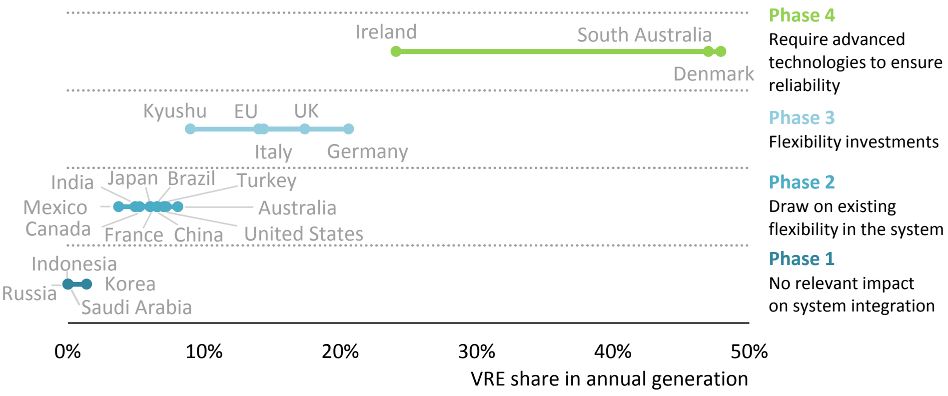
Countries or systems at Phase 1 of the scale, where deployment of the first set of wind and solar power plants have no noticeable impact at the system level include Indonesia, Korea, Russia and Saudi Arabia. At Phase 2, integration challenges begin to emerge. Differences between load and net load become noticeable, but VRE (at about 5-10% share) still has a minor impact on the system. Today, most countries are in Phase 1 or Phase 2, but as the share of VRE increases, many expect to move onto higher phases (Figure 7.18).

VRE determines operational patterns of the power system in Phase 3. Electricity supply has an increased level of uncertainty and variability owing to a higher share of VRE (typically higher than 10%). System flexibility becomes very important for integrating VRE to address greater swings in the supply-demand balance. Countries and systems that are in Phase 3 include Germany, Italy, Kyushu (a subsystem in Japan) and the United Kingdom.

In Phase 4, VRE provides the majority of electricity generation during certain periods. This typically requires advanced technical options to ensure system stability, causing changes in operational and regulatory approaches. For regulators, rule changes may be required for VRE to provide system services. Denmark, Iberian Peninsula, Ireland and South Australia are considered to be in Phase 4.

VRE output frequently exceeds power demand (days to weeks) in Phase 5. In some periods the demand is entirely supplied by VRE and further VRE additions face the risk of substantial curtailment. Enhancing flexibility including via electrification of other end-use sectors such as transport and heating can mitigate this issue.

Figure 7.18 ▷ **Annual share of variable renewables generation and related integration phase in selected regions/countries, 2017**



Many regions are in Phase 1 and 2, with a handful in Phase 4

Notes: EU = European Union, UK = United Kingdom. Kyushu is a subsystem in Japan.

Phase 6 is determined by a surplus or deficit of VRE supply on seasonal or inter-annual timescales. This drives a possible need for seasonal storage and use of synthetic fuels or hydrogen which convert electricity into a chemical form that can be stored cost-effectively.

It is possible for a large system to be in a lower phase, while a certain region or subsystem is in a higher phase of VRE integration. For example, the overall power system in Japan is in Phase 2, but Kyushu, a large island located in the southwest, has a higher share of VRE and faces Phase 3 problems. On Kyushu, the instantaneous PV penetration in certain periods is about 80% of electricity demand. This has motivated the development of cost-effective operational approaches to optimise the existing resources including thermal plants, reservoir hydro and pumped storage hydropower plants. Another example is the region covered by 50Hertz, the company that operates the transmission grid in the northern and eastern part of Germany, where renewables accounted for 53% of electricity consumption in 2017. Also, Hawaiian Electric Industries, which serves 95% of the population of Hawaii, operates five separate island grids where the shares of VRE range between 15% and 35%; and the Gansu and Inner Mongolia provinces in China, both of which have high VRE penetration and curtailment rates.

As the level of VRE increases, electricity systems need to consider changes to their technical, market and regulatory and institutional frameworks to take account of these increases and ensure the provision of sufficient flexibility to maintain continued security of supply. For example, EirGrid and SONI, the two transmission system operators on the island of Ireland, where wind power has been increasing, have established the DS3 Programme to identify the maximum allowable instantaneous penetration of VRE to ensure that the system can operate efficiently and securely.[9] The Ireland and Northern Ireland power system initially had a maximum system non-synchronous penetration (SNSP) level of 50% in 2012. The DS3 Programme aims to address the various factors that influence the SNSP limit, and has thus far resulted in the SNSP level increasing to 65% in 2018, with the ultimate aim of increasing the limit to 75% in 2020. This increase requires measures to enhance system flexibility ranging from integrated planning and system operation, to new tools for control centre operation, to the establishment of new service products that are able to support the system with timescales of sub-seconds to days.

Curtailment levels of VRE beyond a few percent signal an insufficient level of system flexibility, which may have technical, regulatory or institutional causes. Many systems with high rates of VRE, such as Denmark, Italy and Portugal, have managed to achieve very low or zero levels of VRE curtailment by ensuring adequate systems flexibility. The curtailment in the Electricity Reliability Council of Texas (ERCOT) system declined from around 20% in 2009 to less than 2% in 2017 following timely investment in the transmission grid. There are a number of systems that still face high levels of VRE curtailment such as China, where the overall VRE curtailment was around 12% for wind power and 6% for solar PV in 2017, but the curtailment rate reduced in that year as a result of increased electricity demand, higher penetration of distributed electricity and the entering into service of new ultra-high-voltage direct current transmission lines. Electricity market reform also played a role by facilitating increased inter-province electricity trade.

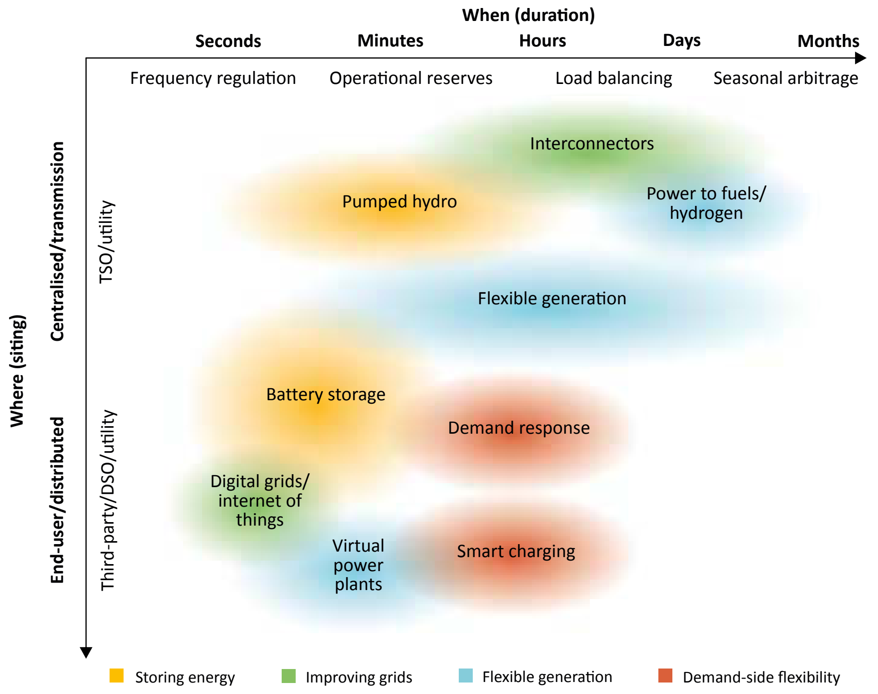
7.4 Electricity flexibility

Energy systems have always needed flexibility: electricity supply needs to balance demand at all times, and demand patterns have always changed hourly, daily, weekly and seasonally. Flexibility has traditionally come from thermal generation and hydropower capacity together with a combination of pumped storage hydropower, interconnections and demand-side response from large industrial and commercial consumers, which today between them provide around 375 GW of flexibility worldwide (Figure 7.19).

The power generation fleet provides the largest amount of this flexibility, followed by interconnections, with pumped hydro providing the bulk of storage capacity (Figure 7.20). The situation, however, is changing rapidly. On the supply side, the growth of non-dispatchable resources such as wind and solar increases the need for flexibility in power systems. On the demand side, digitalization is opening the possibility of making demand more flexible. Steep reductions in battery storage costs are unlocking new flexibility options, while smart grids have the potential to become the backbone of modern and reliable electric systems.

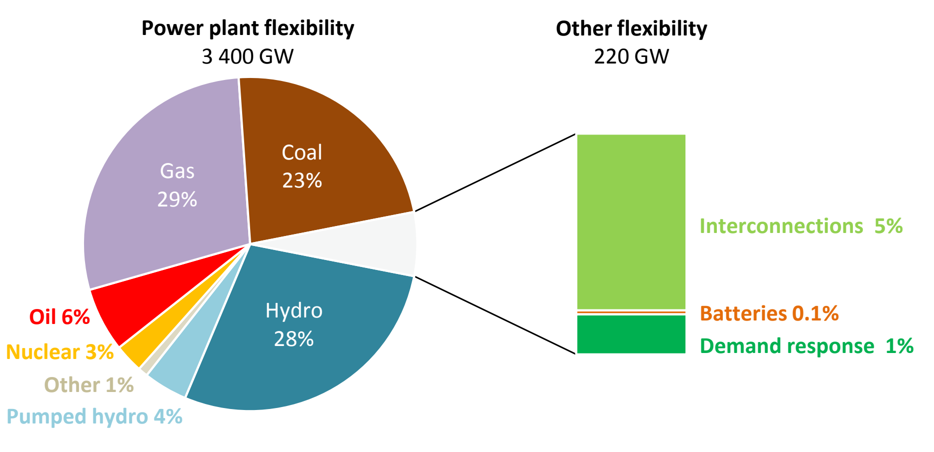
9. Ireland uses non-synchronous penetration (SNSP), which includes wind and high-voltage direct current interconnector imports.

Figure 7.19 ▷ Growing needs and range of options for flexibility



Expansion of electrification, distributed generation and variable renewables will broaden the need and range of flexibility options

Figure 7.20 ▷ Flexibility in the global power system, 2017

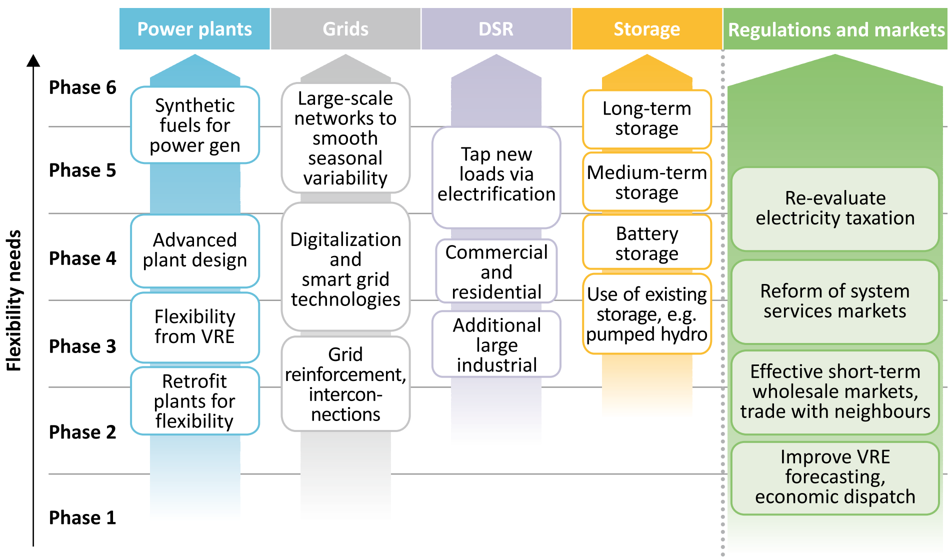


Power plants dominate flexibility options today while pumped hydro, interconnections and demand response account for 10% of total flexibility

New players such as demand aggregators, virtual power plants, energy service companies and peer-to-peer networks are emerging, blurring traditional supply-demand distinctions between generators, networks, retailers and consumers. As a result, distributed resources are becoming increasingly available to network operators as alternatives to traditional forms of flexibility. A number of jurisdictions have taken a pro-active role in facilitating these, including South Australia, and US states of New York and Hawaii. As the need for flexibility increases, the challenges of providing it become more complex and more dependent on regulatory and market design.

There are four main ways to source flexibility to balance power systems: make the power generation fleet more flexible; make demand more flexible; deploy energy storage and upgrade and improve electricity grids and their operation (Figure 7.21). All of these require appropriate regulatory frameworks and market design if they are to function correctly.

Figure 7.21 ▷ Sources of flexibility



As flexibility needs increase, they place increasing demands on power plants, grids, demand-side flexibility and storage, with implications for regulatory and market design

Note: DSR = demand-side response.

7.4.1 Flexibility from power plants

Power plants have traditionally been the main source of flexibility to meet changes in demand. Four elements determine the technical flexibility of a power plant: how fast output can be ramped up or down; how far output can be reduced and remain stable; how fast a plant can be started ; and how long it needs to remain on the system once started or off the system once offline.[10] Increased flexibility needs pose both a challenge and an opportunity for the power fleet to improve designs, retrofit current plants or adjust operations to change these four variables. While not all technologies are able to adapt equally, experience shows there are large amounts of flexibility available from existing fleets when the need arises.

Positive technical characteristics have made gas plants and some forms of hydropower the main providers of flexibility in adapting to changes in load and to VRE supply changes. However, less conventional sources can also provide flexibility. In France, the historical predominance of nuclear generation in the power mix (75%) led to early and sustained increases in ramping flexibility being designed into the nuclear fleet. In many power systems, coal plants have proved that they can also serve as a provider of flexibility: for example, the legacy coal system has been a major enabler of VRE integration in Germany and Denmark. Digital technologies allow flexibility to be provided through virtual power plants, and now account for nearly 18 GW of flexibility in the European Union (Box 7.1). Variable renewables are also able to provide a degree of flexibility beyond simply curtailing their output: "smart" inverters deployed with solar PV systems can provide a range of technical properties to the system that solar PV output otherwise lacks. Wind power plants are also able to provide a limited range of flexibility services, including system inertia.[11]

VRE has increased the need for short-term flexibility (reacting to changes within minutes or hours) and for power plants to follow steeper and less certain ramps up and down. Retrofits can greatly increase flexibility and address operational impacts, but more frequent cycling of thermal plants, increased ramp rates over time and a higher percentage of time operating under minimum load all still have a substantial impact on efficiency, operational costs, wear and tear of technical equipment, and overall plant economics, as well as on emissions performance in the case of fossil fuel generators.

Box 7.1 ▷ Getting real: the promise of virtual power plants

A virtual power plant (VPP) is a network of distributed energy resources, behind-the-meter storage and generation ranging from rooftop PV to combined heat and power production plants, together with demand-side response (DSR) resources. It aggregates and connects that network to markets and services to which its components might not otherwise have access. VPPs can provide bulk electricity and system services such as adequacy, capacity or power quality by aggregating through digital technologies a multitude of small resources. The size of VPPs in 2017 ranged from megawatts to well into the gigawatt range (equivalent to large nuclear or thermal plant) (Figure 7.22).

In the vast majority of cases where VPPs are in place, customers buying energy storage receive an offer of the option to enrol in a VPP, which could lead to financial gains

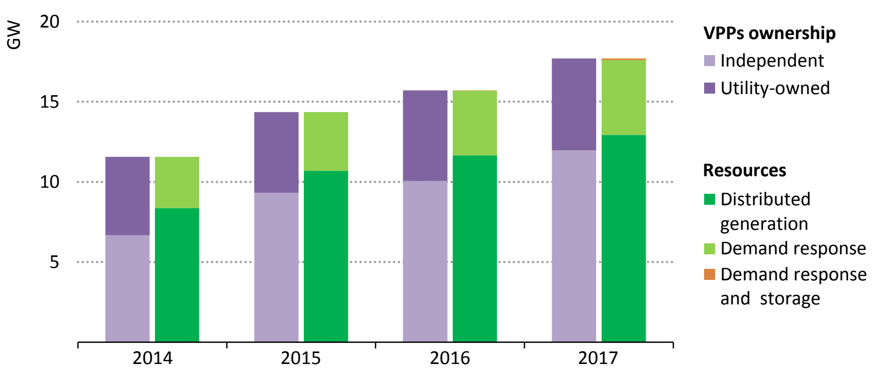
10. Power plant flexibility is interpreted as a technical lower bound for the minimum turn-down under ideal current technical and operational practices, for each technology type.

11. System inertia is a key determinant in how rapidly the system frequency will change in response to a disturbance.

and cost savings. Third-party aggregators are the most common business model: they typically do not own resources, but provide additional value to asset owners. The owner of the VPP itself often, but not always, operates the VPP.

Expansion of VPPs has accelerated notably in recent years: overall investment has quadrupled since 2014, and installed capacity in Europe was around 18 GW in 2017. The most significant development has been a shift in business models towards provision of DSR. Most VPPs in place today provide capacity to utilities or within ancillary services markets. They have had less success in capacity markets, where the longer duration required can be prohibitive, but cost reductions in battery storage could lead to increased success in capacity markets and further expansion.

Figure 7.22 ▷ Virtual power plants in the European Union



VPP deployment has increased by more than 50% in Europe since 2014, with portfolios diversifying towards DSR and storage

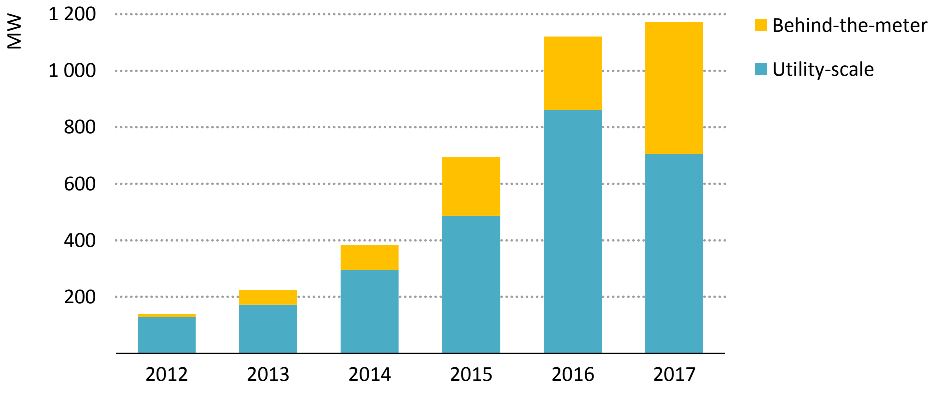
7.4.2 Demand-side response

At the end-user level, demand-side flexibility to date has been limited in deployment, often restricted to large industrial or commercial consumers and to night-time tariffs. Around 40 GW of demand response is in use today amounting to 0.5% of total global electricity generation capacity. Tapping demand-side flexibility in more sophisticated ways could increase the overall capacity of power systems to handle variable renewables and to help reduce overall systems costs. Achieving this is likely to require the use of smart grid infrastructure, including smart meters, sensors and control systems, making use of digital connections, and increasingly offering the opportunity to increase consumer participation in energy systems. Smart meter investment reached a record of nearly $18 billion in 2017, a threefold increase from 2010, and deployment is moving ahead rapidly in some countries and regions. More than 60% of all smart meters are in China, but many other markets have successfully rolled out smart meters on a large scale, such as Canada, Denmark, Finland, Italy, Norway, Spain and Sweden.

7.4.3 Storage

The value and role of storage varies greatly depending on where on the grid it is deployed, at what size and under what market conditions. Pumped storage hydropower currently amounts to 153 GW or just over 2% of power generation capacity worldwide, and accounts for the majority of the capacity to store electricity. Beyond pumped hydro, energy storage systems encompass a largely decentralised, fast growing, diverse and complex set of technologies. While the current installed capacity of these other technologies combined totals around 4 GW, battery storage capacity is growing fast: its installed base has tripled in less than three years, largely driven by lithium ion batteries, which now account for just over 80% of all battery capacity. Small-scale battery storage in particular is making inroads, and 45% of all annual capacity additions are now behind-the-meter. In off-grid solar applications for energy access, the vast majority of systems now include a storage unit.

Figure 7.23 ▷ Annual additions of behind-the-meter and utility-scale battery storage, 2012-2017



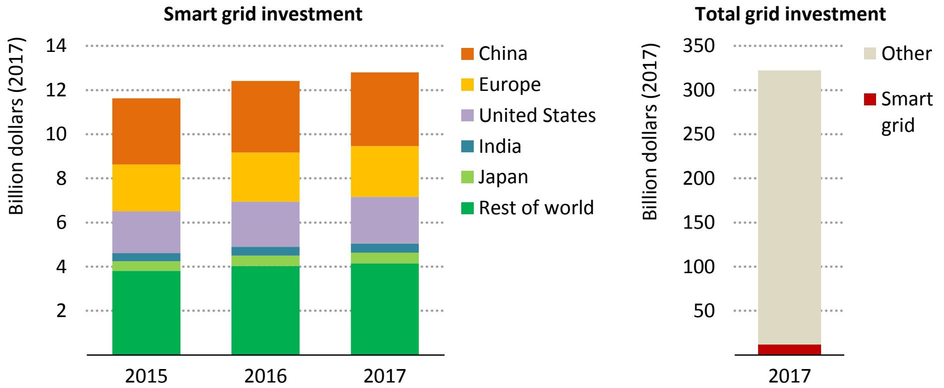
Behind-the-meter installations have compensated for a drop in utility-scale deployments

Pumped hydro remains important, albeit constrained by the location of suitable sites: around 26 GW of additional capacity are expected by 2023, almost 70% of it in China. Lithium ion batteries are expanding rapidly, and are mostly aimed at providing short-term storage. For applications with longer storage durations, other battery types, including sodium sulfur and in particular flow batteries, have attracted increased interest. The costs per unit of energy for flow batteries with storage volumes over several hours can be lower than those of lithium ion batteries: globally, around 70 MW are in place, with a number of large-scale multi-hour storage plants planned or under construction, notably in China. To meet even longer term needs such as seasonal storage, hydrogen is a possible option. Storing hydrogen, however, has a very low round-trip efficiency and the cost of producing hydrogen from electricity remains a key barrier. Almost all of the hydrogen today is produced from fossil fuels, with direct production from electricity through water electrolysis under 1%. However, investment in electrolysis for renewable applications is quickly on the rise, which could help reduce costs and provide additional flexibility. If all planned or under construction projects materialise, cumulative hydrogen electrolysis capacity will rise from 55 megawatts (MW) in 2017 to over 150 MW by 2020.

7.4.4 Expanding and "smartening" electricity grids

Investment in upgrading electricity grids can contribute to flexibility in three ways. First, expanding and upgrading grids can alleviate congestion and increase the capacity to transport electricity to where it is needed. Second, interconnecting with neighbouring grids can tap into their different supply and demand patterns, as well as expand the pool of available flexibility resources. Third, investing in smart grid technologies can help manage power flows more efficiently. The expansion and upgrade of transmission and distribution networks accounted for around $300 billion of investment worldwide in 2016 and 2017. Of this, new or upgraded interconnection between regions brought total interconnection capacity to 177 GW in 2017. The largest centres for regional interconnection today are China, Europe and the United States.

Figure 7.24 ▷ Investing in smart distribution grids, 2015-2017



Investment in smart technologies for distribution grids is increasing, but remain a small share of overall grid expenditure

Sources: IEA (2018c); NRG (2018).

Investment in smart grid technologies such as improved monitoring, control and automation technologies increased to $33 billion in 2017. These technologies can deliver system-wide benefits including reduced outages, improved response times, reduced need for infrastructure investment, and the integration of distributed energy resources. In addition, they allow the introduction of new business models: distributed energy resources themselves offer alternatives to investment in traditional cables and substations through deployment of storage, DSR and distributed generation. New technologies such as digital platforms and blockchain could enable further automation and better management of large numbers of distributed resources by grid operators (Spotlight). In many cases, electricity grids need to evolve to be able to benefit fully from these technologies (see Chapter 10).

S P O T L I G H T

Blockchain and energy: friend or foe?

Blockchain has been heralded as a technology which will fundamentally change how key sectors of the economy work, including energy systems. Compared to technologies traditionally deployed in the energy sector, it is a very particular kind of technology: one that no one can own or control, but anyone can use, with a digital record of events (such as a transaction or the generation of a unit of energy) held not by a central authority, but distributed across participants in a communications network.

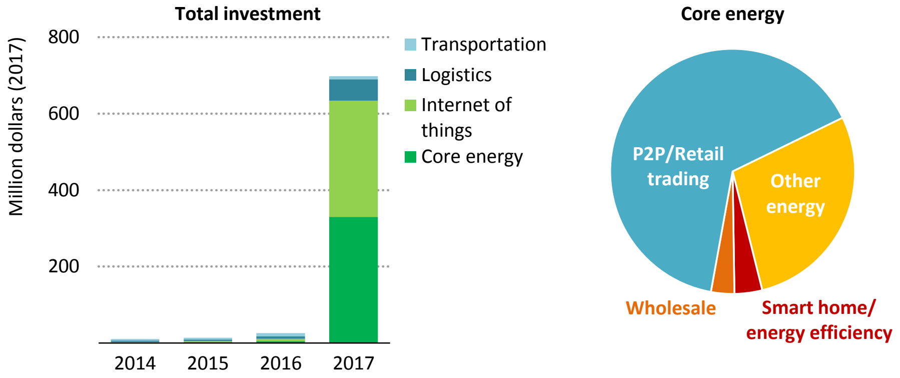
A growing number of connected devices, and distributed energy resources such as rooftop PV systems, small-scale storage and electric vehicles are producing increasing amounts of information. Consumers, utilities and third parties will look to interact with these devices in an efficient way, while system operators will look to manage an increasingly complex system. The distributed nature of blockchain could help circumvent some of the complexity of managing these systems centrally ("smart contracts" secured by blockchain allow energy infrastructure to have certain rules in place for assets to operate in a fully decentralised and automated fashion) and could help make them more secure (because every node holds a copy of the ledger, an attacker would have to disrupt over half of all the nodes to compromise the system).

The growth of interest in blockchain, not always in tried and tested business models, has been spectacular. In 2017, investment in applications that directly relate to energy services was around $300 million (Figure 7.25).

Over time, the ability of blockchain to enable decentralised operations could open the possibility of distributed platforms at scale that exchange energy services locally between peers (P2P), bypassing centralised balancing, trading, billing or retail platforms. Such applications have the potential to be highly disruptive to electricity value chains: current blockchains, however, are unsuited for the volume, speed and scalability that such platforms would require.

Exploration of the potential of blockchain and distributed ledgers has just begun, and it is difficult to predict how it might develop. It is possible that markets such as utilities managing transactions and billing for electric vehicle charging might utilise blockchain in the future. Blockchain could also accelerate other aspects of the energy transitions. New business models at the "grid edge" (VPPs, demand response aggregators, smart charging of electric vehicles, and off-grid electrification) need better data not just on production and consumption, but about the interactions between distributed technologies, its users and grid infrastructure, in order to understand how customers adopt technologies and respond to changes in the system. By tagging and tracking every event and interaction, blockchain could unlock the data needed to accelerate innovation at the crossroads of the digital and energy system transformation.

Figure 7.25 ▷ Investment in the energy and blockchain nexus



Growth in energy-related blockchain projects skyrocketed in 2017, with a large share of exploratory projects focusing on peer-to-peer and retail trading

Note: P2P = peer-to peer. Source: Cleantech Group (2018)

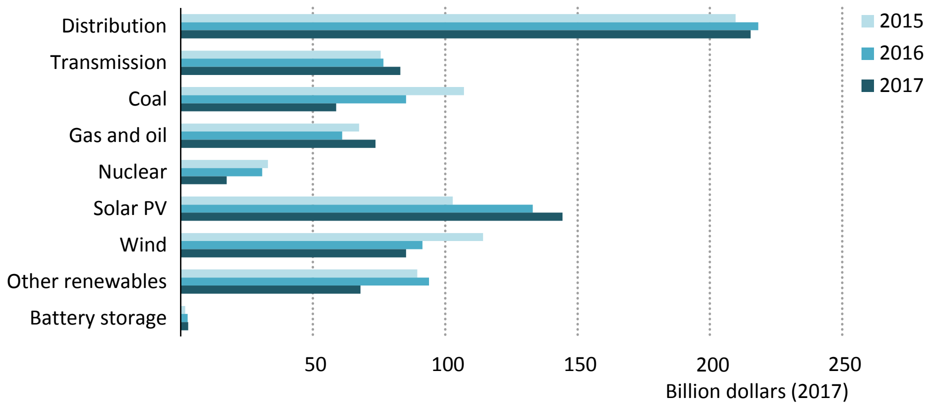
7.5 Electricity investment, markets and security: a changing landscape

7.5.1 Recent investment trends

Global power sector investment fell by 6% to $750 billion in 2017 compared with 2016 (Figure 7.26), and investment in power generation capacity fell by 10% (IEA, 2018c).[12] The number of new coal-fired power plants in China and India declined and final investment decisions (FIDs) for new plants suggest that this trend is likely to continue. Conversely, natural gas-fired generation capacity investments rose by nearly 40% in 2017, led by the United States and the Middle East and North Africa, but at the same time FIDs for new build gas-fired plants fell to their lowest level in over a decade.

12. For more details on the IEA methodology regarding investment, see: www.iea.org/weo/weomodel/.

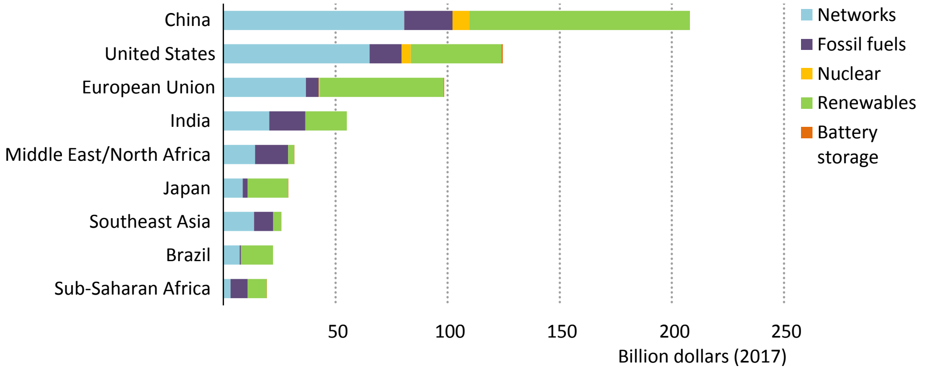
Figure 7.26 ▷ Global investment in the power sector by technology, 2015-2017



Overall investment in the power sector fell by 6% in 2017 compared to 2016, despite record investment in solar PV and electricity networks

The level of solar PV investment reached a new high in 2017 despite declining investment costs per MW of capacity. China, the United States and India led the way in terms of deployment. On the other hand, onshore wind investment fell by nearly 15%, with lower deployment in China, the United States and Canada. Some of this decline, around one-third, was a result of falling costs per MW of capacity. Offshore wind investment, largely in Europe, increased to record levels (WindEurope, 2018). Investment in hydropower fell by 30% to its lowest level in over a decade. Investment in nuclear power plants declined to its lowest level in five years, although spending on lifetime extensions for existing plants rose.

Figure 7.27 ▷ Power sector investment by selected region, 2017



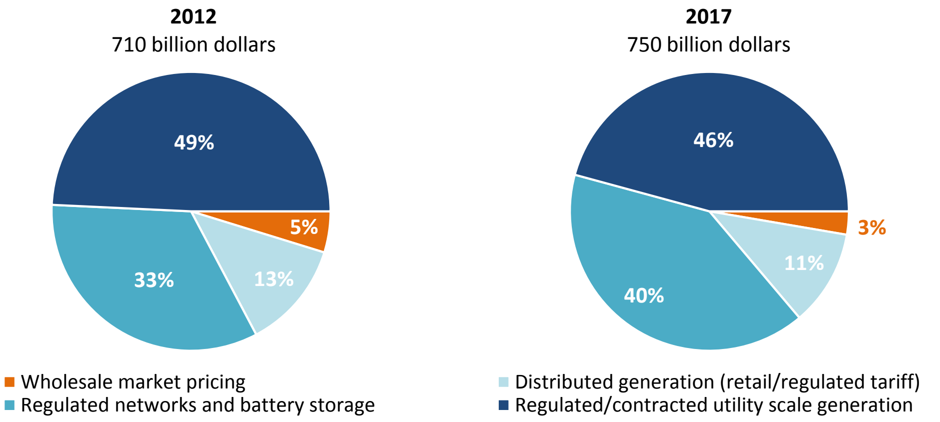
More than 70% of worldwide investment in power generation was in low-carbon sources in 2017

Low-carbon energy sources such as renewables and nuclear accounted for more than 70% of global investment in power plants in 2017; renewables accounted for the majority of this. In most regions, with some exceptions including Southeast Asia, and the Middle East and North Africa, investment in low-carbon technologies exceeded that for fossil fuel-based power (Figure 7.27). The expected annual output per unit of global low-carbon investment was stable in 2017, as the effect of falling costs was offset by greater emphasis on VRE.

Global investment in electricity networks rose very slightly in 2017 to top $300 billion, with the grid's share of power sector investment rising to its highest level in nearly a decade (40%). China ($80 billion) remained the largest market for grid investment followed by the United States ($65 billion) (IEA, 2018c). New technologies that support the integrations of VRE and strengthen the flexibility of the electricity system are accounting for a rising share of networks investments. In 2017, spending on smart grid technologies, such as smart meters, advanced distribution equipment and electric vehicle charging, accounted for over 10% of network spending. Investment in networks is very sensitive to regulation of use-of-system tariffs, which determine the ability of utilities to recover their costs and earn a return on investment. Utilities in developing economies have made mixed progress in improving cost recovery in recent years, with some seeing gains through cost-reflective pricing, new customer connections and reduced operational losses, but others lagging behind the investment levels needed to meet energy access goals.

Stationary battery storage accounted for $1.8 billion of energy sector investment in 2017, a 12% decline compared to the previous year. Around 600 MW of grid-scale batteries were commissioned in 2017, similar to the 2016 amount. A decline in battery costs was the main driver for the fall in overall investment.

Figure 7.28 ▷ Power sector investment by remuneration mechanism ($2017)



Companies operating under regulated revenues or mechanisms to manage revenue risk associated with wholesale markets made more than 95% of power sector investment

7.5.2 Key players

In 2003, the IEA's *World Energy Investment Outlook* (IEA, 2003) listed the ten-largest power companies in the world, ranked by their installed generation capacity.[13] European owned utilities dominated the list and accounted for almost 13% of installed capacity worldwide. American Electric Power (AEP) (United States), ESKOM (South Africa) and Tokyo Electric Power Company (TEPCO) (Japan) were the only non-European companies on the list. Table 7.1 shows today's top-25 power generation companies in a sector that has changed beyond recognition. Today, Chinese-owned utilities occupy six of the top-ten places in our rankings, and account for more than one-eighth of global installed capacity. Since 2003, China's power generation fleet has expanded by nearly 1 350 GW, from around 400 GW to almost 1 750 GW of installed capacity. Only *Électricité de France* (EDF), with its large nuclear fleet, breaks the Chinese hold on the top-five. Korean Electric Power Corporation (KEPCO), followed by Enel SpA and TEPCO complete the top-ten.

In 2017, the top-ten companies account for around 18% of total global installed capacity, while the next 15 companies own around 10%, meaning that the top-25 companies own around 30% of the global installed power generation capacity. Coal-fired plants dominate the overall generation portfolio of these top-25 utilities weighted by capacity (41%). This is largely attributable to the presence of many Chinese-owned utilities and the large share of coal in China's power sector. The Chinese utilities in the top-25 also own renewables-based capacity of around 300 GW (mostly hydro, but also wind) compared with European utility-owned renewables-based capacity of 118 GW.

Over the past three decades, a series of market reforms have altered electricity markets in many regions, often separating networks from generation, introducing wholesale market competition and eventually full retail liberalisation. In this changing business environment, vertically integrated regulated utilities, often operating in regulated markets, have tended to expand capacity. Between fully regulated markets and open competition, there are a number of regions and markets at an intermediate stage of evolution. Mexico's CFE and Japan's TEPCO face the challenges of ongoing liberalisation programmes, while the Saudi Electricity Co. is on its way towards privatisation. The largest US utilities seem likely to keep their hybrid models, operating in a regulated environment, with cost recovery, regulated tariffs and minimal (and even decreasing) merchant exposure of their assets.

Several large European utilities have seen their market value reduce significantly over the past decade – the top-five European-owned utilities combined have experienced a decline of around EUR 56 billion in total revenues over the past five years. This has been driven by a combination of stagnant electricity demand and rapid deployment of new low-carbon capacity additions supported by government subsidies in key markets. In many cases, new capacity is entering the market without accompanying retirements, resulting

13. In the *World Energy Investment Outlook 2003*, the world's largest power generation companies by installed capacity were ranked: 1) RAO-UES (Russia), 2) EDF (France), 3) TEPCO (Japan), 4) E.ON (EU), 5) SUEZ (EU), 6) ENEL (EU), 7) RWE (EU), 8) AEP (US), 9) ESKOM (South Africa), 10) ENDESA (EU).

in overcapacity. As a result of direct government intervention, many markets have ceased to function as competitively as envisaged. This has resulted in many utilities investing in more regulated assets and/or energy-as-a-service type offerings. The composition of the cumulative earnings before interest, taxes, depreciation and amortisation of the top-five European owned utilities indicates that the share of income from regulated activities such as long-term power purchase agreements and transmission and distribution revenues is growing as earnings from competitive activities decline.

Table 7.1 ▹ Top-25 world power generation companies by installed capacity

Rank	2017 (GW)	Headquarters (region)	Parent company	Installed capacity by source				
				Coal	Gas	Nuclear	Renewables	Other
1	230	China	China Energy Investment Group	74%	2%	0%	24%	0%
2	172	China	China Huaneng Group	69%	6%	0%	25%	0%
3	146	China	China Huadian Corp.	61%	10%	0%	29%	0%
4	138	China	China Datang Corp.	66%	3%	0%	31%	0%
5	129	European Union	Électricité de France SA	4%	9%	56%	24%	6%
6	126	China	State Power Investment Corp.	55%	4%	0%	38%	3%
7	90	Korea	Korea Electric Power Corp.	45%	22%	26%	7%	0%
8	85	European Union	Enel S.p.A	19%	18%	4%	45%	14%
9	70	China	China Three Gorges Corp.	1%	0%	0%	99%	0%
10	64	Japan	Tokyo Electric Power Co.	5%	46%	20%	16%	14%
11	63	Saudi Arabia	Saudi Electricity Co.	0%	66%	0%	0%	34%
12	59	European Union	Engie	8%	49%	11%	27%	5%
13	57	Mexico	Comisión Federal de Electricidad	9%	43%	3%	24%	21%
14	54	India	NTPC Ltd.	86%	11%	0%	3%	0%
15	52	United States	Duke Energy Corp.	35%	35%	17%	13%	1%
16	48	European Union	Iberdrola SA	2%	29%	7%	60%	3%
17	47	South Africa	Eskom Holdings Soc. Ltd	83%	5%	4%	7%	0%
18	46	United States	NextEra Energy Inc.	2%	48%	13%	34%	3%
19	46	United States	Southern Co.	27%	47%	14%	12%	0%
20	45	Egypt	Egyptian Electricity Holding Co.	0%	57%	0%	8%	34%
21	43	European Union	RWE AG	42%	35%	6%	10%	7%
22	42	Chinese Taipei	Taiwan Power Company	29%	35%	12%	18%	6%
23	40	Russia	Gazprom Group	36%	64%	0%	0%	0%
24	40	Indonesia	Perusahaan Listrik Negara (PLN)	59%	31%	0%	10%	0%
25	39	Russia	RusHydro Group	17%	5%	0%	77%	1%

Source: IEA analysis based on China Electricity Council, company websites and national energy regulatory authority websites.

The composition of the electricity sector is also changing. New actors in the electricity sector over the past five years range from software companies to major international oil companies, some of which have concluded notable deals involving investments in retail electricity supply and in clean energy technologies such as VRE capacity, battery technology and electric vehicle infrastructure companies. Demand-side response (DSR) aggregators are also becoming more evident.[14] Long in place in North America, aggregators play a key intermediary role in facilitating the uptake of DSR services by enabling individual electricity consumers to bundle their DSR potential and make use of it in a wide range of programmes and markets. In return, the DSR aggregator, which has no physical assets in the supply chain, receives a percentage of the value created by the shifting or shedding of demand to reduce peak load, balance VRE generation, provide a balancing service or increase security of supply.

While traditional interruptibility services and bilateral contracts deliver the lion's share of DSR today, DSR is capable of providing additional flexibility through energy arbitrage in wholesale markets, and of providing ancillary services like frequency regulation to the grid, and firm capacity in capacity markets. Currently the highest share of DSR deployment is in various North American and European markets, but a number of markets are expanding the role of DSR. China and Ireland's latest plans suggest that both see DSR as key to increasing the penetration of VRE. Ontario (Canada) is experimenting with a sophisticated time-of-use tariff, while Arizona Public Service is testing combinations of advanced flexible resources. Consolidation in the DSR aggregation market meanwhile is happening at increased pace, with utilities and large players to the fore. Commercial DSR aggregation service providers active in European markets include Enel X, EnergyPool (acquired by Schneider Electric), REstore (acquired by Centrica) and KiwiPower (in which Engie has a stake) (Table 7.2).

Table 7.2 ▷ DSR aggregators in selected electricity markets

	France	Germany	UK	Other EU	*US CAISO*	*US ERCOT*	*US NYISO*	*US PJM*	Other markets
Enel X (EnerNOC)	🟡	🟡	🟡	🟢	🟢	🟢	🟢	🟢	🟡
REStore	🟡	🟡	🟢	🟢	🔴	🔴	🔴	🟡	🔴
EnergyPool	🟢	🟡	🟢	🟢	🔴	🔴	🔴	🔴	🟡
Actility	🟢	🔴	🔴	🟡	🔴	🔴	🔴	🔴	🔴
Voltalis	🟢	🔴	🔴	🟡	🔴	🔴	🔴	🔴	🔴
NEXT Kraftwerke	🟡	🟢	🟡	🟡	🔴	🔴	🔴	🔴	🔴
CPower	🔴	🔴	🔴	🔴	🟢	🟢	🟢	🟢	🔴
Itron	🔴	🔴	🔴	🔴	🟢	🟢	🟢	🟢	🔴
Powersecure	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🟢	🔴
Autogrid	🔴	🟡	🔴	🔴	🟡	🔴	🟢	🟢	🔴
Kiwi Power	🟡	🔴	🟢	🟡	🔴	🔴	🔴	🔴	🔴

🟢 Large player in the market 🟡 Market presence established 🔴 Not active

14. A typical DSR aggregator is a third-party company that contracts with the individual demand sites (industrial, commercial or residential consumers) and aggregates them to operate as a single DSR provider.

7.5.3 Securing investments

Are there sufficient signals for investment in competitive wholesale markets today?

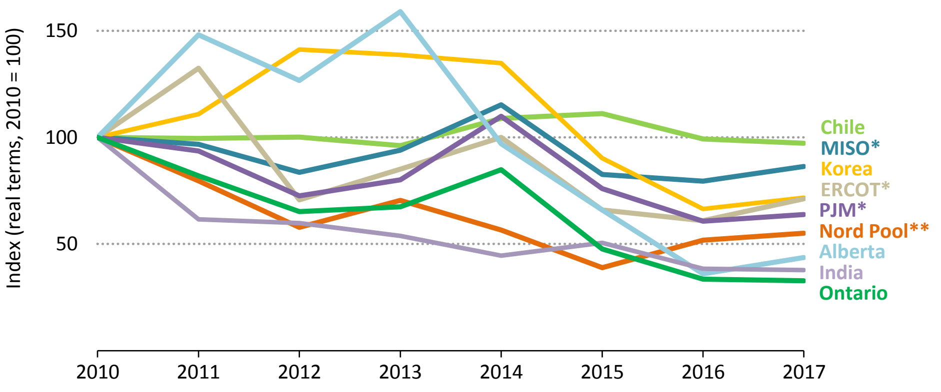
Traditionally, electricity markets developed and operated within strictly regulated frameworks in which vertically integrated utilities handled all or most activities from generation to transmission to retail. Needs were assessed and fulfilled by electricity system planners, and all associated costs were passed on to consumers (IEA, 2002). Since the 1980s, however, many parts of the world have witnessed a move towards competitive markets as a means to procure electricity and many of the support services required to operate a power system in an efficient and safe manner.

Today, countries that rely on competitive markets to maintain efficient operations in the short term, either through bilateral physical contracts, power exchanges or co-ordinated spot markets, account for 54% of the world's electricity consumption. Once China completes implementation of its power sector reform, this share will increase to almost 80%. Other recent examples of large economies that are moving in this direction include Japan, which established an Organization for Cross-regional Co-ordination of Transmission Operators in 2015, and Mexico, where a new electricity industry law (*Ley de la Industria Eléctrica*) came into force in 2014.

Initially, some markets relied on spot prices to drive investment and efficient operations, whereas other used power purchase agreements (PPAs) as a means to support investment, and spot markets to ensure efficient market operations. Market models are inevitably imperfect and some have come under strain for a variety of reasons. Recent trends in Europe suggest that some of its markets may be unable to deliver investment signals that guarantee resource adequacy and lead to an optimal generation mix. Without policy measures to address this shortfall, there is a risk to future security of supply.

Since 2010, some electricity markets have experienced a decline in wholesale energy prices brought about by stagnant demand, low natural gas prices and higher output of generation with low marginal costs (Figure 7.29). Many countries have reviewed their market design in order to address the challenges posed by the way the electricity sector is changing and the pressures this is placing on their market models. Some jurisdictions that rely on markets to attract investment have shifted from markets where energy is the only source of revenue towards the inclusion of a firm or dispatchable capacity product. Colombia, France and the United Kingdom (excluding Northern Ireland) are examples of such markets. More recently, Alberta and Ontario in Canada, Japan and Mexico implemented or are in the process of design and implementation of some form of capacity-based product. Australia is examining a mechanism to incentivise retailers and other market customers to support the reliability of the National Electricity Market through their contracting and investment in resources.

Figure 7.29 ▷ Average wholesale electricity prices in selected competitive markets, 2010-2017



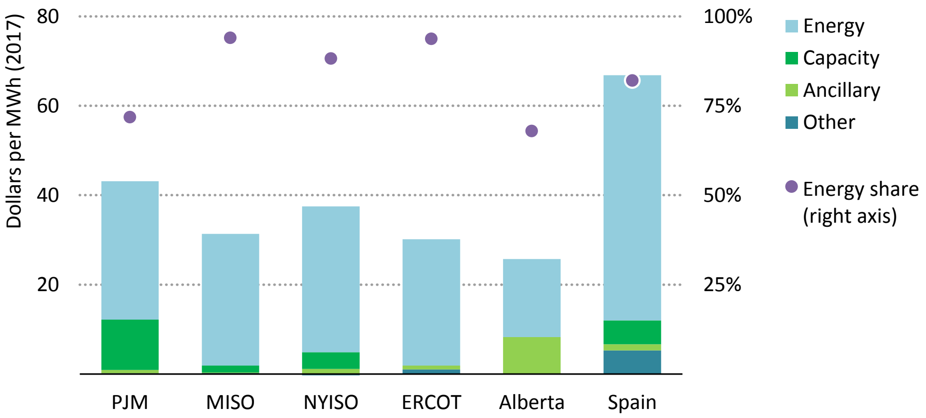
Wholesale electricity prices have been steadily declining in most mature power markets

* ERCOT, MISO and PJM are competitive wholesale electricity markets in the United States. ** Nord Pool is a European power market.

Power markets are also a means to procure system (or ancillary) services, such as secondary regulation and reserves, which ensure the smooth operation of the power system, and allow supply to follow demand in real time. Ancillary services and capacity markets provide only a small portion of total revenue in most markets but those revenues are an essential signal for generators and other agents, such as aggregators of DSR or new providers of system services to contribute to the system's overall flexibility (Figure 7.30). Increasingly, new players other than traditional generators are offering ancillary services, and separate ancillary services markets are developing. Over the longer term, it is possible that the system services revenue stream will need to account for a much larger share of the overall revenue available for investment in the electricity sector.

These points lead to the obvious question: how will the electricity market of the future work? It is very likely that over the medium to long term, markets will continue to experience further downward pressure on wholesale energy prices as more zero-cost power generation enters the market alongside new energy service providers and innovative technological solutions. Policy makers, regulators and energy sector stakeholders need to understand the changes underway and seek new solutions and market designs that can support the transition towards low-carbon electricity markets while at the same time ensuring the security and adequacy of the power systems.

Figure 7.30 ▷ Sources of revenue in selected competitive markets, 2017



Capacity and ancillary services provide a small share of generators' revenue in many markets

Notes: PJM, MISO, NYISO and ERCOT are competitive wholesale electricity markets in the United States. Other includes revenue compensating economic losses to generators incurred by following the system operator's instructions. Price in Spain is for 2015.

Table 7.3 ▷ Power systems with capacity markets or payments and strategic reserves

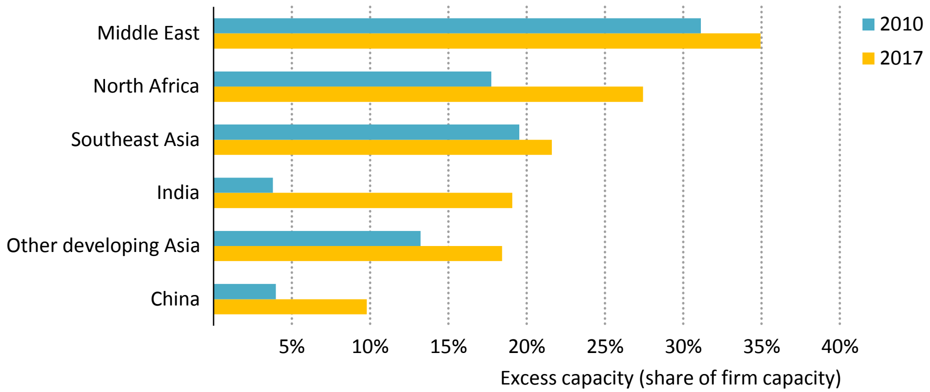
Capacity markets or payments			
United Kingdom*	Market-wide	Colombia	Market-wide
Russia	Market-wide	PJM	Market-wide
ISO-NE	Market-wide	NYISO	Market-wide
MISO	Market-wide	Brazil	Energy auctions
Guatemala	Decentralised	Mexico	Decentralised
Australia	Decentralised	France	Decentralised
Chile	Capacity payment	Peru	Capacity payment
Spain	Capacity payment	Ireland**	Capacity payment
Portugal	Capacity payment	Korea	Capacity payment
Argentina	Capacity payment	Viet Nam	Capacity payment
Strategic reserves			
Finland	Strategic reserve	Germany	Strategic reserve
Sweden	Strategic reserve	Lithuania	Strategic reserve
Poland	Strategic reserve	Latvia	Network reserve
In design process			
Ontario	In design process	Japan	In design process
Alberta	In design process	Italy	In design process

* Excluding Northern Ireland. ** Ireland and Northern Ireland (Integrated-Single Electricity Market). Note: Capacity payments are defined administratively either for the entire dispatchable fleet, or for a subset in the case of a strategic reserve. In capacity markets, a "capacity product" is bought either by the system operator on the behalf of the whole system (market-wide) or by market participants (decentralised and market-wide).

Has investment been efficient in regulated markets?

In contrast, fully regulated markets with vertically integrated utilities face the risk of over-investment.[15] In 2017, for a number of reasons such as lower than planned demand growth, there was significant excess capacity in many regulated markets. Measured in terms of percentage of firm capacity that was over and above an efficient level, most excess capacity was found in the Middle East and North Africa (about 30%), while Southeast Asia, India and other developing Asia countries had around 20% overcapacity while China had about 10% (Figure 7.31).[16] Since 2010, the situation has worsened in all of these regions, as recent capacity expansions outpaced the needs of those systems. Several factors contributed to this situation, including lower than expected economic and electricity demand growth, as well as investment decisions taken independently of the needs of the system.

Figure 7.31 ▷ Estimated excess capacity by region, 2010 and 2017



Many regulated systems have over-invested in new power plants in recent years, in part owing to slower than expected demand growth

The estimated excess capacity is equivalent to additional power plant investment of about $350 billion in total in 2017 across the six regions mentioned. Without this excess capacity, total power generation costs could have been significantly lower in the Middle East (15% lower), North Africa (8%), Southeast Asia (8%), India (5%) and China (2%). The rise of variable renewables is likely to exacerbate this situation in the future as the rest of the system will need to operate more flexibly, and operate with lower capacity factors in order to accommodate the VRE.

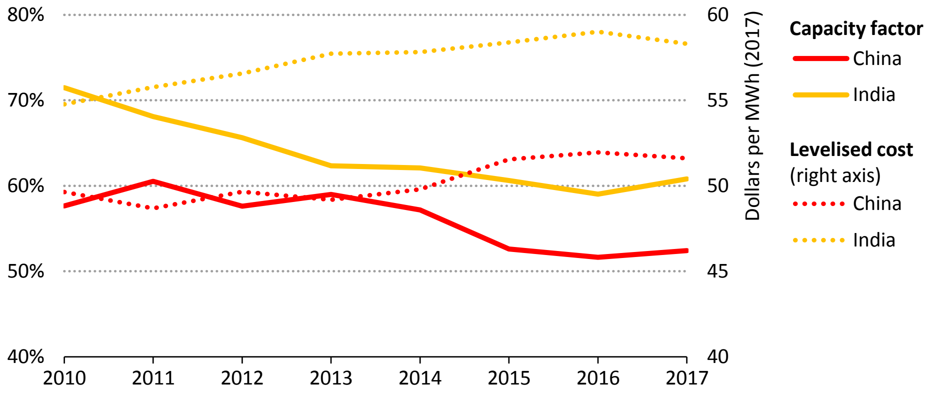
15. Defined as utilities that own or control the entire flow of power from generation to the consumer meter.

16. A standard efficient level of firm capacity was estimated based on a 20% capacity margin, meaning available firm capacity must be 20% above the highest level of average demand in any hour. Capacity margin requirements vary by region, but are generally no higher than 20%, and are set at 15% in many markets.

Excess capacity commonly drives down activity levels across all generators, and lower activity directly reduces their profitability. In China and India, for example, the capacity factors of coal-fired plants declined several percentage points from 2010 to 2017, causing an increase in the LCOE from those plants (Figure 7.32).

Policy makers and authorities in regulated markets should look at what needs to be done to address incentives to over invest and ensure efficient levels of investment, so as to help to reduce costs for consumers and support the profitability of generators. The accumulation of these effects, if not mitigated by the regulator, could pose a threat to the long-term financial health and, ultimately, the security of electricity supply in highly regulated markets.

Figure 7.32 ▷ Capacity factors and levelised cost of electricity for coal-fired plants in China and India, 2010-2017



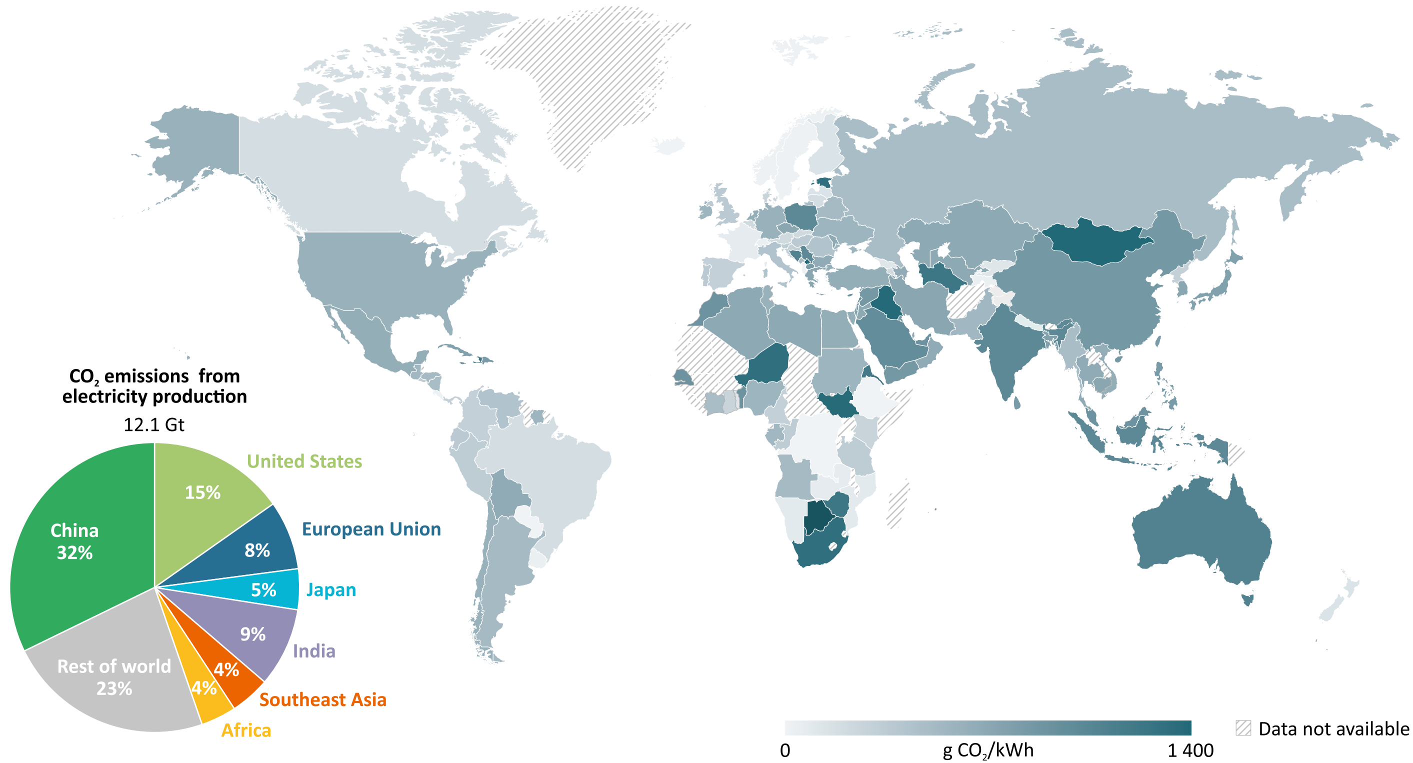
Excess capacity has driven down the capacity factors of coal-fired power plants, in turn pushing up their levelised costs

Notes: Includes electricity-only power plants. Coal prices and plant efficiencies are held constant at 2017 levels in order to isolate the effect of lower capacity factors, actual production costs may differ as a result.

7.6 Power sector emissions

The power sector is the single largest contributor to energy-related GHG emissions, accounting for just over 40% of total energy-related CO_2 emissions. Emissions from coal-fired power plants represent 30% of total energy-related CO_2 emissions. Since 2000, global power sector CO_2 emissions have grown by 4.3 gigatonnes (Gt) (2.3% on average annually), accounting for nearly half of total growth in emissions (Figure 7.34). CO_2 emissions from heat production, increased by less than 10% since 2000, and account for only 8% of power sector emissions today. Nonetheless, CO_2 emissions have grown less strongly than electricity generation as renewables have expanded and as the average efficiency of fossil fuel power generation fleets has improved; producing one unit of electricity today requires around 5% less fuel input than in 2010. On average, the power sector now produces around 500 grammes of CO_2 per kilowatt-hour (g CO_2/kWh) of electricity, but this varies significantly by region.

Figure 7.33 ⊳ Carbon intensity and CO_2 emissions for electricity generation by region, 2016

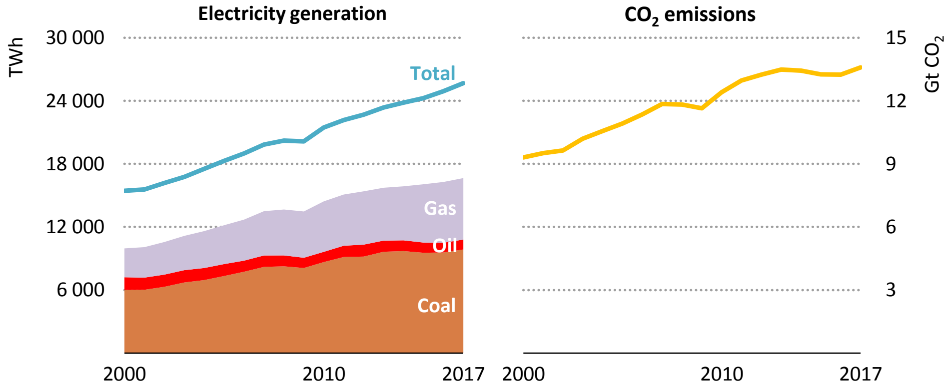


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

While many regions are experiencing reductions in carbon intensity, the power mix varies from one country to another

Sources: CO_2 Emissions from Fuel Combustion, (IEA, 2018e); World Energy Balances, 2018, (IEA, 2018f).

Figure 7.34 ▷ Fossil fuels in electricity generation (left) **and CO_2 emissions from power generation** (right), **2000-2017**



CO_2 emissions in the power sector have increased at a lower rate than fossil fuels power generation, largely thanks to renewables and efficiency improvements

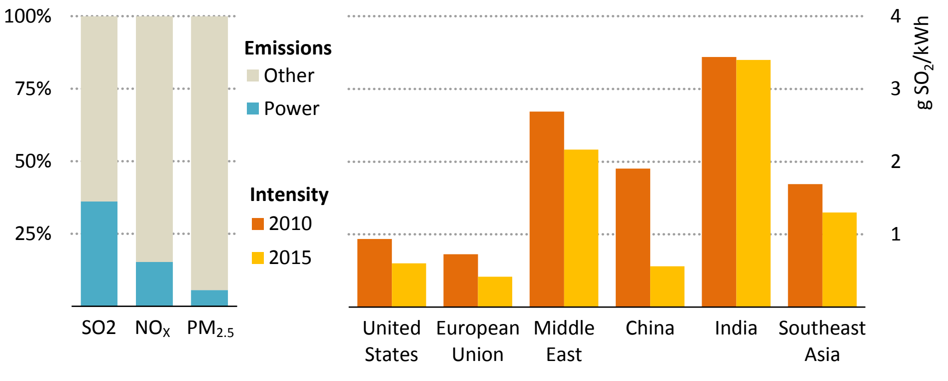
While global CO_2 emissions from power generation increased in 2017, some countries cut these emissions relative to 2016 levels. The biggest reduction was in the United States reflecting an increase in renewables-based electricity generation and lower electricity demand. Following six years of decline, CO_2 emissions from the power sector in the European Union in 2017 were stable compared with the previous year; the trading block has one of the lowest carbon intensities of power generation. CO_2 emissions from electricity production increased in other large economies, including China and India.

The power sector is also a key source of pollutants emissions. In particular, the sector is responsible for more than one-third of total SO_2 emissions while its impact on nitrogen oxides (NO_X) and fine particulate ($PM_{2.5}$) emissions is more limited (Figure 7.35). Coal-fired plants account for the majority of total SO_2, NO_X and $PM_{2.5}$ emissions from the power sector. Developing countries in Asia alone accounts for close to 40% of power-related SO_2 emissions: this is mostly a result of its extensive use of coal. The impact of pollution on health has led to several countries adopting measures to rein in harmful emissions, leading to a significant improvement in the environmental performance of many coal-fired plants across the globe.

Oil combustion in the power sector is another significant contributor to SO_2 emissions, accounting for 20% of the sector's total. This explains the close to 10% share in total power-related SO_2 emissions in the Middle East, a region that relies heavily on oil to satisfy electricity demand. On the other hand, natural gas use in power increases NO_X emissions, though the power sector contributes less than 20% to total global energy-related NO_X emissions.

There have been important reductions in SO_2 and NO_X emissions from power generation – around 20% – since 2010 with some regions improving their pollutant intensities. This means that there are lower pollutants emissions for a given amount of electricity production. In this regard, China has made strong progress to reduce pollutant emissions from coal combustion and the new three-year action plan for cleaner air in China promises to take this progress further. The performance levels of pollutant emissions from electricity production in the European Union also improved thanks to reduced coal use and increased thermal efficiency. India has been moving fast in the direction of enforcing environmental legislation, introducing strict regulations to combat pollutant emissions from coal-fired power plants in 2015.

Figure 7.35 ▷ Share of 2015 power sector pollutant emissions (left) **and SO_2 intensity by region** (right), **2010-2015**



Over one-third of total SO_2 emissions were from the power sector in 2015, many countries have taken steps to cut air pollution through control measures

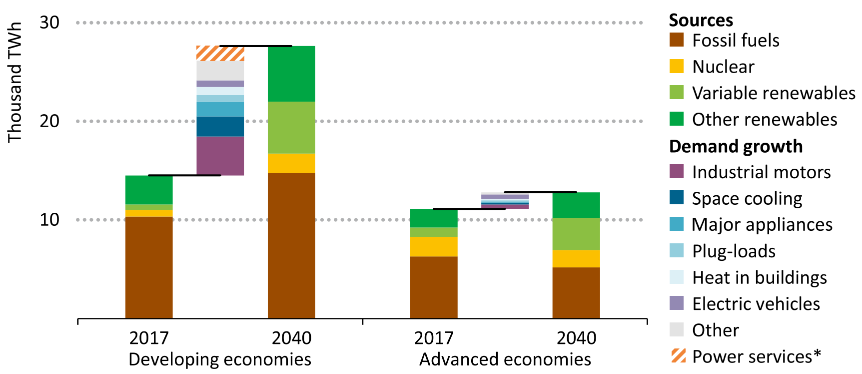
Outlook for electricity demand and supply

On the way to an all-electric future?

SUMMARY

- The role of electricity expands in the New Policies Scenario. Overall energy demand rises from 13 972 million tonnes of oil equivalent (Mtoe) in 2017 to over 17 700 Mtoe in 2040. Electricity demand grows at 2.1% a year, twice the rate of overall energy demand, and satisfies one-quarter of total end-use energy demand in 2040. Nearly 90% of electricity demand growth is in developing economies, while demand in advanced economies rises modestly, due to policies promoting the electrification of mobility and heat (Figure 8.1). In 2040, electricity demand in China is more than twice that of the United States, with India a not-too-distant third, although its per-capita consumption remains one of the world's lowest. Electric motors for industry account for one-third of global electricity demand growth, space cooling for almost one-fifth and electric vehicles for about 10%. In the period to 2040, 680 million people gain access to electricity, but add a mere 3% to overall demand growth.

Figure 8.1 ▷ Electricity demand growth by end-use and generation by source in the New Policies Scenario



Electricity demand grows at twice the rate of overall energy demand, from a variety of end-uses, while renewables and gas increase to meet new demand

* Power operations to provide end-use services, including electricity consumed within power plants and losses from transmission and distribution. Note: TWh = terawatt-hours.

- Globally, coal-fired generation stagnates at today's level but remains the largest source to 2040, with reductions in advanced economies offset by expansion in developing countries, especially in Asia. Natural gas, wind, solar and other sources each contribute about one-quarter of the global increase in electricity supply. The share of natural gas in electricity generation holds steady at about 22%, while coal falls from 38% to 26%. Variable renewables rise from 6% in 2017 to over 20% in 2040. Nuclear provides about one-tenth of generation throughout the period, though the centre of gravity shifts, as nuclear capacity in China overtakes that in the United States by 2030. Despite the 60% growth in electricity demand by 2040, global carbon dioxide (CO_2) emissions from electricity generation remain at around today's level reflecting a changing fuel mix and increasing efficiency. Significant gains are made regarding pollution, with emissions of sulfur dioxide (SO_2) cut by one-half, nitrogen oxides (NO_X) by one-quarter and fine particulates ($PM_{2.5}$) by almost 40%, thanks to changes in the generation mix and to regulations to expand the use of end-of-pipe pollution control technologies.

- Government policies play a central role in reshaping the electricity supply mix, with widespread support for renewables and some measures to limit the use of coal, but market forces also contribute to the expansion of low-carbon technologies. Based on a new metric of competitiveness for power generation technologies, which combines the levelised costs with an estimate of the value provided to the system by each technology, solar photovoltaics (PV) and wind power are approaching competitiveness with conventional sources in a number of markets today. Low-carbon technologies, including nuclear power, continue to become more competitive in the years to 2030, closing the gap with new coal- and gas-fired power plants in most cases. The pairing of variable renewables with storage becomes an attractive option as their costs fall. The ongoing competitiveness of existing fossil-fuelled power plants highlights the challenge of phasing out these assets in a timely manner to achieve environmental objectives.

- The global power plant fleet is changing fast. By the mid-2020s, gas-fired capacity takes the lead from coal. Solar PV surges past wind capacity in the near term, hydropower by around 2030 and coal just before 2040. Recent investment decisions and policies indicate that capacity additions of coal may well have peaked in 2015. Battery storage costs are set to decline rapidly, challenging oil and gas peaking plants and improving the profitability of variable renewables. By 2040, battery storage capacity reaches 220 gigawatts (GW), equal to India's coal capacity today.

- In all markets, electricity system flexibility needs to increase as the profile of demand changes and the share of variable renewables rises. Available sources of flexibility almost double by 2040, with power plants accounting for the bulk of the system's ability to handle hour-to-hour changes. Interconnections, battery storage and demand-side response contribute 1 100 GW. Where the profiles of wind and solar PV output best match demand, their integration is less challenging. Flexibility needs increase dramatically in some regions; Mexico reaches a stage of system integration where few countries are today, and the call for flexibility on an hourly basis triples in India. Several European countries move into uncharted territory in terms of integrating high shares of variable renewables.

8.1 Introduction

Electricity is set to play a larger role in the global energy system in the New Policies Scenario, outpacing the growth of all other fuels to take almost a quarter of total final consumption of energy by 2040. Developing economies, accounting for almost 90%, drive this growth. Today, nearly 1 billion people worldwide are without access to electricity and the aim is to sharply reduce this number in the coming years. In advanced economies, new sources of growth for electricity demand are emerging. On the supply side, renewables such as wind and solar PV are increasingly competitive with conventional sources of electricity, as widespread policy support continues to drive technology cost reductions. The share of natural gas in global generation almost draws level with the declining share of coal by 2040. Ageing conventional power plant fleets in many regions present opportunities for change, as well as challenges related to electricity security. As variable renewables increase as a proportion of the generation mix, so does the need for flexibility to ensure reliability and affordability in power systems. Investment in flexible power plants, expanded cross-border interconnections and rapidly declining costs for battery storage all help to provide the needed flexibility.

This chapter provides an in-depth analysis of the outlook for electricity based on our New Policies Scenario, which is the central scenario of this *Outlook*. The New Policies Scenario incorporates policies and measures already in place and takes into account announced targets and planned policies.[1] The analysis in this chapter:

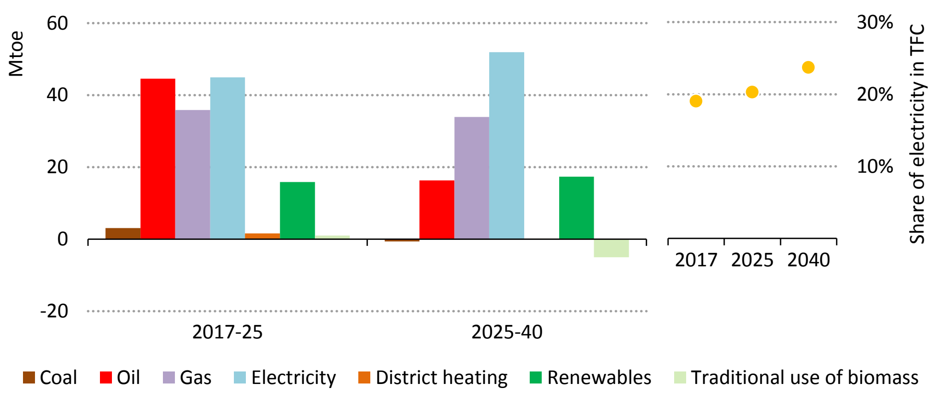
- Examines the outlook for future demand, supply and flexibility in electricity systems.
- Looks in detail at two rapidly changing markets: the European Union, where new ambitious targets on renewables lead to dramatic changes in the power sector; and India, where a huge push towards electrification and the plunging cost of solar are making the its electricity sector one of world's most dynamic.

8.2 Electricity demand in the New Policies Scenario

In the New Policies Scenario, electricity demand reaches around 26 400 TWh in 2025 and over 35 500 TWh in 2040, a 60% increase on today. From now to 2025, electricity, oil and natural gas contribute around 85% of the growth in final energy demand in almost equal parts. After 2025, however, electricity demand growth outpaces that of other fuels by a wide margin, driven by developing economies. Over the projection period to 2040, electricity contributes around 40% of the increase in total final consumption, more than 10 percentage points higher than the contribution of natural gas, the second-largest growing fuel in end-use sectors. By 2040, the share of electricity is pushed to 24%, five percentage points above today's level (Figure 8.2).

1. Possible variations of the future outlook and what might drive them are discussed in Chapter 9.

Figure 8.2 ▷ **Annual growth in total final consumption by fuel** (left) **and share of electricity** (right) **in the New Policies Scenario**



Electricity shows the strongest growth of all energy carriers, expanding its share of final energy use to 24% by 2040

Notes: Mtoe = million tonnes of oil equivalent; TFC = total final consumption. Coal, oil, gas and renewables refer only to the amount used in end-use sectors (i.e. final consumption), thus do not include the amount used in the power sector.

8.2.1 Policies shape electricity demand

In all countries, the future pace of electricity demand growth depends on a number of variables. Economic and population growth play a major role. In developing economies, industrialisation is responsible for one-third (around 3 800 TWh) of the overall increase. An additional 1.55 billion people living in developing economies in 2040, and a more than doubling of average income, drive the 6 400 TWh additional demand in the buildings sector.

The combined effects of policies to enhance electrification and policies to increase energy efficiency also have a determining impact on electricity demand. Policies to support electrification take many forms (Table 8.1). In developing economies, they often aim to provide electricity to those that lack access. The provision of access to those without it adds some 430 terawatt-hours (TWh) (or 3%) by 2040 to global electricity demand growth. Alongside further progress in India, Central and South America, and Southeast Asia, some countries in Africa are taking great strides to achieve full electricity access (see Chapter 2).

In the New Policies Scenario, targets to phase out conventional cars and incentives to use electric cars raise their number from 3 million today to around 300 million by 2040, accounting for 720 TWh. Heating policies that aim to reduce fossil fuel use result in electricity demand growth for heat in buildings by around 45% by 2040. In industry, heat pumps meet about 3% (or 240 TWh) of additional low-temperature heat demand to 2040.

Table 8.1 ▷ Selected initiatives for the electrification of heat and transport, and efficiency policies that impact electricity demand

	Energy efficiency policies	Electrification policies
China	Continuation of industrial energy intensity reduction to support the target of the 13th Five-Year Plan (2016-20), including: • Minimum 10% decrease in energy consumption in iron and steel; • 18% decrease in energy intensity of chemicals; • 18% decrease in energy intensity of non-ferrous metals. Mandatory energy efficiency labels for appliances and equipment.	Promote electricity to replace de-centralised coal and oil burning. Target: electricity consumption in end-use to reach 27% by 2020 (13th Five-Year Plan). Clean Winter Heating Plan: switch from coal to gas and electricity for northern China including the "26+2" main cities in the Beijing-Tianjin-Hebei region. New energy vehicle mandate: 10% in 2019 and 12% credit mandate for sales of passenger cars in 2020.
India	National Mission on Enhanced Energy Efficiency: • Cycle II and III of Perform, Achieve and Trade scheme; • Income and corporate tax incentives for energy service companies; • Risk guarantee for performance contracts and a venture capital fund for energy efficiency. 10 of 21 standards for appliances are mandatory (e.g. ACs, refrigerators, electric water heaters).	Ambition to achieve universal access to electricity by the early 2020s. Electric vehicles to achieve 30% sales share by 2030.
European Union	Energy Efficiency Directive: reduce energy demand by 32.5% in 2030, relative to a baseline development. Industrial Emissions Directive: including energy efficiency indicators. EcoDesign Directive: minimum energy performance standards for electric space and water heating equipment, motors, pumps for industrial applications and buildings. Energy Performance of Buildings Directive: all buildings should meet "nearly zero-energy buildings" requirements by 2050.	Proposal for CO_2 targets for cars and vans including benchmark shares in sales for zero- and low emission vehicles (less than 50 g CO_2 per km) (i.e. electric cars) of 15% in 2025 and 30% in 2030. Set-up of CO_2 emission standards for heavy-duty vehicles in the EU, targeting 15% lower average CO_2 emissions of new heavy-duty vehicles by 2025 and an aspirational target for 30% decrease by 2030 compared to 2019 levels.
United Kingdom	Enhanced Capital Allowance Scheme: market-based measure to help businesses invest in energy efficiency improvements in terms of capital stock and processes via tax breaks.	Road to Zero strategy sets ambition for at least 50% (and up to 70%) of new car sales to be ultra-low emission by 2030 and 40% of new vans.
Japan	Top Runner Programme of minimum energy standards for machinery and appliances.	Electric vehicles to reach 20-30% of car sales by 2030 and a long-term target of 100% electrified cars, including hybrids.
Canada	Energy Efficient Buildings Research, Development and Demonstration programme supporting development and implementation of building codes for existing buildings and new net zero-energy ready buildings.	Electric Vehicle and Alternative Fuel Infrastructure Deployment Initiative and Green Infrastructure Fund allocate funding to support capacity building in the areas of electric vehicles, deployment of alternative fuel infrastructure, and demonstration of innovative charging technologies.

8

The effects of increasing demand are partially offset by energy efficiency savings, both from policies directly aiming at reducing specific electricity demand, such as minimum energy performance standards (MEPS) for industrial motors and household appliances, and from policies that indirectly affect electricity demand, such as building codes. The most obvious example is that of light-emitting diodes (LEDs) for residential lighting. Electricity demand for this energy service has peaked, yet an additional 1.9 billion people have lighting services by 2040.

8.2.2 Electricity demand by region

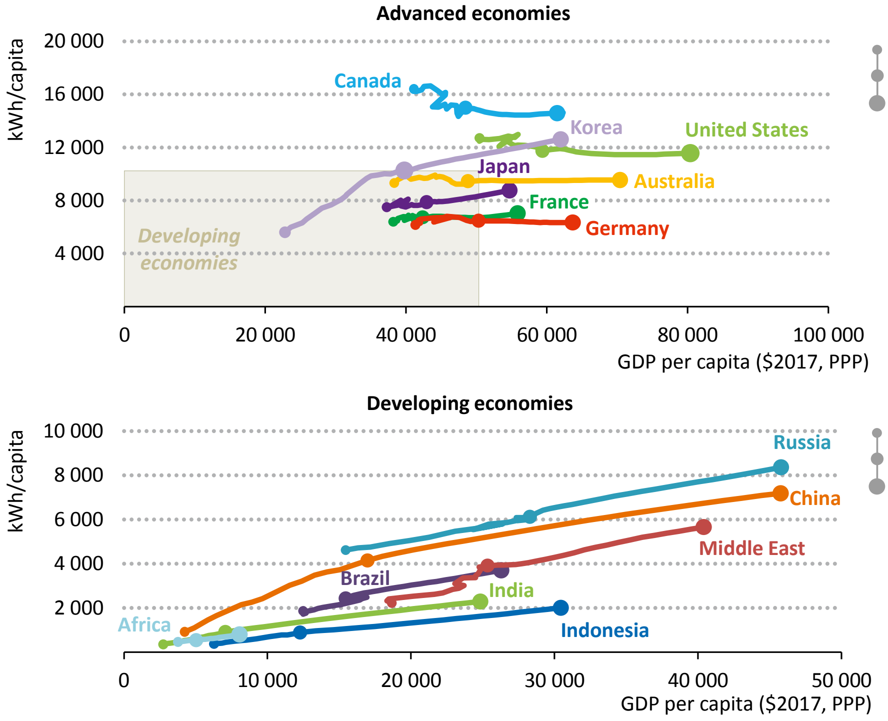
Developing economies continue to dominate global electricity demand growth, accounting for almost 90% of growth to 2040. This dominance broadly mirrors the trends of key indicators: through to 2040, 94% of global population growth and 80% of global gross domestic product (GDP) growth are in developing economies. Electricity demand in developing economies increases by 3 700 TWh to 2025, and by a further 7 950 TWh to 2040 – nearly twice today's level. Yet, electricity use per capita in developing economies remains low in 2040, reaching only 40% of the current level in advanced economies.

The outlook for electricity demand growth in advanced economies is much more sluggish. Energy efficiency acts as a brake on increasing demand for many end-uses. In addition, slowing growth in population and household appliance ownership (most households in advanced economies today own at least one of each major household appliance such as refrigerators, washing machines and televisions), and a shift from industry to the less electricity-intensive services sector all contribute to lower electricity demand growth. On average, electricity demand in advanced economies grows at just 0.7% per year to 2040 in the New Policies Scenario, with the increase largely due to digitalization and policies that incentivise the use of electric vehicles (EVs) and electric heating. Without those policies, electricity demand would continue to flatten out or decline in many advanced economies. Despite the moderate growth rate, the share of electricity increases to 27% in advanced economies by 2040, up from 22% today.

In many advanced economies electricity demand growth scarcely exceeds population increases. As a result, further growth in GDP per capita does not lead to an increase in electricity demand per capita in many advanced economies (Figure 8.3). Korea is an exception. The industry sector in Korea accounts for a large share of electricity demand, and it is one of the few advanced economies that sees industry contribute to overall electricity demand growth on a per capita basis.

China and India account for half of global electricity demand growth in the period to 2040. In India, electricity demand triples and approaches the current level of electricity demand in the United States (Figure 8.5). In China, electricity demand increases about 75% (4 300 TWh), reaching a level more than twice that in the United States, and 15% above the per capita level of the European Union (Box 8.1). The difference in per capita use between China and the European Union largely reflects differences in demand from their industry sectors.[2] Many other developing economies also see electricity demand nearly double, or more than double, in the New Policies Scenario. One of the highest rates of growth (albeit from a very low base) is in sub-Saharan Africa, at around 5% per year, a region where 300 million people gain access to electricity. Nonetheless, per-capita consumption in sub-Saharan Africa remains at around 15% of the world average level in 2040, and 680 million people on the continent lack access to electricity (See section 2.2 for further information on electricity access).

Figure 8.3 ▷ Relationship between electricity consumption and GDP per capita in the New Policies Scenario



Income levels in developing economies look far from the point where electricity demand growth might flatten out

Note: kWh = kilowatt-hours; PPP = purchasing power parity.

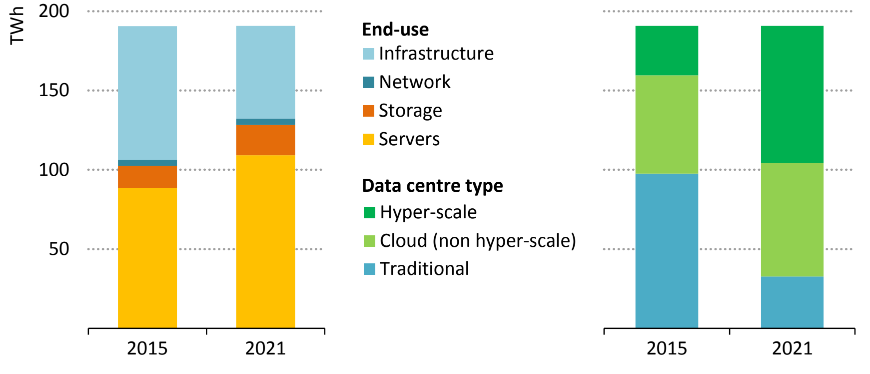
2. Country data show only the electricity consumed within the country and do not include the electricity embedded in imported products, which could dramatically increase the electricity consumption of some countries and decrease it in others.

Box 8.1 ▷ Data centres, a battle between growth and efficiency

As the world becomes increasingly digitalized, information and communications technology is emerging as an important source of electricity demand. Billions more devices and machines are connected over the coming years, using electricity directly and fuelling growth in demand for data centre and data transmission network services.

Electricity demand in the world's data centres in 2015 amounted to 191 TWh, about 1% of global electricity demand. While IP traffic and workloads are projected to triple in the near term, global data centre electricity demand is expected to remain flat to 2021 based on efficiency trends (Figure 8.4). The strong growth in demand for data centre services is offset by continued improvements in servers, storage devices, network switches and data centre infrastructure, as well as a shift to much larger shares of highly efficient cloud and hyper-scale data centres.

Figure 8.4 ▷ Global data centre electricity demand by end-use and data centre type

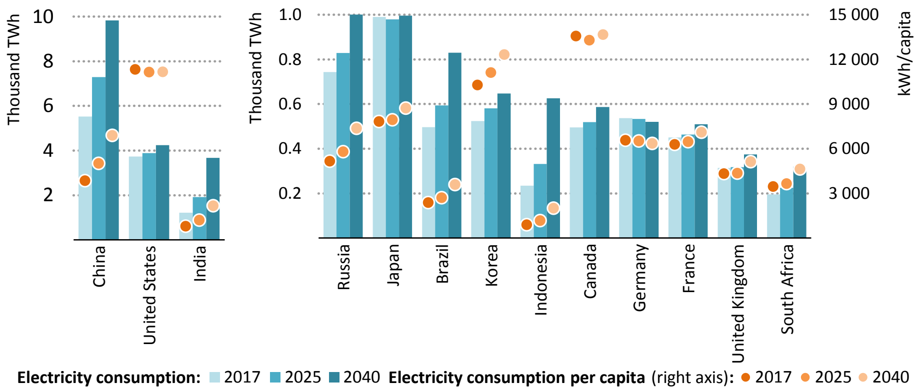


Efficiency gains and shifts to hyper-scale data centres restrain growth in electricity demand to 2021 while workloads triple

Sources: Masanet et al. (2018); Cisco (2018); Shehabi et al. (2016).

Given the rapid pace of technological progress and change, providing credible forecasts of data centre electricity use beyond the next five years is extremely challenging. While demand for data centre services is expected to continue to grow strongly after 2021, how this affects electricity demand will continue to be largely determined by the pace of energy efficiency gains. The continued shift to efficient cloud and hyper-scale data centres will reduce the energy intensity of data centre services, and the use of artificial intelligence and machine learning also may help.

Figure 8.5 ▷ Electricity use and per-capita electricity consumption by country in the New Policies Scenario, today, in 2025 and in 2040



China and India represent half of global electricity demand growth to 2040

8.2.3 What drives electricity growth and what holds it back?

Around half of global electricity demand today is in the buildings sector, which has accounted for 52% of global electricity demand growth since 2000. It retains its important role as a driver of global electricity demand growth in the New Policies Scenario, contributing nearly 55% (7 200 TWh) to global growth through 2040. The share of the residential sector in buildings electricity demand growth rises from 54% in the period 2000-17 to nearly 60% over 2017-25 and 70% over 2025-40. There are various contributing elements: today, around 30% of households worldwide own an air conditioner; only 13% of households use electricity for heating[3]; there are nearly 1 billion people without access to electricity; and electricity needs for information and communication technologies are on the rise in an increasingly digitalized world. Electricity to power cooling services in the buildings sector is the fastest growing among end-uses, at almost 3.5% of annual growth globally.

Energy efficiency improvements in the buildings sector avoid an additional 4 100 TWh by 2040, cutting electricity demand growth in this sector by an amount roughly equivalent to the current electricity demand of the United States. Most of these savings come from more stringent implementations of MEPS for appliances and cooling systems (see section 8.2.2). A particular area of improvement is that of data centres, where efficiency measures, particularly for cooling systems, temper the trend (Box 8.1).

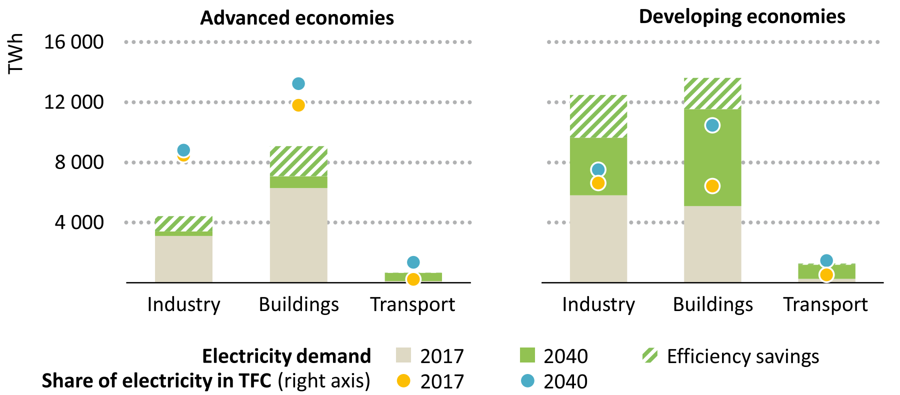
Industry is currently responsible for 40% of global electricity demand, and has accounted for almost 40% of global electricity demand since 2000. Almost 80% of this was in China, driven by its rapid industrialisation. In the New Policies Scenario, the industry sector (mainly

3. The majority of the 265 million households that use electricity for heating are doing so inefficiently via resistance heating rather than heat pumps that are up to three-times more efficient.

industrial motor systems) remains an important driver, accounting for 40% of electricity demand growth through the mid-2020s. After 2025, its contribution falls to around one-quarter. One reason for the slowdown is China's move towards a more service-oriented economy, which reduces industry contribution to China's electricity demand growth from more than 60% since 2000 to 40% from now to 2040.

Demand from the industry sector in India (driven by its "Make in India" initiative) and other countries in Southeast Asia rises, contributing around 30% to global industrial electricity demand growth, which by 2040 is some 4 100 TWh higher than today. Efficiency measures (mostly for motor systems) play a key role and help to avoid nearly 3 900 TWh of additional electricity demand by 2040, cutting industrial electricity demand growth by nearly half (Figure 8.6).

Figure 8.6 ▷ Electricity demand and avoided demand due to energy efficiency by sector in the New Policies Scenario



Global electricity demand growth would be more than 60% higher in 2040 without projected energy efficiency improvements

Note: TWh = terawatt-hours; TFC = total final consumption.

In the transport sector, the contribution of electric cars to global electricity demand today is negligible; the 3 million electric cars on the road worldwide account for less than 0.1% of total electricity demand. In the New Policies Scenario, the stock of electric cars grows by a factor of 100 to around 300 million by 2040, or around 15% of the total car fleet. Electric cars contribute to more than 60% of the increase in electricity demand for road transport, which expands to account for 3% of global electricity demand by 2040, around 1 200 TWh.[4] More than 40% of the incremental increase is in China; demand in the European Union is a distant second (Box 8.2).

4. The impact on oil of increased electrification of mobility modes is discussed in Chapter 3 (Figure 3.10).

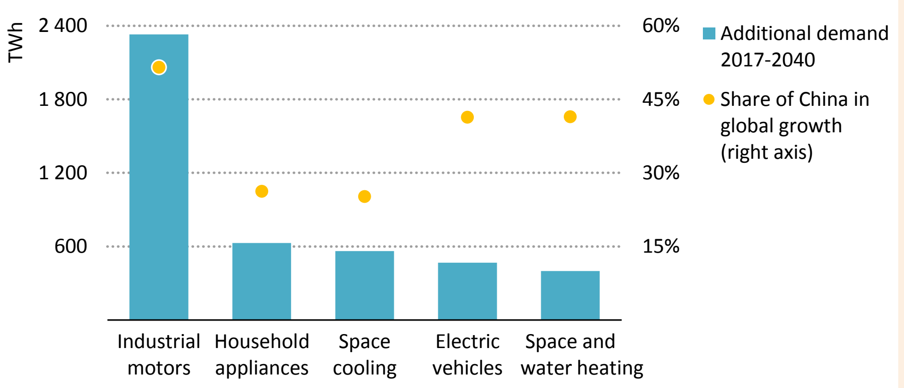
Box 8.2 ▷ Shifting electricity needs in China

The shift towards less energy-intensive industries and services in China leads to its electricity demand growth slowing from an average 10% per year since 2000 to about 2.5% per year in the period to 2040. Nonetheless, electricity demand in China in 2040 is as large as that of all advanced economies combined today, pushed by its 13th Five-Year Plan to raise electricity use in final consumption to 27% from the current 23% level.

Every sector and end-use contributes to the electricity demand growth in China, though industrial motors take the largest share (Figure 8.7). Even on a global scale, China's industrial motor systems are the single largest contributor to electricity demand growth worldwide to 2040, accounting for around 18% of the total. China's plan to transition away from its traditional focus on energy-intensive industry sectors towards high-tech, high value, less energy-intensive industrial activities accounts for increased electricity demand. Electric-driven motor systems typically play a larger role in lighter industries such as electronic equipment or machinery manufacturing, which are important targets for China's industrial development (IEA, 2017). Low efficiency motors currently make up about half of the stock of motors in China's industry sector; this share falls to less than 5% by 2040.

The buildings sector plays an increasingly important role in China's electricity demand outlook, accounting for more than 40% of total growth to 2040. Every end-use (appliances, cooling and electrification of space and water heating) contributes.

Figure 8.7 ▷ Electricity demand growth by end-use in China in the New Policies Scenario



Electricity demand grows for all end-uses in China, with industrial motors driving the increase

Note: Electric vehicles include all road vehicles (cars, buses, two/three-wheelers, and trucks).

The stock of appliances such as refrigerators, washing machines and dishwashers continues to grow in the New Policies Scenario, albeit at a slower rate than in the past. Electricity demand from major household appliances more than doubles to 875 TWh in 2040. Additional demand arises from connected devices, televisions, computers and small appliances. This increases total electricity demand for household appliances by 630 TWh to 2040, or half of the growth of electricity demand in the residential sector.

Of the 1.6 billion air conditioners in use worldwide today, more than one-third are in China, around 2.5 times more than a decade ago. China is rapidly catching up with the United States, the world's largest user of air conditioners, and is projected to reach about one billion units by 2025 and 1.3 billion by 2040. The result is that electricity demand for cooling more than doubles in China in 2040 from current levels.

Electrification of space and water heating account for around 10% of electricity demand growth in buildings. The share of electricity in space heating doubles to more than 25% in 2040, largely driven by China's 13th Five-Year Plan and the Clean Winter Heating Program, which aims to phase out coal and oil for heating.

China accounts for 40% of all electricity use in transport worldwide by 2040 in the New Policies Scenario. All modes of land transport are increasingly electrified, with cars as the biggest contributor. The surge is driven by policy. The government announced a New Energy Vehicle (NEV) credit mandate in 2017, which requires 12% of sales to be NEV-credited by 2020. This equates to a 4% share of sales in 2020 in the New Policies Scenario.[5] Chinese automakers appear ready to deliver; Beijing Automotive Industry Corporation and BYD Auto plan to sell 500 000 and 600 000 electric cars per year in 2020, respectively. In the New Policies Scenario, about 20 million electric cars are on the road in China in 2025 expanding to about 130 million in 2040 (over 40% of the global total). Together with other road vehicles, mainly electric two/three-wheelers and electric buses, they comprise a fleet of 370 million electrified vehicles in 2025 and over 600 million in 2040. Electric vehicles in China require more than 500 TWh by 2040, around 50% of which is for electric cars.

8.2.4 A closer look at electricity demand growth from end-uses

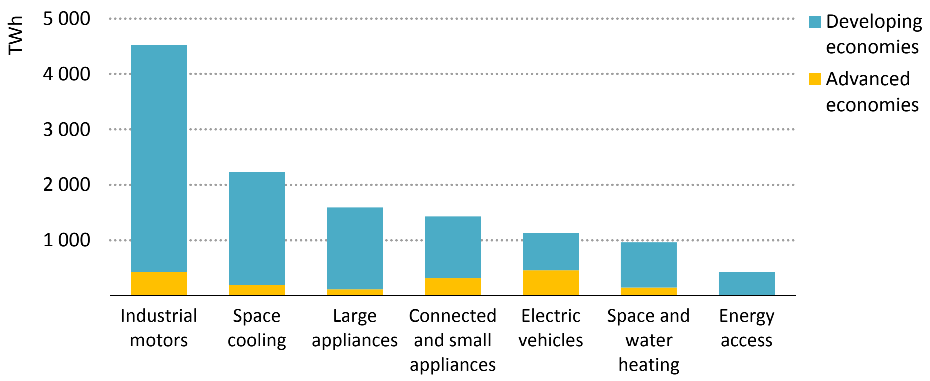
Motor-driven systems in the industry sector remain a central pillar of electricity demand in the New Policies Scenario. Space cooling makes up the second-largest share of in electricity demand growth (Figure 8.8).

For motor-driven systems in industry it is the specific electricity needs rather than the number of units in operation that underscores the importance of energy efficiency policy in containing demand growth. In the buildings sector, air conditioners and household

5. Provided that a credit multiplier from one to six is applied when an electric car is sold. The multiplier depends on the powertrain type (pure electric, plug-in hybrid) and the drive range.

appliances have a relatively low average annual electricity consumption; but the enormous growth of the number of units in operation through 2040 means that they are among the largest contributors to electricity demand growth in the New Policies Scenario.

Figure 8.8 ▷ Electricity demand growth by end-use and region in the New Policies Scenario, 2017-2040



Industrial motors account for a third of the world's appetite for increased electricity while providing electricity access to an additional 680 million people accounts for only 3%

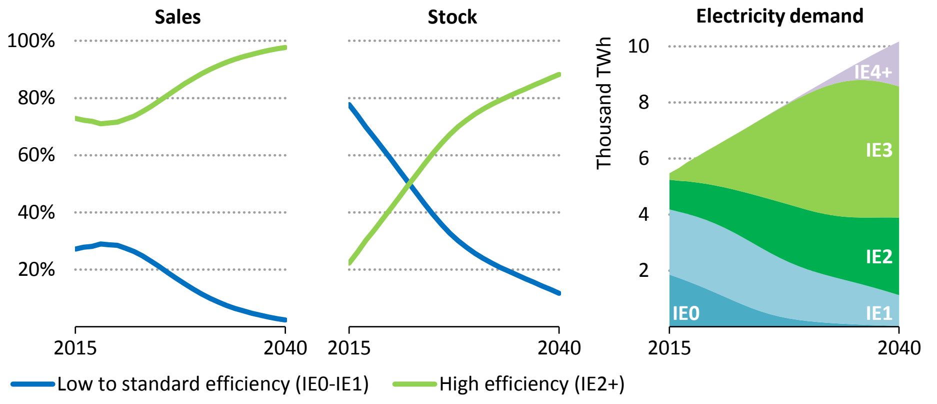
Industrial motors drive electricity demand

In the New Policies Scenario, electricity demand in industry increases by more than 4 000 TWh to 2040. About 70% of the increase is in light industries such as food processing and textiles. These often have a larger share of machine drives and of low-temperature heat in their total energy service demand than heavy industries.

Today, electric motor systems in industry (mostly in developing Asia) account for 75% of electricity demand in industry: in the New Policies Scenario, these systems are responsible for a further 4 500 TWh of electricity demand by 2040, or around the current level of electricity consumption in North America. The efficiency of motor systems therefore plays a critical role in determining electricity needs in the future. There are a number of standards and classifications for motors. Many of them can be benchmarked to the International Electro-technical Commission's "International Efficiency" standards, which range from low (IE0) to super premium (IE4), with minimum efficiency requirements based on size and number of poles. While IE4 motors are commercially available, their current market penetration is minimal. Technical standards for the IE5-level are currently being drafted and suggest about a 20% reduction of losses compared with the IE4-level.

Low efficiency motors make up about 70% of the current stock of motors in the industry sector. Sales of motors at IE1-level and below (low-to-standard efficiency) decline rapidly in the New Policies Scenario (Figure 8.9). Yet, low efficiency motor systems still make up around 10% of the total stock of industrial motors in 2040, even with the rapid deployment of MEPS for motor systems and the near phase out of IE1 and below from sales. Beyond motors themselves, components within a motor system can enable additional efficiency improvements that are even more substantial. For example, the inclusion of variable speed drives can bring about significant efficiency gains by adjusting the speed of a motor in response to process demands (IEA, 2016).

Figure 8.9 ▷ Industrial motors in the New Policies Scenario, 2015-2040



Sales of less-efficient motors decline rapidly, but they still have a long-term impact on electricity demand

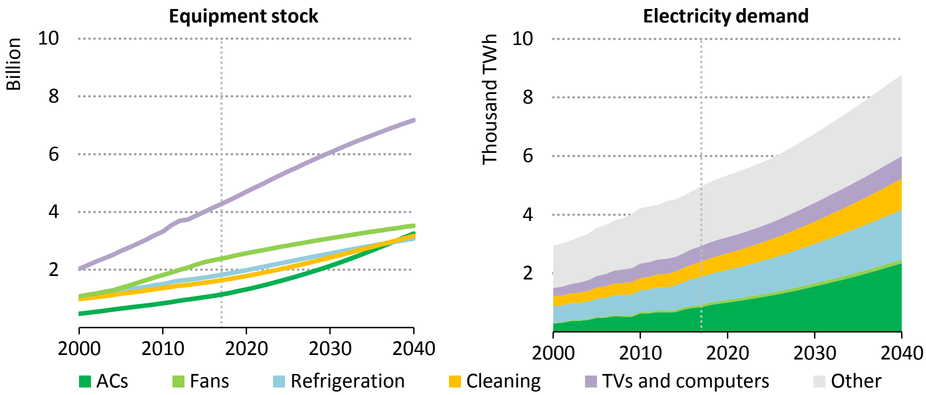
Space cooling and appliances drive electricity demand growth within buildings

Electricity already represents one-third of final consumption in the buildings sector, most of it for appliances (e.g. refrigerators, washing machines) and cooling equipment (electric fans and air conditioners). By 2040, electricity demand in buildings increases in the New Policies Scenario by 7 200 TWh (the current consumption of United States, European Union and Canada combined). Appliances and cooling account for over 5 000 TWh of this growth, representing more than 70% of electricity demand growth in buildings, and around 40% of the global increase in electricity demand to 2040 (Figure 8.10). Almost all of this additional demand comes from developing economies, where the level of ownership per household of refrigerators, washing machines and air conditioners (ACs), is still well below the level of advanced economies.

In parallel, the number of small appliances within households (such as phones and laptops), along with their consequent electricity use, continues to increase. Their rapid growth in the New Policies Scenario is another important component of the increase in residential electricity demand, accounting for an additional 880 TWh by 2040.

Cooling is a particularly important area of growth. Since 2000, cooling demand in buildings has been one of the fastest growing end-uses of electricity. This has led to demand peaks moving to summer in countries that traditionally experienced demand peaks in winter due to heating loads. The basic driver of cooling demand is climate (temperature and humidity of the air), and many of the hottest areas are concentrated within a narrow band running roughly parallel with the equator and covering the tropics and sub-tropics. Today, these hot zones mostly have much lower levels of AC ownership than do the United States and Japan, where more than 90% of households have air conditioning. Affordability and access to electricity are the principal barriers to increased AC ownership in developing economies. A significant portion of the nearly 3 billion people living in hot places today (expected to reach more than 4 billion people by 2040) does not have access to electricity or cannot afford to buy air conditioning equipment (IEA, 2018a).

Figure 8.10 ▷ Equipment stock and electricity demand in residential buildings in the New Policies Scenario



Rapid growth in the global stock of air conditioners and household appliances accounts for 65% of the increase in electricity demand in buildings

Yet ownership and use of ACs is rising rapidly in developing economies such as India as incomes rise and access to electricity improves. In the New Policies Scenario, the global stock of ACs and electric fans increases from just above 3.4 billion in 2016 to just under 6.7 billion in 2040. Electric fans, often a first source of cooling comfort, remain the leading type of cooling equipment: there are 3.5 billion of them by 2040. The biggest increase in absolute terms is for ACs, which consume up to ten-times as much electricity as electric fans, and the number of which rises from just over 1.6 billion today to over 3.2 billion. By 2040, electricity demand for cooling is more than 2 200 TWh higher than today, with energy efficiency improvements avoiding a further 550 TWh of demand.

Heat demand in buildings (space and water heating, and cooking) accounts for three-quarters of final consumption in the sector, but the share of electricity in meeting this demand is currently only 11%. In the New Policies Scenario, this share rises to 15% by 2040.

More efficient electric heating alternatives (i.e. heat pumps) face higher upfront investment costs, limiting the opportunity for broader electrification of heating (see section 6.8 for European Union example).[6]

A few countries have adopted measures to electrify heat demand in the buildings sector. China is advancing its Clean Winter Heating Program, incentivising households to switch from coal to gas and electricity. Loans through the *Crédit d'Impôts* in France have helped the country to become the European leader in heat pump sales.

Electrifying transport — beyond cars

The transport sector uses little electricity today: it accounts for less than 2% of total global electricity use. Rail is the largest user, responsible for about 70% of transport electricity demand. Policies for further electrification in railways and new subways, especially in developing economies, may lead to a small increase.[7] In the New Policies Scenario, however, electric vehicles are the main reason for the increase of global electricity demand for transport, pushing this higher by a factor of nearly five to 2040 and taking overall transport electricity demand to more than 1 850 TWh. With a growth rate of 14% per year, electricity use in road transport overtakes railways to become the largest source of transport electricity demand by around 2030.[8] Developing economies account for 60% of the increase in electricity use for road transport, with China alone using as much as all the advanced economies combined.

The dramatic increase in electricity demand for road transport is mostly driven by passenger cars, which represent 60% of the growth, and is the result of several factors. An important contributing factor is policy commitments at country, regional and city levels to support the electrification of vehicles (Table 8.1). The diverse policy instruments include: direct subsidies to reduce vehicle purchase cost; incentives such as free parking and road toll exemptions; stock and sales targets; public procurement schemes; targets to phase out conventional cars; zero-emissions city targets; and support for charging infrastructure deployment. The increasingly stringent fuel-economy, GHG and air pollutant emission standards for cars in many countries also play an important role. Electric vehicles are still more expensive than conventional vehicles. However, in some regions where driving ranges are not too broad, fuel taxes are high and there is a preference for smaller cars, the total cost of ownership for electric vehicles comes close to that of conventional cars by the middle of next decade, depending on the regional characteristics (see Chapter 9).

Another important factor is the commitment to electric vehicles being shown by the auto industry. This raises the prospect that the number of electric vehicle models will expand

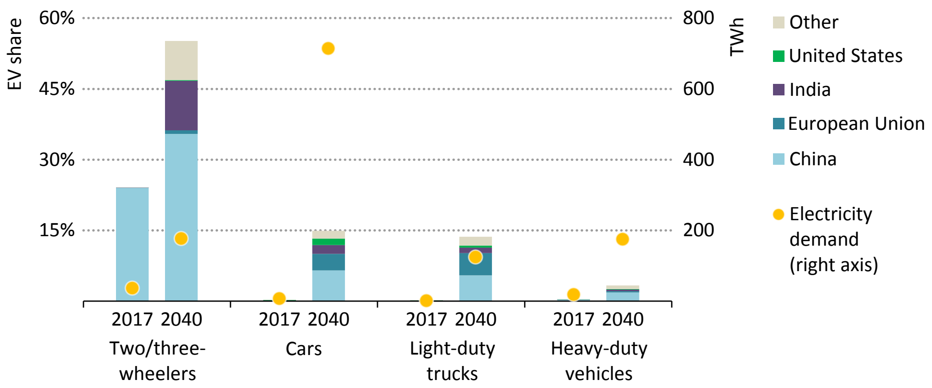
6. Renovation of heating equipment usually happens as a matter of urgency when the existing heater breaks down. Switching to a different type of heating system may require additional changes in the building to ensure that the heat pump works at its highest performance (e.g. new radiators, underfloor heating).

7. The IEA will release *The Future of Rail, a* new report on the prospects for rail transport in early 2019.

8. Oil displacement due to the electrification of mobility is discussed in Chapter 3. Biofuels and energy efficiency in the transport sector are discussed in Chapter 6.

and that component costs (for example battery and motors) will fall. By early 2020, for example, Toyota plans to offer more than ten models of electric cars, and is targeting 1 million global sales of electric and fuel cell cars by 2030. The Beijing Automotive Industry Company) plans to sell only electric vehicles (EVs) in China by 2025. There are many other such examples. European and US car manufacturers have also set up important plans regarding EVs (e.g. Volkswagen plans to offer 80 electric models by 2025 and 300 e-models by 2030, Mercedes targets 50 electrified models by 2025, General Motors plans to offer 20 electric models by 2023 and Ford 16 electric models by 2022). Such announcements are also beginning to spread beyond cars: Volvo and Scania, for example, are working to develop electric trucks; Tesla unveiled the "Semi" truck in 2017; and both Daimler and Renault have recently unveiled e-truck models.

Figure 8.11 ▷ Stock share of electric vehicles and related electricity demand by region in the New Policies Scenario



Whereas two/three-wheelers are the most electrified mode, the biggest incremental electricity demand comes from cars, with China in the lead

In the New Policies Scenario, the electric car fleet amounts to more than 40 million cars by 2025, and one-out-of-five cars sold in the world is electric by 2040, compared with just over 1% today (Figure 8.11). However, this hides regional differences, in China one-out-of-three cars sold by 2040 is electric, while the share of EVs in EU car sales is about 40% by 2040. In contrast, shares are lower in regions lacking a strong policy push and with relatively low taxes on fuel and consumer preferences for bigger cars. In the United States and Middle East, the market of electric cars reaches around 15% and around 1% by 2040, respectively.

Cars are not the only road vehicle mode that electrifies in the New Policies Scenario, but with 300 million cars on road by 2040, they make up over 60% of road transport electricity demand growth, accounting for 715 TWh by 2040. In fact, electric two/three-wheelers already account for a quarter of global sales today, mostly in China, and their numbers rise to over 700 million by 2040, supported by relatively low battery capacity requirements and municipal air pollution policies. With around 55% of two/three-wheelers being electric by 2040, they account for close to 180 TWh of electricity demand. Buses also see major electrification (especially in China and in the European Union): their numbers reach 4 million by 2040. Heavy-duty trucks only see limited electrification in the New Policies Scenario, reaching less than 1 million by 2040, given current deployment hurdles such as the need for very high battery capacity or a specific infrastructure (i.e. catenary lines or other dynamic charging options). Currently, research projects have been realised in a number of European countries (i.e. Sweden, Germany and Italy) for electric highways as an effort to support long-haul routes for commercial freight operations; these projects are at the demonstration stage.

8.3 Electricity supply outlook in the New Policies Scenario

8.3.1 Recent policy developments

Power sector policies in many regions support the clean energy transition and aim to provide affordable electricity to the nearly 1 billion people without it today. Widespread efforts are underway to diversify the fuel mix, decarbonise electricity supply, reduce pollutant emissions that are linked to negative health outcomes and provide universal energy access (see Chapter 2). As a result, there have been a number of recent policy developments that will have a material impact on the electricity supply outlook (Table 8.2).

There are almost 150 countries with targets to increase the use of renewable energy in electricity (REN21, 2018). Globally, solar PV and wind power are the primary focus of policy support. Offshore wind looks poised to gain more support, with targets in China, Chinese Taipei, European Union, Japan and United States, and expectations of further cost reductions (IEA, 2018b). Beyond wind and solar PV, large hydropower development continues in China, Southeast Asia, Africa and Latin America, while bioenergy is strongly supported in the European Union, Brazil and several other countries in power, heat and transport applications (IEA, 2018c). High quality geothermal resources are also being targeted for development, including in Kenya and Southeast Asia. Marine power holds great promise, but deployment has been limited to a few projects in Europe and Korea, with efforts continuing to improve wave and tidal technologies.

Some corporations are complementing governmental policies by procuring renewables through bilateral agreements with project developers. The RE100 initiative, which commits its members to source 100% of their electricity from renewables, has 152 leading companies signed up to date, with a cumulative electricity consumption of 184 TWh per year, equivalent to Thailand's current electricity demand. These companies belong to a diversified list of sectors: consumer staples, information technology, financial companies, telecommunication, industry and health care.[9] The initiative started in the United States and Europe in 2014, and it is spreading internationally.

9. http://there100.org/.

Table 8.2 ▷ Recent major developments in electricity supply policies

Region	Policy	Authority	Release date	Combined impact on outlook for:			
				Renewables	Nuclear	Gas	Coal
China	Three-Year Action Plan on pollution; caps on utility solar PV with feed-in tariffs, set target for distributed solar PV.	State Council; NDRC, NEA, Ministry of Finance	2018	–	–	↑	↓
India	Revised National Electricity Plan.	CEA	April 2018	↑	–	–	↓
European Union	Renewable target to 32% in gross final consumption* by 2030. Coal phase out in Portugal, Italy, Netherlands, United Kingdom, Denmark, France.	EU council and Parliament; member states	June 2018	↑	–	↓	↓
United States	Federal: proposed Affordable Clean Energy Rule; extension of tax credits for renewables. California rooftop solar PV mandate.	US EPA; US Congress; California Energy Commission	2018	↑	–	↓	–
Korea	8th basic plan of long-term electricity supply and demand.	MOTIE	Dec 2017	↑	↓	↑	↓
Saudi Arabia	New Solar Energy Plan 2030.	Crown Prince	March 2018	↑	–	↓	–
Canada	Accelerated phase out of traditional coal-fired plants by 2030.	Ministry of Environment and Climate Change	Feb 2018	–	–	–	↓
Japan	5th Strategic Energy Plan.	METI	July 2018	↑	↓	↑	↓

*Gross final consumption is calculated according to special provisions in the European Directive 2009/28/EC.
Note: NDRC = National Development and Reform Commission in China; NEA = National Energy Administration in China; CEA = Central Electricity Authority in India; EPA = Environmental Protection Agency; MOTIE = Ministry of Trade, Industry and Energy in Korea; METI = Ministry of Economy, Trade and Industry in Japan.

In addition to action on renewables, many countries are limiting or reducing the use of coal (and to a lesser extent oil) in the power sector, and are strengthening policies to reduce air pollution. While some countries are still building new coal plants (some 182 GW are under construction), others have established plans to phase out their use, including Canada, Korea, several countries in the European Union and Chile.[10] Moreover, two of the world's largest coal-consuming countries, China and India, are looking to limit the growth of coal in the near and long term to support multiple environmental goals, and are taking other steps as well to support cleaner air. Efforts to reduce reliance on oil products for electricity and heat production are underway in countries including Japan, Mexico and Saudi Arabia.

10. The Powering Past Coal Alliance includes 29 countries that have committed to phase out existing traditional coal-fired power plants.

There have also been recent policy developments for other clean energy sources. Some countries have committed to phase out nuclear power (Germany and Belgium), while others plan to reduce the role of nuclear progressively over time (including France, Sweden, Switzerland, Japan and Korea). At the same time, there are close to 20 countries developing new projects and raising the share of nuclear in electricity supply, including China, India, Russia, the United Arab Emirates and Saudi Arabia. In addition, Canada and the United States have indicated that they intend to maintain the current role of nuclear power in electricity supply. There are some bright spots for the development of carbon capture, utilisation and storage (CCUS). The United States passed legislation (the Future Act) that expands tax credits for the capture of CO_2 from power plants or industrial facilities (up to $50/t CO_2).[11] The tax credit could also spur investment in CO_2 capture for natural gas processing and refining. Positive developments supporting plans for CCUS and new projects also came from Norway, Netherlands and United Kingdom.

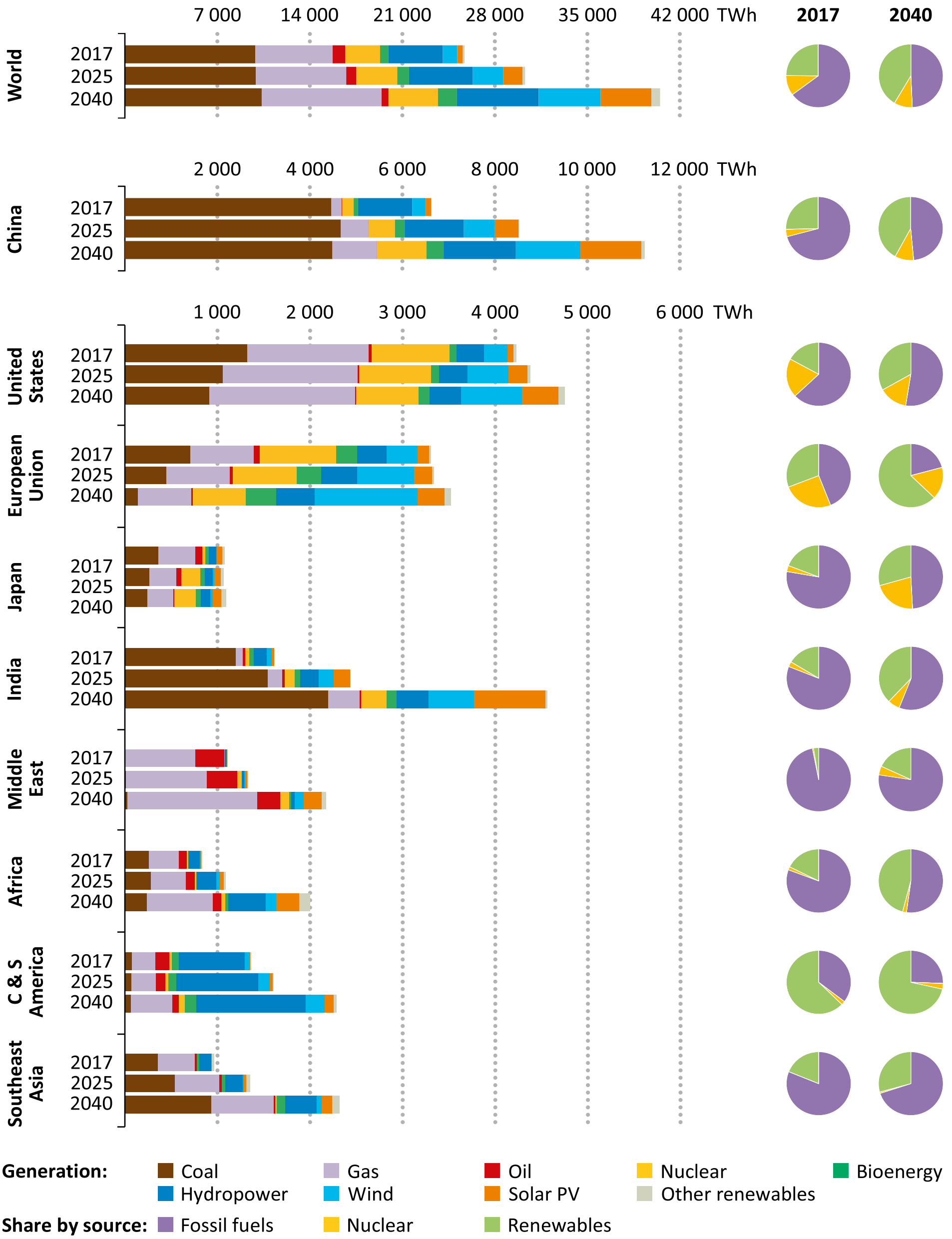
8.3.2 Electricity generation by region

In the New Policies Scenario, based on current and proposed policies, global electricity generation grows by about 15 000 TWh (or 60%) from 2017 to 2040. Natural gas, wind and solar PV supply 70% of the additional electricity generation in nearly equal shares. Despite a drop in its share of generation from 38% today to about 25%, coal remains the largest source of electricity generation through to 2040 (Figure 8.12). By 2040, however, gas is projected to generate 22% of electricity – almost as much as coal. Spurred by policy support and increasing competitiveness, low-carbon technologies grow steadily from 35% of generation in 2017 to 50% in 2040. Hydropower remains the largest low-carbon source of electricity throughout the period, contributing 15% of global generation in 2040. Wind power grows strongly from 4% to 12%, overtaking nuclear (9%) as the second-largest low-carbon source of electricity by 2040. Widespread policy support and falling costs raise solar PV's share of generation from about 2% in 2017 to above 9% by 2040, on a par with nuclear. Other renewables such as bioenergy, geothermal, concentrating solar power and marine power also grow: they supply around 5% of global generation by 2040.

The evolution of the generation mix differs markedly across regions, reflecting the different pace and ambition of policies as well as differences in resource endowments (Figure 8.12). In China, coal-fired generation plateaus around 2025, with coal's share of generation falling from two-thirds in 2017 to 50% in 2030 and 40% by 2040, and with renewables, nuclear and gas stepping up to meet demand growth. By 2040, renewables overtake coal as China's main source of electricity supply. In the United States, natural gas remains the largest electricity generation source, supplying one-third of generation in 2040, while the rapidly improving competitiveness of wind and solar PV helps to raise their share of generation by 15 percentage points, and the nuclear share of generation falls by more than five percentage points as low natural gas prices and falling renewables costs put pressure on its

11. For a medium-size coal-fired power plant, capturing 80% of CO_2 produced could provide upwards of $70 million per year in additional revenue.

Figure 8.12 ▷ **Electricity generation mix and share by source in the New Policies Scenario**



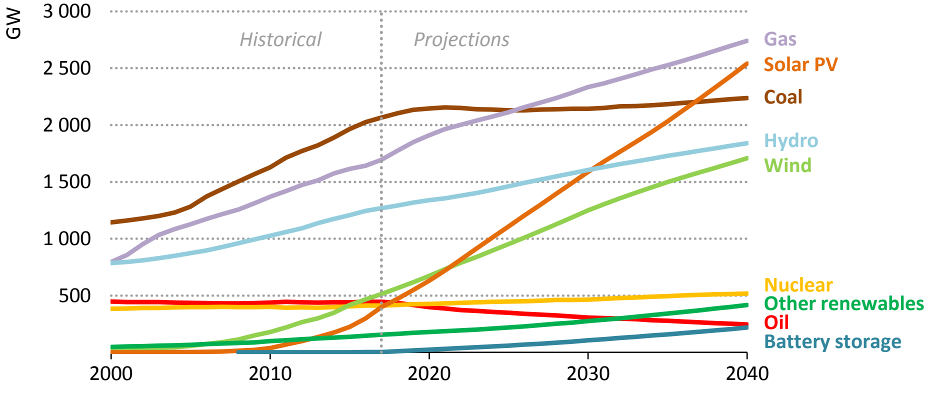
Note: C & S America = Central and South America.

ageing fleet. India's electricity market approaches the size of the United States and undergoes a dramatic transformation (section 8.4). The European Union's ambitious plan of achieving a 32% renewables target sees a large-scale shift in generation from thermal sources to renewables, implying important changes in the way the electricity system works in Europe (see section 8.5.1). Southeast Asia's thirst for electricity sees demand grow by 140% from 2017 to 2040, with about 45% of the additional power met by coal generation, which remains one of the cheapest sources of electricity in the region.

8.3.3 Power generation capacity by region

Global capacity additions of renewables double those of fossil fuels on average to 2040 in the New Policies Scenario. Solar PV emerges as the most deployed power generation technology, with installed capacity overtaking wind in the next few years, hydropower within 15 years and coal soon before 2040. By the mid-2020s, natural gas overtakes coal as the world's largest source of power generation capacity (Figure 8.13). Our projections suggest that additions of coal-fired capacity may have peaked in 2015, with overall coal capacity reaching a plateau in the early 2020s. In the New Policies Scenario, around 220 GW of battery storage are deployed as a means to add flexibility to power systems, supporting the integration of rising shares of variable renewables, and reducing the need for new thermal capacity (see section 8.4.4).

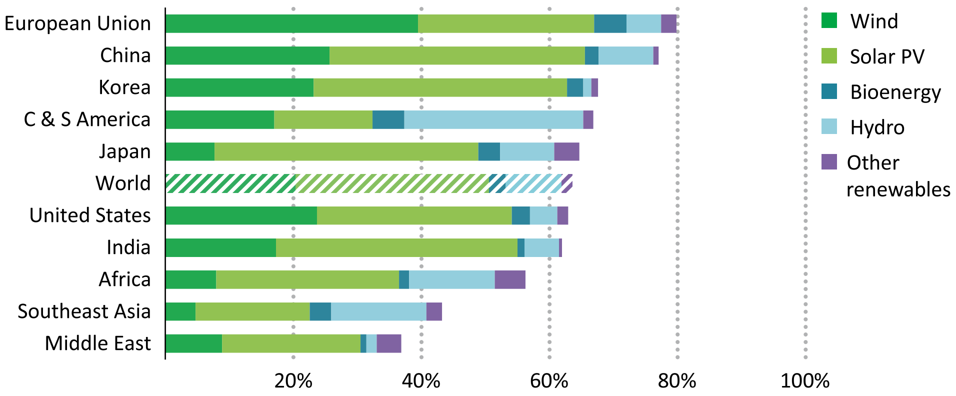
Figure 8.13 ▷ Installed power generation capacity worldwide by source in the New Policies Scenario



With more than 180 GW under construction, coal fuels the most capacity until the mid-2020s when natural gas overtakes it, and renewables are on the rise

In the New Policies Scenario, renewables constitute two-thirds of gross capacity additions in most regions over the period to 2040 (Figure 8.14). By 2035, renewables make up half of global power generation capacity. Solar PV surpasses wind and hydropower in terms of capacity (though electricity generation from hydropower remains more than 60% higher than that of solar PV in 2040).[12] China and India drive this growth; they are responsible for well over half of global solar PV capacity additions. Wind power deployment also grows rapidly, reaching 14% of global capacity by 2040, or around 1 700 GW. China and India again account for about half of capacity additions over the period. In the European Union, wind power reaches almost 370 GW by 2040, accounting for about 30% of the total, with offshore wind growing more rapidly than onshore wind. It increases from about 10% of installed wind capacity today in the European Union to one-quarter in 2040. Hydropower increases across all regions. China sees the biggest increase (166 GW) in installed capacity from 2017 to 2040, followed by Central and South America (88 GW), while hydropower increases by more than 60 GW in India, Southeast Asia and Africa.

Figure 8.14 ▷ Share of renewables in total gross capacity additions by region in the New Policies Scenario, 2018-2040



Renewables dominate capacity additions in most regions of the world, propelled by new solar PV and wind power installations

Note: C & S America = Central and South America.

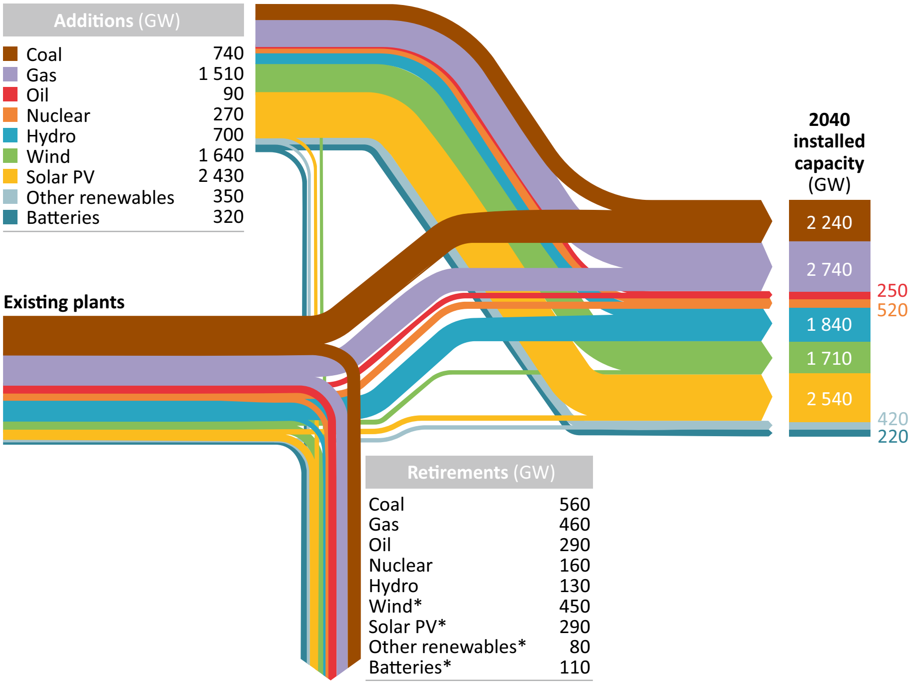
Nuclear power generation capacity is projected to increase by over 100 GW to 2040. Globally, there are around 270 GW of capacity additions, but these are offset in part by plant retirements. Advanced economies currently account for three-quarters of installed capacity, led by the United States, France and Japan, and have ageing fleets: uncertainty remains about lifetime extensions and the pace of retirements (Spotlight). In the New Policies Scenario, the combined installed nuclear capacity in the United States, France and Japan declines by about one-fifth to 2040. Nuclear capacity is projected to decline by about

12. The amount of electricity produced annually from a unit of capacity varies widely across technologies. For example, in 2017, 1 GW of solar PV produced 1.1 TWh of electricity on average worldwide, compared with 2.1 TWh for each GW of wind power, 3.2 TWh for each GW of hydropower, 3.5 TWh for each GW of gas-fired capacity, 4.8 TWh for each GW of coal-fired capacity and 6.4 TWh for each GW of nuclear capacity.

30% in the European Union, as retirements are offset partially by some 30 GW of new builds. However, it increases in developing economies, rising from one-quarter to more than one-half of global capacity by 2040. China overtakes the United States and European Union in nuclear capacity prior to 2030: a significant expansion of nuclear capacity also take places in India, Russia and the Middle East.

Gas-fired power plants are the only fossil fuel technology set to grow in almost all regions, thanks to the low upfront investment cost for new plants, the increasing availability of gas, and the role of gas in system flexibility. From 2025 to 2040, global installed coal-fired capacity increases by only 5%, compared to over 40% in the last ten years. In terms of capacity, gas overtakes coal just after 2025 to lead all sources.

Figure 8.15 ▷ Global power generation capacity additions and retirements in the New Policies Scenario, 2018-2040



Much of today's power plant fleet will still be operating in 2040, with renewables stepping up to replace capacity retirements and meet new demand

* A portion of capacity additions of renewables and battery storage are retired by 2040, consistent with the average lifetime assumption for wind and solar PV of 25 years, and 10 years for batteries.

From 2018 to 2040, around 2 500 GW of capacity is set to retire, equivalent to over one-third of global capacity today. Fossil-fuelled power plants account for more than half of the retirements (Figure 8.15). This is mostly due to the age of the plants concerned; about 30% of the global coal fleet, 20% of gas-fired capacity and almost half of oil-fired power plants are 30 years or older. In addition, some countries are enforcing targets to retire coal-fired power plants. Renewable technologies, excluding hydropower, tend to have shorter lifetimes on average, account for around 950 GW of retirements.

S P O T L I G H T

Lifetime extensions present major uncertainty for the role of nuclear

The nuclear fleet is ageing. While there are 413 GW of nuclear capacity in operation today, more than 60% of the fleet is over 30 years old. The original reactor design lifetimes of most of these plants were between 30 and 40 years. In advanced economies, where most nuclear capacity is located, about two-thirds of the fleet is older than 30 years today. Close to 60 GW have already been operating for more than 40 years. The future of the existing nuclear fleet will have major implications for the security of electricity supply and achieving environmental goals.

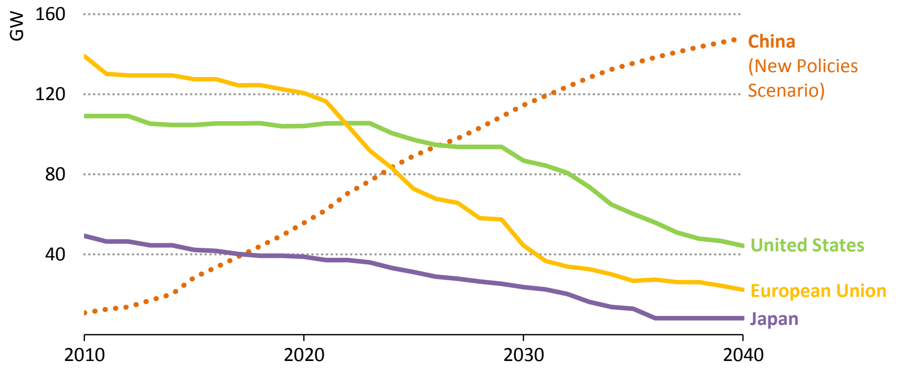
In some countries, many projects have already received lifetime extensions. In the United States, for example, the Nuclear Regulatory Commission has issued license renewals providing a 20-year extension (to 60 years) to a total of 85 of the 99 operating reactors, while four reactors have applied for subsequent licence renewal to extend operation from 60 years to 80 years. Other countries are also looking to grant lifetime extensions. In Europe, Hungary issued lifetime extension licences to all four units at the Paks site, and the Czech Republic is reviewing plans to extend the lifetimes of the four Dukovany units by an additional 20 years. French energy firm EDF also received licences to extend operations to at least 40 years for all its 15 nuclear reactors in the United Kingdom. In Sweden, decisions have been taken to extend the operational lives of five reactors. Canada is pursuing lifetime extensions for much of its nuclear fleet; ten reactors are to be refurbished, extending operations beyond 2050.

These extensions, however, are not guaranteed in the face of significant challenges. Following the 2011 accident at Fukushima Daiichi in Japan, safety requirements have been raised and stress tests have been performed in many countries; new designs now include advanced safety features, including passive features; but public acceptance of nuclear power remains a serious concern in some countries. In Germany, Belgium and Chinese Taipei, the phase-out of nuclear power is planned. Furthermore, market conditions are creating challenging financial conditions for both existing reactors and prospective investment in new reactors. Low wholesale electricity prices are making it

8

difficult to justify the additional capital investment to maintain and refurbish reactors (notably in the United States and much of the European Union). This is also putting at risk nuclear plants that had previously been granted lifetime extensions. Several reactors in the United States announced that they will close prematurely as a result of the financial conditions. Nuclear power also faces fierce competition from the falling cost of renewables and low gas prices in many regions, which mean that re-investment in existing facilities is not a given, as alternatives may be more competitive. New builds also face some of these challenges, particularly the difficult market conditions and cost competitiveness, as well as more stringent safety regulations.

Figure 8.16 ▷ Nuclear capacity without further lifetime extensions or new project starts



Without concerted policy action, the contribution of nuclear power would decline substantially in markets that have long been industry leaders

Notes: Reactors under construction are included. China projected capacity in the New Policies Scenario included for reference.

Without further lifetime extensions and new builds, the share of nuclear in generation capacity will drop substantially. In the United States, nuclear power would drop from 20% of electricity generation in 2017 to around 7% by 2040. In the European Union, nuclear power would drop from 25% of generation today (the largest source of generation) to 5% by 2040. In Japan, the government plans on nuclear power to provide 20-22% of electricity in 2030 compared to 26% on average in the decade preceding the Fukushima Daiichi accident. At the same time, growth in China pushes nuclear capacity beyond that in the United States by 2030.

In the New Policies Scenario, which includes some further lifetime extensions and new builds, the share of nuclear in electricity supply in the United States declines to 14% and in the European Union to 16% in 2040, with Germany having completed its phase out by 2022 and a notable reduction in France. Alongside this, we have analysed the impact of the following theoretical assumptions:

- The United States and countries in the European Union with nuclear plants do not grant further lifetime extensions (existing reactors operate until the end of their current operating licenses and then close down), and no new projects start construction from now on.
- In Japan, no new lifetime extensions are approved, only the two reactors under construction are completed, leaving 8 GW of capacity operational in 2040.

Should such a situation materialise, the loss of large amounts of baseload zero-emissions supply would have major implications for the energy mix, for energy security and for the emissions trajectory. For example, in the case where solar PV and wind power are the primary replacements for lower nuclear output, then their pace of additions needs to be higher than in the New Policies Scenario in order to keep to the same emissions trajectory. It would imply about one-third higher additions in both the United States and European Union, and more than two-and-a-half times the additions of solar PV and wind power in Japan. The additional variable renewables would require a substantial increase in flexibility from thermal power plants in order to ensure the security of electricity supply, as well as investment in grids, storage and demand-side response. Without the acceleration of wind and solar PV, the reduction in nuclear would lead to higher CO_2 emissions in 2040: 170 Mt to 180 Mt in the United States and European Union, and about 100 Mt in Japan.

8.3.4 Power generation technology costs, value and competitiveness

Outlook for technology costs

Technology costs are projected to evolve considerably in the New Policies Scenario. Solar PV continues to move down the cost curve as the industry continues to mature. The global average levelised cost of electricity (LCOE) of utility-scale solar PV drops below $70 per megawatt-hour (MWh) by 2030, or some 40% below the level in 2017.[13] As is the case today, the LCOE of best-in-class projects continues to be about half the global average. The range of regional costs is projected to narrow, but China and India continue to have some of the lowest average costs in the world while the average in the United States, European Union and Japan remain higher than average. Reductions in the overnight capital costs are the primary driver for solar PV LCOE reductions, with average costs projected falling by one-third to $900/kW on average in 2030.[14] At the same time, performance gains are expected from higher efficiency panels, wider use of tracking and improved maintenance

13. See Annex B for power generation cost assumptions and projections for select regions. All technology costs assume a standard weighted average cost of capital of 8% in advanced economies (in real terms) and 7% in developing economies.
14. A 20% learning rate is assumed for solar PV capital costs for every doubling of cumulative deployment.

practices. By 2040, average capital costs for solar PV near $800/kW and the average LCOE drops below $60/MWh.

As a more mature technology, onshore wind power is projected to make more modest gains – average LCOEs fall by 5-15% in most regions to 2030 – limited to an extent by rising labour costs. Less mature technologies make more progress. The average costs of offshore wind power decline by over 30% by 2030, as the technology continues to mature and as wind turbines increase in size (swept area), raising maximum output capacity and performance (IEA, 2018b). The average LCOE of concentrating solar power (CSP) also drops by more than 30% in nearly all markets to 2030. The average LCOEs for wind power and CSP are projected to decline by 10-20% from 2017 to 2040.

The costs of new nuclear projects are assumed to stay relatively stable in most regions. China's nuclear projects produce electricity for less than $70/MWh: it has been able to deliver projects at much lower costs than elsewhere largely by completing most projects in six years or less. Longer construction times raise costs in Europe, though the cost of new designs (Generation III+) are assumed to decline to 2030, to an average of about $125/MWh. Projects in Russia, Eastern Europe, Korea and the Middle East are assumed to have mid-range costs, with levelised costs from $80-90/MWh through to 2040. Commercial-scale CCUS projects in power have been few in number and expensive to date. With few projects visible on the horizon, enhanced government support would be necessary to provide opportunities to drive down costs through learning-by-doing.

Power generation costs from fossil-fuelled power plants tend to increase in the New Policies Scenario. After a drop in the near term, average coal prices gradually increase in most regions to 2040. Existing coal-fired power plants are generally the least expensive among fossil fuels (in the absence of carbon prices), generating electricity for as little as $10/MWh (for lignite) up to $40/MWh for inefficient subcritical plants burning steam coal. The levelised cost of generating electricity at new coal-fired power plants is from $50-$80/MWh in most regions through to 2040. Natural gas prices are at low levels today, but increase over time in the New Policies Scenario. At the far low end of the range, US gas prices were $3 per million British thermal units (MBtu) in 2017, rise to about $4/MBtu in 2030 (and $5/MBtu in 2040), raising the operating cost of existing gas combined-cycle gas turbines (CCGT) in the United States from $26/MWh to $32/MWh in 2030, and the overall LCOE of a new CCGT to about $60/MWh in 2030. Gas prices are higher in most other regions of the world today; in the European Union, average gas prices are close to double those of the United States, while China's prices are another 10% higher. Oil is usually one of the most expensive fuels for power generation. For example, an oil price of $80 per barrel translates to operating costs for oil-fired power plants of $110-170/MWh (without any product mark-up/down). The impact of a CO_2 price on the LCOE of new or existing fossil-fuelled power plants could be sizeable, but would obviously depend on the level of the price. For example, a price of $20/tonne CO_2 would add $18/MWh to the operating costs of an average supercritical coal-fired power plant today and $8/MWh to an average gas CCGT.

Value of electricity produced by technology

Power generation technologies contribute in three main ways to the reliability and security of electricity supply by providing:

- Energy – the provision of energy to meet demand.
- Flexibility and system services – the provision of non-energy system services in support of the quality of power, including primary and secondary reserves, frequency regulation and synchronous inertia.
- Capacity – the provision of support to system adequacy, ensuring that the available electricity supply will be sufficient to meet demand at all times.

All three of these value streams are relevant to the system operator, planner or government ministry responsible for the reliability and affordability of electricity supply. These services must be provided to ensure electricity security and so they are relevant in all markets, from fully liberalised to fully regulated, even where they are not separated into distinct products and remunerated.[15] We have accordingly carried out analysis in an attempt to quantify each value stream by technology for select regions in support of cross technology comparisons. All the value streams are system-specific, depending on many factors including the state and age of the existing system, the fuel mix, fuel prices, the profile of total demand, the activity of demand-side response and energy storage, as well as the nature of renewable energy resources.

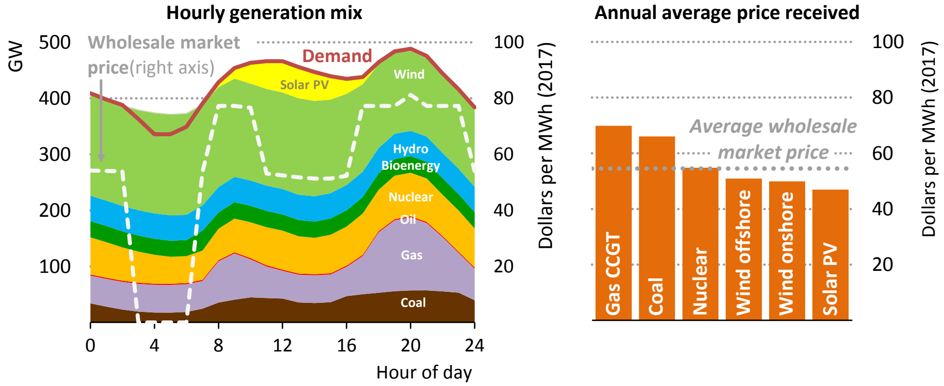
Energy value refers to the market value of electricity supplied. In general, the value of energy is higher when it is needed more – when supply is scarce – and lower when it is needed less, when energy is more abundant relative to demand. So a technology that provides supply at times when it is needed most can obtain a relatively high energy value. In order to calculate the energy value of different technologies, simulations of the hour-by-hour balance of electricity demand and supply were performed in our World Energy Model for select regions using projected installed capacities by scenario. For example, in the European Union in 2030 in the New Policies Scenario, significant hourly fluctuations within the day are projected for electricity demand, the mix of sources that meets demand, and the resulting marginal wholesale market prices (Figure 8.17). The average annual energy value is then calculated, aggregating these results, as the average price received per unit of output ($/MWh) for all operations over the year. For example, in the European Union in 2030, the average annual energy value is highest for coal- and gas-fired power plants, well above the average annual wholesale market price, reflecting the fact that they tend to be readily available when needed.

Over the course of the outlook period, as the share of wind and solar PV increases, our modelling shows several notable impacts on energy values by technology. We see an increasing number of hours with over-abundant supply – excess generation above and

15. Depending on the particular power market design, investment decisions may consider only a subset of these value streams, or they may be based on long-term contracts that shield them from changes in market value.

beyond the needs of demand – leading to low or zero wholesale market prices. This puts downward pressure on the annual average wholesale price, depressing revenues for all sources, including wind power and solar PV themselves, as observed in previous research (Hirth, 2018; Würzburg et al., 2013; IEA, 2016). We also see increased volatility of hourly wholesale market prices, with large price swings over the course of a few hours. This could present an opportunity for new entrants into the market, most notably energy storage technologies.

Figure 8.17 ▷ Hourly generation mix in a sample day and annual energy value in the European Union in the New Policies Scenario, 2030



As the share of variable renewables rises, large hour-to-hour changes in output and wholesale prices become the norm, with implications for the energy value by technology

Notes: CCGT = combined-cycle gas turbine. Coal and gas include combined heat and power plants that primarily serve heat demand and so are less responsive to changes in wholesale market prices.

Flexibility value encompasses non-energy ancillary services that are required in power systems, such as primary and secondary reserves, frequency regulation and synchronous inertia. The flexibility values by technology are grounded in available real-world information and are projected based on the increasing system flexibility needs that stem from rising shares of variable renewables.[16] The ability of technologies to provide these services varies, and their value in terms of flexibility varies with it. For example, open-cycle gas turbines are able to respond to system needs more quickly than coal-fired power plants, and so in existing markets have been able to earn higher revenues in ancillary service markets. Energy storage, including battery systems, also tends to have a high flexibility value because it is usually available and able to respond extremely quickly and accurately to system needs.

16. Based on real-world data from system operators in liberalised markets, a baseline flexibility value was set for each technology, along with establishing a relationship between the average value of flexibility (and so all technologies) and the share of variable renewables was estimated and applied to the projections.

Capacity value reflects the ability of a technology to reliably contribute to the adequacy of the system. It is calculated as the capacity credit of a technology multiplied by a capacity value per unit of capacity credit (in each region and year).[17] The capacity credit reflects the portion of installed capacity that can be reliably expected to be available during times of peak demand. Dispatchable power plants generally have capacity credits that are high proportion of their installed capacity (over 85% in most cases), as they can control their output except for unscheduled outages. On the other hand, the capacity credit of wind and solar PV can be very low (10% or less of installed capacity), as they may not be available during specific hours of the year.

It may look as though the energy value of a given technology captures its flexibility and capacity value too, because the price for energy generated by a given technology varies according to whether there is abundant or scarce supply. However, they are different in that the energy value reflects the amount of electricity delivered, whereas the flexibility value refers to additional services beyond energy, and the capacity value reflects the planning perspective and guarantee of system adequacy rather than operational activities.

Competitiveness of renewables with nuclear, coal and gas

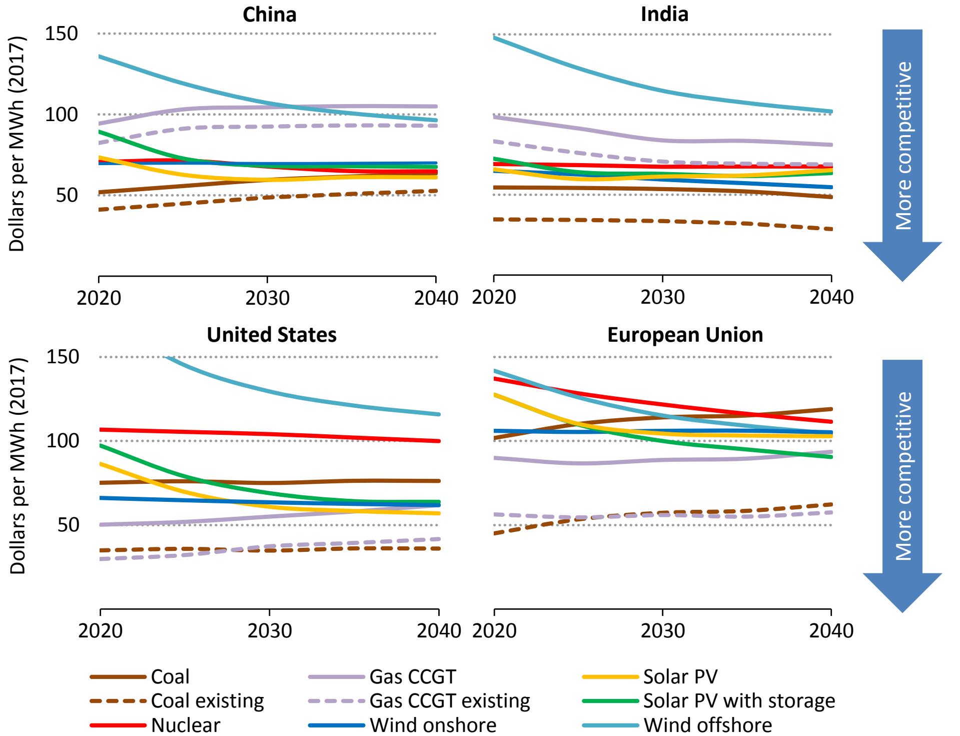
Evaluating the relative competitiveness of power generation technologies for different forms of renewables and fossil fuels requires consideration not just of the costs of the electricity produced but also of its value, as described. We have developed a new metric for competitiveness called the value-adjusted levelised cost of electricity (VALCOE) which attempts to do just this. The VALCOE combines the projected levelised costs of electricity with simulated energy value, flexibility value and capacity value by technology (Box 8.3). In doing so, the VALCOE provides a metric for cross technology comparisons.[18] It is important to make clear, however, that it does not include all costs and benefits related to each technology, and could be improved by including additional relevant elements, such as network integration costs.

The projected VALCOEs indicate that solar PV and wind power are approaching competitiveness in a number of markets for investment decisions today. In China and India, recent cost reductions put solar PV on nearly equal footing with coal as the most competitive sources of new generation (Figure 8.18). Onshore wind power is a competitive option for new investment in all regions, though cost levels vary widely across China, India, European Union and United States. In the United States, very low gas prices make new gas CCGTs very competitive. These findings indicate that geographic-specific circumstances matter when assessing the options.

17. Standard capacity value was projected based on the difference between total generation costs, including capital recovery, and revenue from simulated marginal wholesale market prices and flexibility payments.

18. VALCOE takes the perspective of system planners and policy makers. An investor would also consider costs and value, but would consider different factors. For example, effective costs may be lower due to government financial support or raised by higher financing costs due to technology and market risks. Value prospects would be based on the market design or available long-term contracts.

Figure 8.18 ▷ Value-adjusted levelised cost of electricity by technology in selected regions in the New Policies Scenario, 2020-2040



Based on the costs and value, wind and solar PV are among the most competitive sources of new generation in several regions, under a variety of conditions

Notes: CCGT = combined-cycle gas turbines. Coal refers to supercritical coal plants in India, European Union and United States, and ultra-supercritical coal plants in China. Storage refers to battery storage.

Over the next decade, the competitiveness of low-carbon technologies continues to improve in most cases, as continued cost reductions outweigh any reductions in value. In China, solar PV moves past coal to become the most competitive source for electricity generation, with nuclear power also gaining ground as emissions standards put upward pressure on coal and gas. In India, onshore wind power and nuclear power look increasingly competitive alongside solar PV, though coal looks quite competitive. Solar PV also makes strong gains despite higher capital costs in the United States and relatively low average performance in the European Union. Onshore wind holds steady in these regions, as further cost reductions are offset by downward pressure on its energy value. Offshore wind takes significant strides forward in terms of competitiveness, particularly in the European Union, even at average cost levels, while best-in-class projects are able to compete directly with other sources. New gas-fired power plants also look competitive towards 2030 in the

European Union as the share of variable renewables rapidly rises and system flexibility needs increase.

In the long term, electricity supply looks to become very competitive as the range of VALCOEs narrows in all regions. The costs of renewables continue to fall, but the value of their output also tends to decline relative to the system average. As a result, a comparison of VALCOEs in India in 2040 suggests that solar PV would be less competitive than coal, even though the LCOE of solar PV is projected to be one-quarter below that of coal and the lowest in the world on average. Energy storage seems likely to offer a path to increasing the energy, flexibility and capacity value of a renewable energy project in India and elsewhere. In particular, solar PV paired with battery storage provides a strong value proposition as the share of variable renewables rises. The additional value of storage outweighs the additional costs in India by 2040 in the New Policies Scenario, and does so even more strongly in the European Union, where flexibility is highly valued. Stand-alone storage projects would also become more competitive, combining falling costs and rising energy and flexibility value due to the higher volatility of wholesale market prices linked to rising shares of variable renewables. On the other hand, rising fossil fuel prices are balanced against higher energy and flexibility values for dispatchable plants over time, making the VALCOEs of new gas- and coal-fired power plants more stable than costs alone would indicate in most cases. If fuel prices were to stay low, fossil fuels would get a boost, and would make for stronger competition with low-carbon sources through to 2040.

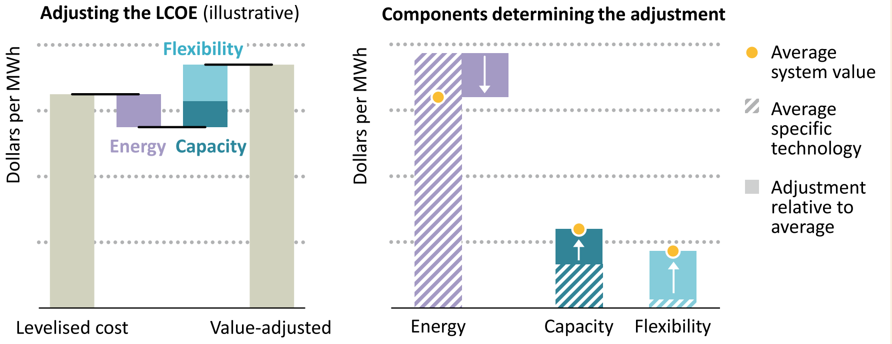
One point of consistency over time and across the world is that existing fossil-fuelled power plants will remain very competitive. Existing coal-fired facilities remain competitive in China, India, the United States and the European Union, while gas CCGTs also continue to be attractive in the United States and European Union.[19] The value of their contributions to system flexibility and adequacy, alongside other sources of electricity, means that the competitiveness of existing plants persists even as fossil fuel prices increase. In order to achieve environmental and climate-related objectives, government action may be required to reduce the contribution of these assets, particularly the least-efficient coal-fired plants.

Box 8.3 ▷ Value-adjusted LCOE in the World Energy Model

The value-adjusted LCOE (VALCOE) is a new metric for competitiveness for power generation technologies and was developed for the *World Energy Outlook-2018*, building on the capabilities of the World Energy Model (WEM) hourly power supply model. It is intended to complement the LCOE, which only captures relevant information on costs and does not reflect the differing value propositions of technologies. VALCOE enables comparisons that take account of both cost and value to be made between variable renewables and dispatchable thermal technologies.

19. Existing coal and gas do not include payments needed to recover the initial capital investment, as decisions to continue operations depend on the ability to recover only fixed and variable operating costs.

Figure 8.19 ▷ Moving beyond the LCOE, to the value-adjusted LCOE



Combining costs and value provides a more robust basis for evaluating competitiveness across technologies than costs alone

The VALCOE builds on the foundation of the average LCOE by technology, adding three elements of value: energy, capacity and flexibility. For each technology, the estimated value elements are compared against the system average in order to calculate the adjustment (either up or down) to the LCOE. After adjustments are applied to all technologies, the VALCOE then provides a basis for evaluating competitiveness, with the technology that has the lowest number being the most competitive (Figure 8.19). The impact of the value adjustment varies by technology depending on operating patterns and system-specific conditions. Dispatchable technologies that operate only during peak times have high costs per MWh, but also relatively high value per MWh. For baseload technologies, value tends to be close to the system average and therefore they have a small value adjustment. For variable renewables, the value adjustment depends mainly on the resource and production profile, the alignment with the shape of electricity demand and the share of variable renewables already in the system. Network integration costs are not included, nor are environmental externalities unless explicitly priced in the markets. Fuel diversity concerns, a critical element of electricity security, are also not reflected in the VALCOE.

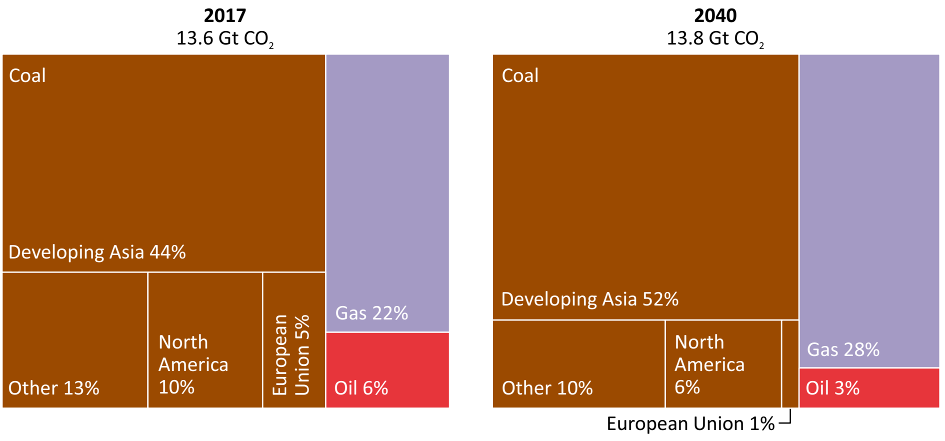
The VALCOE approach has some parallels elsewhere, in other approaches used for long-term energy analysis, as well some real-world applications. Optimisation models implicitly represent the cost and value of technologies, but may be limited by the scope of costs included, such as those related to ancillary services. Other long-term energy modelling frameworks, such as the NEMS model used by the US Department of Energy, have incorporated cost and value in capacity expansion decisions. In policy applications, in the auction schemes in Mexico, average energy values for prospective projects have been simulated and used to adjust the bid prices, seeking to identify the most cost-effective projects.

8.3.5 Power sector emissions

CO_2 emissions

In the New Policies Scenario, global CO_2 emissions from the power sector increase by 2% to 2040, while electricity generation rises by almost 60% and heat production remains flat. The plateauing in power sector CO_2 emissions continues the trend started in 2014. Electricity generation accounts for more than 90% of total power sector emissions. The global average carbon intensity of electricity generation declines by one-third from today to 2040 (from 484 grammes of carbon dioxide per kilowatt-hour [g CO_2/kWh] to 315 g CO_2/kWh), due not only to the rising share of renewables but also to the ongoing efficiency improvements in coal- and gas-fired power plant fleets. In particular, more efficient coal power plants lower the burden of emissions due to coal combustion. This trend is particularly visible in developing countries in Asia, a region accounting for half of total power sector CO_2 emissions by 2040 (Figure 8.20). Of the over 550 GW of new coal-fired power plants built between now and 2040, the vast majority are higher efficiency designs, with less than 70 GW of new subcritical coal. This is an important shift in a region where in the last 25 years almost 440 GW of subcritical coal came into operation. Yet, power sector CO_2 emissions in Southeast Asia double to 2040 (while electricity demand rises by 140%), and increase by 80% in India (while demand almost triples). New construction of coal-fired power plants also presents risks to lock-in emissions for decades to come. The dependence on fossil-fuelled power plants and the improving competitiveness of low-carbon technologies means that the power sector has the potential to play a central role in decarbonising energy systems (see Chapter 9).

Figure 8.20 ▷ Total CO_2 emissions in the power sector by fuel in selected regions in the New Policies Scenario, 2017 and 2040



CO_2 emissions from coal in developing economies in Asia make up half of total power sector emissions in 2040, and natural gas accounts for nearly 30%

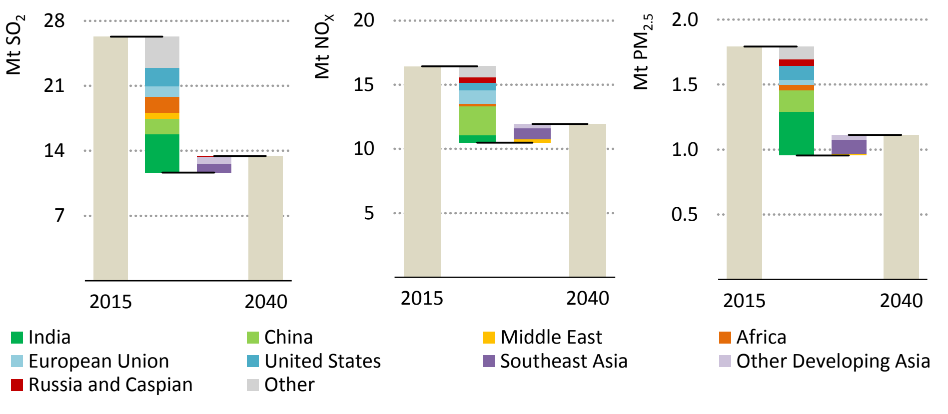
8

Emission trends differ significantly by region and by fuel in the New Policies Scenario: India overtakes the United States to become the second biggest emitter in terms of power-related CO_2 emissions before 2030, while Southeast Asia overtakes the European Union, where the phase-out of coal in many countries means emissions from power are set to decline over the period to 2030. In the United States, CO_2 emissions in the power sector decline by more than 15% to 2030, building on the near 30% reductions over the past decade. China sees its power sector emissions peak before 2030 and the carbon intensity of electricity generation declines by 40% to 2040. This is a marked change from the past decade, in which China's power sector accounted for 43% of the global rise in energy-related CO_2 emissions. Despite being the least carbon-intensive fossil fuel, the strong increase in gas use raises related emissions and represents about 30% of total power sector CO_2 emissions by 2040. However, gas-fired power plants run more efficiently than today: they produce 60% more electricity than now, while emitting just over 30% more emissions.

Pollutant emissions

Emission from all air pollutants in the power sector are reduced by 2040. Emissions of SO_2 fall by 50%, and NO_X and $PM_{2.5}$ emissions decrease by 27% and 38% respectively (Figure 8.21). Most advanced and developing economies alike experience a drop in emissions during the projection period. This comes about because of the shift to renewables. Fossil fuels are the main source of emitting SO_2, NO_X and $PM_{2.5}$, and their use for power declines. Pollutant emissions are also reduced through improved efficiencies and enhanced end-of-pipe measures, thanks to strengthened regulations that are becoming more common in advanced and developing economies.

Figure 8.21 ▷ SO_2, NO_X and $PM_{2.5}$ emissions in the power sector by region in 2015 and 2040 in the New Policies Scenario



Global SO_2 emissions from the power sector are cut by half by 2040, with India and China making significant progress. Pollutants emissions from coal in Southeast Asia increase

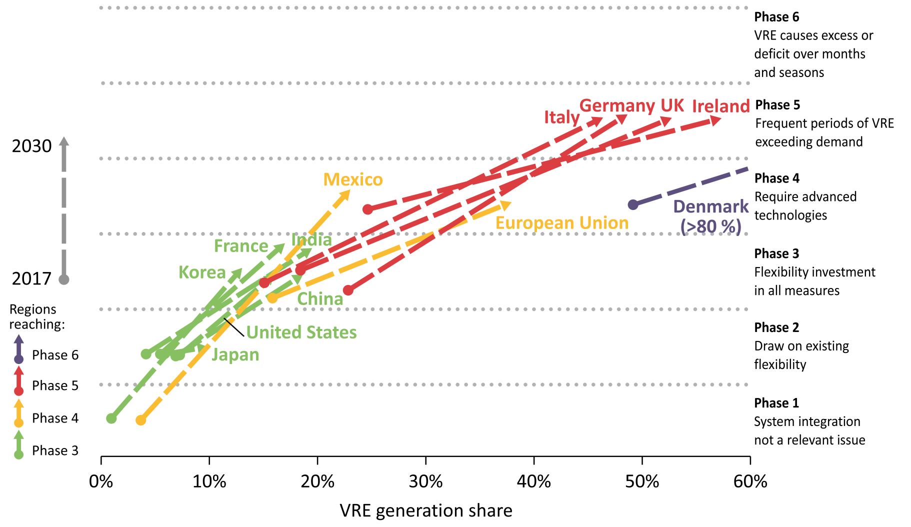
A clear example of this is China and India, where all pollutants emissions are on a downward trajectory, despite steeply rising demand for electricity. These reductions are driven by country level policies aiming at reducing air pollution, which is one of the major causes of premature deaths in those regions. However, all pollutants emissions rise in Southeast Asia and other developing economies in Asia, where coal is used to meet most of the growing demand for electricity, and where fewer power plants are equipped with emissions control technologies.

8.4 Outlook for flexibility in electricity systems

8.4.1 The need for flexibility will increase

The New Policies Scenario sees a step change in the need to source flexibility - the capability of a power system to maintain the required balance of electricity supply and demand in the face of uncertainty and variability in both supply and demand. As time goes by, many countries need more flexibility (Figure 8.22). However, countries enter various phases of the need for flexibility at different times. (See Chapter 7 for the definitions of the phases). The speed of progression depends on the increase in variable renewable energy (VRE), but it also depends on the match with demand profiles and the size of the system: where VRE matches demand (for example where cooling needs and solar PV output largely coincide) and where systems are larger, progression is slower.

Figure 8.22 ▹ Evolving flexibility needs by region, New Policies Scenario

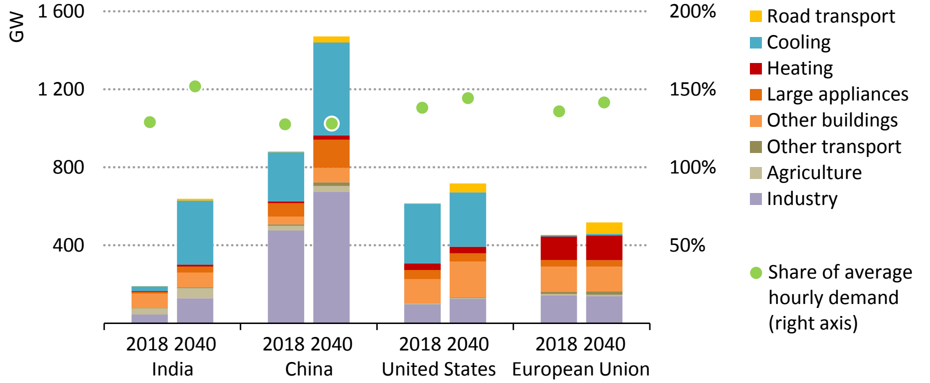


The size of the power system, flexibility of thermal generation, shape of demand profile, imply different needs for additional flexibility even at the same levels of VRE

Note: VRE = variable renewable energy.

Flexibility requirements are also driven by evolution of electricity demand in the outlook: a number of growing end-uses like EVs, heating, or even cooling in some regions concentrate their demand around times of system peak and low availability of VRE (Figure 8.23). Mexico's flexibility needs rise as it climbs three phases to 2040, several regions move up two and some reach levels where no country is today.

Figure 8.23 ▷ Evolution of peak electricity demand in selected regions in the New Policies Scenario

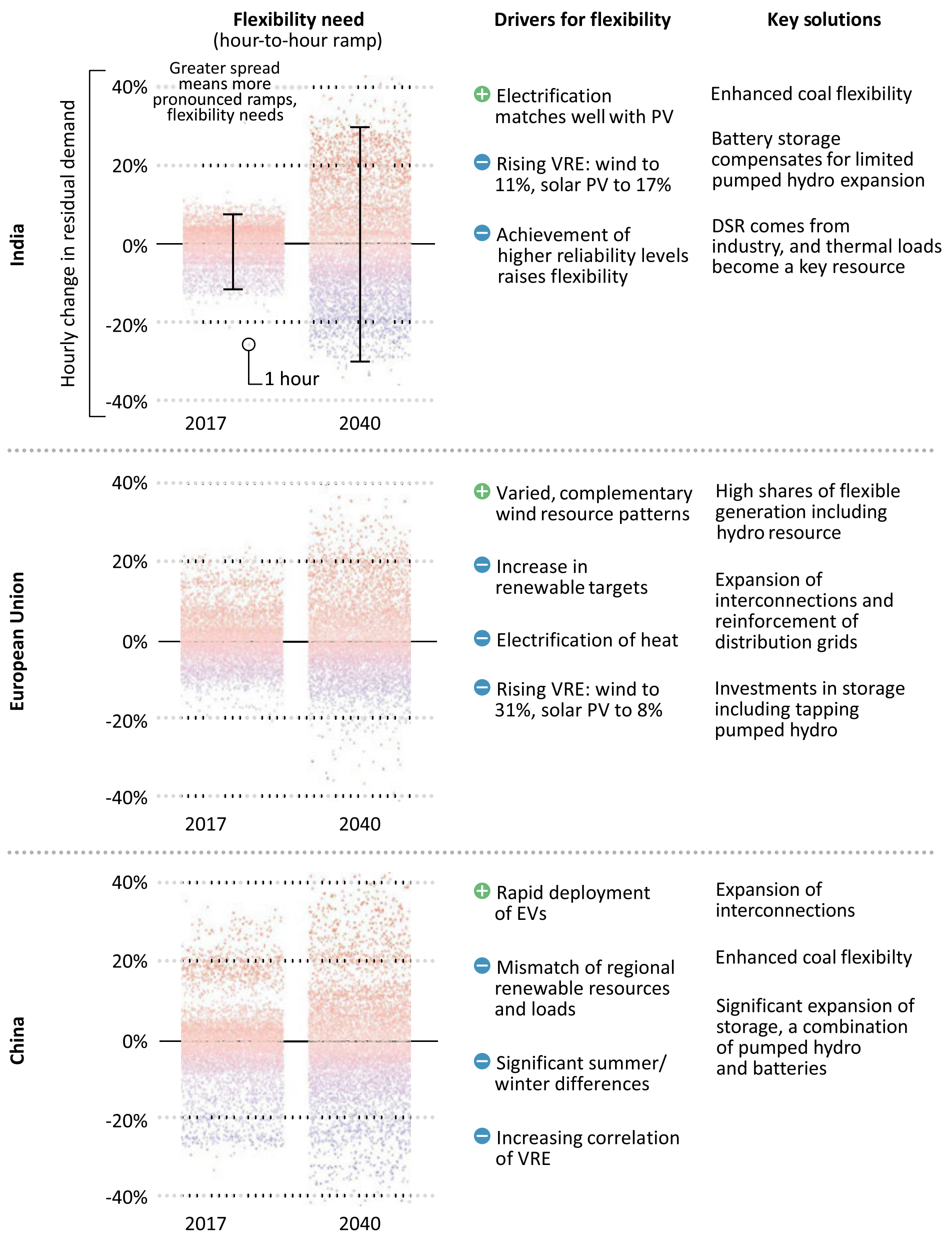


Increasing electricity needs for cooling and transport push up peak demand, but offer flexibility that can reduce system costs and increase security of supply

While flexibility is a multi-faceted issue, the change in the net load from one hour to the next is a robust indicator of overall flexibility need – this is also known as the hourly ramping requirement of the system (Figure 8.24). The more frequent large ramps become, the higher the ramping requirement for the power system becomes, and the greater the need to source more flexibility from existing assets or invest in new sources of flexibility. Increases in VRE are associated with increases in ramping requirements, but there is a range of sources and sinks of flexibility, specific to the geography and local conditions of each region, which shape the strategies that are adopted, together with broader policy and economic trends. As a consequence, needs vary, and so do solutions.

Different flexibility resources can contribute to meet the flexibility requirements of a given system (Figure 8.25). Throughout the outlook, however, power plants remain the cornerstone of system flexibility. VRE increases the variability of net demand, and power plants are able to provide a range of essential flexibility services based on their ability to adjust output, particularly in relation to the minimum level at which output remains stable (minimum turn-down), the rate of change of generation output (ramp rate), and the length of time to start or shutdown. Flexibility is especially important during periods of low demand and high ramping: for example, the average ramp increases during periods of low

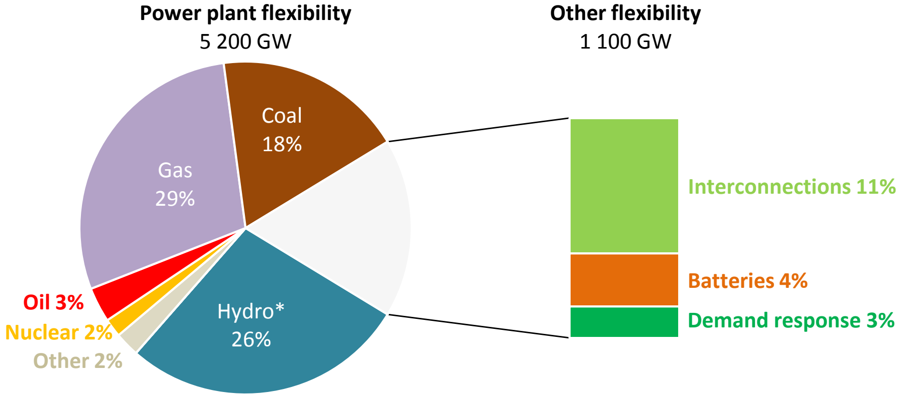
Figure 8.24 ▷ Understanding flexibility in the New Policies Scenario



While flexibility needs increase in all regions in the period to 2040, challenges to flexibility and potential solutions vary widely and are very system-specific

demand by seven-fold in India and three-fold in China in the New Policies Scenario. The flexibility of existing power plants can be improved by retrofitting, while replacement with new more flexible plants is also an option. Changes in policy and regulatory frameworks as well as economic incentives are essential in the New Policies Scenario to unlock the full flexibility potential of existing power plant flexibility and to ensure adequate investment in new flexible power plants, for example through the implementation of markets and mechanisms that explicitly reward flexibility (see Chapter 10).

Figure 8.25 ▷ Potential contribution of flexibility resources in 2040



While power plants remain the cornerstone of flexibility, storage and network investments play an important part in meeting the needs for increasing flexibility

* Includes pumped storage.

8.4.2 Grids provide and enable further flexibility

Grid infrastructure contributes to flexibility by balancing the load between different areas, reducing the amount of ramping that needs to be provided by other resources, and by pooling sources of flexibility from neighbouring areas. Transmission and distribution networks continue to be the backbone of the electricity system, with 77 million kilometres (km) of lines in place today, and an additional investment in 36 million km through the outlook period (in total, enough to cover the distance to Mars and back again). Strengthening and "smartening" grids becomes necessary to increase flexibility: so does investment in distribution networks to facilitate greater use of demand-side response. As a result, annual investment in distribution grids in particular increases by nearly half through the outlook.

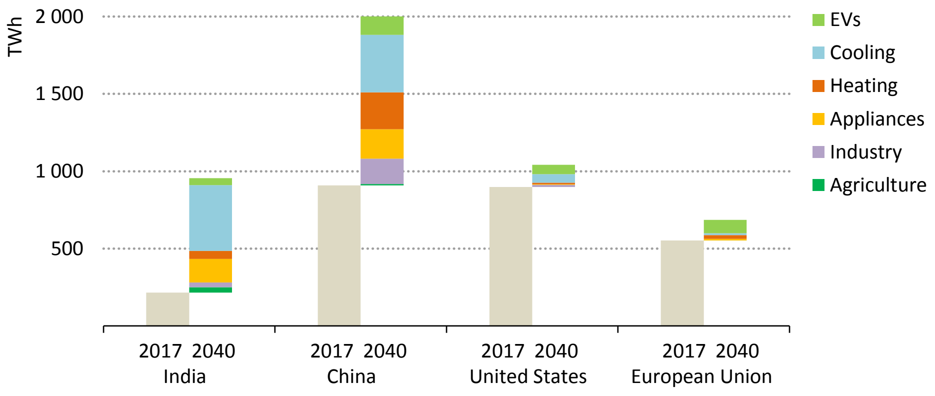
For a number of regions, interconnections are also an important way of increasing flexibility. Interconnections in effect expand the area in which balancing can take place, and in which flexibility can be pooled, thus enabling flexibility to be enhanced by making use of mismatches in demand patterns (for example across different time zones) and in renewable production profiles (for example, across different areas of weather conditions) or by accessing remote energy resources (for example, tapping areas that are rich in wind, solar and hydro resources, but far from demand centres). In China, high-voltage interconnection capacities increase by 280 GW. In the European Union, an additional 100 GW of large-scale transmission interconnections are developed by 2040, with a push for expanding cross-border power flows, reflecting the particular needs and challenges of the EU single market. In India, strengthening of regional interconnections also contributes to greater flexibility.

8.4.3 Demand-side response: the sleeping giant of system flexibility

Until now, the burden of providing flexibility to the electricity system has fallen almost exclusively on the supply side: generation has followed electricity demand from largely passive users. As end-uses electrify and digitalization becomes commonplace, there is growing potential for the demand side also to contribute to flexibility.

Tapping the flexibility of the demand side could transform the increased electrification of end-uses from a potential system burden into a system benefit. In the New Policies Scenario, the potential of demand-side response increases from around 4 000 TWh today to nearly 7 000 TWh in 2040, with over 85% of the increase coming from end-uses in buildings and transport. This represents the sum of flexible loads at each hour of the year, excluding EVs at times when they are expected to be in motion. The size of this potential demand-side response offers considerable scope to reduce peak loads. In the United States, for example, one-third of the projected system peak could be moved to another hour in 2040, and in India up to 40% of the system peak. (Figure 8.26).

Figure 8.26 ▷ Changes in the potential for demand-side response, 2017-40



DSR potential expands to more distributed end-uses in the residential and commercial sectors

Demand-side response represents a major and growing potential for flexibility, and the capacity of demand-side response participation in markets globally increases to some 200 GW by 2040 in the New Policies Scenario, but its potential is far from being fully realised. Industrial and large commercial customers today represent the lion's share of demand-side response capacity available for use. This continues to be the case in the New Policies Scenario, with a lack of policy intervention in many countries limiting the ability of demand-side response to offer flexibility services on an equal basis with the supply side, and with regulatory challenges in some countries for aggregators who wish to tap into the flexibility potential of the smaller end-uses needed to utilise the full potential of DSR.

8.4.4 Energy storage

Storage technologies are diverse and are expanding. Their costs and economic value vary significantly, depending on usage (number of cycles), the volume of energy stored (storage duration), the power required, and the location of the storage asset (behind-the-meter, paired with generation plant on the grid, or as stand-alone facilities).

In the New Policies Scenario, battery storage totals 220 GW in 2040, up from 4 GW in 2017, with the increase in capacity supported by the rise of VRE capacity and by appropriate market design to reward assets for system services. The modularity of batteries, short lead times, wide range of applicability, economies of scale and overall technological progress underpin their explosive growth. Continuing recent trends, many utility-scale battery installations are set to be paired with solar PV and wind power to increase their dispatchability, gain revenues from energy arbitrage and to offer ancillary services to the grid.

Pumped storage hydropower, which currently accounts for 97% of global storage capacity, also continues to expand, albeit at a slower rate than battery storage. Despite a growing shortage of suitable sites in some regions, the installed capacity of pumped hydro increases by two-thirds by 2040, driven by more innovative designs that open new locations and add to existing reservoir hydropower projects. Nevertheless, the very rapid growth in battery storage means that batteries account for almost as much capacity as pumped hydro by 2040.

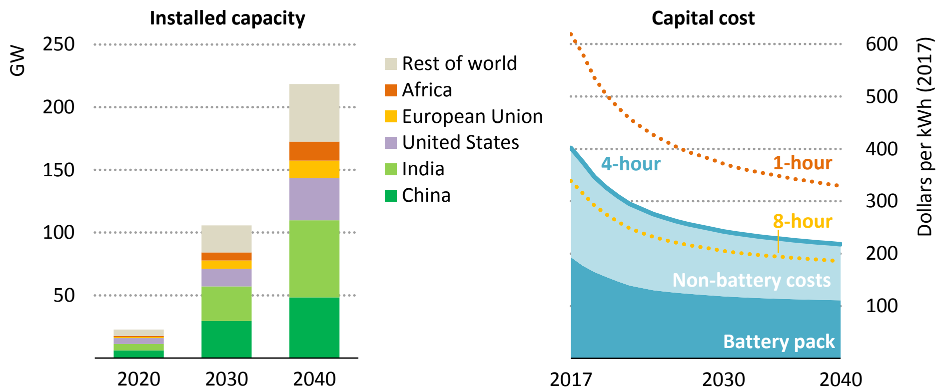
Box 8.4 ▷ Incorporating storage in the World Energy Model

The World Energy Model this year incorporates improved modelling of battery storage. In particular, two types of battery storage deployment are included: utility-scale paired with variable renewables (utility-scale solar PV, wind onshore and offshore) and utility-scale stand-alone systems. Battery storage installations are determined based on the value-adjusted LCOE, taking into account not only the cost of the technology choice but also the value derived from energy, capacity and ancillary service markets. Several durations of storage were analysed, and support the assumption of four hours storage as standard. The scale of storage paired with renewable energy is assumed to be a proportion of the total solar PV or wind capacity installed competitively. Charging and discharging patterns of batteries are applied for daily cycles and are based on hourly simulations. The cost of battery storage is explicitly represented by cost of the battery pack – which is driven by the deployment of EVs – and by balance-of-system costs through global and local learning curves. No specific assumption is made about main battery chemistries.

Because storage competes with other resources to capture the value of flexibility in the outlook, continued cost reductions for battery systems are critically important in sustaining its strong growth. In 2017, about 50% of the costs of a four-hour storage system are taken up by the batteries themselves (Lazard, 2017; BNEF, 2018). About half of the non-battery costs cover climate control, the power management system and the power conversion system, which includes the inverter. Engineering, procurement and construction costs take up around one-quarter of non-battery costs, while the remainder is an amalgam of "soft" costs including customer acquisition, processes for grid connection and project development.

To date, the historic learning rate (i.e. the drop in costs for every doubling of the installed base) for utility-scale projects as a whole has hovered between 12-15%, while for the battery component on its own, costs have followed a steeper 16-22% experience curve. Battery costs are projected to continue to decline at a 20% learning rate, powered by large-scale manufacturing and process improvements for EV batteries, the deployment of which is an order of magnitude higher than grid-scale batteries. Non-battery costs decline at a 15% rate, aided by a combination of economies of scale, digitalization and standardisation that speed up permitting and connection to the grid. As a result, a four-hour battery system falls to about $220/kWh by 2040 (Figure 8.27).

Figure 8.27 ▷ Deployment and costs of utility-scale battery storage systems in the New Policies Scenario



Declining costs for battery storage systems underpin utility-scale deployment to reach 220 GW by 2040, most of which is paired with renewables

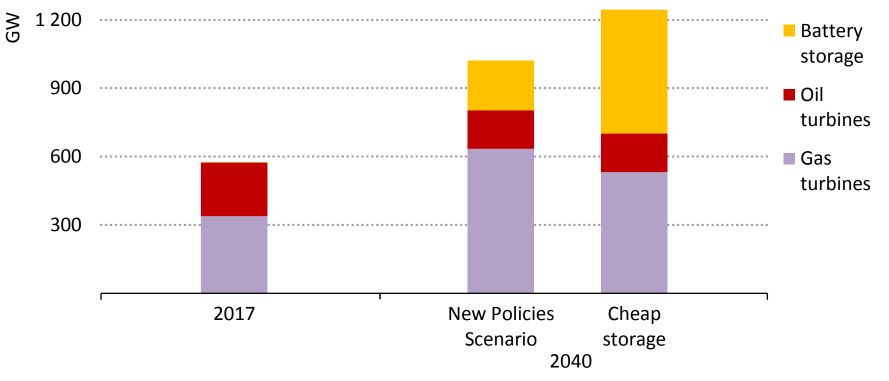
Note: The figure with cost breakdown (on the right) refers to four-hour battery storage.

The need for global peaking capacity is projected to increase by three-quarters to 2040 in the New Policies Scenario. Batteries become competitive on a cost and value basis in many regions in the short term. In India, battery storage becomes competitive soon after 2020. In the United States, batteries close in on gas turbines towards 2030. The cost reductions underpin the strong deployment of batteries in these regions, which make up half of total battery storage capacity by 2040. One of the important consequences of more deployment of storage technologies is a higher overall utilisation of power system assets, translating into a lower risk of overcapacity and higher average revenues for generators.

Box 8.5 ▷ What if battery storage becomes really cheap?

Driven by large-scale manufacturing for electro-mobility, batteries are projected to reduce in cost to around $100/kWh by 2030. Cost reductions achieved in batteries for transport are likely to spill over into power sector applications. In addition, a large number of batteries could be re-purposed after use in an electric vehicle for a second life in the power sector: the reduction in energy storage capacity in a battery that would reduce the range of an electric vehicle to the point where a new battery was needed would not prevent the battery from being useful in grid-scale applications.

Figure 8.28 ▷ Peaking capacity by technology in 2017 and 2040



The availability of second-use batteries and further balance-of-system cost reductions would boost the competitiveness of battery storage

We evaluated the impact on power systems of a more optimistic technological trajectory than the one used for the New Policies Scenario, by assuming the widespread availability of second-use batteries, and a best-in-class reduction in other battery system costs comparable to those experienced in recent years by solar PV systems. On these assumptions, cost reductions would lead to batteries being 70% less expensive than today by 2040, and to battery storage becoming more competitive than alternative options for flexibility several years sooner than in the New Policies Scenario. This would translate into 540 GW of batteries installed by 2040, reducing gas turbines by 100 GW and making battery storage the main technology for peaking capacity by 2040. It would also provide cost savings by avoiding overcapacity in the system and by reducing or deferring the need for some grid infrastructure investment.

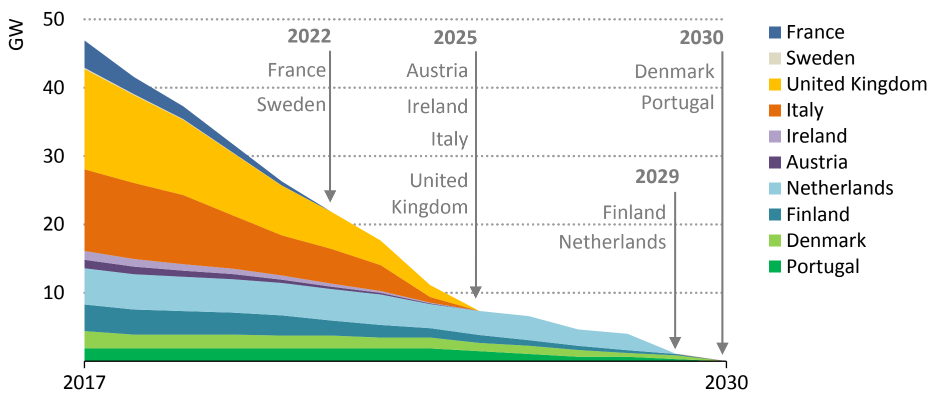
8.5 Regional deep dives

8.5.1 European Union

Recent trends in electricity

The power system within the European Union is undergoing major changes with a growing focus on renewable energy sources, energy efficiency and the electrification of transport and heat for buildings and industry. The Energy Union Strategy[20] depicts a long-term vision for a more secure, sustainable, competitive EU energy market, while providing affordable energy for citizens and businesses. As a part of the "Clean Energy for All Europeans" package, new 2030 targets were set for renewables (32% of gross final consumption) and for energy efficiency (32.5% below the baseline). A revised Emission Trading System (ETS) entered into force in 2018, reinforcing the Market Stability Reserve mechanism, to support a 43% reduction in ETS CO_2 emissions by 2030 compared with 2005.

Figure 8.29 ▷ Plans to phase out coal in the European Union



By 2030, 28% of the existing coal-fired fleet will be retired in line with recent policy announcements

Several national initiatives also support the clean energy transition. For example, utilities in 26 member states have committed to stop building new unabated coal capacity by 2020. Of these, 14 countries joined the "Powering Past Coal Alliance" to close existing traditional coal-fired power plants over the coming decades (Figure 8.29).[21] This is significant as coal is currently the second-largest source of electricity generation in the European Union,

20. A Framework Strategy for a Resilient Energy Union with a Forward Looking Climate Change Policy, presented in 2015.

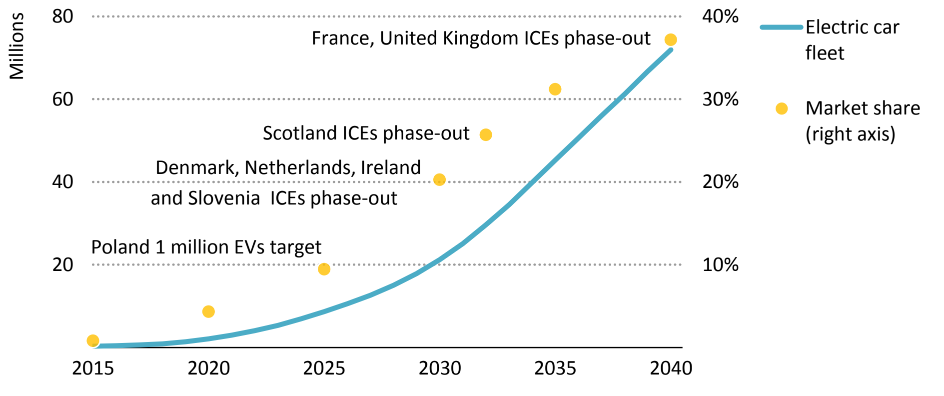
21. This International coalition was launched during COP23 in 2017 by the United Kingdom and Canada, and includes 46 countries, states and cities as well as 28 members from the private sector.

providing 21% of electricity. Nuclear, which accounts for a quarter of electricity generation, is the main source of power generation in the European Union today. However, its outlook is uncertain (see Spotlight in section 8.3.3). These policies imply a further reduction of the traditional backbone of the European power system, providing an opening for new sources of power generation, and in particular variable renewables. Renewables accounted for some 60% of capacity additions built in the European Union over the period 2000-17, with wind alone expanding to 170 GW and matching coal capacity for the first time in 2017.

Electricity demand outlook

Electricity demand started to flatten in the last decade and prospects for growth are limited; in the New Policies Scenario it grows by just 0.4% per year through to 2040. Electric vehicles, fostered by policies, account for three-quarters of the growth. Electricity demand in the buildings sector increases modestly at 0.2% per year as a result of digitalization and electrification of heat. Electricity demand in industry shows a slightly declining trend, in part as a result of projected reductions in chemical sector output and industry-wide efficiency improvements. Cars provide the largest growth in electricity consumption, reaching a share in total electricity of more than 4% in 2040 from less than 0.1% today. The stock of electric cars grows from less than 1 million in 2017 to over 70 million in 2040, with one-out-of-four cars on European Union roads being electric (Figure 8.30).

Figure 8.30 ▷ Electrification of cars in the European Union in the New Policies Scenario, 2015-2040



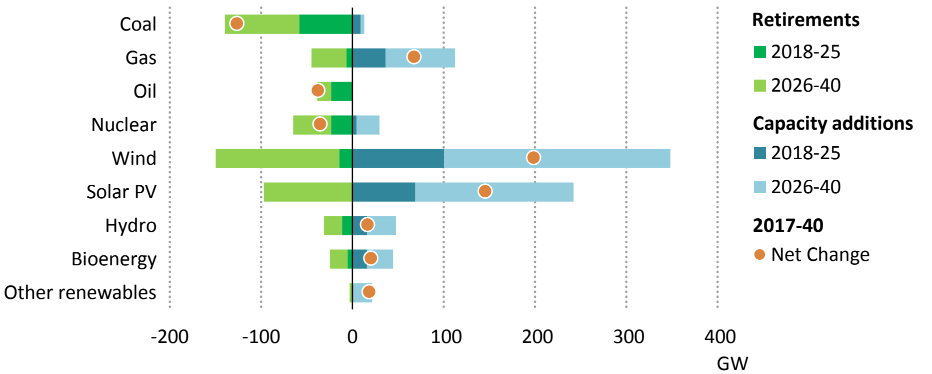
Favourable policies drive rapid escalation in the uptake of electric cars in the European Union

In the short-to-medium term, electrification of mobility is largely the result of stringent CO_2 emissions standards and incentives, and is supported by country and city level initiatives to phase out cars with internal combustion engines. Denmark, Scotland and Slovenia are taking steps in this regard expanding the list of countries that have announced bans on petrol and diesel cars in the coming years, joining the ranks of France, Netherlands and the rest of the United Kingdom. Some cities, such as London, are introducing low emission zones and some others, such as Paris and Rome, also apply restrictions on diesel cars with the ambition to ban diesel car circulation by 2024. These measures, accompanied by investments in charging points create the conditions for further electrification. Increasing EV deployment drives down the total cost of ownership of an electric vehicle, making them competitive with conventional cars by the mid-2020s. Electrification of transport goes beyond cars: the fleet of light-duty commercial vehicles and buses is also progressively being electrified.

Electricity supply outlook

Overall investment needs in the EU power sector total $2.5 trillion over 2017-40 in the New Policies Scenario, one-third for electricity network replacement and extensions, with the majority going to power generation. Most of the 880 GW power plant capacity additions in the European Union over the outlook period are needed to replace the ageing coal and nuclear fleet. The Energy Union targets result in 80% of new plants (and power plant investment) being renewables-based. Most additions are wind installations (40%), followed by solar PV (28%) and gas-fired power plants (13%), which help to ensure electricity supply security, alongside other flexibility options (Figure 8.31).

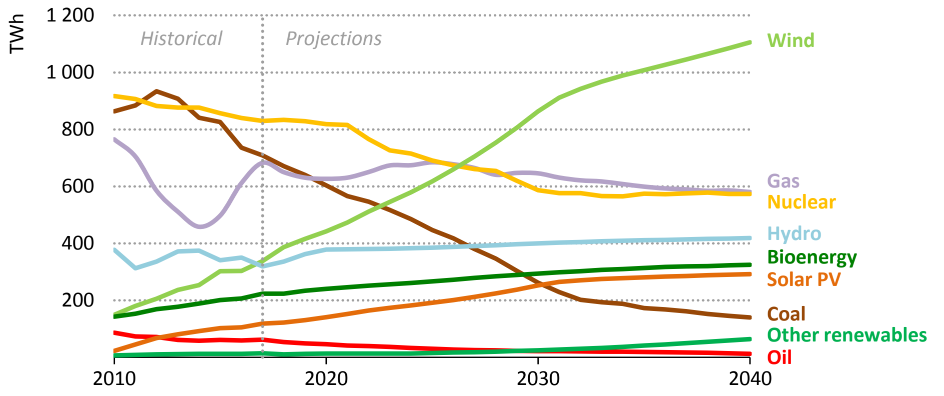
Figure 8.31 ▷ Power generation capacity retirements and additions in the European Union, 2018-2040



Renewables account for about 80% of the 880 GW of new capacity additions in the European Union to replace the ageing fleet of power plants

Traditional sources of electricity generation continue to decline: the reliance on coal shrinks to only 4% of generation in 2040 from 21% today, and nuclear remains the main source of power generation through to 2025, but its share of generation drops by some ten percentage points from 2017 to 2040 (Figure 8.32). Under current and planned policies, wind becomes the first source of electricity generation within a decade, and overall generation from renewables reaches 55% in 2030 (and 63% in 2040). As the share of VRE increases to 40% in 2040, presenting challenges to the power market and electricity grid, requirements for flexibility increase very significantly (see section 8.4 on flexibility).

Figure 8.32 ▷ Electricity generation by source in the European Union, 2010-2040



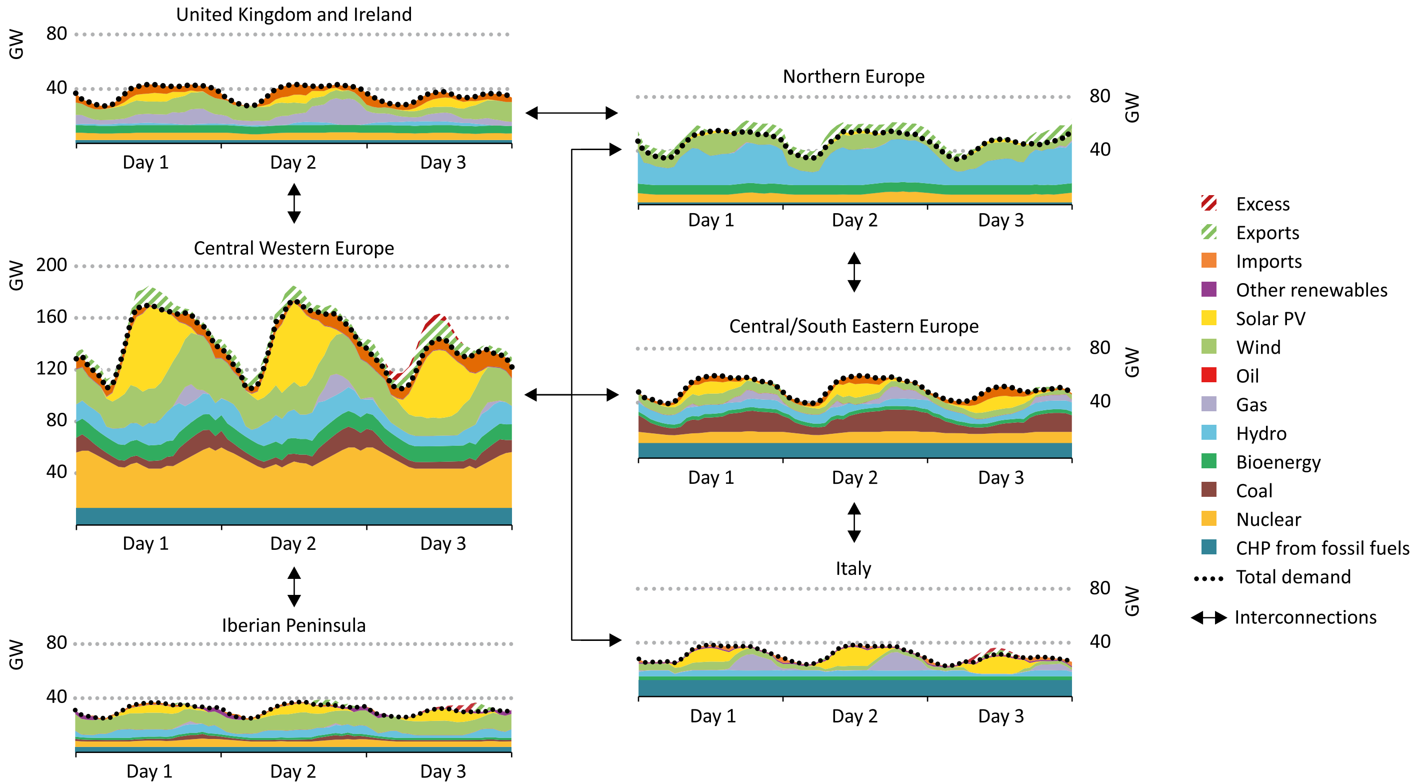
Strong policy support for renewables pushes wind to the fore, gas broadly maintains its market share to provide flexibility

Gas-fired power plants are well suited to a future with increasing contributions from VRE, and retain a market share of around 20%, but the investment environment is challenging. Weak price signals from energy-only markets are making it harder for the operators of gas-fired power plants to recover their investment costs. The design of future power markets is key to ensuring security of supply. The transition to gas as the principal thermal fuel will also require effective co-ordination, adequate fast-draw storage and system stability (see Chapter 4). Grid infrastructure upgrades, demand-side response and storage expansion are crucial to ensure that increasing variable output is put to best use, alongside the contribution that power plants can make.

Pumped storage hydropower has contributed to large-scale grid power management of the European electricity system for decades (around 45 GW in 2017) and remains the dominant source of large-scale energy storage over the outlook period. Today, battery storage represents only a small share of grid-connected storage capacity (a total of 300 MW, mainly in Italy, Germany and United Kingdom), but it is rapidly gaining momentum as costs decline and utility-scale battery storage expands to some 15 GW by 2040.

Cross-border electricity transmission infrastructure between European countries is and will remain central to ensure reliability of the power system (Figure 8.33). National electricity systems are gradually integrating into regional power pools with increasing trade volumes

Figure 8.33 ▷ Hourly electricity generation mix by power pool and electricity trade flows over three sample days, 2030



More efficient use of existing and new interconnections expands the volume of electricity traded

Sources: WEM hourly model; Artelys. (See Box 8.6 for more methodology).

and converging wholesale prices.[22] The planned addition of several new interconnection lines, mainly between Northern Europe, United Kingdom and Ireland, and Central Western Europe, brings the total amount of installed cross-border transmission capacity to around 125 GW in 2030 in the New Policies Scenario. Half of this total connects Central Western Europe to all other regions, enabling it to be the central hub in balancing electricity supply and demand across the Energy Union. A more efficient use of new and existing interconnection facilitates an increase in cross-zone trade flows by 35%. This implies a significant change from today, where only 30% of existing interconnector capacity is made available to the market. The main driver of increased trade within the European Union is cost effectiveness.

The policies adopted to support the climate objective of the Energy Union deliver high levels of renewables generation across all regions in 2030. The integration of these resources are supported by expanded networks. Large additions in wind power electricity generation are expected in the United Kingdom and Ireland (50% of total generation), Central Western Europe and the Iberian Peninsula (around 30% each), as these regions enjoy excellent wind resources. High quality wind sites are also made use of in the Northern Europe power pool, but hydro remains the largest contributor to the generation mix in this region, and provides an important source of flexibility to several others. During periods of low hydro availability, increased imports into Northern Europe enhance the reliability of the region's electricity supply. Solar PV plays a significant role in the south of Europe, supplying some 10% of generation mix in both Italy and the Iberian Peninsula in 2030. The reliance on coal generation in Central/South Eastern Europe declines by almost 40% by 2030 as the mix diversifies with a rise in the use of renewables (over 30% of generation in 2030).

Benefits of the Energy Union

The New Policies Scenario assumes full implementation of the European Union's Energy Union Strategy, and of national policies and measures that are in place or have been announced. Beyond those described in Annex B, it assumes:

- **Timely and adequate expansion of the physical infrastructure** to ensure supply security and avoid network congestion. This includes: sufficient new power plant capacity to balance the load at all times; new interconnection lines between major power pools to allow supply and demand aggregation across larger zones; and deployment of demand-side response and storage to a sufficient level to meet system flexibility requirements.
- **Market design** that ensures efficient investment and operations across the electricity system.[23]

To quantify the costs and benefits associated with the Energy Union Strategy, a "counter-factual case" was built to explore the implications of limited physical interconnections and

22. The European Union transmission zones/regions are specified in Annex C.

23. In-depth analysis on market design for Europe and other areas is in Chapter 10.

a lack of proper investment signals for new flexible power plants. In this case, cross-border interconnections expand to 2027 to the level foreseen by the European Network of Transmission System Operators for Electricity in their "reference grid",[24] but do not expand further. In addition, no improvements to congestion are assumed from 2017 levels. The implications for security of supply, the economic effectiveness of renewables deployment, and consumer bills and electricity network congestion (Table 8.3), using a new expanded analytical set of tools (Box 8.6).

Table 8.3 ▷ Impact of the Energy Union Strategy relative to the counterfactual case on selected indicators, 2030

Region	Shortages	Electricity bill	VRE curtailment	Cross-border network congestion
Europe	-55 hours	-5% (-$20/capita)	-65% (-10 TWh)	-20%
Central Western Europe	↓	↑	↓	↓
Northern Europe	↓	↓	↓	–
Central/South Eastern Europe	–	↓	–	–
Iberian Peninsula	–	↓	–	↓
United Kingdom and Ireland	↓	↓	↓	–
Italy	–	↓	↓	↓

In the counterfactal case, security of supply is more challenging in many parts of Europe. In particular, electricity shortages occur in some pools, and electricity prices see spikes due to these shortages, increasing energy bills. If not supported through co-ordinated actions with other countries, the combination of national initiatives such as coal and nuclear phase out, together with a push for electrification of end-uses, could cause supply disruptions. Resources are allocated less efficiently than in the New Policies Scenario, leading to curtailment of renewables resources (around 15 TWh of generation). Congestion of the network is higher across all zones.

In the New Policies Scenario, investments in generation from renewables, in particular, solar and wind, are more profitable than in the counterfactual case. Because of resource distribution and the importance of gas-fired generation in certain regions, solar PV is most profitable in the Iberian Peninsula, Italy and Central Southern Europe, while wind is most profitable in the United Kingdom and Ireland and Northern Europe. The Energy Union facilitates the optimal use of resources, with higher levels of interconnection allowing generation to flow from countries rich in natural resources (in particular solar and wind) to other countries.

24. ENTSOE Ten-Year Network Development Plan: http://tyndp.entsoe.eu/tyndp2018/.

Box 8.6 ▷ World Energy Model enhancement to assess costs and benefits of the Energy Union

The main World Energy Model (WEM) was expanded and coupled with other tools to provide a detailed picture of the operations of the European Union power system for the analysis of the costs and benefits of the Energy Union.[25]

On the demand side, the model used a detailed analysis to derive hourly electricity demand curves for each one of the 28 European Union countries, plus Switzerland and Norway. Annual electricity demand projections for each end-use sector relied on multiple national macro indicators such as population dynamics and economic growth, integrating the latest policy frameworks and specific national targets. Those were combined with specific end-use sector analysis, looking at economic structure, production levels per final product and trends in energy intensities by fuel for the industrial sector[26], as well as floor area and ownership of appliances per dwelling for buildings. For the transport sector a detailed bottom-up approach was used to model future EV deployment, relying on historical data on stock, sales and plans for road electrification.[27] This disaggregated electricity demand sub-module was coupled with WEM to ensure consistency across the projections, and the aggregate electricity demand of each subsector was matched to the total load profile of a given country.[28]

Power generation capacity expansion at the European Union level was determined in the WEM for each technology, on the basis of the regional levelised cost of electricity combined with modelled estimates of value (for more details on this new metric, the VALCOE, see Box 8.3), with nuclear plans and renewables medium-term trends monitored at the national level.[29] This fleet was then made available for dispatch in the WEM hourly model (106 power plant types – existing and new, of which there were 16 types of renewable energy technologies). The analysis was further complemented by country level projections using Artelys Crystal Super Grid model,[30] simulating the operations of the European Union electricity market in 2030 at the hourly and country level, including an explicit representation of trade flows. Both tools operate on the basis of the short-run marginal operating costs of each plant (which are mainly determined by fuel costs as projected in WEM) and take into account technical constraints for generators, storage and interconnectors. VRE availability constraints were reflected through hourly production profiles for wind power,

25. For the full WEM methodology, see www.iea.org/weo/weomodel/.

26. Harmonised with analysis from the Energy Technology Perspectives, www.iea.org/etp/etpmodel/.

27. Resulting from the Mobility Model: https://www.iea.org/etp/etpmodel/transport/, complemented by Eurostat statistics http://ec.europa.eu/eurostat/data/database.

28. ENTSO-E data to represent the overall load curves of each of the country, www.entsoe.eu/data/.

29. Based on detailed market analysis trends www.iea.org/renewables2018/. Complemented by European Commission for country level insights, https://ec.europa.eu/energy/en/data-analysis/energy-modelling.

30. www.artelys.com/en/applications/artelys-supergrid.

solar PV and hydropower for each country.[31] Cross-border transmission expansion to 2030 includes interconnectors in advanced implementation status from the Projects of Common interest (PCIs) list.[32]

Those complementary tools provided a robust and detailed assessment of European Union electricity systems, allowing us to fully capture the potential of new interconnection lines and to investigate the impact of the renewable energy target.

The Energy Union has the potential to bring about enhanced energy security, lower consumer bills and a better allocation of resources, though effective co-ordination is a necessary pre-condition for achieving these benefits. Policy interactions and co-ordination will be key to avoid unintended consequences. Meeting the 32% renewables target in gross final consumption leads to a 60% reduction in CO_2 emissions from the power sector by 2030 compared to 2005, the reference year for the EU emissions trading system. Although the EU ETS would help to deliver part of the renewable investments, support mechanisms remain an important driver for renewables-based electricity over the outlook period. This could result in reduced demand for ETS allowances and, if the recently reinforced Market Stability Reserve (MSR) mechanism is not sufficient to absorb the surplus, less pressure on the ETS could lead to a CO_2 price signal that is insufficient to incentivise coal-to-gas switching. Coal would then be cheaper to dispatch than natural gas, in the absence of preventive policy or regulatory action. Natural gas would be cheaper to operate than coal if gas prices stabilised in the range of $7.5-8.5/MBtu or if the CO_2 price increased to $50-60/t CO_2. Recent reforms of the MSR have partly reinstated confidence in the ETS, with prices rising from $6/t CO_2 in August 2017 to almost $30/t CO_2 in September 2018.

8

8.5.2 India

Recent trends in electricity

India's energy sector has expanded beyond recognition in recent years. Expected further economic and population growth, allied to structural trends such as urbanisation and industrialisation, point to continued rapid growth in electricity demand. Since 2010, India's population has increased by more than 100 million, and its GDP has grown at an annual average of 6.8%, while demand for electricity has swelled by 7.7% a year. Total electricity demand increased from 730 TWh in 2010 to 1 220 TWh in 2017. However, per capita electricity consumption in India is among the world's lowest (see Chapter 7, Figure 7.5).

31. Compiled from various sources, including EMHIRES database https://ec.europa.eu/jrc/en/scientific-tool/emhires, www.renewables.ninja/, Swiss Federal Office of Energy http://www.bfe.admin.ch/ and Norwegian water resources and energy directorate https://www.nve.no.

32. PCIs are key infrastructure projects, especially cross-border projects, that link the energy systems of EU countries http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html.

More than half of this growth in electricity demand in India is from the buildings sector, which has overtaken industry as the largest consuming sector. Household electrification has been a strong driver of electricity demand growth reflecting a strong policy push: over half a billion people have gained electricity access since 2000. In addition, higher levels of income have allowed households to purchase more appliances: almost 40% of Indian households now own a refrigerator compared to 25% in 2010. The industry sector (predominately textiles) accounted for 30% of the growth from 2010 to 2017, and agriculture another 18%. The coverage of mandatory energy performance standards has expanded: today 10 out of 21 energy efficiency standards are mandatory, compared to only four in 2015 (IEA, 2015). Increasing energy efficiency has avoided an additional 5% of electricity demand over the period 2010-17.

Driven by rapid demand growth, the Indian power sector represents a system in transition. Total generation increased from 1 000 TWh in 2010 to 1 600 TWh in 2017, making India the third-largest electricity market in the world. Coal-fired capacity currently dominates electricity generation (74%), while renewables (16%) and nuclear (3%) have increasing roles. Hydro has long been a part of the system, and solar PV is increasingly the technology of choice thanks to its growing competitiveness. For a good part of the last two decades, efforts have been made to improve the financial health of distribution companies ("DISCOM") in India and enable an environment conducive to sustained investment and improvement in services. The ambitious UDAY scheme, which ends in 2021, will facilitate a new era for DISCOM operations, if it is successful.[33]

Electricity demand outlook

Compared with the last decade, electricity demand growth in India slows in the New Policies Scenario (4.9% on an annual average from today to 2040). Demand triples by 2040 to reach almost 3 700 TWh. Demand growth continues to be driven by economic growth, averaging 6.5% per year to 2040. Despite this growth, India's per-capita electricity consumption remains one of the lowest in the world to 2040, and is a third of the level in China at that time. As the traditional use of solid biomass declines, electricity sees its share in final energy demand increase from 18% today to 24% in 2040.

India's huge infrastructure needs over the coming decades drive the demand for energy-intensive materials, for which India becomes an important manufacturing hub. Industries ranging from chemicals, textiles and food to transport equipment increase their production quickly to satisfy the needs of a larger and more prosperous society, while the "Make in India" programme aims to increase the share of manufacturing in GDP. Light industry's share of overall industry electricity demand increases from 61% in 2017 to 65% by 2040. Over the last ten years, India's Perform, Achieve and Trade (PAT) programme, which benchmarks facilities performance against best practice and enables trading of energy savings certificates, has continued to expand. This has led to improvements, such as the use

33. UDAY (Ujwal DISCOM Assurance Yojana) is a government programme that aims to make DISCOMS financially and operationally healthy so they can supply adequate power at affordable rates.

of variable speed drives to improve motor efficiency. The PAT programme should continue to bring energy efficiency gains.

Cooling systems are also a major driver of increasing electricity demand. The number of households in India owning an air conditioner (AC) has increased by 50% in the last five years. By 2040, two-thirds of households in India are projected to own an AC unit, a staggering 15-fold increase from today. AC performance will significantly shape overall electricity demand in buildings. Currently, the average AC on the market for residential application is typically 50-70% less efficient than readily available models and as much as 2.5-times less efficient than the best available AC models. A similar pattern is apparent in the commercial sector. Minimum performance standards are not keeping up with market developments. Without major improvements in AC performance, electricity demand for space cooling in buildings in India looks set to increase by as much as 700% over current levels by 2040, reaching nearly 800 TWh in 2040, or more than all the electricity consumed in buildings in both India and Indonesia today. About 70% of that growth is expected to come from the residential sector (many offices, shops, hospitals and public buildings already have air conditioning). This will have particular implications for electricity networks, since residential cooling demand tends to peak when the sun has gone down and solar electricity production diminishes.

Electricity access is also a driver of increasing electricity demand. India is on track to deliver universal electricity access well ahead of 2030, and as a result around 180 million people gain electricity access by 2040 in the New Policies Scenario. This adds more than 140 TWh of electricity demand.

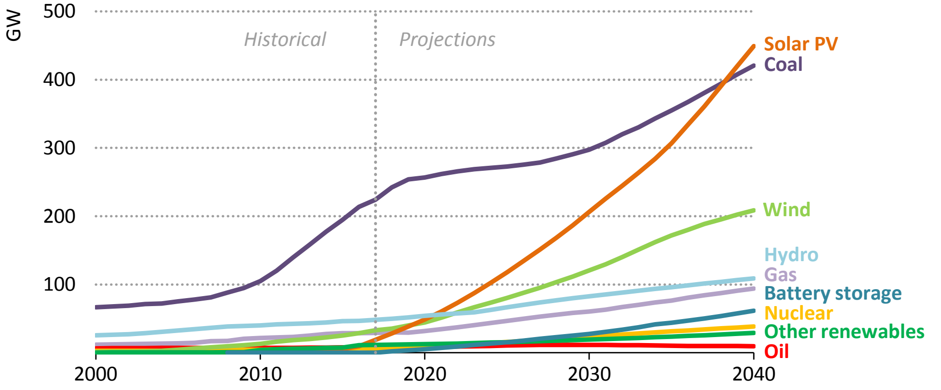
The transport sector contributes a mere 1.5% to electricity demand in India today, but the government has recently announced a 30% target for EVs in 2030. In the New Policies Scenario, the share of transport in electricity demand is projected to be 5% by 2040.

Electricity supply outlook

The design of policies and the effectiveness of their implementation play a critical role in the development of electricity supply in India. The government has set targets for renewables-based capacity of 175 GW by 2022, with 60 GW of utility-scale solar PV, 40 GW of rooftop solar PV, 60 GW of wind power, 5 GW of small hydro and 10 GW of bioenergy. The targets are supported by implementation measures such as land designated for solar development and establishing renewable purchase obligations. There are also plans to expand the nuclear fleet to 63 GW by 2032. The Central Electricity Authority's Draft National Electricity Plan states the aim of deploying no new coal capacity beyond what is under construction from 2022 to 2027. Beyond power plants, efforts are underway to improve the electricity networks, with specific emphasis on expanding interconnections following the creation of a single synchronised national grid.

The nature of the capacity mix in India is on the verge of transformation (Figure 8.34), with solar PV set to play a large role in meeting demand growth and to become the largest among all generation sources (measured by capacity) at 450 GW by 2040. Alongside utility-scale projects, distributed solar PV will be key in helping deliver affordable electricity access to millions, offering an alternative for households and businesses that is sometimes less expensive than utility tariffs for daytime applications. A reduction in the cost of storage would further strengthen the prospects for distributed solar PV. The investment requirements to achieve the rapid scale-up of solar PV and other sources is a major task, particularly considering the challenging financial conditions for DISCOMs today (Box 8.7).

Figure 8.34 ▷ Installed capacity by source in India in the New Policies Scenario



Renewables and battery storage represent 70% of capacity additions to 2040, but new coal capacity is projected in the long term to ensure security

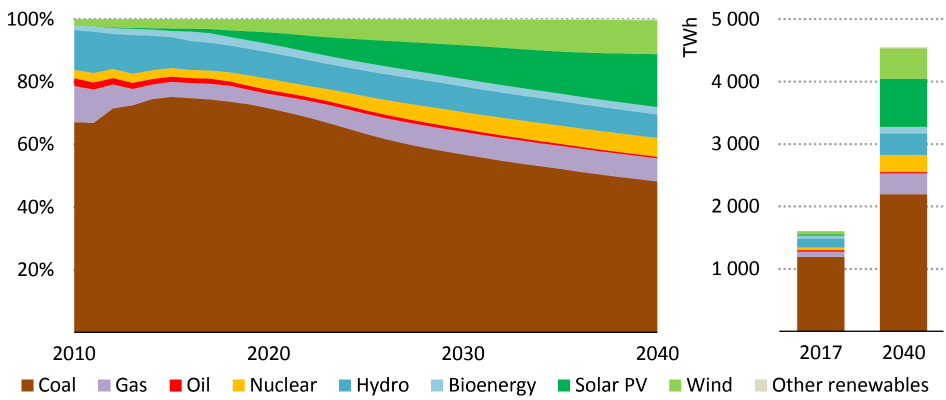
Box 8.7 ▷ Financial challenges of DISCOMs are a critical and recognised issue in India

The poor financial health of many local DISCOMs remains a key structural weakness in India's electricity system. A combination of low average end-user tariffs, technical losses in the network and high levels of non-payment means that revenue often fails to cover the costs incurred by generators in operating and maintaining the system, bringing financial uncertainty to a system in need of strong investment in new sources of generation and network infrastructure. If the rapidly falling costs of solar PV allow distributed generation to expand rapidly, the financial stresses facing DISCOMs are likely to be exacerbated.

Financially sound DISCOMs that can guarantee off-take of power, reduce risk for investors, and provide better terms for financing for renewables capacity are essential to the development of the power sector. As DISCOMs are responsible for most of the investment or off-take agreements for new investment, their financial health and related issues will have to be addressed effectively if they are not to hold back the transformation of the energy system that India needs.

Coal remains the primary source of electricity generation, despite the massive growth of renewables, though its share falls from 74% today to 57% by 2030 and 48% in 2040. The environmental implications of this development are mixed as the absolute amount of coal-fired generation increases over the outlook period, but more stringent regulations on existing and new facilities are expected to reduce the rate of pollutant emissions. CO_2 emissions from the power sector continue to increase, however, from 1.2 Gt in 2017 to 2.1 Gt in 2040, even with a nearly 40% reduction in CO_2 emissions intensity. Progress is also expected in terms of water consumption in the power sector, with the implementation of policies that shift coal-fired power plants to closed-loop systems, an important measure for a country with ongoing water availability concerns.

Figure 8.35 ▷ Electricity generation by source in India in the New Policies Scenario

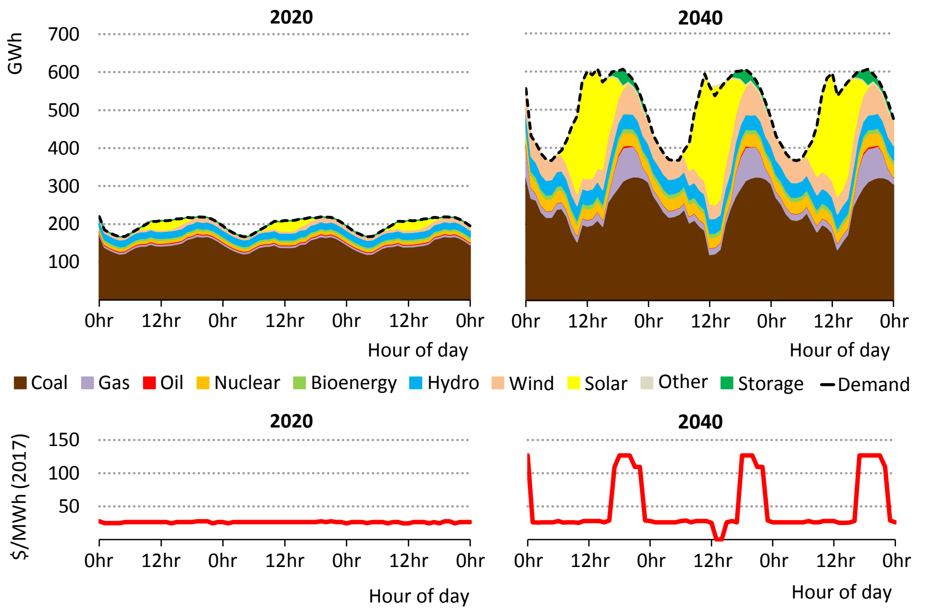


Coal remains the primary source of generation, but the share of renewables expands from 16% today to 38% in 2040

Power system flexibility

Adequate system flexibility is essential to the security and reliability of electricity supply in India in the coming decades. Flexibility needs increase dramatically as the profile of demand becomes more variable, with higher peaks, and as the share of solar PV and wind increases from 4% in 2017 to 28% in 2040 (Figure 8.36). Given the seasonality of India's wind generation and the steep drop in generation from solar at sundown in all the modelled regions, storage looks set to play an important role in the electricity markets. India accounts for 60 GW out of almost 220 GW of global battery storage capacity by 2040. Hydropower also contributes to the flexibility in India's power systems, reaching nearly 110 GW of installed capacity by 2040.

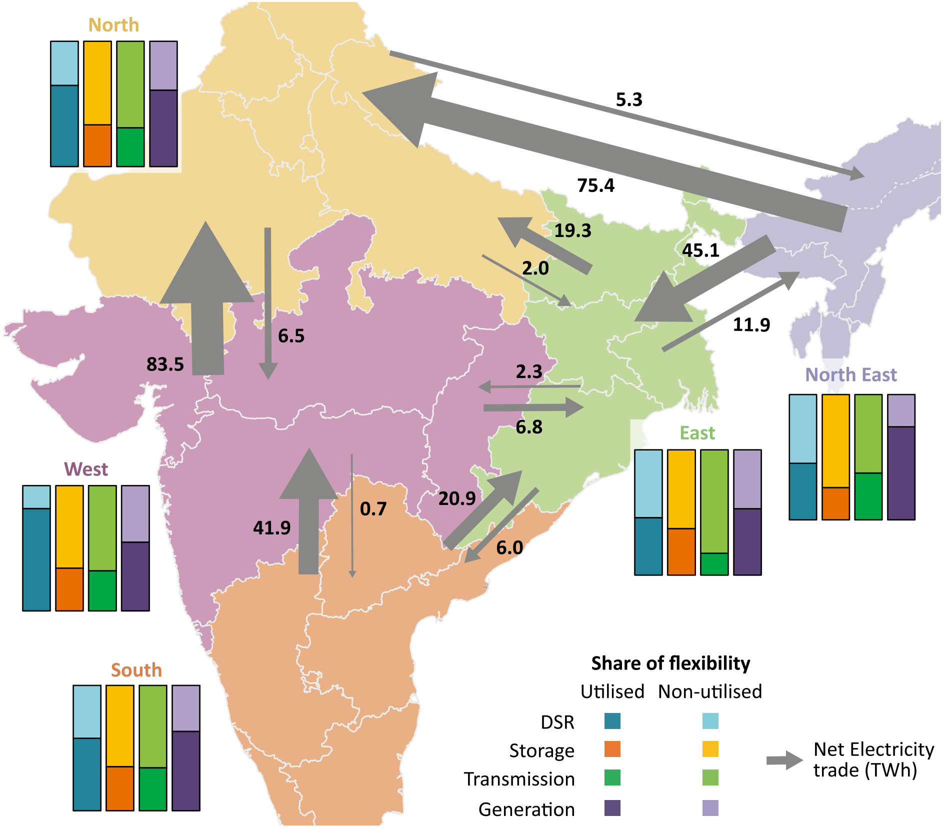
Figure 8.36 ▷ Hourly generation mix and wholesale market price of electricity in India in the New Policies Scenario, 2020 and 2040



The profile of demand becomes more dynamic and VRE account for one-quarter of annual supply, calling for more flexibility in the power system

This higher VRE penetration leads to increased flexibility needs, which were assessed with an expanded suite of modelling tools (Box 8.8). A combination of four flexible resources – power plant flexibility, better interconnections between the five sub-regions, demand-side response and energy storage – helps meet this requirement. The contribution that each of these resources makes varies across regions, reflecting different levels of availability (Figure 8.37). For example, in terms of generation, the northeast region used a high proportion of the flexibility available from hydropower, due to its relatively low operating costs. Given their dominant role in electricity supply, coal-fired power plants are a critical part of the flexibility picture in India, and efforts are underway to enhance their ability to respond to system needs. Use of transmission capacity is similar for each region, with the eastern part being the lowest rate of utilisation of transmission capacity driven in large part by its connectivity with all of the regions. The average use of demand-side response resources is higher in the western, northern and southern regions, driven by the strong presence of wind and solar. Electricity demand for space cooling accounts for a major share of demand-side response potential in all regions, however, barriers exist to tapping this potential, especially in residential buildings. As a result, sources of DSR utilised in our modelling are more diverse, with contributions from water heating (mostly in the north), water pumping in agriculture, electric vehicle charging, commercial refrigeration and certain industrial processes. However, in all of the modelled regions DSR is used at or close to its full potential during times of system stress. Storage shows a more homogeneous use pattern across regions, with the usage level consistent with operation at approximately one daily charge and discharge cycle. Indeed, on most days of the year, available storage is charged and discharged to its maximum.

Figure 8.37 ▷ Regional utilisation of flexibility options versus potential in India in the New Policies Scenario



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

Flexibility from demand-side response measures, storage and transmission are important for accommodating increasing shares of VRE

In the absence of storage or demand-side response, wind and solar output exceed power demand by up to almost 60 GW in some hours. DSR reduces this to less than 6 GW, and storage eliminates all these periods. VRE curtailment due to some generation constraints (such as must-run generation) is about 5 TWh over the course of the year in 2040, meaning that more than 99% of all available wind and solar generation is utilised. These additional flexibility options help to remove barriers that might otherwise limit further deployment of renewables in India. Regulation needs to support an adequate level of capacity to provide supply security, flexibility and stabilisation services to the grid, while avoiding excessive costs to the consumer or to the government, by way of subsidies.

Box 8.8 ▷ World Energy Model enhancement to assess power system flexibility in India

The main World Energy Model (WEM)[34] was coupled with other tools to provide a detailed picture of the operations of India's power system for the flexibility analysis.

Within the WEM, a detailed analysis was performed to derive hourly electricity demand curves for each of the five regions modelled for India. Annual electricity demand projections for each end-use by sector relied on national macro indicators such as population dynamics and economic growth, integrating the latest policy. The potential for DSR by end-use was developed based on the projected demand in each region. Power generation capacity expansion in India was determined in the WEM on the basis of current and proposed policies and the value-adjusted levelised cost of electricity. Projected capacity for existing and new technologies, were made available for dispatch.

The assessment of flexibility was performed in an hourly production cost model,[35] representing the five control regions and the inter-regional transmission connections. Production profiles for renewables were represented,[36] along with operating costs and characteristics for thermal technologies, e.g. minimum stable operating level, ramp rates, minimum up or down times and start-up times. Hourly simulations were based on unit commitment and economic dispatch, considering all available flexibility options, including generators, storage, DSR and imports/exports between neighbouring regions.

These complementary tools provided a robust and detailed assessment of India's electricity system, allowing us to capture the potential of flexibility measures such as DSR, storage and transmission lines to assess the impact of rising shares of VRE.

34. For the full WEM methodology, see iea.org/weo/weomodel/.

35. PLEXOS© was used as the production cost modelling tool.

36. VRE output profiles were based on historical weather profiles from NREL's NRSDB and Wind Toolkit for several thousand sites, with sampling weighted by resource strength and aggregated to each region.

Alternative electricity futures

Electrifying prospects?

SUMMARY

- The world is electrifying, but at different speeds and scales. The potential for further electrification is huge: 65% of final energy use could technically be met by electricity, while today's figure is only 19%. The speed of further electrification depends not just on overcoming economic barriers but also on social and behavioural factors. Future growth in electricity demand is subject to various uncertainties, such as the implications of an increasingly digital world; the pace at which full electricity access is achieved; the amount and efficiency of appliances bought with rising incomes; and the speed of the spread of electricity to new uses such as transport. These issues are explored in the "Future is Electric" Scenario.

- In the Future is Electric Scenario, electricity demand grows to over 42 000 terawatt-hours (TWh) in 2040, about 7 000 TWh above the level of the New Policies Scenario. Part of this growth is due to electrification of services currently relying on fossil fuels, so that electricity meets more than 30% of final energy use by 2040. This is a substantial departure from the New Policies Scenario (Figure 9.1).

- The buildings sector accounts for 40% of the increase in demand relative to the New Policies Scenario, largely as a result of three factors: more digitalized homes; faster electricity access and uptake of appliances in developing economies; and a rise in electric heating, especially heat pumps. In the Future is Electric Scenario, we assume that electric technologies will be widely taken up in this sector as soon as they become cost-competitive, because policy makers remove non-economic barriers.

- Transport sector electricity use rises fastest, albeit from a low base, accounting for one-third of the overall increase relative to the New Policies Scenario. By 2040, nearly 50% of the total car stock is electric (around 950 million electric cars, from 3 million today), along with around 70% of two/three-wheelers. The total cost of ownership of electric cars falls and they become cheaper than conventional cars by the mid- and late-2020s in parts of Europe, and in India and China.

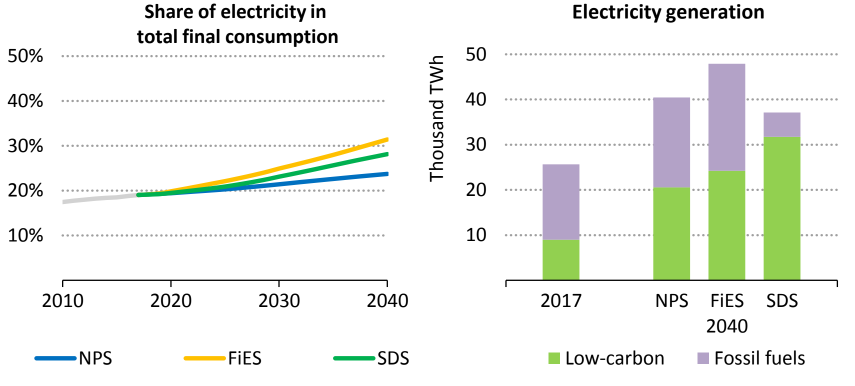
- Electrification of industry is more challenging, absent major technology breakthroughs, but some increases come from using electricity to produce low temperature heat (which accounts for a quarter of industrial heat demand today). Across sectors, more is possible; wild cards for higher demand include hydrogen production through electrolysis, and digital technologies such as crypto-currencies.

- Most power generation technologies grow strongly in the Future is Electric Scenario, and the resulting generation mix is similar to that of the New Policies Scenario. The Future is Electric Scenario does not therefore lead to significant environmental benefits. Carbon dioxide emissions are almost the same as in the New Policies

Scenario and while reduced fuel combustion at the point of use may bring some benefits for local air pollution, total emissions of air pollutants reduce only slightly.

- The Sustainable Development Scenario shows a very different outlook for the electricity sector. Energy efficiency is the most important factor for reaching the Sustainable Development Goals most closely related to energy, and considerable efforts on energy efficiency temper electricity demand growth in this scenario. As a result, total electricity demand is around 7% lower than in the New Policies Scenario by 2040. Electrification nevertheless features strongly in the Sustainable Development Scenario: a switch to electric end-uses means that electricity accounts for more than 40% of useful final energy in 2040, a 16 percentage point increase on today.

Figure 9.1 ▷ Share of electricity in total final consumption and share of low-carbon electricity generation by scenario



The Future is Electric Scenario sees the highest rate of electrification, but more low-carbon generation and energy efficiency are needed in the Sustainable Development Scenario

Notes: NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario. Fossil fuels category excludes electricity generation from plants using CCUS technology.

- In the Sustainable Development Scenario, power generation is all but decarbonised by 2040: 85% of global generation comes from low-carbon sources, compared with 51% in the New Policies Scenario, and 35% today. Emissions of outdoor air pollutants also fall sharply, due to lower thermal generation. By 2040, wind and solar photovoltaic (PV) account for almost 40% of generation. Nuclear and power plants fitted with carbon capture, utilisation and storage (CCUS) account for 13% and 6% of generation respectively in 2040.

- The need for system flexibility increases in the Sustainable Development Scenario as the average share of variable renewables reaches a level that only Denmark has reached today. This means that some regions need to integrate shares well beyond where any region is today. The level of flexibility required depends on the portfolio of variable renewables and the power mix in each country.

9.1 Introduction

As with all *World Energy Outlook (WEO)* scenarios, the electricity outlook presented in the previous chapter is not a forecast. It is a projection of how the electricity system could evolve if today's policies and plans do not change. In rapidly evolving sectors, with changing policy and technology landscapes, many other pathways are possible. This chapter looks at alternative futures for the electricity system, exploring what would happen to electricity demand and supply under different assumptions about policies and technological trends.

Electricity is at the heart of modern economies. It is the second most-used energy source globally, after oil, and currently accounts for 19% of total final consumption. Electricity use is growing fast, powering an expanding industrial sector in developing economies and supporting a growing middle-income class buying more electric appliances and devices. Electricity is also crucial for our increasingly digital world, not only to charge our smartphones and power our computers, but also to enable the exponential growth of data that has become central to daily life, with ever-expanding needs for data storage and processing (IEA, 2017a). The rate of electricity demand growth however is one of the major uncertainties in the energy sector today. Gaining a better understanding of how the sources of uncertainty vary across countries and how they are influenced by policies is central to designing a secure and sustainable electricity system for the future.

To shed light on these uncertainties, this chapter:

- Presents the "Future is Electric" Scenario, which starts with the New Policies Scenario and explores what would happen if specific policies and technology cost reductions were to lead to a substantially faster pace of electricity demand growth. The drivers of electricity demand growth considered include the electrification of existing energy services currently supplied by other fuels (such as transport and heating) and the effect of new or expanded energy services requiring electricity (such as an increasingly digital economy and the provision of electricity access to the nearly 1 billion people still without it). The scenario also quantifies the implications of higher electricity demand for electricity supply, security and the environment.
- Takes a deep dive into the role of electricity in achieving the Sustainable Development Scenario. In the Future is Electric Scenario, policies leading to increased electricity demand are not accompanied by further policy changes affecting electricity supply and, as a result, emissions. So, for example, a faster uptake of electric vehicles might not be supported by new policies to decarbonise the power sector. The Sustainable Development Scenario, on the other hand, sets out an integrated pathway to simultaneously achieve key energy-related SDGs, namely universal energy access, substantially reducing the health impacts of air pollution and reducing carbon dioxide (CO_2) emissions in line with the Paris Agreement. The two scenarios have very different implications for electricity. (For a discussion of how the Future is Electric and Sustainable Development scenarios differ, see Box 9.6).

9.2 Pushing the frontiers of electricity demand

9.2.1 Overview of demand in the Future is Electric Scenario

Identifying uncertainties for electricity demand

The Future is Electric Scenario starts from the conditions of the New Policies Scenario and explores key areas of uncertainty for future electricity demand. One main type of uncertainty relates to increased electricity demand for new or expanded energy needs. For example, in countries where substantial numbers of people still lack access to electricity, governments are pushing to achieve full electrification by 2030, but the speed of uptake and level of consumption of newly connected households may vary. At the same time, cooling needs and appliance ownership in developing economies are driving up electricity demand, as millions of consumers purchase air conditioners for the first time, and the pace of uptake and level of use of such appliances is uncertain (IEA, 2018a). Another example of this kind of uncertainty is the energy needs of digitalization.

Another main type of uncertainty relates to the electrification of end-uses, and the extent to which electricity can provide services that previously relied on other fuels. For example, rapid cost declines in batteries have induced several jurisdictions to introduce policies that favour the electrification of transport. Such measures have been swiftly rising up the policy agenda in many countries as governments seek to lead on new technologies and to reduce urban air pollution.

To make sense of these uncertainties, our analysis takes a sector-by-sector and region-by-region approach to identify levers for increased electricity demand, using the macroeconomic and policy backdrop of the New Policies Scenario (including for policies related to energy efficiency). The key uncertainties we explore are:

- **Electricity needs in a digital world**: In what ways will the increasing digitalization and connectivity of our homes, businesses and vehicles transform electricity demand? In the Future is Electric Scenario, we assess the electricity demand implications of a faster uptake of connected devices, creating higher demand in homes and from data centres. Connected devices are everywhere and are set to expand, creating vast amounts of data that require electricity for processing and storage. While data centres have made significant progress in energy efficiency in recent years, future processing needs are a key source of uncertainty (see Chapter 8, Box 8.1). The demands of new digital technologies such as crypto-currencies further add to this uncertainty. But digital technologies are not only a demand source – they also have a crucial role to play in underpinning the smart, flexible power grid of the future (see Chapter 7, section 7.4).
- **Electricity access and subsequent uptake of appliances**: Providing first-time electricity access to those still deprived is an important milestone, but what are the likely implications for electricity demand of the improving livelihoods of millions of lower and middle-income families in developing countries? In the Future is Electric Scenario, as well as achieving universal electricity access by 2030, we assume a higher rate of

uptake of electric appliances among households who have recently gained access to electricity. The level of ownership of appliances is a major uncertainty for electricity demand. In developing countries, ownership rates still lag far behind advanced economies – in 2017, for example, there were 0.7 refrigerators per dwelling, less than half the rate in advanced economies. Demand for space cooling is also expected to increase rapidly, in particular in developing economies. In India only 5% of dwellings currently have an air conditioner, compared with over 90% in Japan.

- **Electrification of space heating, transport and industry:** How large is the technical and economic potential for electric cars, buses and other means of electric transportation? How large is the economic potential for electric heat pumps in buildings? How far can electricity – and hydrogen produced by electricity – reasonably go in powering industrial processes? In the Future is Electric Scenario, we assess the economic potential for the electrification of key processes, and how quickly electric end-uses might ramp up once they become cost-competitive with other fuels.

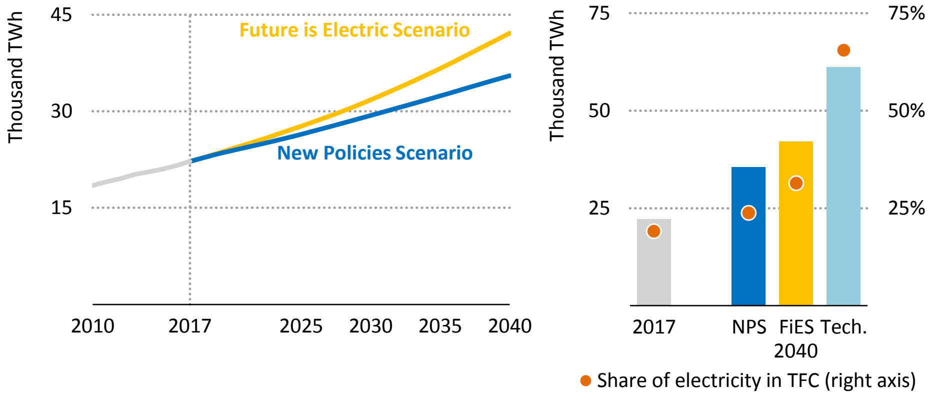
Electricity demand in the Future is Electric Scenario

Widespread deployment of currently available technologies could take the proportion of electricity in final energy use from 19% to a maximum technical potential of around 65% – for example, if heat pumps become widespread in industry, if electric vehicles (EVs) take over on the roads, if all heat in buildings is provided by heat pumps, if induction stoves become the only mode of cooking, and so on. The potential for higher electrification therefore is very large, even though around 35% of final consumption would still require other energy sources, including most shipping, aviation and certain industrial processes.

In reality, electric end-use technologies are in many cases not yet economically competitive with fossil fuel counterparts because of equipment costs and in some cases taxation of electricity. However, they are also held back by other barriers not related to overall cost of ownership, such as high up-front costs (even if running costs are low), split incentives (such as between tenants and landlords), preferences for sticking with existing technology, and complexity in replacing only parts of industrial systems. Together, these factors prevent the full technical potential of electric technologies being realised.

In the Future is Electric Scenario, policies succeed in removing non-economic barriers to the deployment of electric end-use technologies, so that they are widely taken up as soon as they become cost-competitive. This means that they come closer to achieving their maximum technical potential. The result, combined with rapid digitalization, electricity access and uptake of appliances, is that total electricity demand in the Future is Electric Scenario increases by around 3% per year through to 2040, maintaining the level of growth seen in 2017 and on average since 2000. Total electricity demand reaches over 42 000 terawatt-hours (TWh), 19% more than in the New Policies Scenario (Figure 9.2). However, demand only starts to outstrip the New Policies Scenario after 2025, once major electric technologies become cost-competitive with fossil fuels (on a total cost of ownership basis). By 2040, the scenario sees additional demand equivalent to more than today's electricity use in China, on top of the growth expected under current trends.

Figure 9.2 ▷ Electricity demand and technical potential for electricity demand in the Future is Electric and New Policies scenarios



Electricity demand in the Future is Electric Scenario is about 7 000 TWh higher than in the New Policies Scenario by 2040, but is still far from the technical potential of electricity

Notes: NPS = New Policies Scenario; FiES = Future is Electric Scenario; TFC = total final consumption. Tech. refers to the electricity demand where electrification is pushed to its maximum technical potential as assessed by IEA analysis.

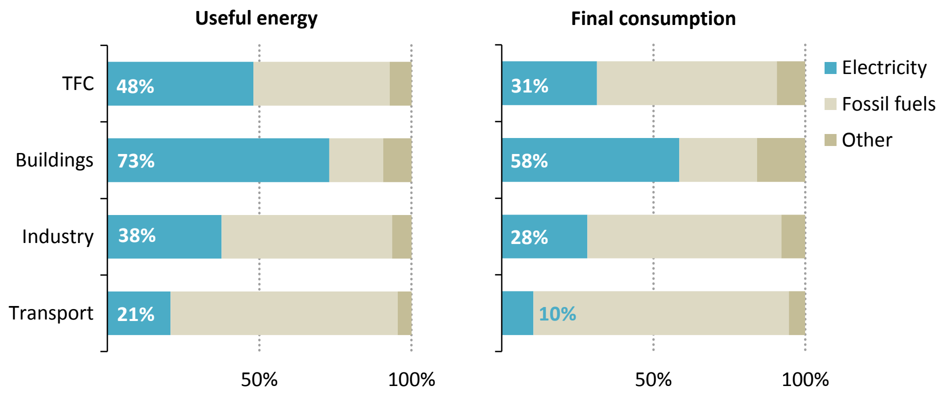
This increased electrification means that the proportion of electricity in final energy consumption rises to 22% of energy consumption globally by 2025, and to more than 30% by 2040 (Table 9.1). The share of electricity is even higher when measured in terms of useful energy, once conversion losses at the point of use are taken into account (Figure 9.3). Electricity provides nearly half of all useful energy (also known as energy services demand) in the Future is Electric Scenario, including over 70% of useful energy in buildings.

Table 9.1 ▷ Global electricity demand by sector in the Future is Electric and New Policies scenarios

Indicator	Sector	2017	2025		2040		CAAGR: 2017-40	
			NPS	FiES	NPS	FiES	NPS	FiES
Electricity demand (TWh)	**Total**	**22 209**	**26 417**	**27 676**	**35 526**	**42 133**	**2.1%**	**2.8%**
	Buildings	11 416	13 440	14 220	18 634	21 329	2.2%	2.8%
	Industry	8 945	10 630	11 087	13 074	14 757	1.7%	2.2%
	Transport	378	660	695	1 861	4 174	7.2%	11.0%
	Other	1 470	1 687	1 673	1 957	1 872	1.2%	1.1%
Share of electricity in sector consumption	Buildings	32%	35%	41%	43%	58%	1.2%	2.6%
	Industry	21%	21%	23%	23%	28%	0.4%	1.4%
	Transport	1%	2%	2%	4%	10%	6.0%	10.0%

Notes: CAAGR = Compound average annual growth rate; NPS = New Policies Scenario; FiES = Future is Electric Scenario; TWh = terawatt-hours. Other includes electricity demand from agriculture and energy transformation sectors.

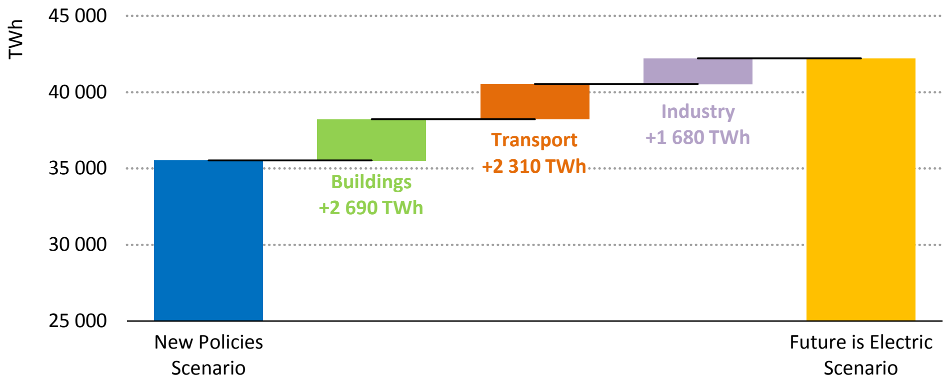
Figure 9.3 ▷ Electricity as a share of useful energy delivered and of total final consumption in the Future is Electric Scenario



The share of electricity is even higher when measured in terms of useful energy delivered, meeting over 70% of energy service needs in buildings

Notes: TFC = total final consumption. Useful energy refers to the energy that is available to end-users to satisfy their needs. This is also referred to as energy services demand. Due to transformation losses at the point of use, the amount of useful energy is lower than the corresponding final energy demand for most technologies. Equipment using electricity often has higher conversion efficiency than equipment using other fuels, meaning that for a unit of energy consumed electricity can provide more energy services.

Figure 9.4 ▷ Change in electricity demand by sector in the Future is Electric Scenario relative to the New Policies Scenario, 2040



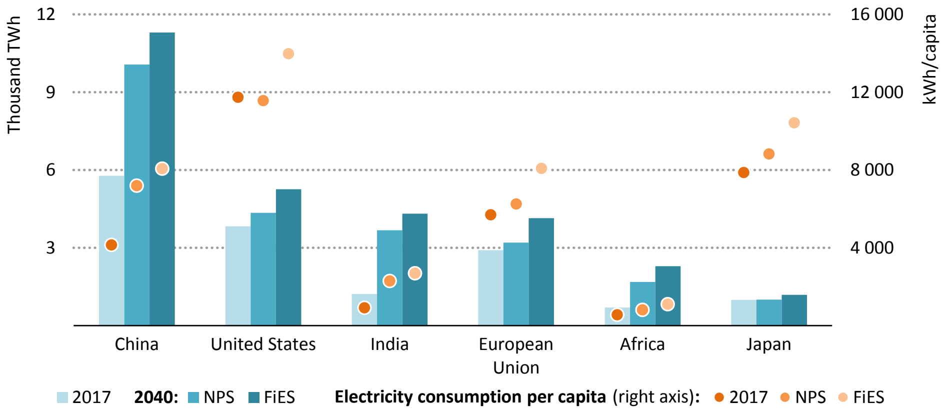
The largest total demand increase in the Future is Electric Scenario is in buildings, due to the combined impact of electrification of heat, digitalization and electricity access

Note: Other sectors (not shown) contribute a decrease of 80 TWh, mostly in the oil and gas sector due to lower oil demand.

The buildings sector accounts for 40% of the increase in demand, 60% of which is due to electrification of space and water heating, split equally between advanced and developing economies. Transport accounts for one-third of the increase and shows the fastest growth of all end-uses through to 2040. Electrification of industry accounts for the remainder: its scope for electricity demand growth is more limited (Figure 9.4).

Across regions, developing economies account for most of the demand increase (Figure 9.5). The highest overall demand – and the biggest global increase – is seen in China, accounting for one-fifth of the increase in demand over the level in the New Policies Scenario. India and Africa each account for about 10% of the increase. Among the advanced economies, the European Union and the United States each contribute around 14% of the increase.

Figure 9.5 ▷ Electricity demand in the Future is Electric Scenario by region (total and per capita)



All regions see higher electricity demand in the Future is Electric Scenario; in advanced economies per-capita electricity demand rises by over 20%

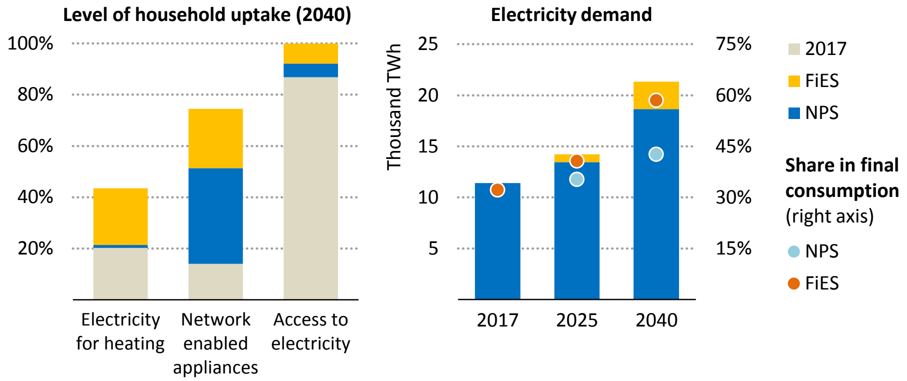
Note: FiES = Future is Electric Scenario; NPS = New Policies Scenario; TWh = terawatt-hours; kWh = kilowatt-hours.

9.2.2 More electrified and digital homes and services

Three main sources of electricity demand in buildings, and the uncertainties around them, are particularly important in the Future is Electric Scenario (Figure 9.6):

- The provision of electricity access to first-time consumers and the subsequent uptake of appliances in developing countries, including for cooling.
- Increasing digitalization in homes, and in particular increases in network-enabled digital appliances that create additional demands for data processing.
- The uptake of electric space heating as it becomes increasingly cost-competitive.

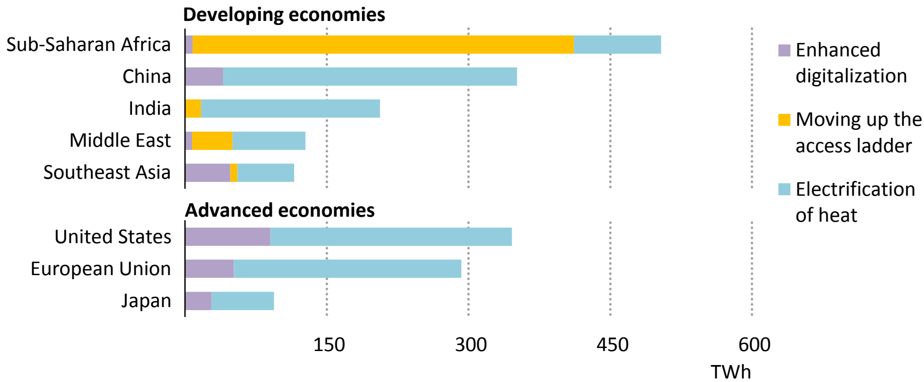
Figure 9.6 ⊳ Drivers of electricity demand growth in buildings by source and impact on electricity demand in the Future is Electric and New Policies scenarios



Electricity demand growth in the Future is Electric Scenario accelerates after 2025, as electrification of heat becomes competitive and universal access to electricity is achieved

Notes: NPS = New Policies Scenario; FiES = Future is Electric Scenario. Access to electricity denotes share of households with an electricity connection.

Figure 9.7 ⊳ Change in electricity demand in buildings by region in the Future is Electric Scenario relative to the New Policies Scenario, 2040



Sources of additional electricity demand growth vary considerably across regions, with space heating dominating in advanced economies

In the Future is Electric Scenario, sources of additional electricity demand from buildings vary considerably among regions (Figure 9.7). In sub-Saharan Africa, the provision of electricity access and the subsequent uptake of electric appliances by new consumers make up a large part of additional demand. In advanced economies, opportunities for electric space heating make up the majority of additional demand, a reflection of the generally colder climate and therefore higher heating needs in those countries. In China, also, electric space heating makes up the majority of additional demand. This reflects a push to move away from reliance on coal for heating in the colder provinces of northern China, combined with falling costs making electric heating increasingly competitive. Increased electricity use due to increased uptake of digital devices and appliances is an important but minority share across all regions.

Moving up the ladder: providing electricity access is only the start

Providing first-time electricity access to those without it is a crucial pillar of sustainable development. The impact on electricity demand of those first-time connections is itself relatively modest (IEA, 2017b). However, the rate at which new electricity consumers in developing countries subsequently move up the electricity ladder, for example by acquiring appliances and space cooling devices, is a source of uncertainty for electricity demand.

In the Future is Electric Scenario, full electricity access is achieved by 2030, in line with Sustainable Development Goal (SDG) target 7.1. This means an extra 650 million connections, on top of the 570 million people who stand to benefit from first-time access under current policies and plans. These additional first-time connections represent 4.4% of the growth in electricity demand to 2040 in the Future is Electric Scenario. Globally, the increase in electricity demand due to electricity access to 2040 is 870 TWh, double the increase in the New Policies Scenario by 2040.

In the Future is Electric Scenario, those who gain access to electricity also go on to make fuller use of this access more quickly than in the New Policies Scenario. Electricity demand is pushed higher as those with first-time connections more quickly approach the appliance ownership levels of the middle class. This is already happening in some countries, such as Kenya and Tanzania, where inexpensive appliances are provided as part of first-time electricity access kits.

More rapid growth of appliance ownership contributes an additional 80 TWh to electricity demand in 2040. The impact is most pronounced in regions with the lowest electricity access rates today, notably sub-Saharan Africa, where an additional 580 million people gain electricity access by 2030 in the Future is Electric Scenario relative to the New Policies Scenario – around 40% of the population at that time. Higher demand due to electricity access and more rapid uptake of appliances contributes to per-capita electricity consumption in sub-Saharan Africa increasing by 150% from today to reach 930 kilowatt-hours per capita (kWh/capita) in 2040.

Providing access to clean cooking facilities is another key dimension of the energy access challenge. Policies targeting the provision of clean cooking solutions to date have focussed mainly on improved biomass cookstoves and liquefied petroleum gas (LPG), with a role for natural gas in some urban areas. However, new technologies mean that electric cooking is an increasingly viable option in both rural and urban areas, and a joint approach to electricity access and clean cooking access may further increase the attractiveness of electric cooking (Box 9.1).

Box 9.1 ▹ Sunny-side up: electricity for clean cooking

Relatively little attention has been paid to the potential for electric stoves to displace solid fuel for cooking, though some 1.7 billion of the 2.7 billion people without clean cooking access already have an electricity connection. There are several explanatory factors. Where supply exists, electricity may be unreliable or more expensive than other alternatives, including LPG. Using electricity for cooking may have potential implications for the adequacy of networks and generation capacity: for households using electricity for lighting, phone charging and a television, electric cooking can increase annual electricity demand by more than five-times (IEA, 2014), with a bigger impact on peak demand. There are also cultural and behavioural barriers to the uptake of electricity for cooking, such as a preference for food cooked over an open flame.

Nevertheless, electricity for cooking presents an opportunity, particularly as governments are striving for universal electricity access. New and efficient electric cooking technologies may offer additional potential: electric induction stoves have become relatively inexpensive (costing as little as $15), and they have a heating performance similar to LPG. There is already a mature market for electric induction stoves among urban households in India and some other countries. Pressure cookers, rice cookers and insulated pots are other options: with appropriately sized battery systems, they can operate with an unreliable grid or with variable renewable electricity supply.

In addition, recent research suggests that jointly planning clean cooking and electrification has significant co-benefits and may offer further opportunities. A study conducted for this report[1] covering a representative region of east Africa uses an electrification planning model to show how increased electricity demand from electric cooking can decrease the unit costs of electricity from both on- and off-grid supplies, potentially lowering household energy bills. Joint planning of clean cooking and electricity access results in electricity costs of $0.21/kWh, with the average cost of cooking a meal falling to $0.33, making electric cooking more competitive than LPG for over 80% of households. Conversely, without co-ordinated planning, electricity costs are 50% higher, with average cooking costs per household meal of $0.51 when using electricity, well above the LPG average of $0.44 per meal.

1. This analysis has been developed in collaboration with the MIT-Comillas Universal Energy Access Lab, based on the Reference Electrification Model, http://universalaccess.mit.edu/#/rem.

Affordability is also a key concern as consumers move beyond energy access to acquire and use electric appliances. For example, space cooling is an important potential source of new electricity demand in developing economies. Cooling needs are high in developing countries, but ownership rates of cooling systems are often low currently due to lack of electricity access and the cost of cooling equipment. The average ownership rate is only 8% in the hottest developing countries (IEA, 2018a), compared with more than 90% in Japan and the United States. In very hot countries with relatively wealthy populations, cooling demand is already very high: in Saudi Arabia, cooling demand in 2017 accounted for around 50% of electricity demand, equivalent to around 300 thousand barrels per day (kb/d) of oil, or more than 2% of the country's oil production. As average wealth rises, space cooling represents a substantial source of demand, which is already included in the New Policies Scenario: for example household cooling demand in India increases from less than 50 kWh/capita today to over 330 kWh/capita in 2040.[2]

Digitalization and the impacts of an increasingly plugged-in world

Even in the New Policies Scenario, the share of total appliances electricity demand accounted for by connected devices increases from around 15% of appliances demand today to nearly 50% by 2040. In the Future is Electric Scenario we see a more rapid penetration of digital devices as the "internet of things" more rapidly becomes the global norm, with connected devices growing to account for three-quarters of appliances electricity demand by 2040, as things like televisions, refrigerators and other plug loads in buildings are increasingly equipped with a data connection as well as an electricity connection. This accelerated digitalization means that electricity demand from appliances and other connected equipment such as air conditioners increases in 2040 by 420 TWh more in the Future is Electric Scenario than in the New Policies Scenario.

The substantially higher share of connected devices leads to increased demand for storage and processing of data, though the electricity demand implications of this are initially offset by efficiency improvements. Data centre electricity demand in the Future is Electric Scenario is about the same as in the New Policies Scenario in 2025, but by 2040 it is 30% higher, an extra 100 TWh. Such longer term projections of data demands are however fraught with uncertainty. One key source of uncertainty relates to the level of uptake of bitcoin and other crypto-currencies (Box 9.2).

Accelerated digitalization would impact demand in different ways across regions. Advanced economies see a significant level of digitalization even in the New Policies Scenario, meaning that additional electricity demand from digitalization is modest in the Future is Electric Scenario. Further digitalization also leads to the rationalisation of devices, tempering the size of this increase: for example, smart phones are increasingly replacing other devices such as cameras. In developing economies, more rapid digitalization means a big jump in

2. Although not explored in the Future is Electric Scenario, an additional major uncertainty for cooling demand is the average level of efficiency of new cooling equipment (IEA, 2018a).

associated electricity demand, reflecting their lower starting point today and the slower pace of growth built into the New Policies Scenario.

Box 9.2 ▷ Miner growth: energy use of blockchain and crypto-currencies

Of all the potential implications of blockchain technologies for the energy sector, the rising energy use of crypto-currencies – and bitcoin in particular – has attracted the most attention in recent months (see Spotlight in Chapter 7 on the potential applications of blockchain in the energy sector).

Bitcoin's prolific energy use comes from the way the network makes use of its underlying technology – blockchain – which offers a new way to conduct and record transactions, such as sending money. In a traditional exchange, central authorities (e.g. banks) verify and log transactions. Blockchain removes the need for a central authority and ledger; instead, the ledger is held, shared and validated across a distributed network of computers running a particular blockchain software.

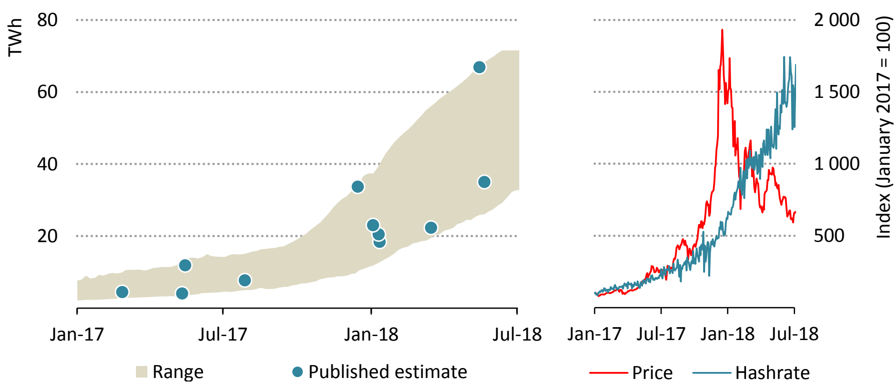
The lack of a central, trusted authority means that blockchain needs a "consensus mechanism" to ensure trust across the network. In the case of bitcoin, consensus is achieved by a method called "Proof-of-Work" (PoW), where computers on the network ("miners") compete with each other to solve a complex math puzzle. Once the puzzle is solved, the latest "block" of transactions is approved and added to the "chain" of transactions. The first miner to solve the puzzle is rewarded with new bitcoins and network transaction fees. The energy use of the bitcoin network therefore is both a security feature and a side-effect of relying on the ever-increasing computing power of competing miners to validate transactions through the PoW consensus mechanism. Other crypto-currencies and blockchains use consensus mechanisms that use much less energy per transaction, such as "Proof-of-Stake" (PoS) or "Proof-of-Authority" (PoA). These consensus mechanisms can ensure trust without relying on computing competition among its participants, and are therefore much less energy intensive.

The energy use of the bitcoin network is a function of three inter-related factors: 1) energy efficiency of IT infrastructure (e.g. mining hardware, cooling); 2) "hashrate" at which miners guess different solutions to the puzzle; 3) "difficulty" of solving the puzzle, which is adjusted in response to the total computing (hash) power of the network. The rising price of bitcoin has driven massive increases in hashrate and difficulty, along with development of more powerful and energy efficient mining hardware. The latest hardware is around 50 million times faster and a million times more energy efficient in mining bitcoin than a decade ago.

Recent estimates for bitcoin's total electricity demand are wide-ranging: around 20-70 TWh annually, or about 0.1-0.3% of global electricity use (Figure 9.8) (Bendiksen and Gibbons, 2018; Bevand, 2018; BNEF, 2018; De Vries, 2018a, 2018b; Morgan Stanley, 2018). Assuming that all miners are using the most efficient hardware, the bitcoin network currently consumes at least 32 TWh per year (based on average hashrates in

June 2018). However, with diverse modelling methodologies, limited data availability and highly variable conditions across the industry, all estimates should be interpreted with caution. The most frequently cited estimate in news media is the *Bitcoin Energy Consumption Index* (BECI), which takes a top-down approach by assuming miners spend (on average) 60% of their revenues on electricity at a rate of $0.05/kWh. BECI numbers are at the high end of estimates to date: altering the assumptions or the approach would alter the estimate. The future outlook for bitcoin energy use is also highly uncertain, hinging on efficiency improvements in hardware, bitcoin price trends, and potential regulatory restrictions on bitcoin mining and use in key markets.

Figure 9.8 ▷ Bitcoin energy use estimates and price and mining trends



Estimates of bitcoin energy use vary considerably based on the price of bitcoin, hashrates and other assumptions, as well as differences in methodology

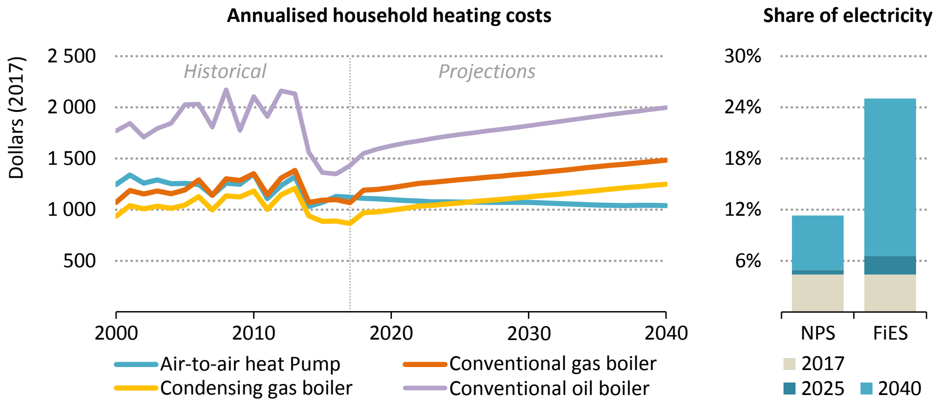
Bitcoin mining is fast becoming a local concern in regions with large mining operations. Mining operations depend on a balance of three key factors: access to low-cost electricity, fast internet connections and cool climates (Hileman and Rauchs, 2017). For these reasons, China, Georgia and Iceland are key bitcoin mining centres. An estimated 70% of global bitcoin is mined in China or by Chinese-owned companies (BNEF, 2018). Mining facilities are concentrated in remote areas of China where electricity is cheap, largely due to overcapacity and insufficient long-distance transmission to reach demand centres on the east coast. Deregulation has also allowed bitcoin miners to negotiate cheap electricity contracts with power companies, often avoiding taxes and grid fees, resulting in a form of indirect subsidy. In Iceland, electricity use from bitcoin mining could soon exceed the entire country's household electricity consumption. Regulators are stepping in to protect other ratepayers from rising prices. In New York, state regulators have approved a new rate structure to protect other ratepayers from increased costs arising from bitcoin mining (Bloomberg, 2018).

Heating in buildings

In countries with cool climates, space heating in buildings accounts for an important part of overall energy consumption. Globally, demand for space heating tends to be concentrated in advanced economies: they account for 60% of global heating demand in buildings, compared to only 30% of all other energy consumption needs combined. Nevertheless, certain developing economies also have high demand for space heating, notably China.

Today only 20% of global space heating needs are met by electricity, in contrast to cooling needs, which are almost all electric. There are no technical constraints to the full electrification of heating, whether through resistance heating or the use of high efficiency heat pumps powered by electric motors, but the share of electricity in heating energy demand has increased only slightly in recent decades. This can be explained by two main types of barrier: those relating to cost (including tax implications of different fuels), and those relating to behavioural and societal barriers.

Figure 9.9 ▷ Competitiveness and rate of uptake of electric space heating in selected European countries in the Future is Electric Scenario



Heat pumps are becoming competitive with conventional natural gas-fired boilers; uptake accelerates after 2025 in the Future is Electric Scenario

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario.

In many regions of the world natural gas- or oil-fired boilers remain more cost-competitive than heat pumps and other electric heating, especially in older, less well-insulated buildings. However, the economics are evolving: heat pump costs continue to decline and efficiencies are improving, and heat pumps are expected to become widely cost-competitive with conventional boilers in the coming years. In some European countries, for example, air-to-air heat pumps are already competitive with conventional gas boilers today, and become competitive with the most efficient condensing gas boilers by 2025 (Figure 9.9). A key economic advantage of heat pumps is their high efficiency relative to combustion technologies: heat pumps can achieve seasonal energy efficiency ratios well above 200%, and more advanced heat pump technologies, such as those using the ground as a heat source, can reach efficiencies of around 400%.

The increasing cost-competitiveness of heat pumps leads to an increasing share of electricity in heat energy demand in buildings in the New Policies Scenario, rising to nearly 19% by 2040. However, this uptake is limited by other barriers. One important barrier relates to retrofitting existing buildings currently supplied by combustion-based central heating systems: heat pumps require space outside and a larger heat diffusion system (such as underfloor heating) to be as effective as higher temperature heat sources, and this can significantly increase installation costs in existing buildings. Other barriers include a lack of awareness of the availability of alternative solutions to combustion heating, and the problem of split incentives, for example in rentals where building owners are reluctant to retrofit heat pump technology as they will not directly benefit from lower operating costs.

In the Future is Electric Scenario, we quantify the potential to increase electrification of building heating where the growing cost-competitiveness of heat pumps is strongly supported by policies to overcome these other barriers. As a result, electricity meets over half of total demand for heating services in buildings by 2040 (when measured in terms of useful energy) and 34% of total energy demand for space heating. These shares are much higher than today's levels of 20% and 13% respectively. The electrification of heating in residential buildings, where economic on a lifecycle basis, would add an additional 1 180 TWh to global electricity demand (including cooking), with buildings in the services sector adding another 570 TWh.

9.2.3 Electrifying transport

A billion electric cars on the road in 2040?

Another key source of uncertainty for electricity demand, and the most widely discussed, is in transportation. After many decades of the dominance of oil-based fuels in the transport energy mix, to what extent can electricity supplant oil as the main energy source for providing mobility, and how quickly? Already today, fully electric technologies for cars and light vehicles are on the market all around the world and in many cases are being supported by high profile policies. Some countries, such as France and the United Kingdom, have announced cut-off dates after which they will not allow conventional internal combustion engine vehicle sales, and some manufacturers have announced ambitious plans to move towards all electric powertrains over time. On the railways – the first transport sector to experience substantial electrification – plans for further deployment of electric powertrains are in place in India and elsewhere. What does all this mean for electricity demand from transport? Will demand for electricity extend beyond rail and light road vehicles into freight and other non-road transport?

In the Future is Electric Scenario, we assess the overall cost of ownership of battery electric vehicles against comparable vehicles running on oil-based fuels. As with buildings and industry, we assume that policies succeed in eliminating many of the barriers not related to total ownership costs, such as lack of charging infrastructure. This facilitates a quick ramp up of market share of EVs once economic parity is reached. Unsurprisingly, different types of EVs become competitive at various times in different regions.

For light-duty vehicles, including passenger cars and light-duty trucks, cost parity is reached as early as the mid-2020s in Japan, Korea and many European countries, due to preferences for relatively small vehicles (which means a lower battery capacity and hence a lower purchase cost) and relatively high taxes on petroleum fuels. In India, where the level of fuel taxation is lower but average vehicle size is also relatively small, electric light-duty vehicles reach parity soon after, followed by China and Southeast Asian countries in the late 2020s, where the size of the average car is bigger. Cost parity in North America is more challenging due to relatively low fuel taxation and to customer preference for larger vehicles with a long driving range. Figure 9.10 shows the year in which several major regions achieve cost parity for cars, buses, and two/three-wheelers, based on total cost of ownership.

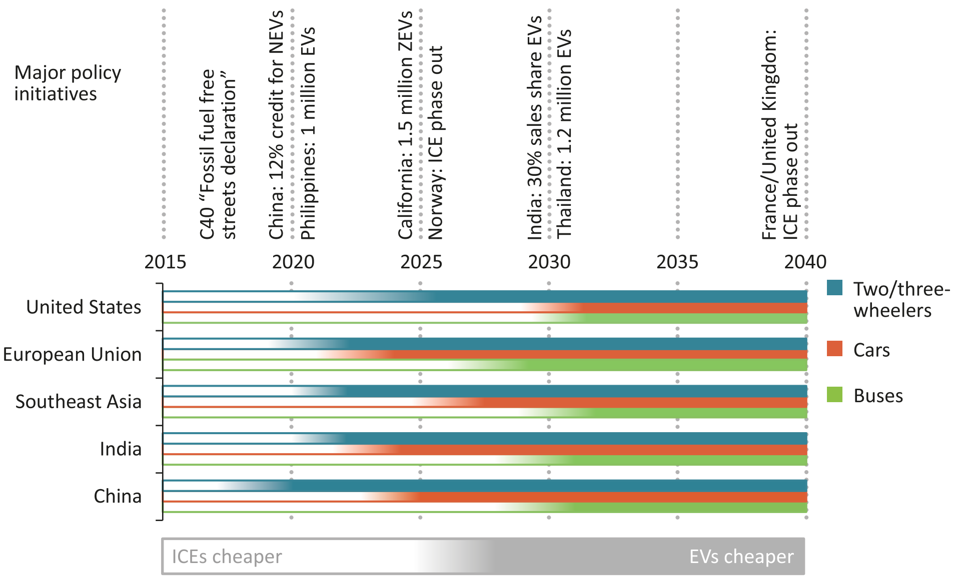
Electric trucks equipped with overhead catenary lines start to be cost-competitive with diesel medium- and heavy-duty trucks in the European Union in the early-2030s and in China from the mid-2030s. The rate of decline in future battery cost, accompanied by co-ordinated investments in fast-charging infrastructure and overhead catenary lines, the level of taxation applied on a rising oil price and other economic incentives are all important factors in this assessment.

Two/three-wheelers are strong candidates for electrification, with low battery capacities (most are used for short trips) and hence a relatively small purchase cost gap with petrol versions. In developing economies, 26% of these vehicles are already electric, covering 94% of the global electric stock. Several countries are actively pushing electric two-wheelers to tackle pressing air and noise pollution concerns. For example, China has supported the electrification of two-wheelers by allowing access to bicycle lanes and exemption from ownership restrictions affecting gasoline versions. These incentives, in combination with short average daily distance in China, lead to earlier electrification of two/three-wheelers compared to other Asian countries (IEA, 2018b). Globally, the share of electric two/three-wheelers grows from 24% today to 35% by 2025 and 69% by 2040 in the Future is Electric Scenario, compared with 32% and 55% in the New Policies Scenario.

Urban electric buses have been experiencing a boom in recent years as municipalities tackle local pollution and noise. Buses are more easily electrified than other modes, since they make routine trips which facilitate regular charging. By 2040, the number of electric buses is twice as high in the Future is Electric Scenario than in the New Policies Scenario. The lower fuel cost of electricity is a great advantage for these vehicles, which are often driven more than 50 000 km per year. Since 2009, subsidies provided in China have stimulated rapid progress in the uptake of battery electric, plug-in electric and fuel cell vehicles. In Shenzhen, for example, these subsidies brought the purchase price of battery electric buses close to those of diesel buses, and the city finished converting its fleet of over 16 300 buses to full electric models in 2017. In India, the Ministry of Finance has approved around

$350 million funding for supporting electric powered public transport in ten cities over the next five years. Initiatives such as the Soot-free Bus Project of the Climate and Clean Air Coalition, and the C40 Clean Bus Declaration Act should also help to encourage further electrification of bus fleets around the world, driven by opportunities to reduce pollution given the predominance of (generally diesel) buses in urban areas (IEA, 2018b).

Figure 9.10 ▷ Competitiveness of electric vehicles in selected regions, 2015-2040



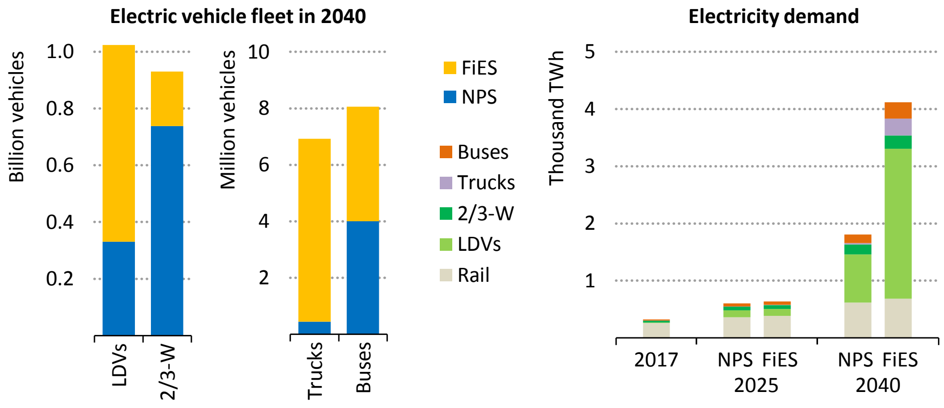
Electric vehicles are becoming increasingly competitive, with electric cars reaching cost parity with internal combustion engine cars around the year 2025 in many major markets

Notes: Colour gradient indicates estimated period when cost-competitiveness occurs. NEV = new energy vehicle (battery, plug-in hybrid electric and fuel cell electric vehicles); ZEV = zero emission vehicle; ICE = internal combustion engine; EV = electric vehicle. The C40 Cities Climate Leadership Group is an initiative connecting 90 cities across the world, focussed on reducing climate and air pollution and increasing the well-being of urban residents. The cost components of this analysis include both annualised purchasing costs and running costs under a New Policies Scenario price environment. Vehicle mileage, engine size and fuel price assumptions differ across regions. Engine power varies from 60 to 170 kilowatts. Annual kilometres (km) are related to regional consumer preferences (e.g. 17 000 km for a gasoline car in the United States and around 10 000 km in Europe). Fuel prices range $0.4-1.6 (2017) per litre of gasoline equivalent.

In the Future is Electric Scenario, electric vehicles make big inroads in all road transport modes. By 2040, there are 950 million electric cars, nearly half of the total fleet of over 2 billion. There are also 74 million electric light commercial vehicles, and 15 million electric heavy-duty vehicles (including buses and trucks). About 70% of two/three-wheelers are electrified too. The result is an increase in electricity consumption by road transport vehicles of around 3 400 TWh by 2040, three-times the increase in the New Policies Scenario, with strong growth in both advanced and developing countries (Figure 9.11).

Nearly all the divergence from the New Policies Scenario occurs in the latter part of the outlook period, between 2025 and 2040, because of the time needed for stock turnover and to develop charging infrastructure, in addition to reaching cost parity.

Figure 9.11 ▷ Electric vehicle fleet and transport electricity demand in the Future is Electric and New Policies scenarios



Rapid growth of electric vehicles across vehicle types means electricity demand from road transport increases substantially after 2025

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario; LDVs = light-duty vehicles; 2/3-W = two/three-wheelers; Trucks = heavy-duty trucks only.

Achieving this level of electrification will require a massive roll out of charging infrastructure. Currently, charging infrastructure deployment targets are in place in a number of countries including China (4.3 million private outlets and 500 000 publicly accessible by 2020) and European Union countries. We estimate investment needs for charging infrastructure at more than $4 trillion between now and 2040, excluding grid enforcement costs.[3] An additional ramification is that vehicles are likely to be increasingly automated (Box 9.3). This could increase their energy consumption, not only for on-board batteries but also for extra upstream demand for data centres and data transmission infrastructure (see section 9.2.2).

3. To estimate investment requirements, region-specific parameters have been used, for example future ratio of public chargers per electric vehicle is based on historical data, population density and policy targets (IEA, 2018b).

Box 9.3 ▷ Energy and emissions implications of autonomous vehicles

Autonomous vehicles (AVs) have the potential to reduce costs while improving the safety, accessibility, and convenience of road transport. But the consequences of automation on long-term energy demand and emissions are highly uncertain, hinging on the combined effect of changes in consumer behaviour, policy intervention, technological progress and vehicle technology.[4]

For instance, AVs would allow users to make more productive use of travel time, making private car travel more attractive. AVs may also induce demand from non-drivers, such as children and the elderly. And road freight is likely to become much less expensive, encouraging more goods shipments. These factors could encourage more road travel activity and exacerbate urban sprawl, increasing energy demand. On the other hand, if AVs are shared and appropriately sized, they could improve overall efficiency; and if shared AV fleets are electric, their high utilisation rates and rapid stock turnover could accelerate electrification trends in road transport.

There are clear synergies between AVs and electrification, but there are also trade-offs. Commercial fleets – the most likely early adopters of AVs – will look for low operational costs and high efficiencies, and this may favour electric AVs. But they will also want utilisation rates and driving ranges that require larger and more expensive battery packs or more frequent recharging, while the power needed for on-board computing and electronics may reduce the range of vehicles (Slowik, 2018).

Analyses of a range of scenarios in the US context find that automated vehicles in some cases could reduce fuel consumption by more than 90% or increase it by as much as threefold (Brown, Gonder and Repac, 2014; Fulton, Mason and Meroux, 2017; Greenblatt and Saxena, 2015; Stephens et al., 2016; Wadud, MacKenzie and Leiby, 2016). The eventual long-term impacts on energy and emissions will depend on efforts to make the most of potential synergies between electrification and automation, and that depends on the answers to a number of key questions, including:

- What level(s) of automation will be deployed, when and for what uses?
- How will consumers and freight companies adopt and use AVs? Will they be shared and/or electric? What modes will they substitute or complement?
- How will governments regulate AVs, including key questions and issues around cyber security, privacy and liability?

4. To advance its understanding of these key issues, the IEA is undertaking a new project to assess the potential trajectories, interactions and impacts of AVs by enhancing and leveraging the modelling capabilities of the IEA Mobility Model. The analysis will provide policy insights that advance energy, climate, air quality and other socioeconomic objectives and will be published in 2019. Proceedings of a relevant workshop held in June 2018 are available at: www.iea.org/workshops/automation-connectivity-electrification-and-sharing-aces-transforming-road.html.

The rail sector currently accounts for the majority of electricity demand for transport. In the New Policies Scenario, electricity demand from rail increases as the switch from diesel to electric locomotives continues, in particular in countries with a high share of urban population and relatively high density, but electric inter-city rail does not gain traction in large countries with dispersed populations such as Canada and Russia. In the Future is Electric Scenario, there is a slightly faster increase in electricity demand from rail, with an increase in electricity demand over the projection period that is 11% higher than in the New Policies Scenario. This corresponds to an additional 67 TWh of electricity demand in 2040.

Beyond the road and rail sectors, the technical feasibility of electrified transport is less certain. There are some electrification projects in aviation, such as the prototypes that Easyjet, Airbus, Siemens and Rolls-Royce Aviation have developed for short-haul flights, and in shipping, such as the electric ferries being operated in Norway. Their large-scale feasibility remains unproven, however, and so direct use of electricity for these modes is not included in the Future is Electric Scenario.

9.2.4 Electrifying industrial processes

The Future is Electric Scenario differs from the New Policies Scenario on three key assumptions about the electrification of industrial processes. The Future is Electric Scenario assumes:

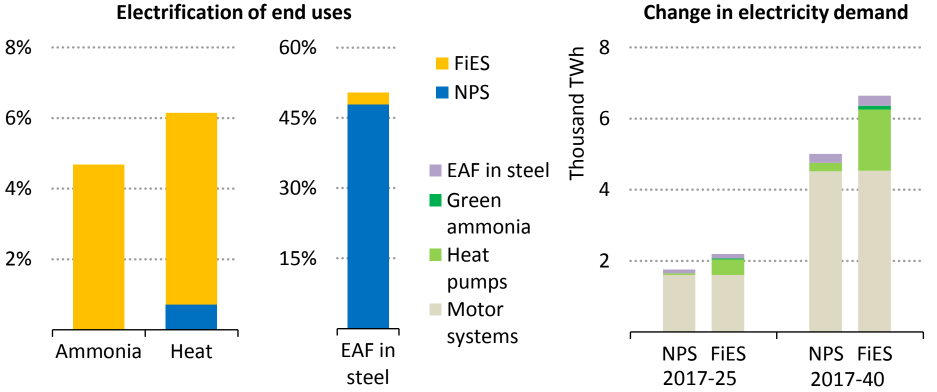
- Increased uptake of heat pumps for low temperature heat.
- Increased use of electric arc furnaces (EAF) for steel making, marking a shift to greater use of recycled steel.
- A switch from natural gas to decarbonised energy to generate hydrogen feedstock for ammonia production, requiring additional electricity for hydrogen production.

The result is that the share of electricity in industry demand rises to 37% globally in 2040, compared with 29% in the New Policies Scenario (Figure 9.12). This leads to an increase in demand of almost 1 700 TWh by 2040, most of which occurs after 2025.

As for buildings, the potential for increased electricity demand has been assessed based on the economic potential of technologies under the conditions of the Future is Electric Scenario. The result is that heat pumps for low temperature heat account for most of the extra electricity demand, with EAF and hydrogen for ammonia playing smaller roles.

Significant further uptake of electricity is especially challenging for industry and, compared with other sectors, there have been relatively few recent breakthroughs. A variety of factors explain the challenges. First, capacity for fuel switching in industry is limited; a change in fuel often requires a change in process. Second, high temperature electric heat – important across most energy-intensive industries – requires significant changes to furnace design. Third, the highly integrated nature of industrial processes means that changing one part often requires changes to other parts of a given process. Fourth, industrial production facilities tend to have long lifetimes and a slow turnover of capital stock.

Figure 9.12 ▷ Electrification in industry and change in electricity demand in the Future is Electric and New Policies scenarios



Using electricity to provide low temperature heat provides the biggest opportunity to increase the electrification of industry

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario; EAF = electric arc furnace.

The future technical potential of innovative new technologies is nonetheless of potentially great importance for the long-term decarbonisation of the industry sector. Some relevant technologies are discussed in Box 9.4, but these are not included in the Future is Electric Scenario because either they have not yet been demonstrated at commercial scale, or they are not expected to become competitive in the price environment of the scenario.

Heat pumps for low temperature heat

The increased uptake of heat pumps provides the greatest realistic potential for increased electrification in industry (Figure 9.12). The low temperature heat (up to 100 °C) provided by heat pumps (and competing technologies) can meet at least some of the demand for heat in a wide range of the industrial sub-sectors modelled.[5] In the pulp and paper sector, and in the chemical industry, low temperature heat makes up roughly a quarter of heat demand, versus less than 5% of heat demand in the cement, aluminium, and iron and steel sectors. In light industry, e.g. food and beverage, pharmaceuticals and textiles, it makes up nearly half of total heat demand.

In the Future is Electric Scenario, heat pumps increase to cover 6% of world industrial heat demand by 2040, compared to less than 1% in the New Policies Scenario. In advanced economies, heat pumps provide 8.3% of total industry heat demand by 2040, compared to 5.9% in developing economies. Overall, this increase accounts for the majority of increased

5. Applications for medium temperature heat exist in the pilot stage, and while there is technical potential for uptake within industry, they do not factor into the Future is Electric Scenario due to economic uncertainty.

electricity consumption in industry in the Future is Electric Scenario – an additional 1 500 TWh of electricity demand by 2040, as compared to the New Policies Scenario. However total industry energy use is 11% lower, despite this increase in electricity use, as a result of efficiency gains stemming from the high coefficients of performance of heat pumps. Heat pumps use a refrigerant cycle to transfer heat from a heat source to a heat sink, and are designed to generate a thermal energy output well in excess of electrical energy inputs.

As a result of their impressive energy performance, heat pumps can be economically competitive. In certain regions, the payback period for moving from natural gas powered heat to electric heat pumps is already short enough to stimulate investment. When differences in efficiency are taken into account alongside investment costs and annual energy costs, India, China, Korea and Southeast Asia are estimated to have payback periods of below three years. Elsewhere, for example in Japan and much of Europe, modelling suggests rapid improvement in payback periods over the coming years, driven by the price of gas rising relative to electricity, as well as changes to the share of gas in power generation. Due to the high efficiency of heat pumps, payback periods are more sensitive to natural gas prices than they are to electricity prices. Gas prices well below the ten-year average mean that estimated 2017 payback periods are longer than those in previous years. In China and India, gas and electricity prices are relatively independent because of their coal-dominated grids: the lower responsiveness of electricity prices to gas prices contributes to slower declines in payback periods in those countries.

However, various non-economic barriers help to explain the current modest penetration of heat pumps. For example, heat pumps in industry often require a waste or excess heat stream as input to achieve temperatures up to 100 °C efficiently. Availability of excess or waste heat streams can be a further limiting factor. Additionally, lack of information and inertia in well-established industrial systems play a role.

Box 9.4 ▷ Powering on: frontier electric technologies in industry

Beyond the drivers of electricity demand considered in the Future is Electric Scenario, there is a wide range of additional possibilities for electrification of industry (Eurelectric, 2018; EPRI, 2018; Jadun et al., 2017; McKinsey, 2018). These other options have not been considered in the scenario because of uncertainty about the economic and technological feasibility of wide-scale deployment and substitution across industry. Examples of these frontier technologies include the following:

- The electrification of clinker production using induction or microwave heat offers the potential to electrify the cement sector's most energy-consuming step, though such technology is at the laboratory stage. This technique would only reduce emissions related to fuel combustion, amounting to about a third of the direct CO_2 emissions generated in cement production (the rest being process emissions).

- Hydrogen-based direct iron reduction for primary steel production could allow for substitution from coal or natural gas to electricity – if the hydrogen is generated from electrolysis. Prevailing industry and expert views suggest that 100% electrolytic hydrogen-based steel production is not sufficiently advanced to allow for economic potential to be exploited under the conditions and timeframe of the Future is Electric Scenario. Partial injection of hydrogen is possible up to about 25% without major process transformations, but is highly dependent on economics.
- Electro-technologies for process heat, such as infrared and ultraviolet heating (with applications in drying and curing processes), induction melting and electric boilers (which are commercial – though challenges remain to scale up) offer further potential for electrification across a range of industrial activities.
- Mechanical vapour recompression can provide higher temperature heat than what is currently practicable using heat pumps. Such technology could be beneficial in pulp and paper, and certain chemical production processes, though to be economical it requires higher electricity prices (relative to natural gas) than those projected in the Future is Electric Scenario.
- Carbon capture, utilisation and storage linked to industrial processes could also increase electricity demand associated with industrial production.

Further electrification in industry could bring about environmental performance and productivity gains which are not always factored into evaluations of economic potential. Such gains – in particular those connected to reductions in greenhouse gas (GHG) intensity – could help to push cutting-edge electric technologies into the mainstream more rapidly.

Electricity for steel production

Electric arc furnaces (EAF) for steel making provide another opportunity for increasing the share of electricity demand in industry. In the Future is Electric Scenario, the impact is relatively modest, with the share of 2040 steel production using an electric arc furnace process increasing from 48% to 50%, resulting in an electricity demand increase of just under 30 TWh, or 2% of the total increase in 2040 industry electricity demand compared to the New Policies Scenario.

This small increase is because EAF is mostly used for recycled steel, and the scope for recycled steel is constrained by limitations on steel scrap as an input. Producing virgin steel via EAF is technically feasible via direct reduction techniques, but this production method is often uneconomic and it therefore accounts for only a minor share of production in both the New Policies and Future is Electric scenarios. There are currently significant regional differences in the mix of iron and steel production processes. In China, which produces about half of the world's steel, the majority of steel is produced using the basic oxygen steel production technology, with the share of EAF production currently close to 10% (though it has been increasing recently). Indonesia, on the other hand, uses the EAF method for almost all of its domestic production.

Renewable hydrogen to produce "green" ammonia

The use of hydrogen in the ammonia industry provides the third main driver of increased electricity use in industry in the Future is Electric Scenario. Switching from natural gas to electrolysis for around 5% of global ammonia production creates 110 TWh of additional electricity demand.

Ammonia is one of the most widely used chemicals in the world. It is predominantly used as a fertiliser – 88% of all ammonia goes into fertilisers – but is also used in the production of explosives, cleansers and refrigerants. Current ammonia production globally is around 190 million tonnes (Mt) per year, and represents a market of around $80 billion. Ammonia is produced by combining nitrogen and hydrogen in the "Haber-Bosch" process. Nitrogen is relatively simple to extract from the air while nearly all of the hydrogen is produced today using steam methane reforming (which breaks down natural gas using steam) and coal gasification (mainly in China). Both of these processes result in CO_2 emissions, and the production of ammonia caused over 200 Mt of CO_2 emissions in 2017. Switching to hydrogen produced by electricity – whether by electrolysis or by "methane splitting" – could therefore also play a part in climate change mitigation, provided that the electricity is generated from low-carbon sources (see Chapter 11, section 11.4.5).[6]

9

One of the key advantages of developing an ammonia facility drawing on low-carbon produced hydrogen is that there would be no need for a grid connection or large-scale electricity or hydrogen storage. Most of the electricity demand would come from the electrolysers, so ammonia would be produced when electricity is being generated by the renewables system and the process simply shuts down if there is a temporary drop in generation. Producing one tonne of ammonia in such a facility would require around 10 megawatt-hours (MWh) of electricity.

Transporting pure hydrogen over long distances as a liquid fuel can be expensive because of the need to cool it to very low temperatures; ammonia liquefies at a much higher temperature and lower pressure and is therefore easier to store and transport. Besides its current uses, ammonia could play a wider role as an energy or hydrogen carrier (see Chapter 11).

6. In addition, other CO_2 reduction options exist for methane steam reforming: the concentrated CO_2 stream could be increasingly used in other chemical processes (for example in the production of urea), or the hydrogen production facility could be equipped with CCUS.

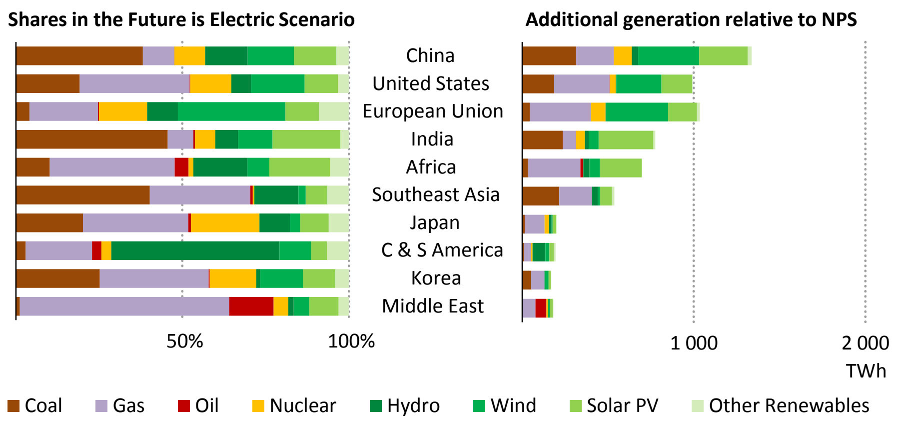
9.3 Electricity supply for an electric future

9.3.1 *Higher electricity demand leads to more renewables and more fossil fuels*

Electricity generation

Global electricity generation reaches 47 900 TWh in the Future is Electric Scenario in 2040, which is nearly 20% higher than the level in the New Policies Scenario, and an 85% increase on today's level. Renewables are the biggest winners in the race to meet higher demand in the Future is Electric Scenario, given rapidly falling costs projected over coming decades, even without further policies supporting deployment. About 45% of the difference in demand between the New Policies Scenario and the Future is Electric Scenario is met by renewables, meaning that renewables generation in 2040 is three-times today's level. However, the increase in demand is so marked that fossil fuels also have an important role to play. Gas-fired power generation accounts for around 30% of the extra demand relative to the New Policies Scenario, and coal-fired generation for around 20%. Nuclear also contributes, making up 5% of the difference. By 2040 the split of power generation technologies is similar in both scenarios.

Figure 9.13 ▷ Power generation shares in the Future is Electric Scenario in selected regions, and additional generation relative to the New Policies Scenario, 2040



Renewables satisfy much of the additional demand, with gas the second-largest contributor

Note: C & S America = Central and South America; NPS = New Policies Scenario.

These global numbers mask regional differences in how the additional electricity supply is provided (Figure 9.13). While advanced economies account for only 10% of electricity demand growth from now until 2040 in the New Policies Scenario, they make up 40% of the additional electricity demand in the Future is Electric Scenario. This has implications for the total split in electricity generation sources. Of the additional generation in advanced economies, 45% is renewables and a further 37% is gas. Much of the remainder is supplied by coal, half of which is in the United States. Of the 60% of additional demand growth that occurs in developing economies, about one-third is in China, and this is met in large part by gas, renewables and coal. India and sub-Saharan Africa each make up roughly 10% of additional global demand, and renewables meet around half of the additional supply in both cases. There are marked differences in how the remaining share is generated however; it is mostly gas in Africa and mostly coal in India.

Energy access: implications for electricity supply

Energy access accounts for about 7% of total additional electricity demand in the Future is Electric Scenario. While over 95% of new connections since 2000 have been from the grid, new technology trends and business models are set to make decentralised renewables-based solutions viable, transforming the provision of access. In the Future is Electric Scenario, 65% of additional demand due to access is met through renewables and there is a stronger shift towards mini- and off-grid technologies in rural areas than in the New Policies Scenario, though grid connections account for all of the new connections in urban areas in both scenarios. The market for decentralised renewables, especially solar, has been accelerating in sub-Saharan Africa and Asia as cost reductions in photovoltaics (PV), battery storage and new business models based on mobile payments have made solar home systems affordable (IEA, 2017b). This is allowing populations without access to grid infrastructure (often in remote rural areas) an affordable source of electricity without waiting for the grid to be extended.

Power generation capacity grows across all technologies

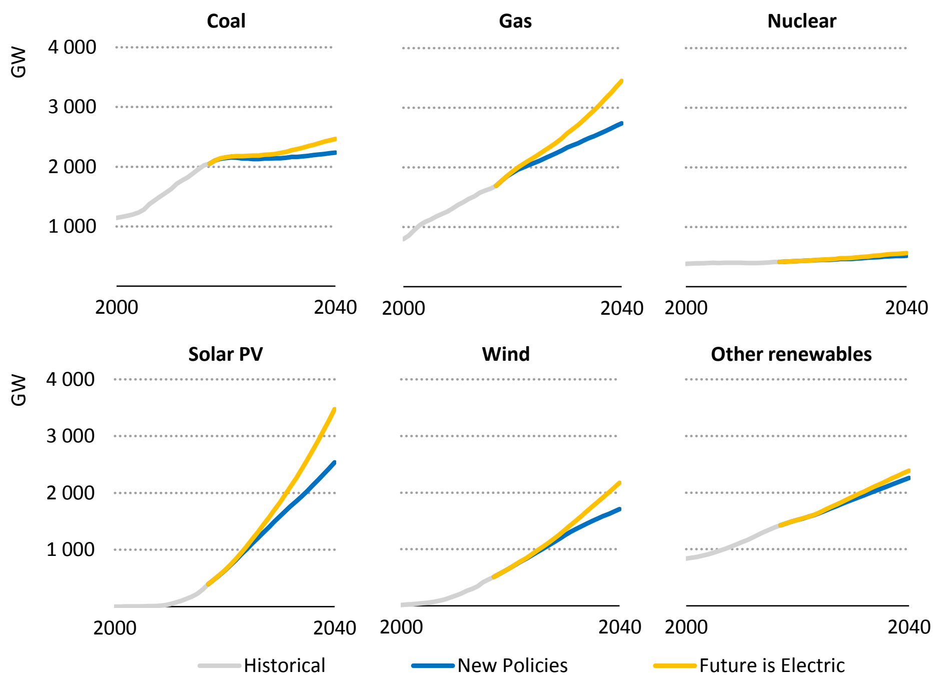
Driven by the increase of electricity demand in the Future is Electric Scenario, total installed capacity reaches 15 100 gigawatts (GW) in 2040, compared with 12 500 GW in the New Policies Scenario. All technologies see an increase in total capacity installed relative to the New Policies Scenario, but the margin varies considerably between fuels (Figure 9.14).

Renewables make up the majority of capacity increases relative to the New Policies Scenario. They account for 60% of the increase, the majority of which is from solar PV, which reaches 3 500 GW by 2040, far outstripping coal and on a par with gas. Renewables make up a larger share of additional capacity than they do of total electricity generation because variable renewables such as wind and solar PV have relatively low average capacity factors. There are several options for making better use of renewable resources and increasing capacity factors, including by increasing the flexibility of the power system (see section 9.5). The production of hydrogen as a transportable energy carrier also offers potential as a means of exploiting renewable resources found in remote areas (Spotlight).

Coal-fired capacity grows slowly in the Future is Electric Scenario, but existing and new capacity sees much higher utilisation rates, meaning coal accounts for nearly 20% of additional generation. The reason is that plants built for reliability and security are under-utilised in the New Policies Scenario (even as excess capacity diminishes) so their utilisation rates rise in the Future is Electric Scenario.

The technology share of capacity additions varies widely from region to region. The United States and the European Union account for about 25% and 20% of additional growth in natural gas-fired capacity respectively, while China and India combined make up almost 60% of growth in coal-fired capacity. Nearly three-quarters of the 42 GW of additional nuclear capacity deployment comes from developing economies (notably China and India), with the United States, Japan and some European countries making up the remaining 30%. The growth of renewable capacity is evenly distributed across regions and follows broadly the same pattern as in the New Policies Scenario: for example, China, India and the European Union each contribute between 15% and 20% of the additional solar PV capacity additions in the Future is Electric Scenario. China deploys nearly 150 GW of additional wind capacity (more than 30% of new additions), followed by the European Union (122 GW) and the United States (73 GW).

Figure 9.14 ▷ Installed power generation capacity by type in the Future is Electric and New Policies scenarios



Installed capacity grows for all technologies, notably solar PV and gas, with solar overtaking coal and catching up with gas by 2040

SPOTLIGHT

Can hydrogen unlock stranded renewable resources?

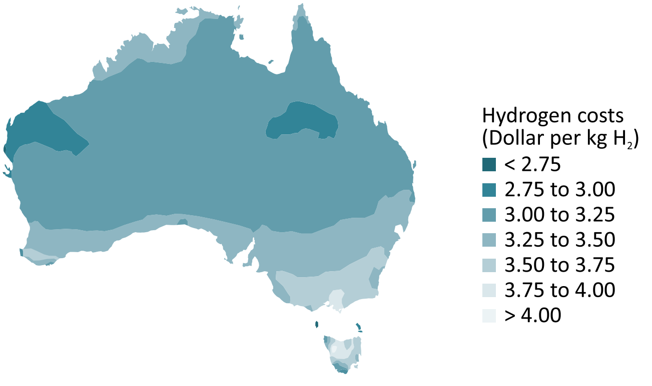
There are many potential uses of hydrogen in the energy system. It can be used simply as an electricity-storage medium and converted back to electricity using a fuel cell (either close to where it was produced or after being transported). Hydrogen, or a hydrogen-based fuel, can also be combusted directly, for example to replace oil and gas in the transport, buildings, power or industry sectors. Hydrogen produced from renewables-based systems can also be used as a feedstock for industrial processes: for example in refining (see Chapter 11) and iron and steel (see section 9.2). However, converting electricity to hydrogen is not cheap: if electricity is purchased from the grid, the hydrogen would cost around \$6 per kilogramme of hydrogen (kg H_2) today, around three-times higher than the least expensive current option to produce it (reforming natural gas using steam).

What is now of particular interest is the prospect of establishing new hydrogen production facilities in parts of the world with significant renewables-based electricity potential. Developing off-grid electricity systems in these areas could produce electricity at low cost (albeit intermittently) which, if combined with an electrolyser, could be used to produce zero-carbon hydrogen. One key consideration is that the electrolysers used to convert electricity into hydrogen are expensive. Even though their costs are likely to decline in the future, running them as much as possible is important to minimise overall costs. A hybrid off-grid system involving a solar PV facility co-located with a wind farm in a resource-rich location offers a possibility to increase operating hours of electrolysers, since times of maximum wind generation are often uncorrelated with times of maximum solar PV generation. Hydrogen is much easier to transport over long distances than electricity (although costs are not negligible) and so establishing new hydrogen production facilities in renewable-rich locations could be one way to maximise their value.

We have taken Australia as a case study to examine this potential. Australia has excellent solar and wind resources (often in close proximity) and has launched a number of pilot projects aiming to accelerate the development of hydrogen technologies. We looked for the optimal combination of solar PV, wind and electrolyser capacity in a hybrid system located at all points across the country, taking into account costs and the capacity factors of renewable electricity technologies.

Australia's potential to produce hydrogen in this way could be vast (Figure 9.15). Utilising only the best locations within 50 km of the coastline (to avoid the need for much inland transport) and excluding protected areas, land dedicated to other uses or water-stressed locations could provide nearly 100 million tonnes of oil equivalent (Mtoe) of hydrogen, equivalent to 3% of global gas consumption today. The cost of electricity in these locations in 2040 would be less than \$47/MWh with the hybrid systems operating at capacity factors of between 30% and 40% (depending on the optimal combination of solar PV and wind). This 100 Mtoe of hydrogen could be manufactured at less than \$3/kg H_2. While this would be nearly double the projected cost of producing hydrogen in 2040 from steam methane reformation, it would be closer to the costs of such a system equipped with CCUS (see Chapter 11). Costs could be even lower if projects were to be financed with government support (to lower the discount rate) or if the cost of renewable technologies or electrolysers were to decline faster.

Figure 9.15 ▷ Hydrogen production costs from hybrid solar PV and wind systems in Australia in the New Policies Scenario, 2040



Australia could produce vast quantities of hydrogen: hybrid solar PV and wind systems near the coast could provide over 100 Mtoe of hydrogen for less than \$3/kg H_2

Notes: Costs assumptions: onshore wind = \$1 770/$kW_{electric}$; utility-scale solar PV = \$800/$kW_{electric}$; electrolyser = \$550/kW H_2; discount rate 8%.

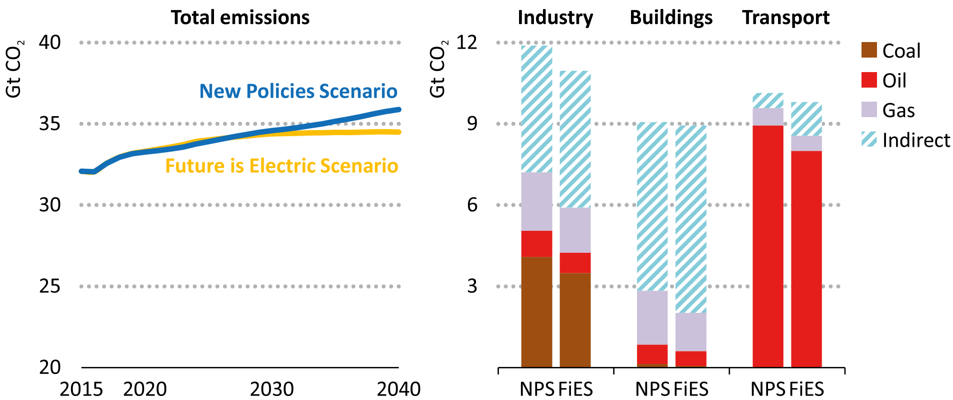
9.3.2 Electrified does not necessarily mean sustainable

The electricity system in the Future is Electric Scenario does not explicitly consider additional environmental and sustainability constraints beyond those already included in the New Policies Scenario, other than the important goal of providing universal electricity access.

Electrification by itself will not deliver on sustainability goals. While switching from combustion fuels to electricity has clear environmental advantages at the point of use, in particular due to reduced emissions of local air pollutants, the overall environmental impact needs to be considered at the system level.

In the Future is Electric Scenario, the pathway for total energy sector CO_2 emissions is only slightly lower that of the New Policies Scenario: emissions continue to rise, reaching 6% above today's level by 2040 (Figure 9.16). This is a very different future to the one called for by the Paris Agreement, which requires CO_2 emissions to peak soon and then enter a steep decline.

Figure 9.16 ▷ CO_2 emissions by end-use sector by scenario, 2040



Total CO_2 emissions are only slightly lower in the Future is Electric Scenario, due to a switch from end-use to "indirect" emissions from electricity generation

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario.

Although the overall trajectories are similar, the sector breakdown of CO_2 emissions is quite different between the scenarios. In the Future is Electric Scenario, CO_2 emissions are more concentrated in the power sector. Increased dependence on electricity in end-uses means that direct CO_2 emissions in those sectors decrease. However, most of these emissions are transferred to the power sector. The effect is most noticeable in transport, where an 11% decrease in oil consumption (due to EVs) leads to only a 3% decrease in CO_2 emissions, once electricity emissions are factored in.

The shift in fuel use from end-uses to electricity generation has more implications for air pollution than it does for CO_2. Total emissions of the main pollutant categories are reduced in the Future is Electric Scenario compared to the New Policies Scenario. The difference is limited for nitrogen oxides (NO_X) and sulfur dioxide (SO_2), but significant for fine particulate ($PM_{2.5}$) emissions (though this is mostly due to reduced reliance on traditional use of biomass thanks to achieving universal access to clean cooking). In the power sector, pollutants decline compared to today, reflecting continued strong regulation on power plant emissions, but the decline is less than that seen in the New Policies Scenario, because of increased generation from thermal plants to meet the higher demand in the Future is Electric Scenario.

The link between air pollution emissions and impacts on human health is complex and depends on more than total emissions (see discussion in Chapter 2). Geographic factors are important. For example, an increasing role of electricity in end-uses is likely to have notable advantages for air pollution in densely populated urban areas by removing direct combustion of fossil fuels. Overall, the net implications will depend on how the increased electricity is generated and on the location of fossil fuel plants (see Chapter 10).

Increased electricity demand also has implications for the supply of fresh water. Supply choices made to meet the demands of the Future is Electric Scenario can have important consequences for both withdrawals and ultimate consumption of water by the power generation sector (Box 9.5).

In short, while electrification by itself may bring some environmental gains, the Future is Electric Scenario falls short on most sustainability goals, with the exception of achieving universal energy access. This is a very different outcome to that in the Sustainable Development Scenario, which combines electrification with efficiency and supply-side policies to achieve decarbonisation.

Box 9.5 ▷ Will water hold back the tide of an electric future?

Will pushing the boundaries of electrification lead to increased water withdrawals and consumption in the power sector?[7] It may, depending on the location and the fuels and technologies used to achieve an electric future.[8] Though water withdrawals for power generation in the Future is Electric Scenario in 2040 are 8% lower compared to levels seen in 2016 (285 billion cubic metres [bcm]), consumption increases by a third to reach 20 bcm (Figure 9.17).[9] While the shift towards more solar PV and wind is helpful in terms of water use – as these technologies use very little water – the accompanying high levels of coal, natural gas and nuclear power generation temper any potential improvements from fuel switching. As a result, by 2040, the Future is Electric Scenario has significantly higher water withdrawals and consumption than the New Policies Scenario, which in turn has much higher levels than the Sustainable Development Scenario (see Chapter 2).

In areas of water abundance, this is unlikely to be an issue. However, many countries already face some degree of water stress; by 2040, one-out-of-every-five countries is anticipated to have a high ratio of water withdrawals to supply. Several countries that are large energy consumers, such as India, China and the United States, may find their plans to increase power generation in at least some parts of the country to be critically dependent on water availability. Droughts and water shortages are already impacting India's thermal power plants: India lost 14 TWh of thermal power generation in 2016 due to water shortages (Luo et al., 2018). Water temperature may also curtail power generation. In summer 2018, France had to shut down four nuclear reactors when high ambient air temperatures rendered them unable to comply with the temperature regulations for water discharge. For countries that rely significantly

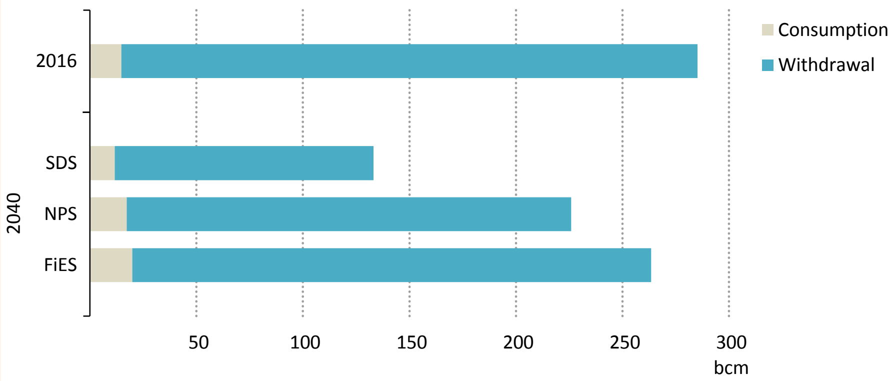
7. Water withdrawals are defined as the volume of water removed from a source and are always higher than or equal to consumption. Water consumption is defined as the volume withdrawn that is not returned to the source (i.e. is evaporated or transported to another location) and is no longer available for other users.

8. A more detailed look at the water needs of the energy sector, can be found in *Water-Energy Nexus: World Energy Outlook Special Report* (IEA, 2016).

9. Values are for the operational phase of electricity generation, which includes cleaning, cooling and other process related needs; water used for the production of input fuels is excluded.

on hydropower, potential changes in water availability, including due to the impacts of climate change, could increase uncertainty around generation potential. As such, plans for power generation that rely on more water-intensive technologies will need to take into account current and future water availability in the choice of sites and cooling technologies, as well as potential constraints on discharge from water temperature.

Figure 9.17 ▷ Global water use by the power sector by scenario



A more electric future has the steepest water penalty in 2040 of all scenarios, raising questions about its viability in some regions already experiencing water stress

Notes: SDS = Sustainable Development Scenario; NPS = New Policies Scenario; FiES = Future is Electric Scenario. Hydropower is excluded given the lack of agreement on a standardised measurement for consumption (see Chapter 2 for more).

9.4 Electricity in the Sustainable Development Scenario

9.4.1 Electricity demand in the Sustainable Development Scenario

The Sustainable Development Scenario puts forward an integrated approach to achieving the three most important energy-related Sustainable Development Goals: achieving universal energy access, reducing CO_2 emissions in line with the Paris Agreement, and reducing the severe health impacts of air pollution. Introduced for the first time in the *WEO-2017* (IEA, 2017c), and highlighted this year in Chapter 2, the Sustainable Development Scenario differs markedly from the Future is Electric Scenario (Box 9.6).

In terms of electricity demand, energy efficiency is the most important factor differentiating the Sustainable Development Scenario from both the New Policies and Future is Electric scenarios. Improved end-use efficiency means that by 2040 electricity demand is around 7% lower than in the New Policies Scenario, while total final energy consumption is around 20% less and the overall energy intensity of the economy is 23% lower. Lower demand through vastly improved energy efficiency is the most important factor for achieving the

CO_2 and air pollution reductions at the heart of the Sustainable Development Scenario (see Chapters 2 and 10).

The Sustainable Development Scenario assumes that non-economic barriers to electric technologies are minimised, as in the Future is Electric Scenario. But the lower fossil fuel prices prevailing in the Sustainable Development Scenario mean that the uptake of electric technologies is not as widespread as in the Future is Electric Scenario. Nevertheless, electricity plays a bigger role in the energy system of the Sustainable Development Scenario than in the New Policies Scenario. Electricity represents 28% of total final consumption by 2040, considerably higher than the 24% in the New Policies Scenario. Three-quarters of cars sold in 2040 are electric in the Sustainable Development Scenario and 32% of households use electricity for space heating; in the New Policies Scenario the equivalent figures are one-out-of-five cars and 22% of households with electric space heating.

Box 9.6 ▷ Different worlds: how do the Sustainable Development and Future is Electric scenarios compare?

The Future is Electric Scenario starts with the economic and policy landscape of the New Policies Scenario and alters several assumptions with the effect of increasing both overall electricity demand and the proportion of electricity in final energy use. As all other policies remain the same as in the New Policies Scenario, including those affecting electricity supply, the electricity generation mix in the Future is Electric Scenario is similar to that of the New Policies Scenario.

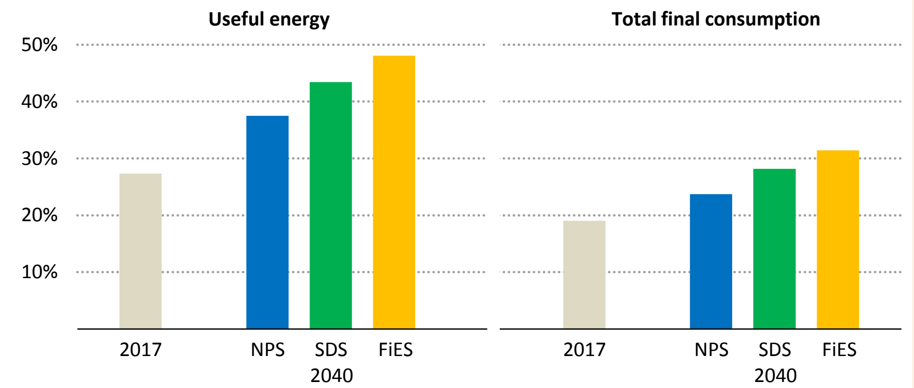
Table 9.2 ▷ Assumptions in the Sustainable Development and Future is Electric scenarios relative to the New Policies Scenario

		FiES	SDS
Electricity demand	Policies for further electrification of transport, space heating and industry.	+	+
	Faster electricity access and uptake of appliances.	++	+
	Accelerated digitalization.	+	NPS
	Additional energy efficiency beyond announced policies.	NPS	+
System flexibility	Enhanced flexibility to increase renewables integration.	NPS	+
Electricity supply	Further measures to decarbonise the power sector.	NPS	+

Note: FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario; NPS = same as in the New Policies Scenario.

The Sustainable Development Scenario paints a very different picture for electricity. On the demand side, three key factors act to temper electricity demand growth, relative to the Future is Electric Scenario (Table 9.2). First, the Sustainable Development Scenario includes ambitious energy efficiency policies that go considerably beyond the announced policies included in the New Policies and Future is Electric scenarios. Second, the accelerated uptake of digital technologies is not included in the Sustainable Development Scenario, and although universal electricity access is achieved in both scenarios, the subsequent rate of uptake of electric appliances in developing countries is slightly slower in the Sustainable Development Scenario. Third, the energy price environment alters the economic case for electric technologies. The result of these differences is that although overall electricity demand is lower in the Sustainable Development Scenario than the other scenarios, the share of electricity in total energy demand is in-between that of the New Policies and Future is Electric scenarios (Figure 9.18). The same is true for useful energy, where electricity accounts for more than 40% in the Sustainable Development Scenario and nearly 70% of useful energy in buildings.

Figure 9.18 ▷ Electricity as a share of useful energy delivered and of total final consumption, 2017 and by scenario in 2040



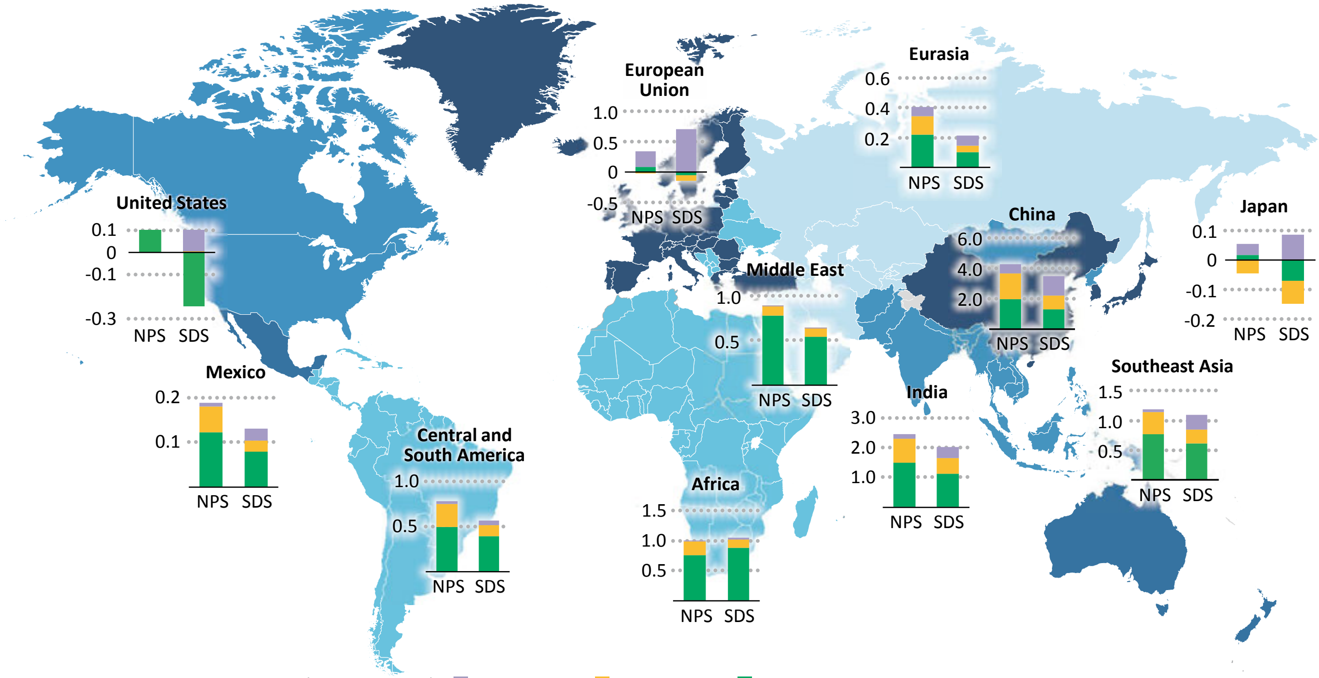
By 2040, the share of electricity in useful energy is higher than today in all scenarios, at 43% in the Sustainable Development Scenario and 48% in the Future is Electric Scenario

Note: FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario; NPS = New Policies Scenario.

Other key differences relate to policies affecting electricity supply and the level of flexibility in the power system. In the Sustainable Development Scenario, CO_2 emission constraints, combined with renewables targets and other policies, lead to a much faster switch towards low-carbon sources of generation. To support the faster integration of renewables in particular, the Sustainable Development Scenario also assumes a higher level of power system flexibility (see section 9.5 and Chapter 10).

The difference in scenarios is also highlighted by the different way that energy access goals are achieved in the Future is Electric Scenario (where access is not integrated with other sustainability goals) and the Sustainable Development Scenario (where it is achieved in parallel with climate and air pollution objectives). Universal electricity access is achieved in both cases, but with a higher proportion of decentralised renewables in the Sustainable Development Scenario.

Figure 9.19 ⊳ **Electricity demand growth in the Sustainable Development and New Policies scenarios, 2017-2040**



Change in electricity demand 2017-40 (thousand TWh): Transport Industry Buildings and agriculture
Share of electricity in TFC in 2040 in SDS: >35% 30-35% 26-30% 20-25% <20%

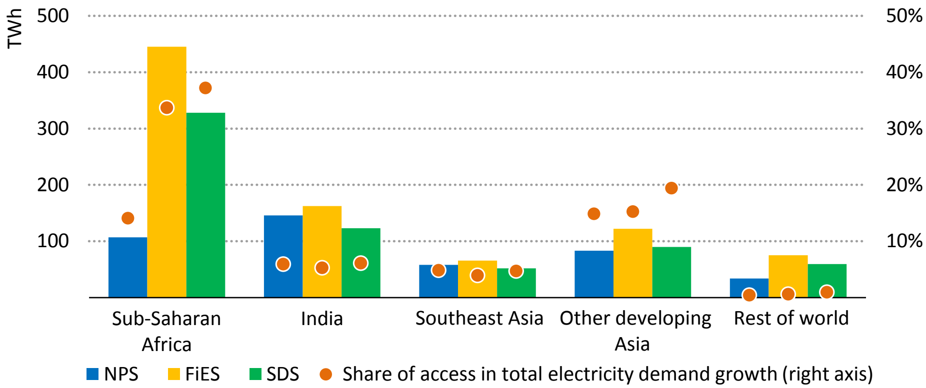
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

In advanced economies, electricity demand growth in the Sustainable Development Scenario is dominated by transport; in developing economies, energy efficiency is the more notable factor

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario; TFC = total final consumption.

The evolution in electricity demand in the Sustainable Development Scenario varies across regions (Figure 9.19). In advanced economies, total electricity demand in the Sustainable Development Scenario reaches the same level as the New Policies Scenario, but the composition of demand is very different. Strong efficiency gains in the buildings and industry sectors are almost entirely offset by the demand from EVs (which, in turn, reduces oil demand, as discussed in Chapter 2).

Figure 9.20 ▷ Electricity demand attributed to electricity access by scenario, 2040



Electricity demand from universal electricity access is lower in the Sustainable Development Scenario across all regions, due to stringent energy efficiency policies

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

In developing economies, electricity demand growth is generally lower in the Sustainable Development Scenario than the very fast growth seen in the New Policies Scenario. This is thanks to stringent efficiency policies applied in the Sustainable Development Scenario, which act to absorb demand increases, such as from the rapid uptake of EVs. In general, electricity access makes only a small contribution to demand growth, in particular due to high levels of energy efficiency in the Sustainable Development Scenario even for new connections (Figure 9.20). Africa is an exception: providing electricity access to nearly a billion people by 2040 has a greater impact in bolstering electricity demand growth than other regions (though energy efficiency is still important, as shown by the higher demand growth in Africa in the Future is Electric Scenario than in the Sustainable Development Scenario).

9.4.2 Electricity supply in the Sustainable Development Scenario

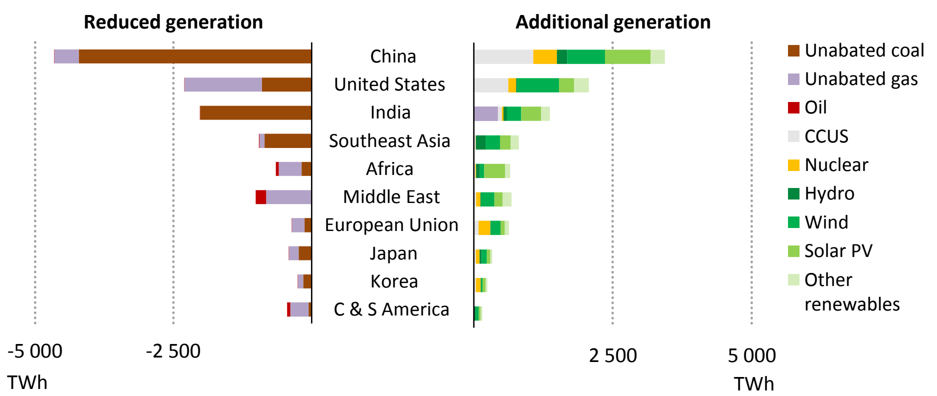
Electricity generation

The Sustainable Development Scenario requires a profound transformation of the power generation sector. The objectives of reducing CO_2 emissions, cutting air pollution and achieving energy access all influence how the power generation mix evolves over the coming decades. The carbon intensity of electricity generated is extremely important for achieving the goals of the Sustainable Development Scenario.

In the Sustainable Development Scenario, power generation is all but decarbonised by 2040: 85% of global generation comes from low-carbon sources, compared to 51% in the New Policies Scenario, and only 35% today. This causes emissions of air pollutants as well as CO_2 to fall sharply.

Generation from renewables rises to almost four-times today's level by 2040, led by wind and solar PV, which account for almost 40% of total generation in 2040 (Figure 9.21). In the Sustainable Development Scenario, the combination of CO_2 and air pollution policies contributes to a reduction in total power generation from coal to only 5% of the global total in 2040, of which 65% is from plants fitted with carbon capture, utilisation and storage (CCUS). Natural gas fares better, because of its lower CO_2 and air pollution footprint, with total gas-fired generation increasing globally until 2030, before falling to 14% of the total by 2040. By that time, 17% of gas-fired power generation is from plants fitted with CCUS.

Figure 9.21 ▷ Change in electricity generation by source in selected regions in the Sustainable Development Scenario relative to the New Policies Scenario, 2040



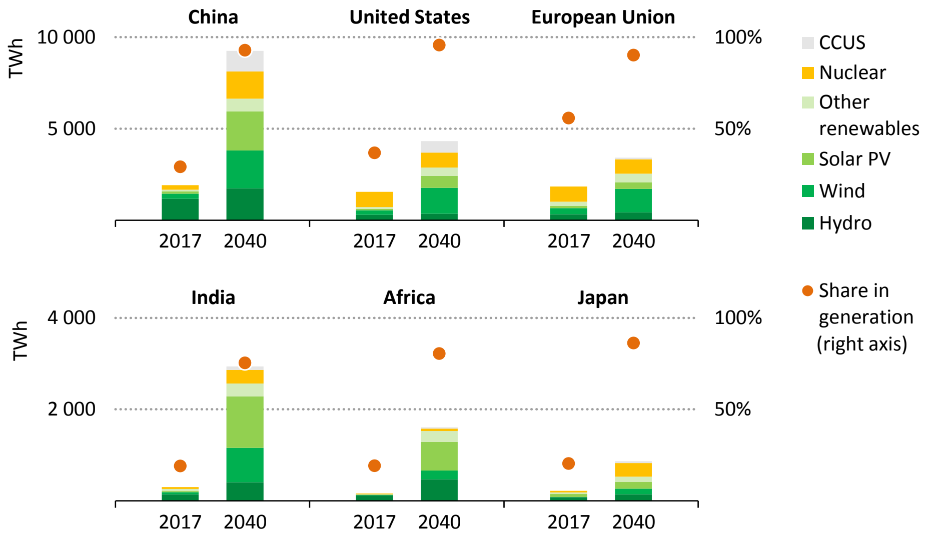
85% of global generation in the Sustainable Development Scenario is projected to come from low-carbon sources

Note: C & S America = Central and South America; CCUS = carbon capture, utilisation and storage.

The difference in the power generation mix in 2040 between the Sustainable Development Scenario and the New Policies Scenario varies by region. In most regions reduced generation from unabated coal (and in some cases gas) plants is greater than additional generation from low-carbon sources such as renewables, nuclear and CCUS. India, however, sees additional unabated gas-fired generation in the Sustainable Development Scenario relative to the New Policies Scenario, and this gas generation acts to displace some coal-fired generation from the mix. In China, unabated coal-fired generation decreases substantially, while increases in generation with CCUS (mostly coal) offsets around a quarter of this. Nuclear generation also increases in China in the Sustainable Development Scenario, as it does also in the United States and the European Union to a lesser extent, as well as in several other regions. This is partly due to countries enacting lifetime extension plans to maintain the contribution of existing nuclear plants longer than was initially foreseen. Wind and solar PV are the big winners across the board, with substantial additional generation almost everywhere.

The split between different forms of low-carbon generation varies significantly (Figure 9.22). While wind and solar PV show the biggest change from now to 2040, hydropower and nuclear remain important components of low-carbon generation in China in particular. CCUS in power generation only really makes inroads in China and the United States.

Figure 9.22 ▷ Low-carbon electricity generation by region in the Sustainable Development Scenario

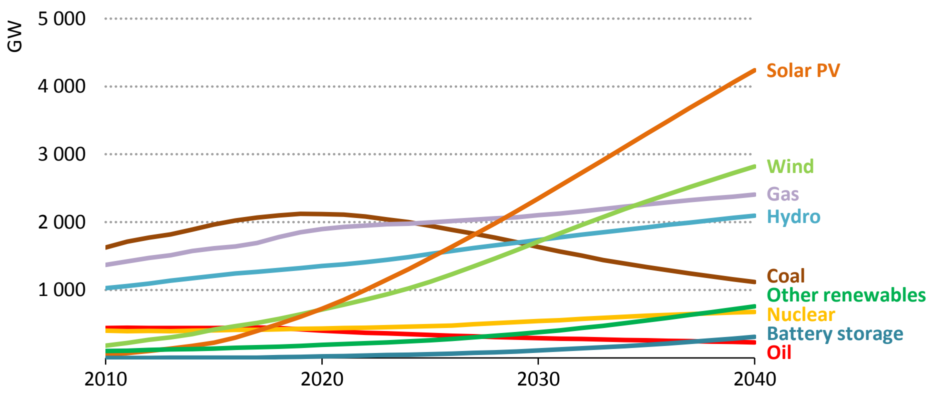


The power system in most regions is almost completely decarbonised by 2040; hydro and nuclear remain important, particularly in China

Power generation capacity: solar PV to the fore

Power generation capacity in the Sustainable Development Scenario expands from 6 960 GW today to more than 14 600 GW in 2040 (compared with 15 100 GW in the Future is Electric Scenario and 12 500 GW in the New Policies Scenario). The policies adopted to support the objectives of the Sustainable Development Scenario deliver a significantly different technology mix than in the New Policies Scenario, with low-carbon technologies reaching 75% of total capacity in 2040 (Figure 9.23). Solar PV takes the lead in installed capacity by 2030, rising to more than 4 200 GW of installed capacity in 2040. Its rapid rise is bolstered by all three of the scenario's objectives: it plays a key role in delivering electricity access due to its distributed nature, as well as in supporting air pollution and climate goals. Wind power (onshore and offshore) becomes the second-largest technology in terms of capacity, with more than 2 800 GW in 2040.

Figure 9.23 ▷ Total power generation capacity in the Sustainable Development Scenario



Solar PV takes the lead in installed capacity before 2030; unabated coal capacity declines from 2020

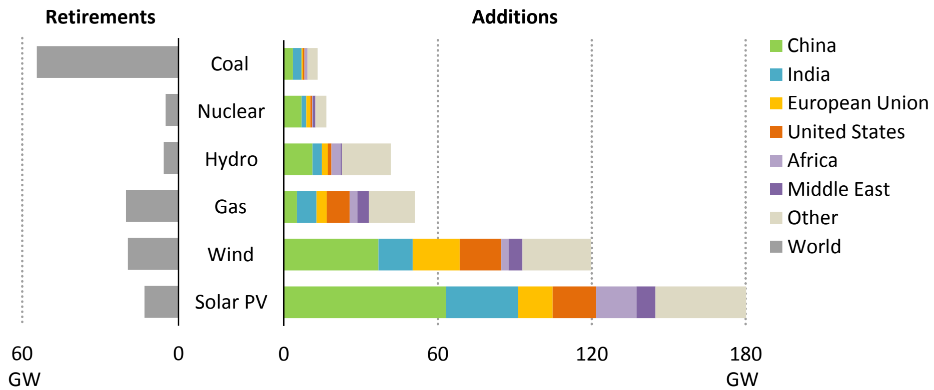
The share of hydropower decreases slightly by 2040 but nevertheless grows in absolute terms, with almost twice the level of new capacity additions as in the period 2000-17: an impressive increase for an already established and mature technology. Nuclear capacity reaches 680 GW, with 17 GW of additions per year on average: China accounts for over 40% of the new additions.

On the fossil fuel side, gas-fired capacity grows by more than 40% and is the third-largest generation source in terms of installed capacity by 2040. Of the 2 410 GW of gas capacity, around 7% is fitted with CCUS. Unabated coal-fired capacity soon enters a rapid decline, falling by almost 60% by 2040. Coal-fired power retirements rapidly outpace additions at around 55 GW per year on average, with most capacity additions in China and India. By the end of the outlook period, some 20% of coal-fired power is fitted with CCUS, mostly in the United States and China, and coal with CCUS is responsible for 65% of coal-fired electricity generation.

Overall changes in the capacity mix are reflected in total additions and retirements for each technology out to 2040 (Figure 9.24). Renewables make up the bulk of new capacity. Solar PV is the most deployed technology with an average 180 GW of additions per year. China and India alone make up about half of all solar PV additions. Wind also grows rapidly with 120 GW of additions each year on average, although growth is slowed by nearly 20 GW of retirements each year on average as older machines are replaced with larger and more efficient turbines. China also drives this expansion with more than 35 GW of additions each year, followed by the European Union with 18 GW and the United States with 16 GW.

The very high share of generation capacity from renewables by 2040 requires an extremely flexible power system to ensure stable and secure systems. The implications of this for the Sustainable Development Scenario are discussed in section 9.5.

Figure 9.24 ▷ Global capacity additions and retirements by technology and region in the Sustainable Development Scenario, 2018-2040 (average annual)

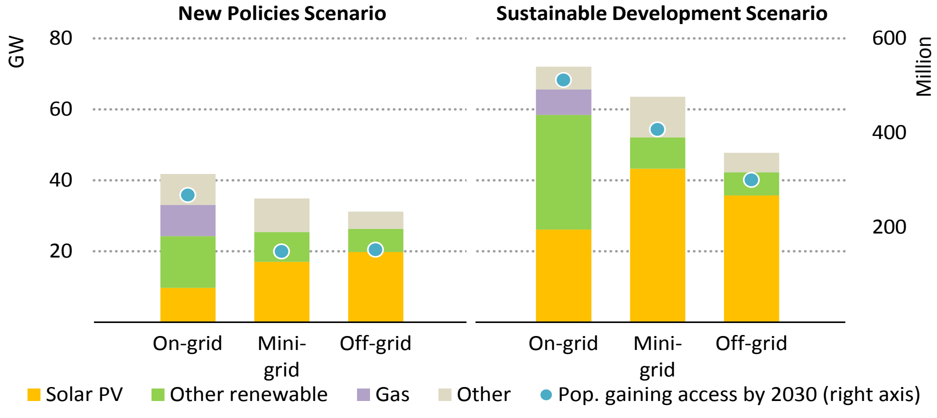


Solar PV and wind provide the lion's share of new capacity, while coal sees the most retirements

Energy access: implications for electricity supply

The Sustainable Development Scenario sees a strong shift in the means by which electricity access is provided compared to how connections have been provided in the past and what can be expected from current plans (Figure 9.25). Nearly 60% of additional connections to 2030 are from mini-grid and off-grid solutions, with the role of mini-grids in particular growing strongly as higher concentrations of power demand in rural areas improve their cost-effectiveness over stand-alone solar home systems. Mini-grids have the potential to scale up production and provide power for community services and local industry, and eventually to be interconnected with the grid, provided that workable financing models for this can be secured. With detailed spatial models of electricity demand, governments can generate electrification plans, which are a necessary step for achieving universal access (Spotlight).

Figure 9.25 ▷ Capacity additions for electricity access and population gaining access by source, 2018-2030



Renewables supply a bigger share of grid, mini-grid and off-grid connections to provide energy access in the Sustainable Development Scenario

S P O T L I G H T

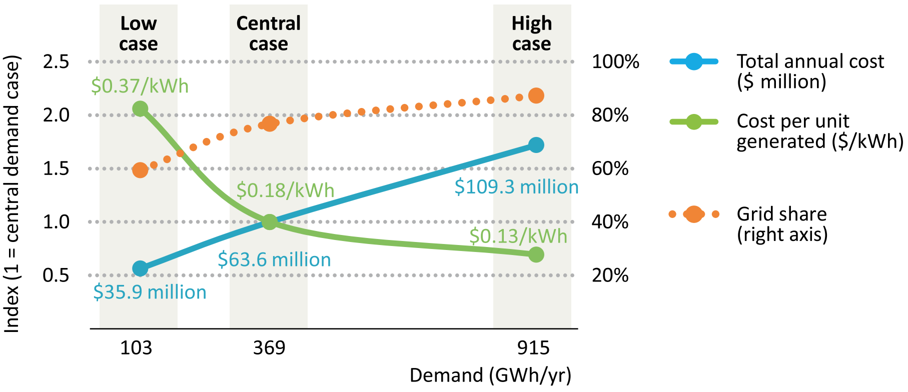
Enlightened thinking: the value of high-resolution electrification planning for achieving universal electricity access

Around $50 billion in investment is needed annually to meet the goal of universal electricity access. With 80% of those without access living in rural areas, electrification master plans are an essential instrument to achieve universal electricity access in a cost effective manner. Such plans allow governments to determine the optimal mix of grid extension, stand-alone and mini-grid solutions while serving the energy needs of households, communities and businesses in different regions. They can also inform the timescale of infrastructure development and give clarity to investors.

Electrification planning models are important tools for developing master plans based on geospatial maps of populations, energy resources and infrastructure. By also modelling the evolution of electricity demand over time, electrification planning models allow governments to understand the trade-offs between electrification master plans that seek to meet demand in the short term and plans that aim to develop infrastructure capable of meeting longer term demand projections. These tools are most effective when they take into account real-world energy needs at a high spatial resolution, as well as covering demand from all major productive use sectors, such as agriculture, mining, industry and services.

A new analysis undertaken for this report shows how accurate demand projections, combined with detailed spatial analysis at the building level, are critical in supporting government decision making, and can significantly reduce the cost of bringing electricity access to all.[10] The analysis takes the case of an 11 000 square kilometre (km^2) area of the South Service Territory in Uganda, comprising 367 000 buildings. Twenty consumer types are represented, ranging from households with small and large electricity demand to mines, factories and small businesses.

Figure 9.26 ▷ Electrification planning and the impact of demand on cost and optimum grid share for a 11 000 km² area in Uganda



Electrification planning can support optimal electrification strategies

Three cases, low demand at 103 gigawatt-hours (GWh), central at 369 GWh and high at 915 GWh show the effects of using various time horizons when designing electrification master plans (Figure 9.26). Significant economies of scale are associated with planning for the higher levels of demand expected in the years following electrification: the average cost in the central case ($0.18/kWh) is half that of the low demand case ($0.37/kWh), yet economies of scale are less apparent if governments plan for higher levels of demand further into the future. The results also show that the optimal share of grid extension relative to off- and mini-grid solutions grows with increasing demand.

10. This analysis has been developed in collaboration with the MIT-Comillas Universal Energy Access Lab, based on the Reference Electrification Model, http://universalaccess.mit.edu/#/rem.

This analysis points to the importance of adequately estimating demand and its evolution: under building infrastructure and generation capacity results in shortages and higher per-unit costs, while over estimating demand leads to over-built systems and failure to recover costs, as well as missed opportunities for off- and mini-grid systems (as higher demand amplifies the case for grid extension). The analysis also highlights the benefits of representing the diversity of consumer load profiles when planning for electrification: using homogenous load profiles increases the cost of the central case by 10%, compared with using the 20 heterogeneous consumer profiles.

These findings highlight the need for better demand data, which are especially scarce in developing countries, so that particular local contexts can be taken into account when delivering access solutions. New technology including digital metering and satellite imagery are becoming feasible and could help with acquiring better data.

9.5 System flexibility for alternative electricity futures

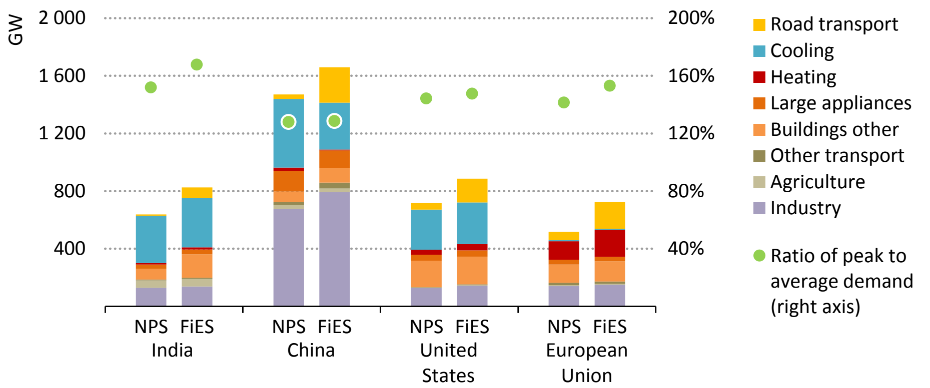
9.5.1 Combined drivers of electrification, digitalization and variable renewables

Accelerated electrification of end-uses, a higher share of non-dispatchable renewables in the generation mix, increased electricity demand from digitally connected devices and improved energy access all act to drive up both annual and peak electricity demand in the Future is Electric Scenario. As demand rises, so does the importance of system flexibility and of the smart infrastructure and digital connectivity that facilitate it. In the Future is Electric Scenario, the increased demand is not accompanied by any particular efforts for smarter management of the system. A single minded pursuit of electrification in this scenario is not matched with sound data strategies and investments in smart infrastructure and digital connectivity. As a result, electrification, and particularly electricity demand for road transport and heating, place an increased burden on the electricity system relative to the New Policies Scenario.

Electric vehicle charging is a case in point. Times of peak demand for newly electrified end-uses such as electric vehicle charging often correspond to times of existing peak demand. This means that, in regions where the system peak is already driven by loads in the evening, higher electrification further increases the need for flexibility as the ratio of peak demand to average demand grows (Figure 9.27). In regions where the peak occurs during the day, such as India and China, the impact of increased electrification shifts the system peak to later in the day when electric vehicle charging demand is higher.

A common factor across all regions is the increasing share of electric vehicles in peak electricity demand, ranging from 1% to 11% in the New Policies Scenario and from 9% to 26% in the Future is Electric Scenario. The impact of increasing electrification of transport is greatest in the European Union and China, where the competitiveness of electric cars drives up their share in the total car fleet to 67% in the European Union and 65% in China in 2040, compared with 25% in both regions in the New Policies Scenario.

Figure 9.27 ▷ Peak electricity demand in selected regions in the Future is Electric and New Policies scenarios, 2040



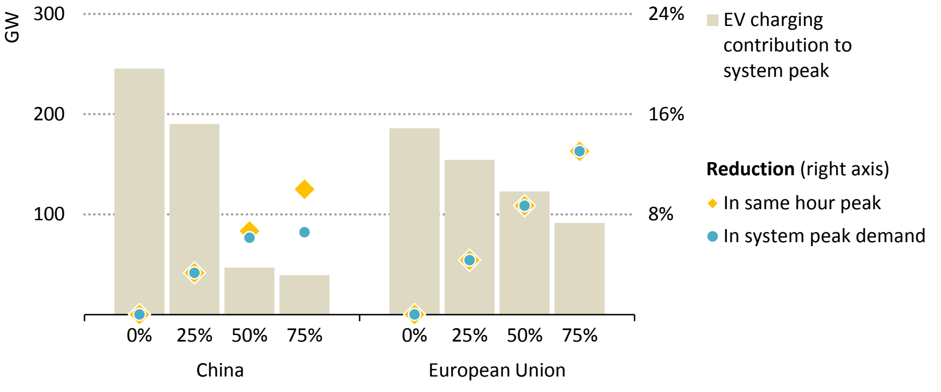
Further electrification of heat, and especially transport, increases peak demand by an average of 25%

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario.

The need to charge growing numbers of EVs illustrates how a co-ordinated approach can contribute to system efficiency and flexibility. Uncoordinated charging of EVs risks exacerbating challenges for grid operators in balancing supply and demand, as well as placing additional pressure on the network. This could lead to a need for increased investments in peaking resources. Co-ordinated charging of EVs offers the potential to help smooth the increase of peak demand. This would mean adjusting charging times to match system needs. With such "smart" charging, electricity demand can be shifted from peak times to periods when either demand is low (such as at night) or when there is a surplus of generation from renewables (for example at mid-day in a system with high solar penetration). In this way vehicles become part of a wider demand-side response strategy, which can bring gains not only for the system but also for consumers, who may be able to benefit from incentives to charge when demand is low or supply exceeds demand.

The impact of smart charging will depend on what percentage of the electric vehicle fleet participates. In the Future is Electric Scenario, peak demand in 2040 is reduced by 7% in China and 13% in the European Union when 75% of EVs participate in co-ordinated charging, compared to a world in which there is no co-ordination of charging (Figure 9.28). This would reduce peak demand by 110 GW in China and over 90 GW in the European Union.

Figure 9.28 ▷ Impact of various levels of co-ordinated charging of EVs on peak electricity demand in the Future is Electric Scenario, 2040



Co-ordinated charging of electric vehicles has the potential to significantly lower peak demand, reducing the need for grid upgrades and peak generation capacity

Note: Co-ordinated charging assumes that the majority of charging loads are available to be shifted to outside of peak demand periods, however, user constraints will mean that even with 100% co-ordinated charging, demand for vehicle charging will not be zero during peak times.

In certain regions, the demand reduction from co-ordinated charging is sufficient to shift the day and time of peak demand. In China, the result of co-ordinated charging of 50% or more of the electric vehicle fleet in 2040 is to shift the peak from weekdays to Sunday evenings in summer, when the contribution of vehicle charging to the system peak is low, but demand for other end-uses such as cooling is high. As a result, further increasing the share of co-ordinated charging leads to only marginal reductions in peak demand. Nonetheless, the potential for peak reduction from co-ordinated charging remains significant, with implications for the level of investment required to maintain security of supply at peak times. For example, a reduction of 100 GW in peak demand would remove the need to invest over $40 billion for power plants in China.

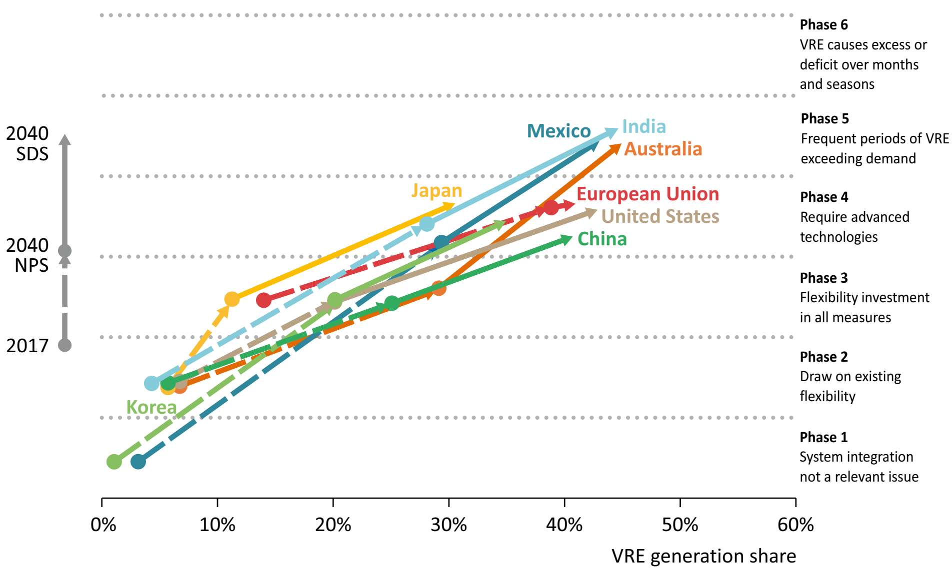
A number of co-ordinated charging pilot projects are currently being developed by automakers (such as the BMWi ChargeForward Project) and utilities, among others. Co-ordinated EV charging is also on the radar of governments. For example, the United Kingdom has committed to investing around $42 million in smart charging and vehicle-to-grid innovation. Ensuring the success of co-ordinated charging programmes is not straightforward. Car owners will need to choose to participate, and smart grid infrastructure and time-of-use pricing will need to be available to provide economic incentives for vehicles to be charged at optimum times for the grid. Schemes that share the benefits from charging in off-peak hours between providers of charging services and car owners may be one way to increase participation levels. This could also serve to narrow the cost gap between electric and conventional cars, further accelerating the uptake of electric cars.

9.5.2 A smarter push for decarbonisation reveals vast amounts of flexibility in the Sustainable Development Scenario

Electrification and digitalization shape flexibility in the Future is Electric Scenario, and in doing so they highlight some of the challenges that increased electrification in isolation could bring. The Sustainable Development Scenario shows a smarter transformation of the electricity sector that more fully exploits the flexibility from storage, demand response, cross-sector integration and the generation fleet in order to reach the SDGs.

In the Sustainable Development Scenario, the share of low-carbon generation rises to 86%, compared with 51% in the New Policies Scenario. The decarbonisation of the electricity sector is propelled by increased use of wind and solar resources, coupled with changes in the structure of electricity demand. The world as a whole reaches a wind and solar share of 38% (only one country today – Denmark – has a higher share). All regions reach at least phase 3 of the flexibility ladder, where additional investment in flexibility measures is required (see Chapter 7 for explanation of this scale). Seven regions reach phases that see structural deficits and surpluses, while regions like Mexico, India and Australia see frequent periods where the generation from variable renewable energy (VRE) on its own is high enough to exceed overall demand (Figure 9.29).

Figure 9.29 ▷ Evolving flexibility needs by regions in the Sustainable Development Scenario

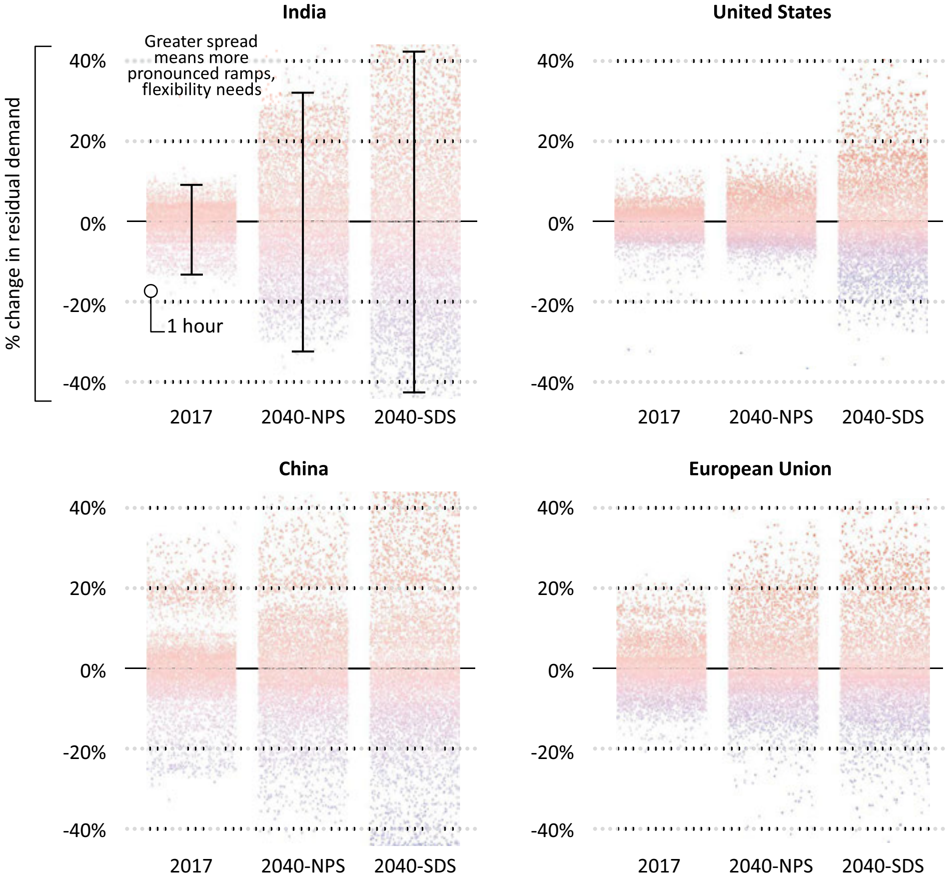


Flexibility needs experience a step change, with all large markets reaching phases of VRE integration where few countries are today

Note: NPS = New Policies Scenario. SDS = Sustainable Development Scenario. VRE = variable renewable electricity.

While VRE is the key driver of flexibility needs in the Sustainable Development Scenario, there are other variables that affect the extent of the need for additional flexibility to meet the requirements of a sustainable energy system. For example, two countries with an identical share of VRE can be in different phases depending on the relative contribution to generation of wind and solar PV (because they have qualitatively different flexibility needs) and on the characteristics of their electricity demand.

Figure 9.30 ▷ Unleashing flexibility in the Sustainable Development Scenario



Flexibility needs expand significantly in the Sustainable Development Scenario, particularly in regions where solar PV makes a high contribution to achieving the scenario goals

Notes: NPS = New Policies Scenario; SDS = Sustainable Development Scenario. Residual hourly demand refers to the total load on the system minus the output from wind and solar PV plants.

The need for flexibility can be approximated by the hour-to-hour change in the ramping that the power fleet (including flexibility resources) experiences to compensate for the variability of wind and solar (Figure 9.30). Across all regions, power systems experience a sharp increase in flexibility needs. In the European Union, average net demand falls by 15% compared to today, and yet flexibility needs double. In the United States, there are sharp differences between the New Policies Scenario, where a 22% share of VRE is reached by 2040 and flexibility needs grow marginally, and the Sustainable Development Scenario, where the share of VRE reaches over 45% and flexibility needs nearly triple. In the case of China and India, despite the significant growth in capacities to meet rising demand, the need to source flexibility outpaces the expansion of the system. Demand in India nearly triples, but flexibility needs are five-times higher. In China, a 60% growth in demand brings a doubling of flexibility needs.

In the Sustainable Development Scenario, different strategies for achieving deep decarbonisation also create different needs for additional flexibility. Countries that rely heavily on solar PV to decarbonise their electricity supply tend to require substantially more flexibility than systems that have a more balanced portfolio of low-carbon sources and systems that emphasise wind power, such as those in the European Union.

The Sustainable Development Scenario reveals the merits of digital strategies and allocating investment in "future-proof smart infrastructure" that fully exploits the connectivity potential from electrification, decentralisation and decarbonisation. As countries move to higher degrees of decarbonisation and increased use of variable renewables, extended periods of surplus generation appear, along with some periods of deficits. At such times, making use of demand-side flexibility on the part of residential and commercial end-users shows clear benefits. All in all, demand-side response facilitated by digital strategies and smart infrastructure contributes nearly 450 GW of flexibility globally in the Sustainable Development Scenario. An increase in battery storage penetration compared to the New Policies Scenario (reaching over 300 GW by 2040, over one hundred times today's installed base) provides further flexibility.

Global implications of an electrifying future

The more the better?

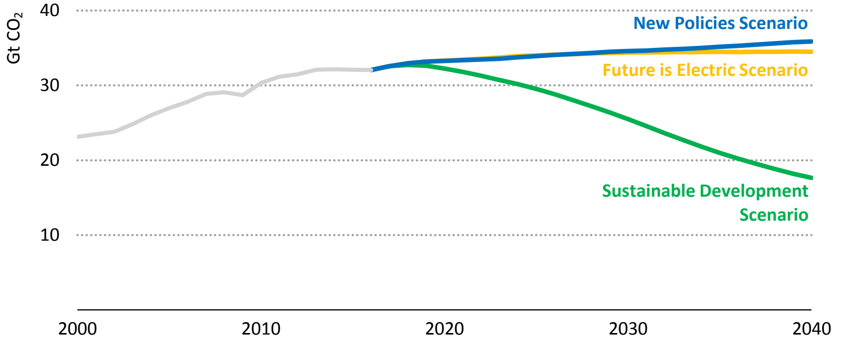
S U M M A R Y

- Electricity increasingly permeates all aspects of today's life as our homes, cars and factories become ever more digitalized, as emerging electric technologies challenge conventional ones in more and more applications, and as increasing levels of access to electricity in developing countries help open paths to economic prosperity and well-being. There is huge potential to expand the role for electricity in the future energy mix, and policy makers have a key role to ensure that we make the most of this while safeguarding electricity security and affordability.
- Electricity security is becoming more central to overall energy security. The power systems of the future will be characterised not only by generation and capacity, but also flexibility. Attracting adequate investment in the technologies required for reliable system operation is essential to ensure that the lights stay on. There are already some signs that competitive markets may face challenges in doing so. A widening gap between electricity sales revenue and total generation costs is being created by downward pressure on wholesale market prices – mainly due to the combination of high reliability requirements, higher shares of renewables with zero marginal costs and stagnant demand. Market structures and incentives that better reflect the value of capacity and flexibility provided to the system will support timely and efficient investment. Resilience to cyber-attacks will also be critical to future energy security.
- Power sector investment to meet new demand and replace ageing infrastructure averages \$870 billion per year in the New Policies Scenario, matching investment in oil and gas supply. The share of power sector investment that depends on full or partial revenue guarantees, established by regulation, is likely to remain very high. Power plant investment averages \$500 billion each year, of which 70% is for renewables. Solar photovoltaics (PV) leads the way at \$120 billion, followed by: wind (\$110 billion); hydro (\$73 billion); nuclear, gas- and coal-fired plants (about \$50 billion each); and battery storage (\$13 billion). Network investment averages \$360 billion per year to reinforce grids, connect new generation capacity, expand regional trade and provide first-time access to 510 million people. In some heavily regulated markets, this may mean risks of continued over-investment and risks to consumer affordability. Power plants under development in China, India, the Middle East, North Africa and Southeast Asia are set to outpace projected needs from electricity demand growth to 2030, adding to the current excess capacity that collectively totals 350 gigawatts (GW). Eliminating this over the period to 2040, would save up to \$17 billion per year, equivalent to almost \$15 per household each year.
- Power sector investment needs could turn out to be higher if additional efforts were made to further electrify end-uses or to further decarbonise power generation, as

in the Future is Electric and Sustainable Development scenarios. In these scenarios, power sector investment is some 30% higher than in the New Policies Scenario and far outpaces that in oil and gas supply. The additional investment in the Sustainable Development Scenario is focused on renewables, nuclear and carbon capture, utilisation and storage (CCUS).

- Consumer bills for electricity are set to increase in all scenarios. For households, the share of electricity in total energy spending could increase by up to 25 percentage points to 60% by 2040. Retail electricity prices are set to increase in many regions, as the fixed costs to recover network and power plant investment more than offset any reductions in fuel costs due to higher shares of renewables. The need to recover these fixed costs means that the price of electricity to consumers will not approach zero, even with much larger amounts of variable renewables that have zero marginal costs. Distributed energy resources, led by rooftop solar PV, could provide an attractive option for consumers, but payments for distributed energy need to reflect the value of output if distortions in the system are to be avoided. Stable governance, policy continuity and the harnessing of competitive market forces within a well-regulated framework help to ensure consumer affordability.
- Electrification efforts alone do not guarantee environmental benefits. In the Future is Electric Scenario, CO_2 emissions are only marginally lower than in the New Policies Scenario, as the reduction in end-use emissions is partially offset by the increase in power sector emissions (Figure 10.1). While electrification can help to reduce monitoring and enforcement needs to meet air quality targets, a comprehensive energy sector strategy is needed to meet Sustainable Development Goals. Such efforts are part of the Sustainable Development Scenario and include targeted efforts to decarbonise the power sector, improve the efficiency of energy uses and spur the uptake of additional low-carbon technologies across all sectors.

Figure 10.1 ▷ Energy-related CO_2 emissions by scenario, 2000-2040



Electrification policies alone do not bend the CO_2 trend

10.1 Introduction

Increasing the use of electricity is an important energy policy objective for countries where people still lack access to electricity. Increasing the role of electricity in energy consumption is also a cornerstone of energy policy in other countries for a variety of reasons. Electricity can help to diversify the fuel mix and thus enhance energy security. It can also help achieve environmental goals, as electricity is clean and efficient at the point of use; its use in buildings, factories or cars is not directly linked to any emissions of local pollutants. To make the most of electricity in the future, however, we need to understand the opportunities and challenges of its potential pathways. The New Policies Scenario provides an outlook for electricity based on existing and planned policy announcements, as detailed in Chapter 8. In Chapter 9, we examine possible variations of the future for electricity demand and supply through the lens of the Future is Electric Scenario and the Sustainable Development Scenario. In this chapter, we use all three of these possible futures for electricity to provide answers to four key questions:

- What are possible future roles for electricity, and what are the consequences for the way the world produces and consumes energy?
- Does electrification support the achievement of global as well as local environmental goals?
- Are current electricity markets ready to ensure electricity security in the energy transitions? Does energy security improve with increasing levels of electricity demand?
- How affordable is energy in an electrifying world?

The intention of this chapter is to provide energy sector stakeholders with analytical input to support their energy sector planning in a dynamic area which is critical for the global energy future.

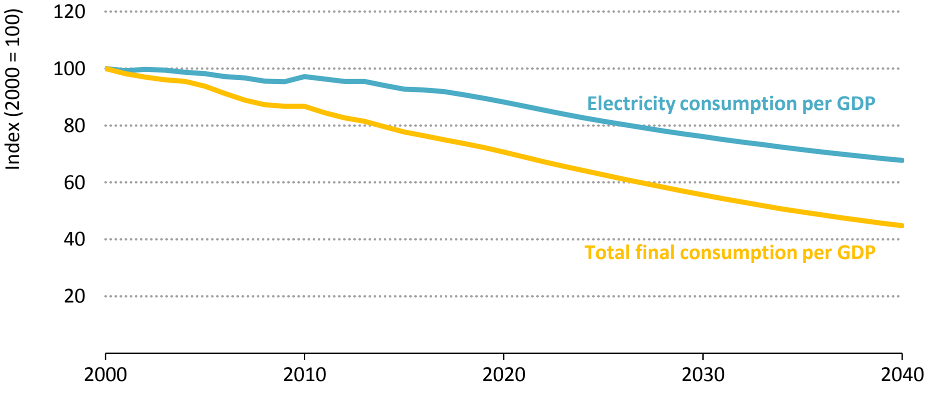
10.2 Electrifying the global energy sector – is it the start of something new?

There is no doubt that the future will be increasingly electric. Electricity has gradually expanded its share in world total final consumption by two percentage points per decade since 1980 to reach 19% in 2017. Existing and planned policies as analysed in the New Policies Scenario suggest a continuation of this trend through to 2040, reflecting not only the trend towards further electrification, but also the policy focus on improving the efficiency of fossil fuel use, which tends indirectly to increase the share of electricity in final consumption (Figure 10.2).

The scenarios explored in this year's *World Energy Outlook (WEO)* suggest a continuation or further acceleration of electrification efforts. Electricity demand growth outstrips total energy demand growth by a wide margin in all scenarios, but the scale of growth differs by scenario (Figure 10.3). The higher end of expectations is marked by the Future is Electric

Scenario, which shows that electricity demand could nearly double over today's level to around 42 000 terawatt-hours (TWh) by 2040 if non-economic barriers for electrification are removed to unlock new electricity uses in key sectors such as industry and transport; if a more widespread digitalization of homes and services facilitates higher electricity use in buildings; and if full access to electricity is achieved in all countries. A lower end of electricity demand growth projections is marked by the Sustainable Development Scenario, although this is in many ways also a "high-electrification" scenario. In this scenario, electricity permeates all sectors, but demand growth is limited to 33 000 TWh through additional policies to increase energy efficiency across all sectors and technologies in support of global action to achieve the United Nations Sustainable Development Goals.

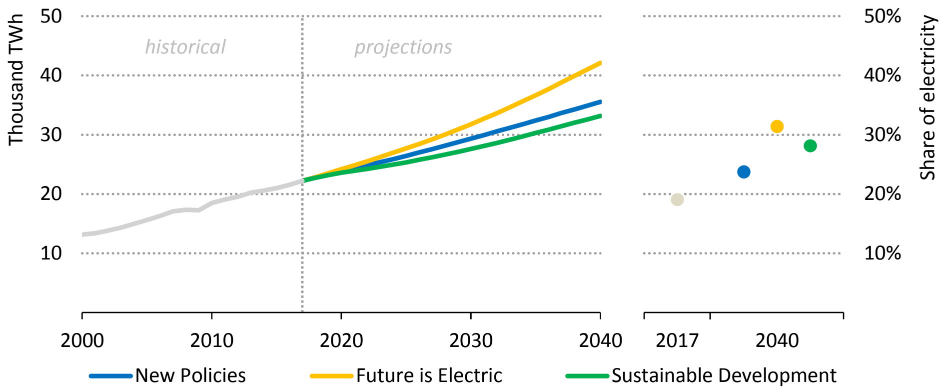
Figure 10.2 ▷ World total final consumption and electricity intensities of GDP in the New Policies Scenario



Energy efficiency policies help to reduce the overall energy intensity of the global economy; electrification efforts across sectors slow the decline in electricity intensity

In all scenarios in this year's *Outlook*, the share of electricity in total final consumption grows. In the Future is Electric Scenario, it reaches 31%, or two-thirds above today's share. In the Sustainable Development Scenario, it similarly rises significantly above today's level, and well above the level that is achieved in the New Policies Scenario. Full electrification of energy demand is nevertheless not achieved in any of the scenarios over the projection period. In some cases, this is because the economics of electricity-based technologies are less favourable than those using other fuels, in the absence of new policy measures. In others, there are technical limitations: for example, without further technological breakthroughs large passenger aircraft cannot be operated using just electricity for long-distance travel.

Figure 10.3 ▷ **Electricity demand by scenario and share of electricity in total final consumption**



Electricity use expands in all scenarios, but the extent depends on future policy support and the pace of technology development

Electrification is generally perceived as an efficient way of using energy, although losses in electricity generation and distribution mean that overall efficiency gains are not as high as is often expected. For example, in the Future is Electric Scenario, total final consumption in 2040 is 10% lower than in the New Policies Scenario, but overall primary energy demand is only 5% lower as a result of losses in electricity supply. There remains considerable scope to improve the efficiency of electricity use in the Future is Electric Scenario, both at the level of the equipment itself (Table 10.1) and through wider systemic efficiency improvements. The Sustainable Development Scenario assumes that such efficiency potential gains are realised, which is a key reason why projected electricity demand is much lower than in the Future is Electric Scenario, despite providing the same service.[1]

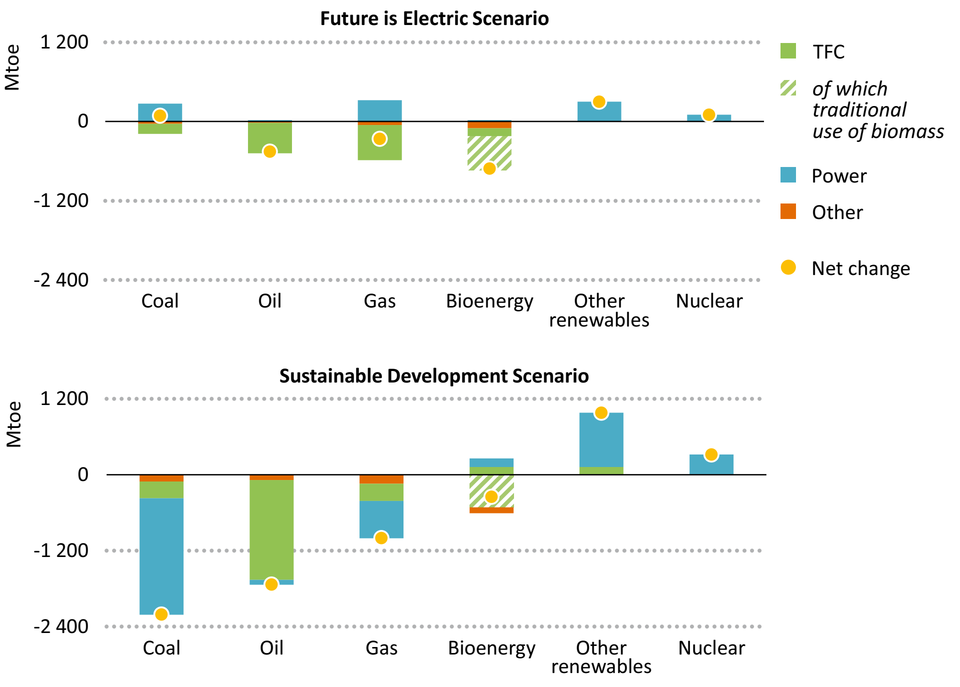
Higher levels of electrification mean that the way we use energy in our homes, cars and factories change in the future. The impact on other fuels at an overall system level depends on how much incremental demand is simply new demand for electricity and how much of it reflects displacement of other fuels (Figure 10.4).

1. The Future is Electric Scenario represents a case that explores the upside potential of electricity demand with a view to the energy system-wide implications (see Chapter 9). It reaches higher shares of electricity in total final consumption than the Sustainable Development Scenario for three main reasons: first, the Sustainable Development Scenario assumes a stronger push towards more energy efficiency. Second, the Future is Electric Scenario explores an upside case for digitalization by assuming a faster uptake of connected devices, which does not contribute directly to decarbonisation efforts and only creates a demand for additional digital services. Third, that the price environment between both scenarios differs, and so does the economic case for electricity-based end-use technologies in comparison to other low-carbon options, such as renewables.

Table 10.1 ▷ **Global electricity demand for the same service in selected sectors in the Future is Electric and Sustainable Development scenarios** (TWh)

Sector	Technology	2017	2040	
			Future is Electric	Sustainable Development
Industry	Industrial motors	6 520	11 040	8 880
Residential buildings	Lighting	500	440	385
	Air conditioners	920	2 645	1 700
	Space heating equipment	560	1 495	655
Transport	Electric cars	4	1 050	940

Figure 10.4 ▷ **Changes in primary energy demand by scenario relative to the New Policies Scenario, 2040**

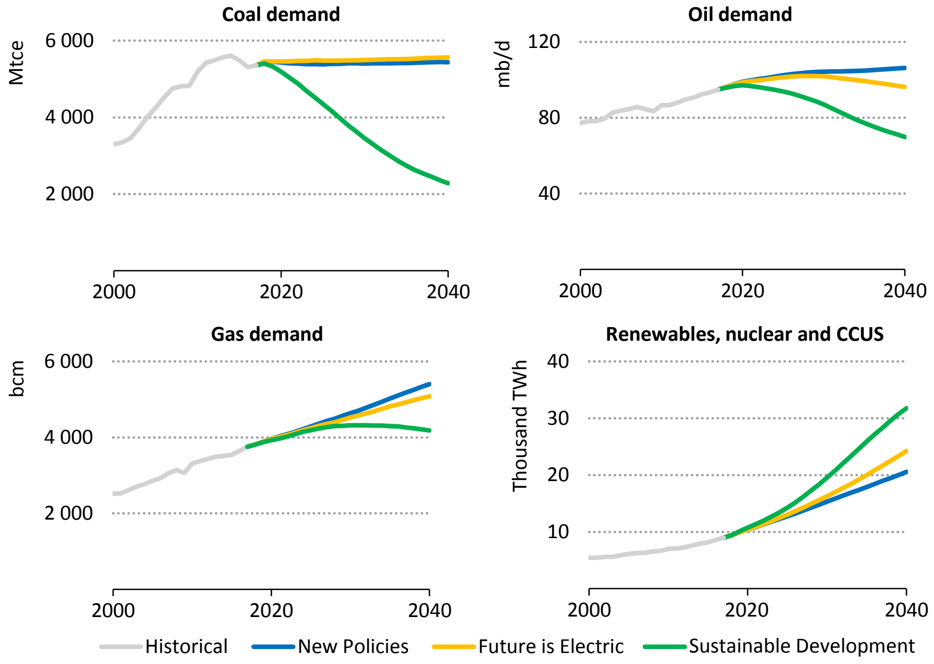


Expanding electrification affects all fuels, though broader clean energy transitions in the Sustainable Development Scenario have a much stronger impact

Notes: Mtoe = million tonnes of oil equivalent; TFC = total final consumption. Hashed area denotes traditional use of biomass.

Electricity demand will be driven to some extent by demands for new types of services. Digitalization is a key example: digital advances for everyday objects like watches, telephones, home appliances and cars make them more connected to communications networks and provide additional services and applications in fields such as personal healthcare, home automation and intelligent transport. Although there is a possibility that these new uses, to some extent, displace demand for other products and fuels, they in part simply create new electricity demand, including in data centres. In the Future is Electric Scenario, such new uses contribute 6% of the additional overall electricity demand in 2040, compared with the New Policies Scenario.

Figure 10.5 ▷ World fossil fuel demand and low-carbon electricity generation by scenario, 2000-2040



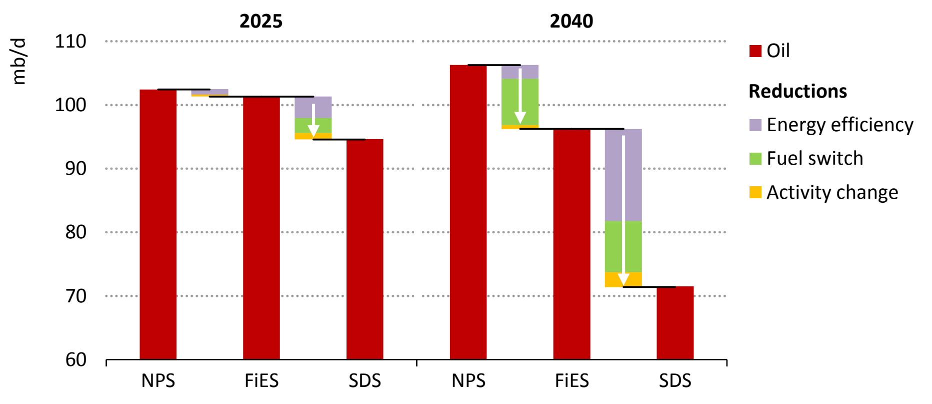
The time required to electrify end-uses at scale mean that the impact on overall energy demand in the Future is Electric Scenario is largest after 2030

Notes: Mtce = million tonnes of coal equivalent; mb/d = million barrels per day; bcm = billion cubic metres; TWh = terawatt-hours ; CCUS = carbon capture, utilisation and storage.

There are also instances in which electricity competes with other fuels at the point of use, as new electricity-based technologies develop and mature across an increasing number of markets. The extent to which this competition affects the overall demand for other fuels depends on how electricity is being produced. In the case of space heating, for example, electric heat pumps compete with gas boilers at the point of use, but the impact on overall natural gas demand is limited where gas is being used to generate electricity. In the New Policies Scenario, gas-fired electricity generation expands by 1.9% per year through 2040. In the Future is Electric Scenario, this growth is even higher, at 2.9% per year. The decline in the Sustainable Development Scenario comes on the back of rising carbon dioxide (CO_2) prices. In this scenario, gas use for power generation peaks before 2030 and then declines to 2040 to a level that is around 10% lower than today.

The competition between electricity and oil is much more clear-cut, as oil is rarely used in electricity generation, except in the Middle East, parts of Asia, Latin America and Africa. Electric cars are a good example: to the extent that electric cars compete successfully with conventional cars, electricity in effect displaces oil in road transport, reducing global oil demand. In the Future is Electric Scenario, the electric car stock reaches 950 million cars by 2040, nearly half of the global car fleet, and other road transport modes are also electrified at scale. Oil demand peaks as a result, although this occurs later and is less pronounced than in the Sustainable Development Scenario (Figure 10.5), in which additional measures help increase the efficiency of oil uses across all sectors and promote other alternatives fuels such as biofuels or natural gas (Figure 10.6).

Figure 10.6 ▷ Change in world oil demand by scenario and measure relative to the New Policies Scenario, 2025 and 2040



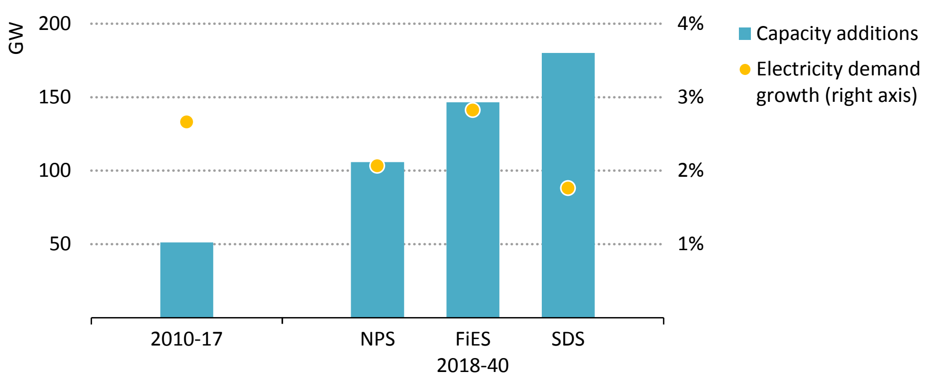
An oil demand trajectory compatible with climate targets requires robust energy efficiency gains and fuel switch

Note: mb/d = million barrels per day; NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

Understanding future electricity demand growth is particularly important for assessing future power market requirements and their implications for new renewables capacity. As the costs of renewables fall rapidly and they become competitive in an increasing number of markets across all *WEO* scenarios, additional investment in renewable capacity essentially depends on the pace of electricity demand growth; the pace at which existing thermal capacity is phased out; and the extent to which other deployment hurdles can be overcome, including access to project financing and measures to ensure system integration of renewables.

A comparison of solar photovoltaic (PV) deployment in the Future is Electric and the Sustainable Development scenarios illustrate this point (Figure 10.7). In the Future is Electric Scenario, high electricity demand growth expands solar PV capacity additions over the level of the New Policies Scenario, as solar PV is very competitive with other sources of new generation in many countries. Further growth however is hampered by the lower costs of generation from existing thermal plants; a lack of access to financing in developing countries; and, in some markets, a lack of measures to accommodate the variable nature of solar PV generation. In the Sustainable Development Scenario, higher levels of solar PV deployment take place despite lower demand, as measures are assumed to be taken to phase out existing coal-fired power plants (especially the least-efficient ones); as CO_2 prices change the balance of competitiveness with existing thermal generation; and other deployment hurdles are overcome.

Figure 10.7 ▷ World average annual solar PV capacity additions and electricity demand growth by scenario



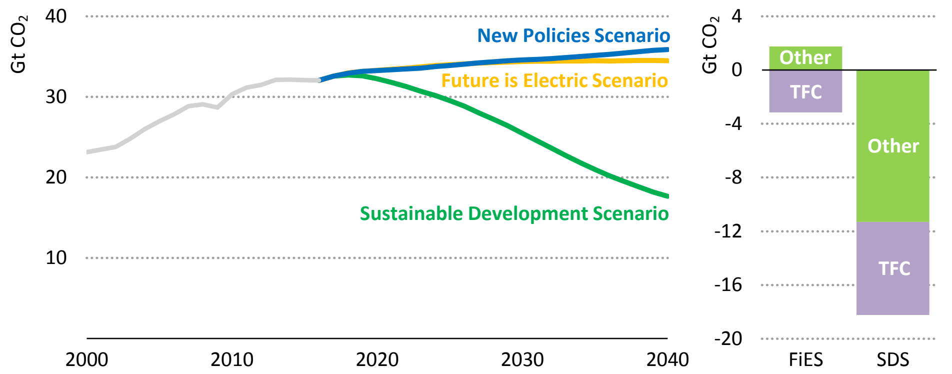
Solar PV deployment depends on technology cost reductions, electricity demand growth and policies to decarbonise the power sector

Note: GW = gigawatts; NPS = New Policies Scenario, FiES = Future is Electric Scenario, SDS = Sustainable Development Scenario.

10.3 Achieving environmental goals through electricity

The use of electricity has a key advantage over the use of other fuels in that it does not require the combustion of fuels at the point of use and therefore considerably reduces related greenhouse gas (GHG) and air pollutant emissions (although its use does not necessarily avoid air pollutant emissions altogether: an electric car will for example still emit fine particulate emissions from abrasion, brakes and tyres). Whether or not electrification contributes to reducing GHG and air pollutant emissions across the entire supply chain depends on how the electricity is being produced.

Figure 10.8 ▷ World energy-related CO_2 emissions by scenario (left) **and change in CO_2 emissions by sector in 2040 relative to the New Policies Scenario** (right)



Electrification alone is not sufficient to put the world on track to meet climate goals; it requires a more comprehensive energy system strategy

Note: Gt = gigatonnes; TFC = total final consumption; Other = power generation and other transformation; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

As described in Chapter 2, current efforts are not sufficient to meet the well-below 2 °C target of the Paris Agreement. In the New Policies Scenario, energy-related CO_2 emissions keep rising through to 2040 (Figure 10.8). Electrification alone, even if widespread and pervasive, does not materially alter this outcome. In the Future is Electric Scenario, energy-related CO_2 emissions are only 1.4 gigatonnes (Gt) lower in 2040 than in the New Policies Scenario. Without further policy measures to change the fuel mix and decarbonise the power sector, higher electrification has the effect of transferring emissions from the point of end-use to the point of generation (Box 10.1 and Figure 10.10).[2] The deep cuts in emissions required to reach the goals of the Paris Agreement are only achieved in the Sustainable

2. Applying the average power generation emissions intensity of the Sustainable Development Scenario to the Future is Electric Scenario would further reduce CO_2 emissions from the power sector in the Future is Electric Scenario by around 12 Gt in 2040.

Development Scenario, which assumes the implementation of additional system-wide measures improve energy efficiency, increase the pace of power sector decarbonisation; and the uptake of renewables in end-use sectors, and roll out critical technologies such as carbon capture, utilisation and storage (CCUS).

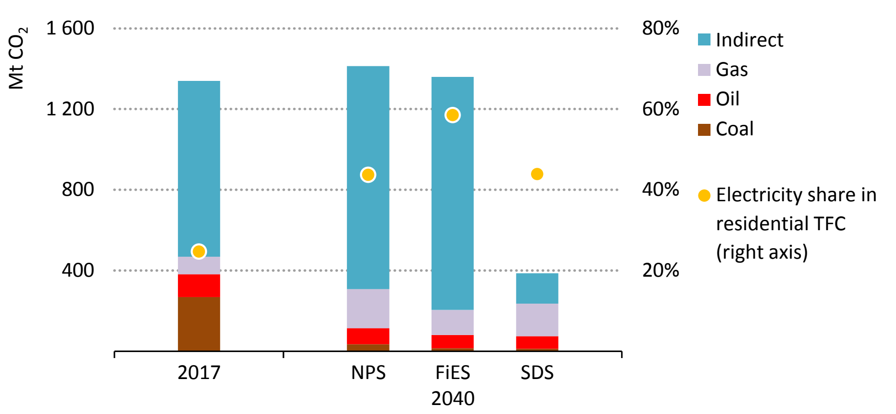
Box 10.1 ▷ Electrification of residential buildings in China

Residential buildings in China currently emit around 470 million tonnes (Mt) of CO_2 from direct fuel combustion, nearly 60% of it from coal. This total nearly triples once emissions from electricity generation are included, because electricity already accounts for around 25% of energy consumption in residential buildings in China, and the emissions intensity of electricity is still relatively high.

In the New Policies Scenario, the share of electricity in China's residential energy use is set to rise to almost half by 2040, as coal gives way to electric heating and electric appliances become more prevalent. In the Future is Electric Scenario, these trends are reinforced, with the share of electricity rising to around 55%. However, total CO_2 emissions from residential buildings barely change from today's level in either the New Policies or the Future is Electric scenarios. Lower direct emissions are balanced by higher indirect emissions from electricity supply. In the Sustainable Development Scenario, however, CO_2 emissions fall by 70% from today's level – thanks mostly to the decarbonisation of power supply.

10

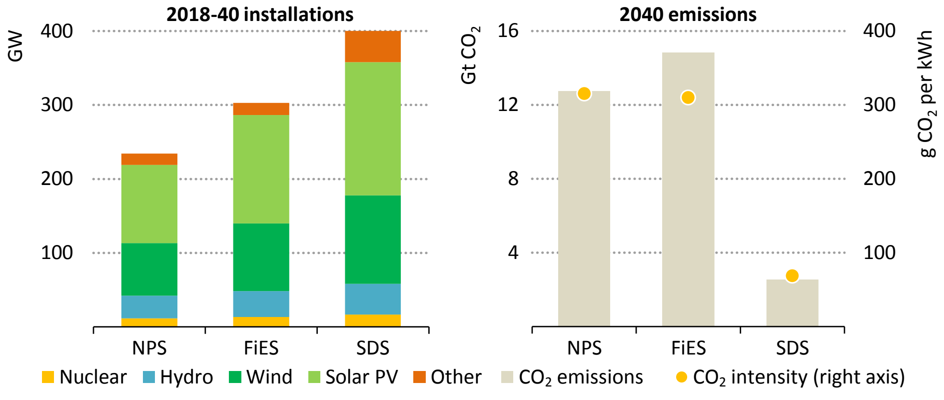
Figure 10.9 ▷ Direct and indirect CO_2 emissions from residential buildings in China by scenario



Decarbonising electricity is essential for reducing the CO_2 emissions footprint of residential buildings in China

Note: Mt CO_2 = million tonnes of carbon dioxide; TFC = total final consumption; NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

Figure 10.10 ▷ **World average annual low-carbon capacity additions 2018-40** (left) **and CO_2 emissions and intensity from electricity generation 2040** (right) **by scenario**



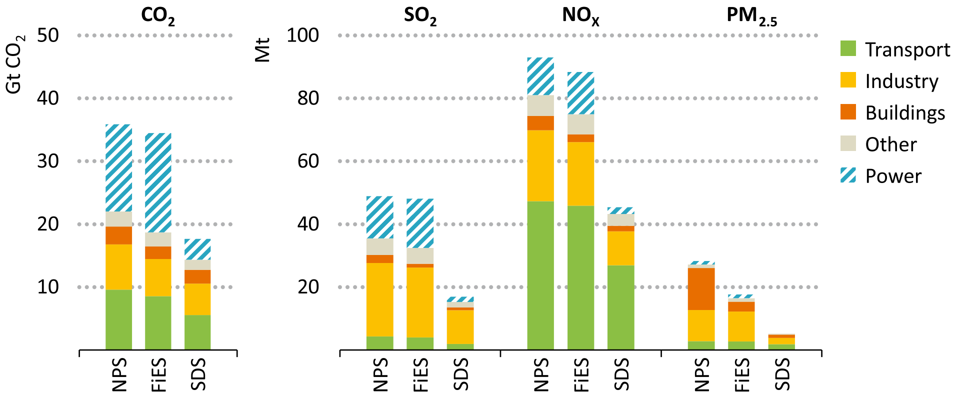
Bringing down CO_2 emissions from the power sector requires not only an increase of capacity additions of low-carbon technologies, but a change in the fuel mix

Note: GW = gigawatts; Gt CO_2 = gigatonnes of CO_2; g CO_2 = grammes of CO_2; kWh = kilowatt-hour; NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

In terms of air pollution, the Future is Electric Scenario achieves significant reductions of emissions at the point of end-use compared with the New Policies Scenario (Figure 10.11). By 2040, combustion-related sulfur dioxide (SO_2) emissions from end-use sectors are lower by 2.8 Mt (or one-fifth), nitrogen oxide (NO_X) emissions by 5.8 Mt (around 10%) and fine particulate ($PM_{2.5}$) emissions by 10.7 Mt (60%). The contribution by end-use sector depends on its relative importance to the emissions of each pollutant and the ability of each sector to reduce them through electrification. For SO_2, around half of the global decline in the Future is Electric Scenario comes from the buildings sector, and mostly stems from the electrification of cooking and heating, which displaces bioenergy and coal. For NO_X, the decline of emissions comes from industry (40%), buildings (35%) and transport (one-quarter), with the latter mostly reflecting the electrification of cars and buses. For $PM_{2.5}$, reductions come mostly from providing access to clean cooking to those currently without it (the use of biomass for cooking today is the largest source of $PM_{2.5}$ emissions).

The measures taken in the Sustainable Development Scenario achieve an even steeper decline in air pollutant emissions than the Future is Electric Scenario. By 2040, total energy- and process-related SO_2 emissions are lower by another 31 Mt (or 65%); NO_X emissions by another 43 Mt (50%); and $PM_{2.5}$ emissions by another 12 Mt (70%), relative to the Future is Electric Scenario. This reflects the additional measures in the Sustainable Development Scenario to accelerate the transition towards more efficient use of energy and lower polluting fuels, to adopt best practices for post-combustion treatment of air pollutant emissions across all sectors, and to decarbonise the power sector.

Figure 10.11 ▷ World emissions of CO_2 and air pollutants by sector and scenario, 2040



Electrification reduces CO_2 and air pollutant emissions, but not enough to meet the Sustainable Development Goals

Note: Gt = gigatonnes; Mt = million tonnes; NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

SPOTLIGHT

How clean is your car?

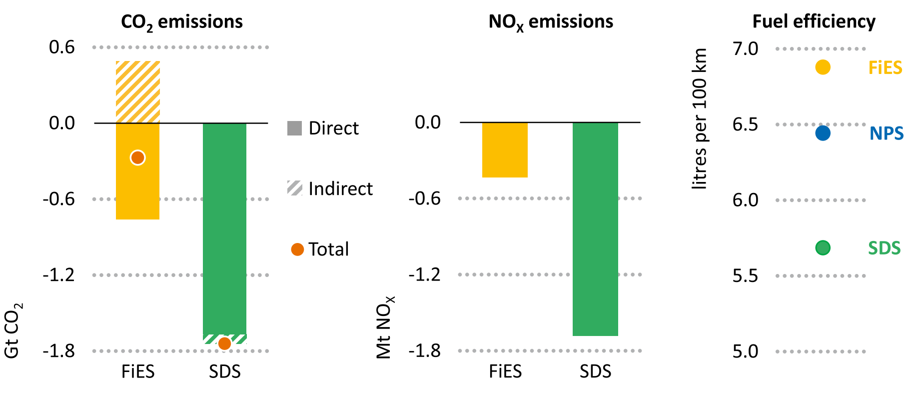
Electric cars offer an important opportunity to reduce CO_2 and NO_X emissions in the transport sector, but measuring their environmental benefits compared with conventional cars is not straightforward. In the case of NO_X emissions, the problem is not the lack of stringent regulatory standards for conventional cars: the Euro 6d standard is generally deemed sufficiently ambitious to meet air quality limits, and is a blueprint for standards in many other countries.[3] The problem is with real-world performance and enforcement. A variety of laboratory and field tests in recent years have revealed that many conventional cars do not meet regulatory requirements for air pollution (or indeed for fuel economy).[4] Regulators are therefore looking to enforce existing vehicle pollution standards more effectively, and the new "World Light-duty Test Procedure", together with other regulatory measures that are currently being taken, should improve the representation of real-world driving for testing.

3. Standards equivalent to Euro 6 are due to be adopted in many countries over the next few years, including in major car markets such as China and India. The United States has similarly ambitious standards.

4. Both diesel and gasoline cars have been identified that do not to comply with regulatory limits, although the scale of the problem is much larger for diesel. A recent study showed that, for Euro 6 gasoline vehicles, even the manufacturers with the worst performance in real-world NO_X emissions were within 1.5 times the type-approval limit. In contrast, for Euro 6 diesel vehicles, even the best performing manufacturer group averaged real-world NO_X emissions of more than twice the type-approval NO_X limit (80 mg/km). All other manufacturer groups were at least four-times this limit, and the average measured emissions of four manufacturer groups were more than 12 times the limit (Bernard et al., 2018).

In the New Policies Scenario, the result of such measures is that NO_X emissions from passenger cars are significantly reduced over time. As Euro 6-equivalent standards become the norm in most of the world's largest car markets, global NO_X emissions from passenger cars fall by nearly 60% by 2040 relative to today, despite a near-doubling of the global car stock. In the Future is Electric Scenario, global NO_X emissions from passenger cars are only reduced by an additional six percentage points in 2040, despite an electric car fleet that is more than three-times larger relative to the New Policies Scenario (Figure 10.12). This suggests that controlling air pollutant emissions from conventional cars can achieve similar improvements in air quality as can be achieved by deploying electric cars at scale, and underlines the importance of regulatory standards and their effective enforcement. Nonetheless, electric cars have a key advantage to conventional ones in that they avoid tailpipe emissions altogether, meaning that the emphasis for enforcement of air quality standards shifts to electricity generation, where compliance is easier to monitor (IEA, 2016).

Figure 10.12 ▷ Emissions from passenger cars by scenario relative to the New Policies Scenario and average fuel use of conventional cars



Despite an additional 650 million electric cars in the Future is Electric Scenario than in the New Policies Scenario, CO_2 and NO_X emissions reductions are limited

Note: FiES = Future is Electric Scenario; NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

The benefits of electric cars in terms of CO_2 emissions depend on the power generation mix. Today, an average electric car sold on global markets emits around one-third less CO_2 per kilometre driven than a new internal combustion engine (ICE) conventional gasoline car. The extent to which GHG emissions reduce in future years depends on the speed of power sector decarbonisation. In the Future is Electric Scenario, the additional 650 million electric cars over and above those in the New Policies Scenario only avoid an additional 0.6 Gt (or 2%) of global energy-related CO_2 emissions in 2040. In the Sustainable Development Scenario, which assumes the same number of electric cars as the Future is Electric Scenario but a more rapid decarbonisation of the power sector, indirect CO_2 emissions are five-times lower, increasing by 50% the CO_2 emissions savings from electric cars.

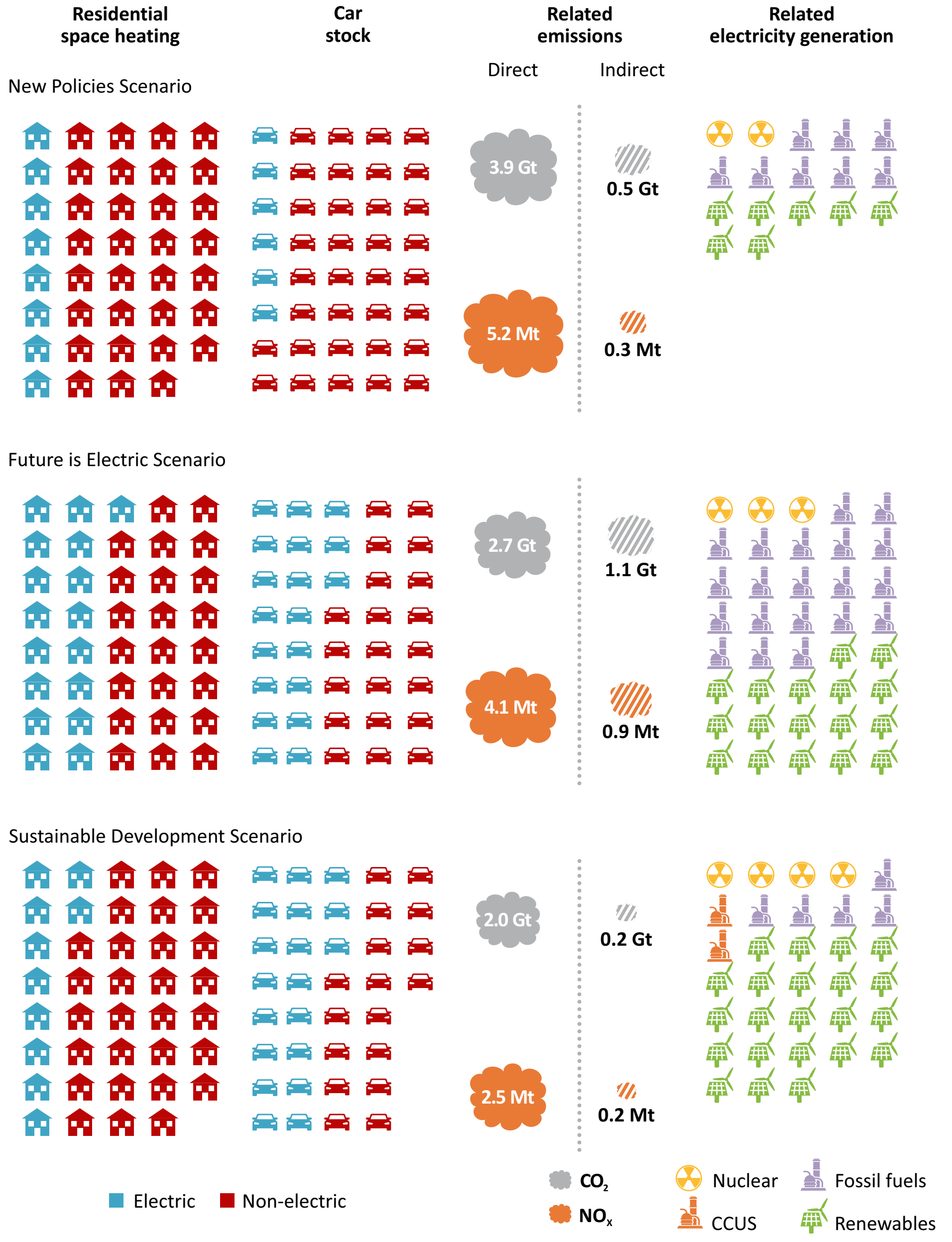
An additional policy consideration for electric cars is their impact on fuel efficiency improvements of ICE cars. In the European Union, for example, the share of electric cars in passenger car sales reaches 20% by 2030 in the New Policies Scenario, and the average fuel use of a new conventional car is around 40% lower than today. The mix of vehicles to meet the recent proposal of the European Commission for post-2020 CO_2 targets could, however, turn out to be different, depending on the future development of policy support schemes for electric cars and industry strategies. The higher the share of electric cars, the lower the need to reduce the fuel consumption of conventional cars: for each additional percentage point of electric cars sales by 2030 over the level of the New Policies Scenario, the requirement to reduce average fuel use of conventional cars would be 5% lower, relative to 2021. In order to achieve global climate goals, there is a need to ensure that the fuel economy of ICE cars increases rapidly even as the uptake of electric cars accelerates. In the Sustainable Development Scenario, by 2040, ICE cars still constitute close to half of the global car fleet, and they are around 20% more efficient on average than in the Future is Electric Scenario as measures are assumed to be taken to simultaneously increase the uptake of electric cars and to improve the fuel economy of conventional cars.

Reducing air pollutant emissions brings important health benefits. Today, around 2.6 million people die prematurely from the impacts of household air pollution, mostly as a result of the traditional use of biomass for cooking in developing countries. In the Future is Electric Scenario as well as the Sustainable Development Scenario, universal energy access is achieved by 2030. This enables people currently without access to switch to cooking with electricity and other fuels, and so reduces the number of people that die prematurely from smoky indoor environments to less than 0.7 million by 2040 (Figure 10.14).

At present, around 2.9 million people die prematurely each year from the impacts of outdoor air pollution. Outdoor air pollution stems from a wider variety of sources, but its impact on human health is largest in urban environments. The decline in air pollutant emissions from the transport and buildings sectors in the Future is Electric Scenario reduces the number of premature deaths, compared with the New Policies Scenario. The more integrated and holistic approach taken in the Sustainable Development Scenario reduces them farther.

The analysis shows that electrification by itself does not avoid air pollution or GHG emissions altogether. What the use of electricity does, however, is to move the majority of emissions away from the many millions of small and often mobile applications (e.g. cars, cookstoves and boilers) towards fewer more concentrated stationary applications (power plants) (Figure 10.13). This helps to reduce human exposure to air pollutants. It also helps

Figure 10.13 ▷ Direct and indirect CO_2 and NO_X emissions from residential buildings and passenger cars by scenario

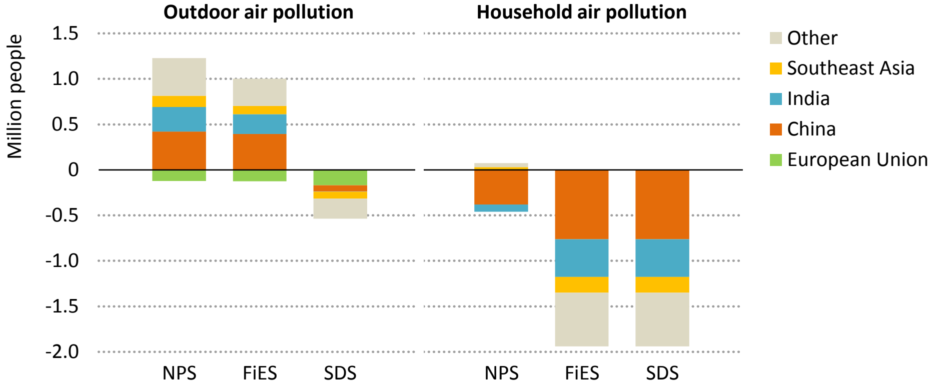


Electrification improves urban air quality, but additional changes to the generation mix are required to make a major difference to overall CO_2 emissions

Note: CCUS = carbon capture, utilisation and storage.

to reduce the risks of non-compliance with pollutant standards as stationary point sources can be more readily monitored. But electrification by itself does not help with CO_2 emissions at the scale required to meet climate goals: from the point of view of climate change, it does not matter where GHG emissions are emitted, and whether they occur at the point of generation or at end-use.

Figure 10.14 ▷ Changes in premature deaths from air pollutant emissions by scenario and region, 2040 relative to today



Achieving universal energy access significantly reduces the effects of household air pollution, but electrification alone has little impact on outdoor air pollution

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

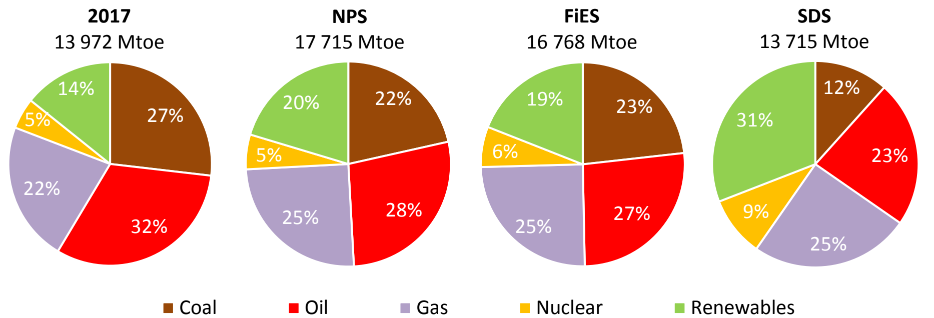
10.4 Energy security and investment in an electrifying future

Ensuring that energy is available without interruption at an affordable price is a primary energy policy. Ensuring first access to electricity where none is presently available is the starting point (see Chapter 2). Beyond that, from an energy systems perspective, short-term energy security is concerned with the ability of the energy system to react promptly to sudden changes in the supply-demand balance. In the longer term, there are many aspects of energy security, and no simple and universally agreed measures or indicators that neatly capture it. There are however several metrics that are worth consideration when assessing the degree to which electrification may or may not improve energy security. They include fuel diversity (as a measure for flexibility), energy import dependency and energy spending (as measures of vulnerability). In the following section, we use the three scenarios to assess the implications of an electrifying future on traditional and emerging energy security concerns. We then take a deep dive into related electricity security considerations and how they evolve through to 2040.

10.4.1 Energy security in an electrifying world

Energy security concerns change as economies mature. For many countries, energy security is in part about diversifying the energy mix to help ensure energy system flexibility and enhance energy security. At a global scale, the energy mix today is fairly diversified, although there are wide differences between countries depending on their respective resource endowments and level of development. In the New Policies Scenario, the diversity of the global energy mix further increases from today's level as renewables make inroads and as energy efficiency moderates the growth of oil (see Chapter 3) (Figure 10.15). Electrification is an important contributor to diversification, although mostly at the level of final energy use.

Figure 10.15 ▷ Shares of fuels in world primary energy demand today and in 2040 by scenario

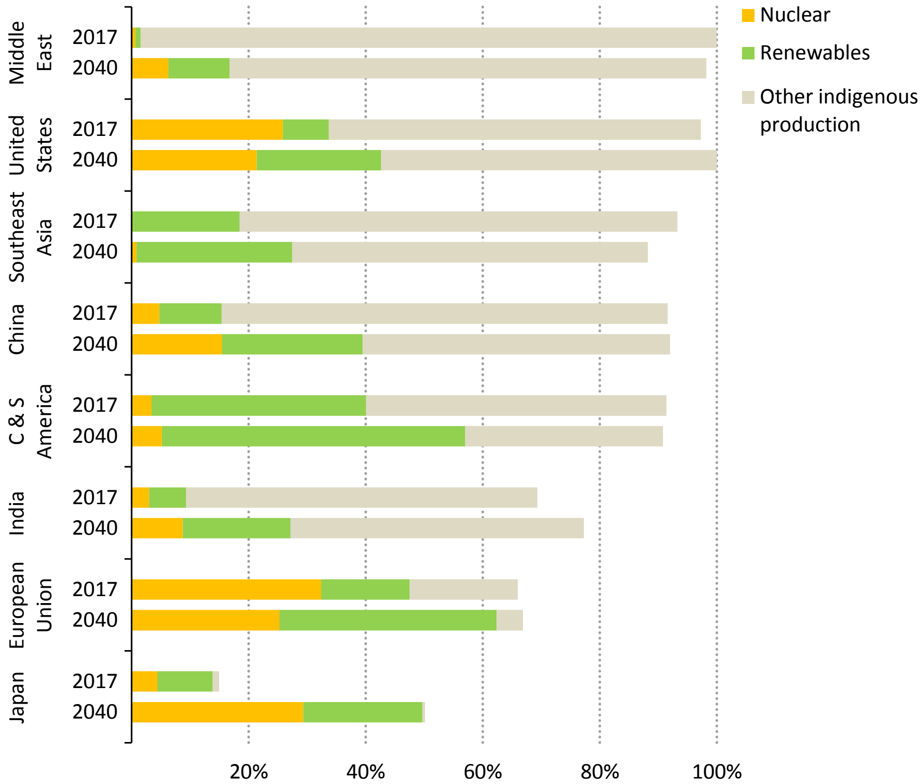


Promoting energy security is an important policy consideration; electrification, together with energy efficiency and other alternative fuels, can help achieve this goal

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

From the point of view of fuel diversity, the power sector can draw on a wider variety of commercially available and economically viable fuels and technologies than any other sector. But this does not necessarily translate into diversity: most countries have traditionally put the emphasis on using domestically available resources to satisfy fuel demand for electricity generation and to increase energy security (Figure 10.16), and on the fuels that minimise the cost of supply. The increasing competitiveness of renewables is set to further strengthen the emphasis on using domestically available resources: in the New Policies Scenario, renewables grow faster than any other form of energy in the power sector. For countries that rely heavily on fuel import, the growing use of renewables as well as nuclear offers opportunities to further increase the use of domestic options for power production. For others, it is an opportunity to diversify the power mix so as to enhance energy security and to reduce emissions.

Figure 10.16 ▷ Share of domestically sourced energy supply for power generation in selected regions in the New Policies Scenario

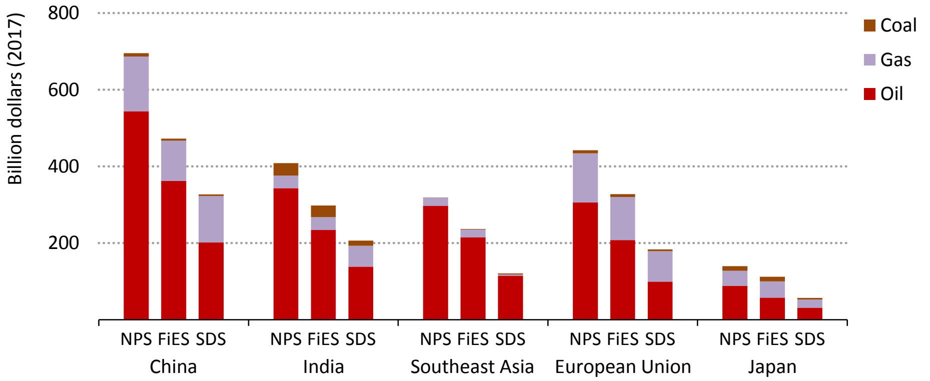


The rising share of low-carbon generation increases the use of domestically sourced resources and diversifies the fuel mix for power generation

Note: C & S America = Central and South America.

Increasing the role of renewable and other domestic resources, and thus diversifying the fuel mix, tends to be a particularly important policy consideration in countries that are net importers of energy. Spending on imported coal, oil and natural gas puts a strain on the balance of payments of many importing countries and exposes them to the risks associated with fluctuations in international fuel prices. Spending on energy imports is set to grow in many developing economies as the population increases, the economy expands and overall fuel prices rise. Electricity demand growth contributes to rising energy import needs where it bolsters demand for imported coal and natural gas for electricity generation. But there is also scope for electrification to contribute to a decline in the need for imports, as well as to alter the pattern of import needs. For example, in the Future is Electric Scenario, the increasing use of electricity in transport in particular reduces spending on oil imports in many countries (Figure 10.17).

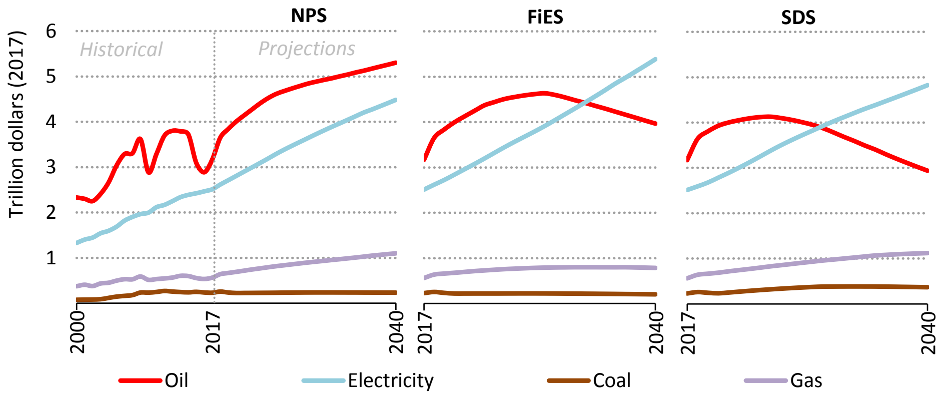
Figure 10.17 ▷ **Net expenditures for fossil fuel imports in selected regions by scenario, 2040**



Electrification reduces spending on energy imports in the Future is Electric Scenario; energy efficiency efforts in the Sustainable Development Scenario cut such spending further

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

Figure 10.18 ▷ **Consumer spending on energy by type and scenario, 2000-2040**



Electricity claims the largest portion of energy spending in the Future is Electric and Sustainable Development scenarios

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario.

Regardless of whether a country is importing energy or not, spending on energy use is generally set to rise (Figure 10.18). The increase depends on the combination of projected growth in demand and prices (including carbon prices) in each scenario. Globally, spending on oil use has historically constituted the largest part of energy expenditure, driven by rising demand and prices. But spending on electricity has been catching up rapidly in recent years, to the extent that it is nearing the level of spending on oil. Spending on electricity increases across all scenarios in this year's *Outlook*. In the Future is Electric Scenario, the increase is driven mainly by higher electricity demand, with retail electricity prices similar to those in the New Policies Scenario, and the additional spending on electricity is more than offset by less spending on oil. In the Sustainable Development Scenario, spending on electricity is pushed up due mainly to higher retail electricity prices in most regions (though these are more than offset by energy efficiency gains). But all scenarios considered in this year's *Outlook* suggest that electricity prices are set to become an even more important policy consideration than they already are, underlining the need to ensure that power systems operate as cost-effectively as possible (see section 10.5).

10.4.2 Electricity security in a changing world

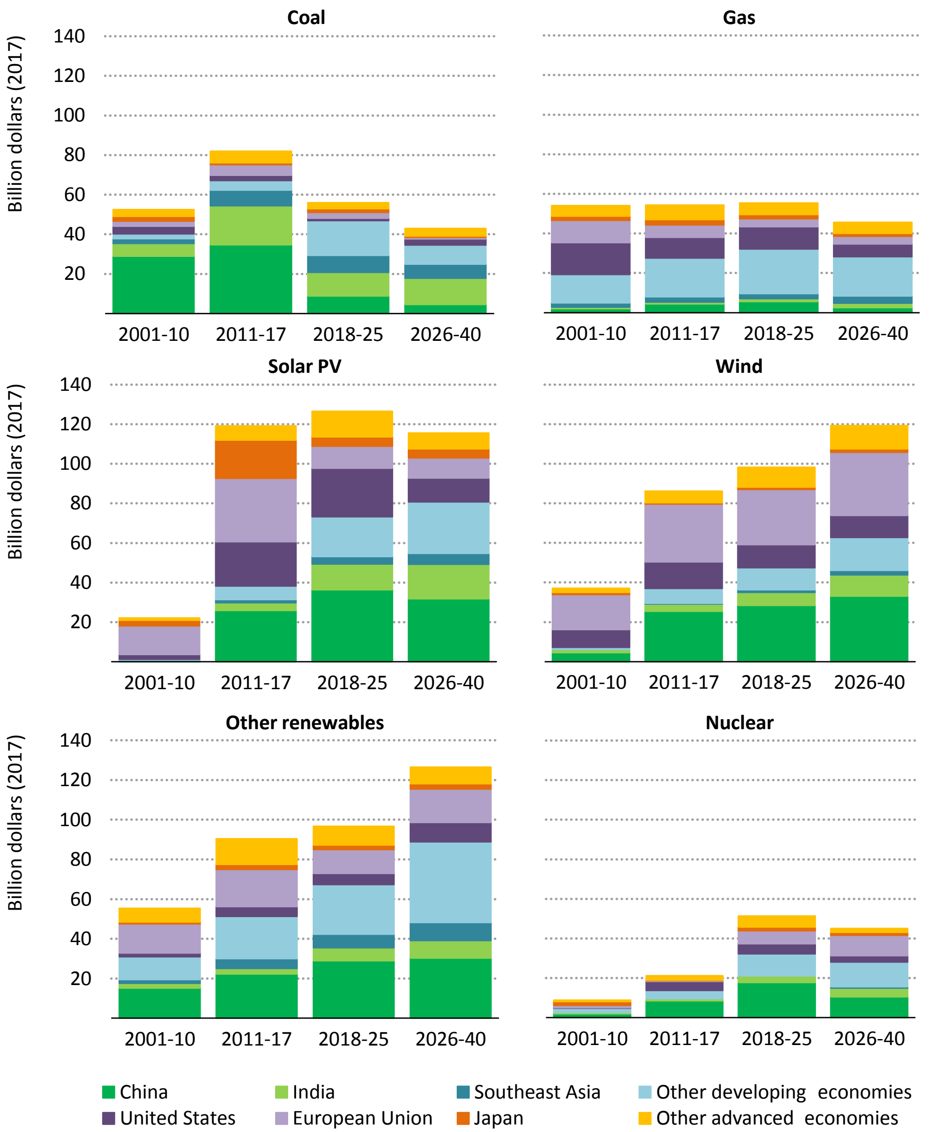
Electricity security is fundamental to well-functioning modern societies and economies. Digital technologies, communications infrastructure, industry and many consumer energy services depend on the reliable supply of electricity. For those who lack it, access to reliable electricity can provide a pathway to economic prosperity and improved well-being. As the world moves towards more low-carbon sources, energy systems require a higher degree of flexibility to ensure a constant balance of electricity supply and demand, and provision of this flexibility will be an important element of electricity security. In the long term, the security of electricity supply will hinge on ensuring efficient and timely investment, in some cases stimulated by competitive market-oriented incentives, in others by incentives derived from regulation. Both market arrangements are facing new security challenges alongside familiar ones. In this section, we examine the implications of electricity demand projections and what the changing power sector policy landscape means for electricity security. It begins with an overview of power sector investment needs in the New Policies Scenario, the Future is Electric Scenario and the Sustainable Development Scenario. It then discusses the challenges of securing adequate investment, and concludes with a look at distributed generation.

Power sector investment by scenario

In the New Policies Scenario, cumulative global power sector investment to meet increasing electricity demand totals $20 trillion over the period to 2040 and represents nearly half of total energy supply investment.[5] This total includes investment in new power plants and transmission and distribution lines, as well as refurbishments and upgrades. Transmission and distribution networks represent over 40% of the total power sector investment, with average annual investments of about $90 billion and $270 billion dollars respectively. The average annual investment in power plants required in the New Policies Scenario is almost 15% higher than in 2017, and 20% higher in the case of networks.

5. Energy supply investment includes that for the production of oil, gas, coal and biofuels, and for electricity supply-related infrastructure.

Figure 10.19 ▷ Average annual power sector investment by region in the New Policies Scenario



Solar PV and wind make up almost half of investment in power plants, driven by growth in developing economies

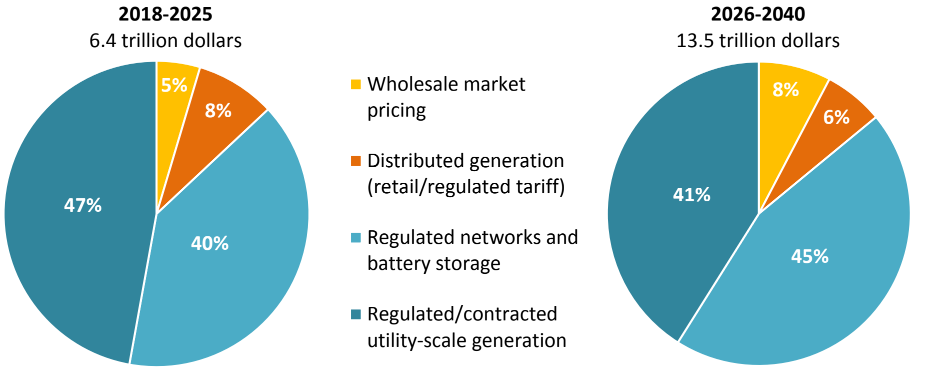
Recent decades have seen surging investments in coal-fired power plants, especially in China and India, but this is set to change in the New Policies Scenario. Once the 182 GW of new coal-fired plants currently under construction are completed, total global investment in coal-fired plants is set to fall to just over $40 billion per year from 2026 to 2040, about half the level from 2011 to 2017 (Figure 10.19). The vast majority of new investment in coal-fired power plants is in developing economies in the New Policies Scenario, mainly in India, China and Southeast Asia. Global investment in natural gas-fired power holds steady in the near term, to $55 billion per year to 2025 on average, before falling back in the long term. This global trend, however, masks a regional shift: advanced economies accounted for about 60% of the cumulative investment in gas-fired power plants from 2000 to 2017 (of which three-quarters was in the United States and European Union), while 60% of future investment is in developing economies.

Renewables accounted for 60% of investment in power plants over the past decade. This increases over the outlook period, with average annual investment of $350 billion through to 2040 making up 70% of total power plant investment. Even with declining costs for solar PV in all regions, it remains the technology with the highest average annual investment in the New Policies Scenario, accounting for some $120 billion dollars over the period to 2040. Almost 30% of total solar PV investment is in China. Projected investment in wind power continues to increase in most regions. A close second to solar PV, global average wind power investment is over $110 billion per year in the New Policies Scenario to 2040. The European Union and China each spend about $31 billion per year to 2040, which represents the majority of the total investment in wind power. Investments in other renewable technologies are stable in the near term and step up beyond 2025. Globally, other renewable technologies represent almost one-quarter of power plant investment to 2040 in the form of hydropower (14% of the total), bioenergy (5%), concentrating solar power (2%), geothermal (1%) and marine power (1%).

Nuclear power remains an important low-carbon option for many countries. Globally, average annual investment for nuclear is $47 billion in the period to 2040, including lifetime extensions for existing plants and new construction. The majority of nuclear investment is in China (28% of the total), the European Union (19%), Russia (11%), India (9%) and the United States (8%), though many other countries are interested in expanding their nuclear power plant fleets.

Investment under regulated market frameworks continues to represent the vast majority of new spending. Transmission and distribution networks are natural monopolies, and so the related investment (over 40% of total power sector investment) continues to be heavily regulated. Nuclear power and those renewable technologies that are characterised by long-lead times and construction risks (e.g. hydropower), which may also include social acceptance concerns, are set to remain in most cases under investment frameworks that provide some form of revenue guarantee. However, the falling costs of renewables combined with decisions to move away from direct support measures in many countries results in more wind and solar PV being built based on anticipated wholesale market revenues (Figure 10.20).

Figure 10.20 ▷ Power plant investment in competitive markets and under regulated frameworks in the New Policies Scenario



Power sector investment continues to be driven by regulated market frameworks, though falling costs for renewables help raise investment in competitive markets

In the Future is Electric Scenario, the power sector requires additional investment of $260 billion per year on average beyond the New Policies Scenario (over $1.1 trillion per year in total), split roughly equally between power plants and networks. Renewables capture two-thirds of the additional power plant investment, led by solar PV and wind power, which together account for close to 60% of the increase. This scenario also sees additional annual investment of about $20 billion in gas-fired power plants and $12 billion in coal-fired power plants.

In the Sustainable Development Scenario, electricity demand follows a lower trajectory as a result of stronger efforts on energy efficiency in all end-use sectors, but significant investment in low-carbon generation and system flexibility is still required. Achieving the targets of the Sustainable Development Scenario requires annual investment of $220 billion for power plants over and above that in the New Policies Scenario. Of the additional investment, renewables account for 94%, led by wind power (35%) and solar PV (29%). Dispatchable renewables, including hydropower and bioenergy, also see a notable increase, particularly after 2025 (Table 10.2). Alongside renewables, other low-carbon sources capture higher investment relative to the New Policies Scenario: nuclear is almost 40% higher while facilities fitted with CCUS technologies account for more than 40% of investment in fossil-fuelled power plants (up from less than 2%). Overall, total investment in fossil-fuelled power plants declines by just 7%. Average annual network investment is about 10% higher (up $40 billion) than in the New Policies Scenario, with more investment to connect new renewables partially offset by less investment in grid reinforcements as energy efficiency measures lower electricity demand.

Table 10.2 ▷ Average annual power sector investment by source and scenario ($2017 billion)

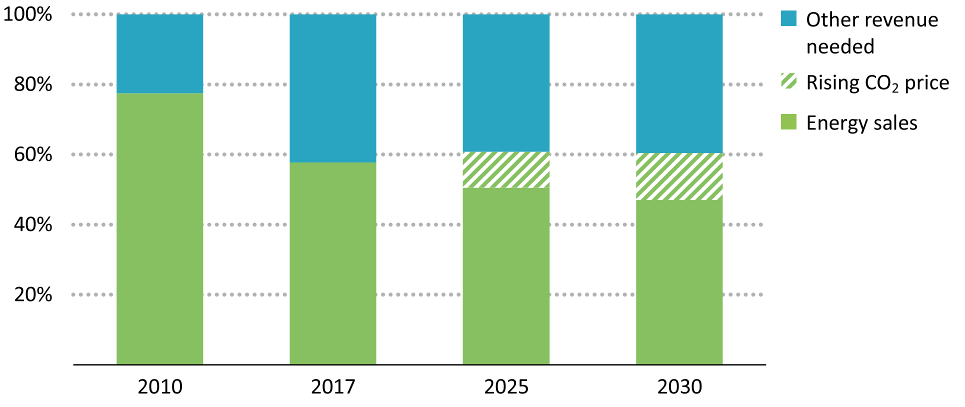
			New Policies		Future is Electric		Sustainable Development	
	2000-10	2011-17	2018-25	2026-40	2018-25	2026-40	2018-25	2026-40
Total	**423**	**744**	**810**	**899**	**916**	**1 240**	**884**	**1 260**
Fossil fuels	120	158	116	91	133	133	92	92
Coal	51	82	56	43	63	58	41	40
Gas	53	54	55	46	65	72	47	50
Oil	17	22	4	2	4	3	4	1
Nuclear	10	21	51	45	53	54	56	69
Renewables	109	296	322	361	349	485	441	616
Hydro	37	59	70	75	74	89	90	104
Bioenergy	15	25	19	27	20	29	27	39
Wind	35	86	98	119	105	169	134	218
Solar PV	20	119	127	116	142	172	177	186
Other renewables	2	6	7	25	8	27	13	68
Battery storage	0	1	9	15	10	21	8	21
Network	183	268	313	387	371	547	286	462
Transmission	40	71	85	97	99	138	79	104
Distribution	143	198	228	290	272	410	207	358

Ensuring sufficient investment in competitive electricity markets

The evolving nature of electricity supply raises questions about the ability of competitive markets to provide adequate revenues to sustain the existing fleet and to provide adequate signals for timely and efficient investment. The issue stems from the low wholesale market prices for electricity that have occurred in many markets, as a result of rapid deployment of variable renewables, the requirement for high levels of reliability (through healthy capacity margins), and, in some cases, low natural gas prices. While periods of reduced profitability are a natural part of competitive markets, declining revenue in lean systems where investment is needed – which we see in some markets today – may signal a need to re-evaluate market design and its ability to deliver investment and electricity security, especially since the main conditions that have depressed wholesale prices are likely to continue at least in the near term.[6] Competitive markets can take a number of forms, and offer several approaches to regulators and policy makers to ensure the security of electricity supply in the face of these conditions, with many trade-offs to be considered (MIT, 2016). With new sources of capacity and flexibility in power systems becoming more widely available and cost-competitive, future regulatory frameworks or market reforms should strive to ensure a level playing field for all system resources, including power plants, energy storage systems and demand-side response.

6. Revenue sufficiency for individual power plants has long been a concern for competitive markets. This issue is commonly referred to as the "missing money problem", but is distinct from the revenue sufficiency for the entire fleet of power plants.

Figure 10.21 ▷ **Share of long-run generation costs covered by energy sales in the European Union, historical and in the New Policies Scenario**



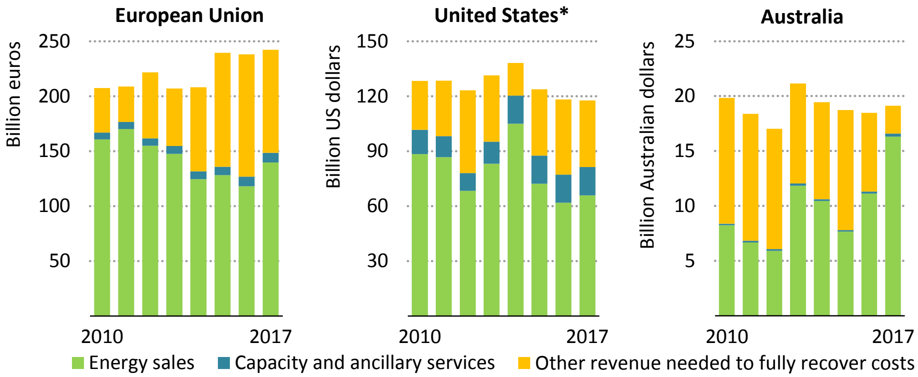
The widening gap between the value of electricity sales and total generation costs raises questions about the ability of some competitive markets to attract timely investment

Notes: Historical energy sales totals are estimated based on hourly prices and production volumes reported by the European Network of Transmission System Operators for Electricity (ENTSOE) for the European Union. Historical production costs are estimated in the World Energy Model incorporating data for power plant investment, fuel consumption and prices, estimated operation and maintenance by plant type and applicable CO_2 prices. Projected production costs are based on New Policies Scenario projections for power plant investment, fuel consumption and prices (including a rising price for natural gas), operation and maintenance, and CO_2 prices (assuming a perfectly functioning carbon market).

Sources: IEA analysis, ENTSOE.

There has been a widening gap between total revenue from wholesale electricity sales and total generation costs in recent years in some of the largest competitive electricity markets, and this trend is set to continue. In the European Union, the share of total production costs covered by electricity sales fell from 77% in 2010 to about 60% in 2017, and looks set to continue declining, even with a rebound in natural gas prices (Figure 10.21). Rising CO_2 prices could help to lift the value of energy sales, though there is uncertainty over both the price level and the benefit to electricity suppliers. Total EU generation costs have been relatively stable since 2010, though the share from renewables has increased from about one-third to over half. From 2010 to 2016, the gap between generation costs and total electricity sales had been widening (Figure 10.22), as there was downward pressure on wholesale electricity market prices due to increasing volumes of renewables and declining coal and gas prices. In 2017, the gap narrowed, as wholesale electricity prices and total electricity sales increased by about 20%, mainly as a result of an increasing natural gas price, a lower contribution to generation from hydropower than usual, and extended outages for some nuclear power plants. The underlying causes of the partial recovery in 2017 however are unlikely to continue.

Figure 10.22 ▷ Gap between wholesale electricity market revenues and total generation costs, European Union, United States and Australia, 2010-2017



The gap between electricity sales revenue and total generation costs has been widening in the European Union in recent years, while narrowing in Australia

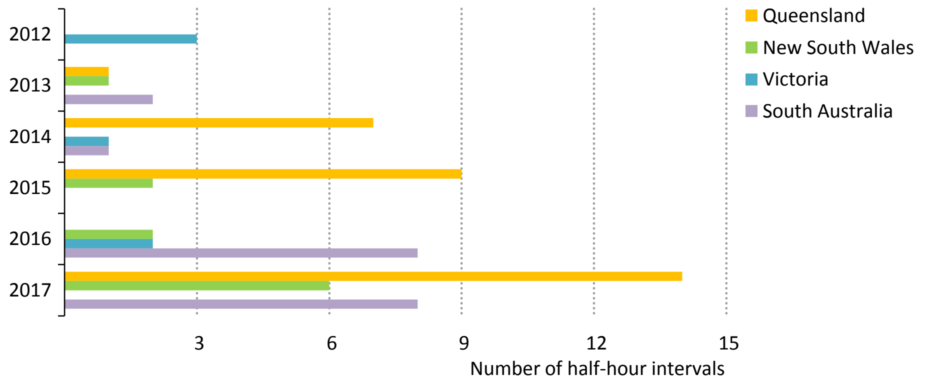
* Includes data and estimates for six US competitive markets: PJM, NYISO, ISONE, MISO, ERCOT, CAISO. Note: Total generation costs include annual capital recovery needs for existing power plants (excluding fully depreciated assets), fuel costs, operation and maintenance and CO_2 price-related costs.

Sources: ENTSOE; PJM, NYISO, ISO New England, MISO, ERCOT, California ISO, RGGI; Australian Energy Market Operator, Australian Energy Regulator.

In the United States, the share of total generation costs covered by wholesale electricity sales is also declining as a result of relatively low natural gas prices. Stagnant demand and the rising share of variable renewables, led by wind power, have added to the downward pressure on wholesale electricity prices in several US electricity markets. The main drivers of low wholesale electricity prices look likely to remain in place, with wind and solar PV set for further growth to meet state-level policy goals, and natural gas prices set to remain relatively low in our scenarios. Electricity sales may therefore continue to recoup less than the total cost of generation, despite the possibility of a return to growth for electricity demand spurred by space cooling and the electrification of heat and transport.

In Australia, home to a large competitive wholesale electricity market, recent experiences have been quite different. Here the market has seen very high prices (upwards of 60-times the average price) at times when extra capacity is limited – an example of scarcity pricing (Figure 10.23). These prices have covered a rising portion of total costs of generation in the past few years, more than offsetting the downward pressure on wholesale market prices from increasing amounts of variable renewables – their share in generation tripled between 2010 and 2017 to about 7.5%. At the same time, wholesale gas prices doubled from 2010 to 2014, before falling by half to 2017. In Australia, efforts are focused on driving down end-user prices while providing the conditions needed to attract investment in new sources of generation.

Figure 10.23 ▷ **Scarcity episodes in Australian National Energy Market by state, 2012-2017**



Occasional episodes of very high wholesale market prices have raised revenues for generators in Australia's National Energy Market

Notes: Scarcity episodes here refer to half-hour intervals with prices above AUD 5 000 per megawatt-hour. Tasmania had no scarcity episodes during these years.

Source: Australian Energy Regulator.

In competitive energy-only markets, scarcity pricing is the key mechanism to provide signals for new investment.[7] Several markets – including those in Australia, New Zealand, ERCOT in the United States, and in Alberta – are designed to rely on very high energy prices for a few hours of peak demand per year as a means of providing adequate revenue for generators to recover all their costs (including capital invested). As the occurrence of scarcity pricing increases, it provides the signal for new investment in new power plant and energy storage capacity, because it increases the likelihood of capturing very high prices in the future. Demand-side response may also be able to benefit from scarcity pricing, although this is not always the case. While intervals of extremely high prices only add marginally to the annual bill of consumers, there are public acceptance challenges, and these have contributed to the implementation of price caps in several markets. These price caps, however, can limit the usefulness of scarcity pricing to provide sufficient signals for new investment. If very high peaks in prices are politically unacceptable, the alternative for policy makers and regulators is to adjust some elements of regulation governing competitive power markets so as stimulate necessary new investment without the need for regular episodes of scarcity pricing.

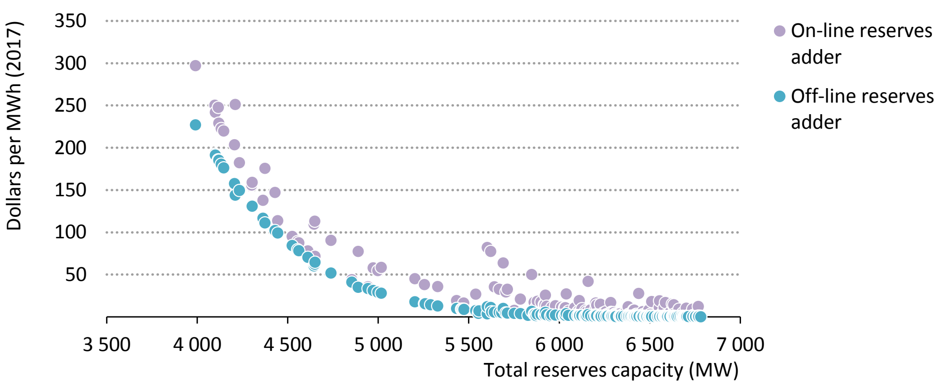
Wholesale electricity markets can also be designed to provide additional revenue streams for non-energy services. The call for more flexibility in the system means that growing shares of variable renewables would be likely to create opportunities for enhanced

7. Energy-only market refers to those without additional interventions, such as capacity remuneration mechanisms.

non-energy revenues. Non-energy revenues come from providing a variety of products commonly referred to as system or ancillary services. These products safeguard against unforeseen changes in demand or available supply (primary and secondary reserves), as well as products that support the quality of power (reactive power, frequency regulation and inertia). They provide revenues to sources that, even if not essential for the adequacy of the system, support the reliability of supply and quality of power delivered.

A new mechanism being implemented in order to incentivise generators during periods of stress in a system and to reward services needed by the system is the "operating reserves demand curve". This mechanism allows small amounts of reserves shortage to be reflected in energy prices, adding small amounts to the wholesale market price in a large number of hours. In the ERCOT market in the United States, the single highest price increase attributable in 2017 to the operating reserves demand curve was $300 per megawatt-hour (MWh) (Figure 10.24), an order of magnitude lower than scarcity prices in Australia. This approach has distinct advantages over scarcity pricing: the regularity of slightly increased prices reduces the revenue uncertainty for investors, and it also reduces the risk of high price spikes (which itself further reduces risk for investors). Many US markets have implemented mechanisms to increase prices when available reserves are limited (ERCOT, PJM, MISO, NE-ISO and NYISO), while others (Southwest Power Pool, plus Mexico) are in the process of implementing similar measures.

Figure 10.24 ▻ Operating reserve prices in Texas (US), August 2017



By reflecting the amount of stress in the system, the operating reserve price can improve price signals for investment while limiting price volatility

Source: ERCOT.

Capacity remuneration mechanisms also offer scope for revenue streams for generators and are now a feature of many markets. The product in this case is capacity (measured in megawatts) expected to be available at specified times. Capacity available at times of peak demand is generally what is rewarded, although the definition of the capacity product may vary from market to market. This product can be either procured by the system operator or traded by market participants in order to fulfil regulatory requirements. The simplest versions of capacity remuneration mechanisms involve a direct payment, with a central authority defining the size of a payment per unit of capacity based on an administrative calculation. Other systems, such as those applied in PJM (a market in the east of the United States), the United Kingdom (excluding Northern Ireland), and France have opted to implement competitive processes that allow the market determine the price per unit of awarded capacity.

Non-energy revenue needs vary substantially by technology, and so the approach taken to address the widening revenue gap has a direct impact on the relative attractiveness of various technology options. Those technologies that rely mainly on energy revenues, for example coal-fired power plants and gas-fired gas turbines, will tend to be the most reliant on scarcity pricing or the operating reserves demand curve. All technologies face potential challenges from market rule changes and regulatory interventions that change existing products or introduce new ones. For example, a regulatory change that decreased the relative value of fast response services in 2015 in the PJM market cooled off a rapidly growing market for energy storage.

The experiences of established competitive markets provide useful examples of the potential concerns and solutions to other countries, including those looking to transition to competitive markets. For example, Japan is pursuing electricity market reforms that establish a set of markets – for baseload, transmission usage, capacity, balancing and zero emission credits – that provide a basket of complementary revenue streams. Mexico is also pursuing market reforms that aim to transition away from regulated to competitive markets and that take account of the experience of other countries.

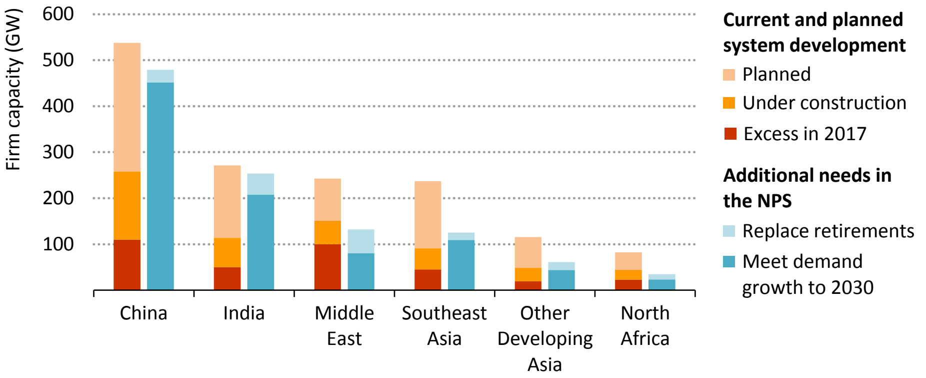
Efficient investment in heavily regulated markets

Efficient and timely investment is a key concern for central authorities in heavily regulated markets – those where investment decisions are often made centrally rather than in response to market forces – just as it is for regulators in competitive markets. The central concern in regulated markets is the risk of over-investment, however, rather than the risk of under-investment. Where investment outpaces the needs of the system, overall costs are higher than they need to be, and there are risks to the profitability of the power plant fleet that ultimately may pose a threat to electricity security. Between 2010 and 2017, excess capacity increased in many heavily regulated markets, and authorities in those markets now face the challenge of drawing down current excess capacity and better matching the pace of investment with electricity demand growth in the future.

Excess capacity, already substantial today, could potentially increase in many cases. If all capacity currently under construction and planned is completed, new capacity would outpace projected demand growth, raising the amount of excess capacity in the Middle East, North Africa and many countries in developing Asia through to 2030 (Figure 10.25).

In the case where excess capacity (relative to peak demand) remains at current levels, power generation costs in these selected regulated markets would be up to $17 billion higher per year compared with the New Policies Scenario. In other words, paring back the excess capacity offers the opportunity to save up to $400 billion in total power generation costs from today to 2040, equivalent to almost $15 per household per year. By region, this equates to some $50 per household per year in the Middle East, $30 per household in India, and about $5 per household in Southeast Asia and China.

Figure 10.25 ▷ Planned capacity additions and system needs to 2030 in selected regulated markets in the New Policies Scenario

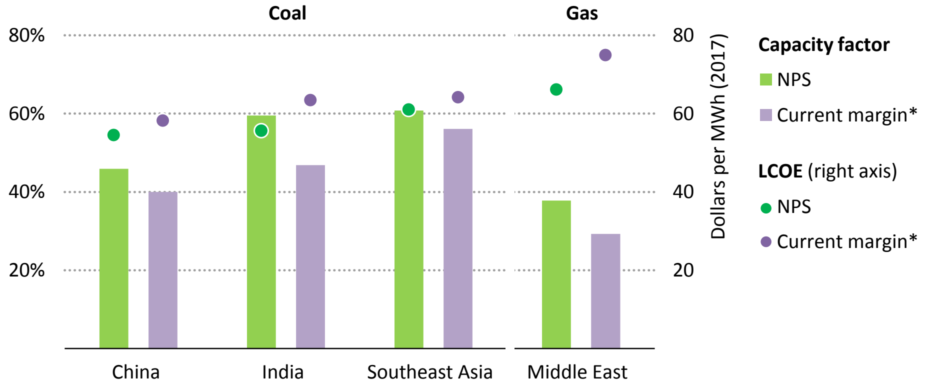


Excess capacity is likely to continue growing in several heavily regulated markets to 2030, signalling the need to better match investment to the pace of demand growth

Notes: NPS = New Policies Scenario. Under construction and planned capacity from S&P Global Platts World Electric Power Plant Database, additional needs based on projected electricity demand growth and retirements.

Excess capacity can also reduce the profitability for the fleet of power plants. In many markets, plants are paid fixed tariffs, independent of operation. In others, excess capacity results in fewer operating hours and higher levelised costs of electricity (Figure 10.26), squeezing the profitability of plants. In India, higher levelised costs for coal-fired power plants would put additional financial pressure on distribution companies, already in a large amount of debt today. In the Middle East, over-capacity may not penalise generators, but it would represent inefficient costs that must be absorbed elsewhere in the broader economy (see *World Energy Outlook Special Report, Outlook for Producer Economies* [IEA, 2018]). In China, investing in additional excess capacity could have near-term distribution of revenues and long-term implications for the economics of all power plants as it transitions towards a competitive market model. Reducing excess capacity could also contribute to reducing curtailment of wind and solar PV output (IEA, 2017).

Figure 10.26 ▷ **Power plant capacity factors and levelised costs of electricity in selected regulated markets, 2040**



Paring back excess capacity in regulated markets increases operating hours for the remaining fleet, improving their profitability

* Current margin refers to the case where the observed 2017 capacity margin (in percentage terms) is held constant over time, rather than declining towards long-term standards as it does in the New Policies Scenario. Note: NPS = New Policies Scenario; LCOE = levelised cost of electricity.

The authorities in regulated markets have the tools at their disposal to temper investment, improve the accuracy of demand projections and develop flexible power sector development plans. However, a lack of available information, along with institutional and operational barriers may hamper progress. For example, lack of co-ordination of balancing activities across geographic areas may slow efforts to reduce excess capacity.

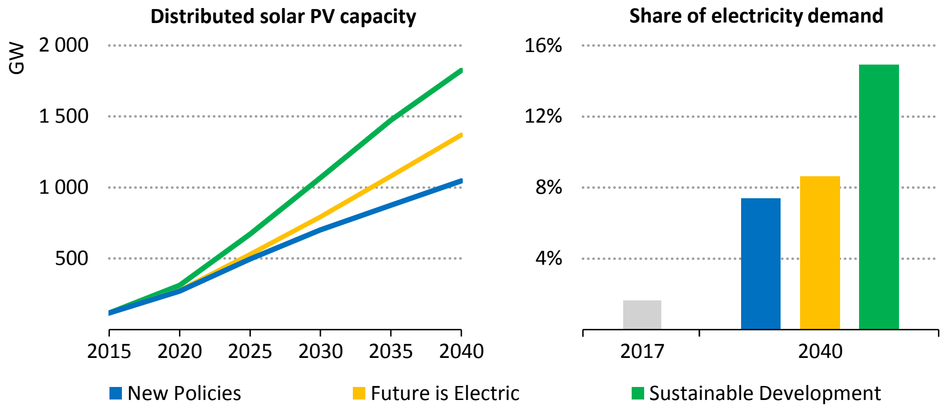
Distributed energy resources could change the picture

Distributed energy resources, including rooftop solar PV, behind-the-meter battery storage and demand-side response, have been expanding rapidly in recent years. They have benefited from strong cost reductions and policy support, and have the potential to change the electricity supply picture in the future. Distributed solar PV is projected to continue rapidly increasing in the New Policies Scenario, with developing economies accounting for two-thirds of all small-scale solar PV capacity additions in the New Policies Scenario. In the Future is Electric and Sustainable Development scenarios, the push to provide full access to electricity draws heavily on distributed energy sources. Continued developments of both hardware and digital software add to its growth potential (see Chapter 7, Spotlight).

In the New Policies Scenario, distributed solar PV grows significantly, exceeding 1 000 GW of capacity installed by 2040 and representing over 40% of total solar PV installed worldwide (Figure 10.27). Growth is even more rapid in both the Future is Electric and the Sustainable Development scenarios, where distributed solar PV in 2040 nears 1 400 GW and surpasses

1 800 GW respectively. The result is that an increasing share of electricity demand in the buildings sector is met by distributed solar PV: by 2040, its share is four-times higher than today's level in the New Policies Scenario, and nine-times higher in the Sustainable Development Scenario.

Figure 10.27 ▷ Distributed solar PV capacity and share of electricity demand in the buildings sector met by solar PV by scenario



Distributed solar PV grows fast in all scenarios, meeting 15% of electricity demand in buildings in the Sustainable Development Scenario

As more consumers become aware of the technology and as costs continue to fall, there is potential for enormous growth for distributed generation. The remuneration arrangements for generation sold to the grid are critically important (Box 10.2). There need to be adequate incentives for people to adopt distributed generation, but over-generous remuneration for distributed generation can lead to equity concerns as (often better-off) households with distributed generation systems are in effect cross-subsidised by those (often less well-off households) without them. As the share of households with distributed generation increases, the equity and affordability implications of over generous tariffs are likely to rise. Regulatory frameworks need to be adapted to unlock the full value provided by distributed resources, and to remunerate this value fairly in a transparent manner to consumers and investors. They also need to take account of cyber security concerns while providing for and protecting decentralised energy trading.

Distributed energy resources could be an important provider of flexibility in power systems on even shorter timescales than those of conventional power generation, particularly where battery storage is present. The use of digital technologies could further enhance this. Creating decentralised energy trading markets through peer-to-peer transactions could help people to benefit from lower priced electricity directly supplied by neighbours.

It could also serve to modify consumption patterns and reduce demands on the centralised power system. By reducing peak demand, it could help to defer investments in distribution grids and substations as well as in additional dispatchable capacity.

The ownership of distributed energy resources also has an important role in the economics of distributed energy resources and the likelihood of providing flexibility services. Direct ownership by customers of decentralised assets usually means that customers deal directly with the local utility through remuneration based on retail price signals. Third-party ownership models, usually procured by an aggregator, have been extensively employed in the United States, where the aggregator owns the assets and establishes a lease agreement with the customer. Since the aggregator deals directly with the local utility and sells the overall decentralised generated electricity into the wholesale and ancillary services markets, this lowers the risk of initial investments and shields customers from price signals.

Box 10.2 ▷ Economics of distributed solar PV

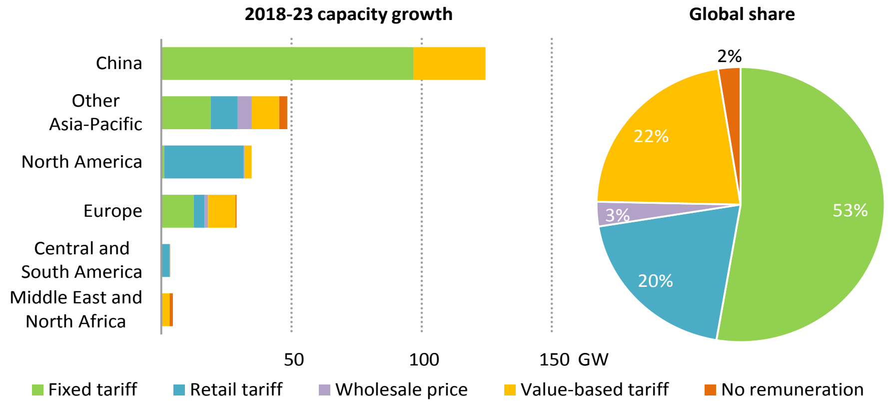
There are a number of key variables for an investor when considering the economic attractiveness of distributed solar PV: the level of retail electricity prices; the total cost of the solar PV installation; the amount of generation consumed onsite: the remuneration of excess generation; and the availability of financial incentives.

Distributed solar PV owners self-consume (or self-use) only a portion of what they generate, which generally range from just a few percent to over 50% depending on their consumption patterns and the size of the solar PV system. The system of remuneration for surplus generation (or all generation) is the key determinant of the level of uptake of community-level, commercial and residential solar PV systems. The value of surplus electricity from distributed solar PV systems can range from zero to values higher than retail power tariffs, depending upon the type of policy at national and/or sub-national levels. Possible policy and regulatory changes in the future remain a key uncertainty for the outlook.

Based on current remuneration policies in place, over half of distributed solar PV capacity to be commissioned in the next six years is anticipated to receive a fixed feed-in tariff (FiT) for all its electricity generation (Figure 10.28). The value of a FiT varies: in China it is higher than the retail price, but in Germany it is lower. In China, the incentive to self-consume at the residential level is limited, while in Germany new customers will try to maximise their use of self-generated electricity to save money. One-third of distributed generation falls under classical net metering schemes where solar PV generation is valued at the level of the retail tariff.

Recently, regulatory bodies and policy makers have sought to estimate the "real" value of distributed generation and introduced calculation methods based on the avoided increases in new generation capacity and all additional cost or benefits to the system or society (such as grid integration costs and CO_2 reduction value). Value-based tariffs usually fall somewhere between retail and wholesale electricity prices. Continued efforts to reflect the value of energy provided and costs of energy delivered, included for services provided by the grid, support the long-term growth prospects for distributed generation.

Figure 10.28 ▷ Distributed generation capacity by remuneration type, 2018-2023

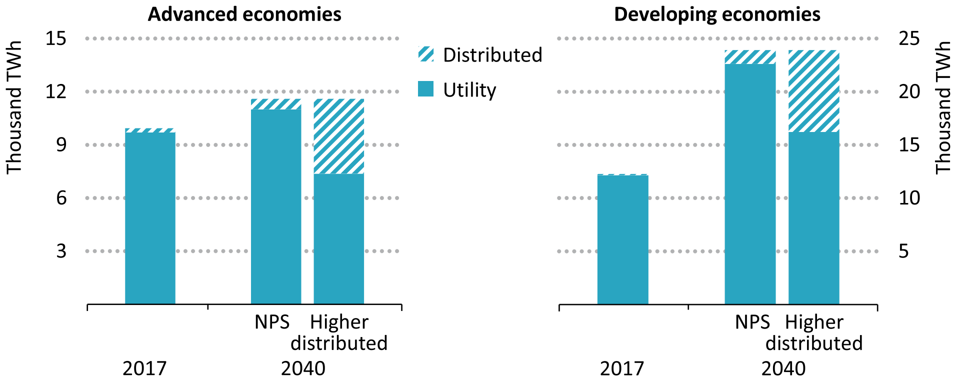


Over half of projected distributed solar PV capacity in the near term receives a fixed tariff

To illustrate the potential impact of rapid uptake of distributed energy resources on the need for utility-scale generation, we considered a case in which half of buildings demand and a significant portion of industry demand are satisfied by distributed generation. In advanced economies, utility-scale generation could decline by about one-quarter from 2017 to 2040 (Figure 10.29). This could put additional financial strains on suppliers, reducing the profitability of the existing fleet. In developing economies, high electricity demand growth means that utility-scale generation would continue to grow even with this high penetration of distributed generation, although additional challenges could emerge if this accelerated deployment was not factored into long-term planning.

Massive growth of distributed energy resources has the potential to upend the traditional utility business model. One critical factor is the way in which electricity is priced. Under existing structures, where consumers often pay small fixed charges and large variable charges, distributed energy has the potential to expand very rapidly. Depending on remuneration arrangements, this could imply transfers of costs between those with distributed generation assets and those without. It could also threaten the financial health of utilities. Under cost reflective network tariffs, by contrast, customers would pay a charge proportional to the costs they impose on the system, and in effect pay a tariff in return for the security benefit they gain from the system, irrespective of how much electricity they consume at any point in time or whether they are exporting and importing power.

Figure 10.29 ▷ **Impact of accelerated uptake of distributed energy resources on utility-scale generation**



Rapid expansion of distributed resources could shrink revenues from the utility-scale market in advanced economies, while slowing growth in developing economies

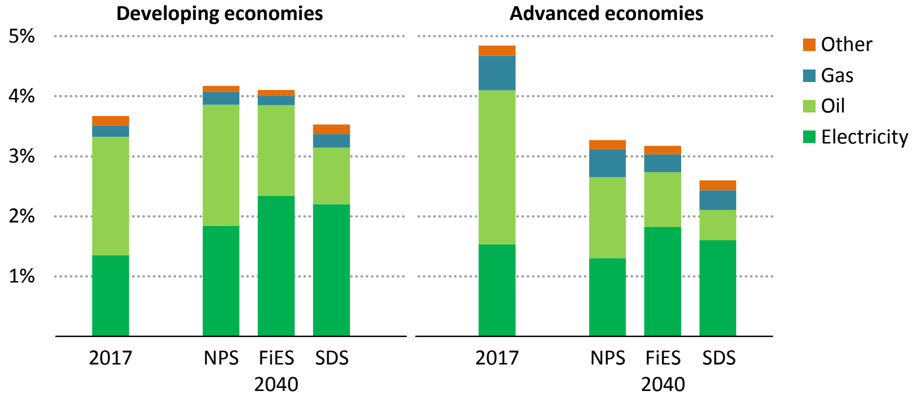
Notes: NPS = New Policies Scenario. Higher distributed refers to the case where 50% of residential and services demand and 20% of industry demand are satisfied by distributed sources in 2040.

10.5 Affordability of electricity

The affordability of energy is a primary concern for policy makers, businesses and consumers and taxpayers. The typical energy bill of a household is composed of many parts, as different forms of energy are being used for a variety of purposes including lighting, heating, cooling and mobility. The share of energy in overall household expenditures is typically below 10%, though it varies considerably and is generally higher in countries where energy taxes are high. Advanced economies currently spend more of their disposable income on various kinds of energy than do developing economies (Figure 10.30). Across all countries, the use of oil-based fuels (mostly for driving) and electricity constitute the main elements of household energy bills.

The critical determinants for the outlook of household energy expenditures are the growth in energy demand by fuel and the level of fuel prices. In the New Policies Scenario, the outlook for household energy expenditures differs notably between developing and advanced economies. In developing economies, residential electricity demand more than doubles over today's level and brings up the share of energy in total household expenditures to around 4% by 2040, or 0.5 percentage points above today's level. In advanced economies, residential electricity demand growth remains sluggish, but the share of electricity in overall energy expenditures rises as energy efficiency improvements bring down the share of expenditure on oil-based fuels.

Figure 10.30 ▷ **Share of energy in overall household spending by scenario**



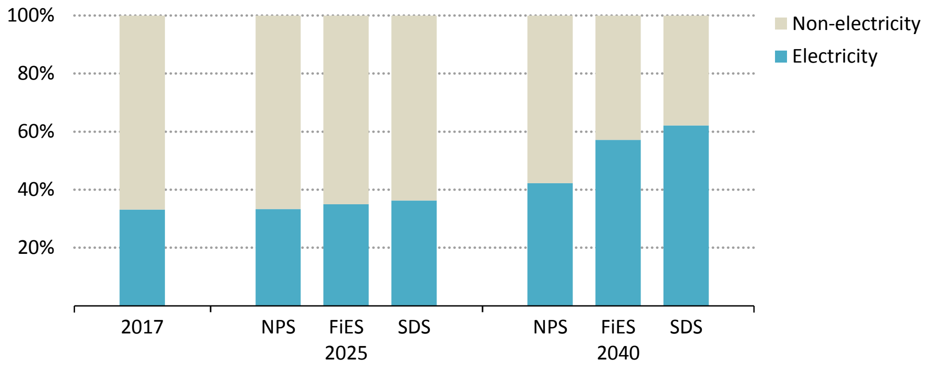
Wide electrification means that electricity takes a more important role in household energy spending, making electricity prices an important affordability concern

Notes: NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario. Other includes coal, heat and modern biomass. Traditional use of biomass is excluded from spending estimates as it is commonly obtained at little or no financial cost. Calculations based on United Nations and IEA data.

Further electrification beyond the level of the New Policies Scenario increases household spending on electricity, although this increase is entirely offset by a decline in spending on other fuels, mostly as a result of the electrification of cars: while purchase costs of electric cars are higher than for conventional cars, the annual fuel bill can easily be two-thirds lower. In the Future is Electric Scenario, the share of electricity in total household energy spending makes up around 60% of the total by 2040 (Figure 10.31). The share is similar in the Sustainable Development Scenario, despite lower levels of demand. With increased household spending on electricity, electricity prices will inevitably become increasingly important in determining the affordability of household energy.

End-user electricity prices are a highly visible element of the overall affordability of energy. While the overall spending on energy is what matters most to consumers, the marginal cost of electricity is commonly a point of comparison across regions (though prices can also vary widely within a region). The United States has relatively low residential electricity prices compared with other advanced economies, and they are another one-third lower in China. In both cases, the average production costs of electricity are relatively low due to abundant domestic resources: coal and gas in the United States, and coal in China. Residential electricity prices are further reduced in China by cross subsidies from industry. On the other hand, Japan and the European Union have relatively high residential electricity prices. In Japan, the reliance on high-cost imported fuels has pushed up electricity prices in recent years, due in part to the suspended output of nuclear power plants following the accident at Fukushima Daiichi. In the European Union, high energy taxes account for about one-third of EU prices today.

Figure 10.31 ▷ Share of electricity in household energy bills by scenario



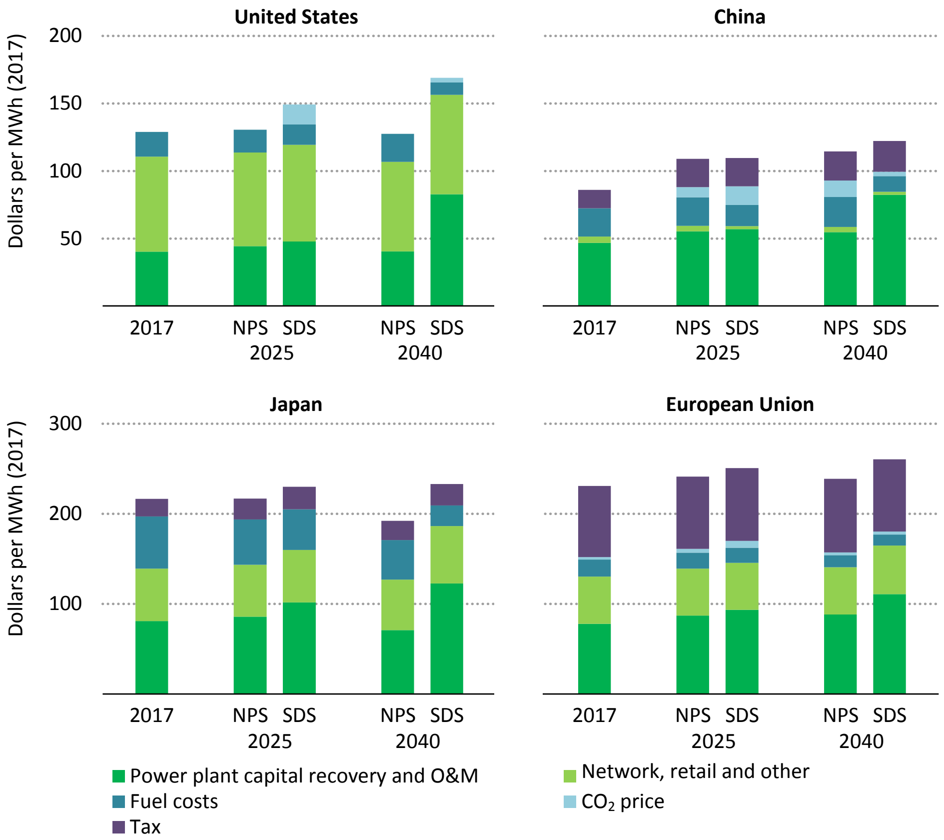
After 2025, electricity is set to account for a rising portion of household spending on energy, especially where electrification accelerates and environmental goals are pursued

Note: NPS = New Policies Scenario; FiES = Future is Electric Scenario; SDS = Sustainable Development Scenario. Non-electricity includes the costs of coal, gas, oil, renewables and district heat paid by residential consumers both inside and outside the household, including for mobility services.

Residential electricity prices are fairly stable in the New Policies Scenario, though Japan is an exception, as the gradual restart of nuclear helps drive down prices by some 10% in the New Policies Scenario, mainly by reducing fuel costs (Figure 10.32). With continued investment in capital-intensive technologies, most notably wind and solar PV, the cost structure of electricity becomes more capital intensive. Where CO_2 prices are introduced or increase substantially, they tend to have a strong impact on electricity prices, especially in markets with substantial amounts of fossil fuels, such as China or the United States. Taxes and subsidies continue to play a major role in electricity prices, keeping EU prices high, and prices in China low.

The Sustainable Development Scenario leads to a more capital-intensive cost structure than the New Policies Scenario, and to modestly higher residential electricity prices in most countries. Japan and the United States see prices that are 20-30% higher in 2040 than the levels of the New Policies Scenario. The European Union see prices within 10% of those in the New Policies Scenario, as recently agreed policy targets for renewables call for ambitious action that is largely in line with a long-term clean energy transition. China also sees similar prices across scenarios, even though its efforts to reduce CO_2 emissions are greatly accelerated in the Sustainable Development Scenario. In general, the Sustainable Development Scenario sees higher prices because it requires countries to limit the use of the existing fleet of fossil-fuelled power plants and invest heavily in cleaner energy sources. Faster deployment of renewables does drive their costs down more quickly, but this only partially offsets the upward pressures on the average costs of production.

Figure 10.32 ▷ Residential electricity prices in selected regions by scenario



Electricity prices span a wide range, but are set to increase modestly in these regions

Notes: NPS = New Policies Scenario; SDS = Sustainable Development Scenario; O&M = operation and maintenance costs. Network, retail and other costs in China incorporate subsidies provided.

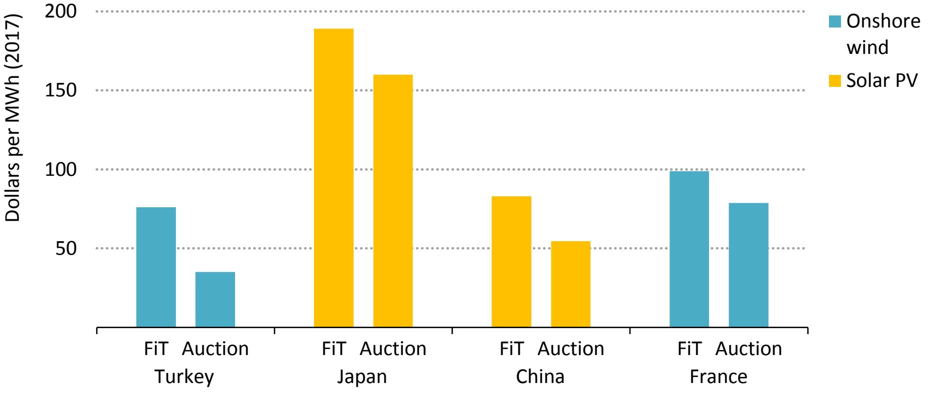
Enhancing the affordability of electricity

There are a number of approaches that policy makers can take to improve the affordability of electricity for consumers. Stable governance and continuity of policies can reduce the risks of operation in both the near and long term, and thus the rates of return required by investors, which can have a substantial impact on generation costs considering the capital-intensive cost structure of renewables (see Chapter 8, section 8.3.4). Supporting innovation through research, development, demonstration and deployment activities can open up new and cheaper technologies. And harnessing competitive forces in the procurement of new investment and in system operations can significantly improve the affordability of electricity.

Competitive forces are increasingly being used to drive down the price of deploying renewables, with governments transitioning away from feed-in tariffs to competitive auctions for long-term power purchase agreements. Defining remuneration levels for utility-scale renewables through such agreements helps reduce their risks and therefore their financing costs. Since 2010, the number of countries implementing auction schemes for renewables has quadrupled to over 70 in 2017.

Recent experiences demonstrate the extent to which competition can reduce the price of new renewable energy projects. In 2017, shifting from FiTs to auction schemes in Turkey, Japan, China and France led to contract prices that were some 15-50% below the previous FiTs (Figure 10.33). Announced auctions results for onshore wind and solar PV for projects to be commissioned over 2019-24 ranged from $20/MWh to $40/MWh in Mexico, Argentina, United Arab Emirates, Chile, India and Brazil.[8] The high-quality of the resources available in these countries, together with low-cost financing, enabled these contract prices to be achieved. While auction prices and actual project delivery need to be monitored over time, the experience so far indicates that expanding competitive pricing could support further cost reductions in other regions in the coming years.

Figure 10.33 ▷ Feed-in tariffs and auction results in selected countries, 2017



Recent auction results indicated 15-50% contract price reductions compared with FiTs

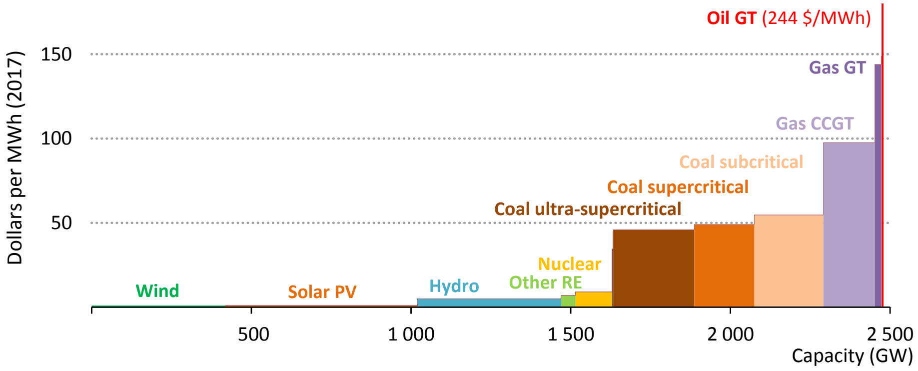
Notes: FiTs = feed-in tariffs. Varying project sizes may account for some of the difference between FiT and auction results.

Competition is also a powerful tool to reduce the operating costs of power systems. Expanding the application of competitive wholesale markets into previously regulated systems can provide significant cost gains by prioritising the cheapest sources of generation. This is not a small task, considering that such an exercise has to be done for each dispatch interval, which can be as short as five minutes, and that in many markets hundreds of

8. Auction results may not reflect the full costs of projects. In particular, concessions may be granted in the form of free or low-cost land or grid connection. They also benefit from support-enabled low-cost financing.

market participants can be involved in a single hour of operation, either as retailers or generators. The main function of spot markets is to provide a space for trading between generators and retailers, but efficient and liquid spot markets provide scope for many additional transactions that bring efficiencies, for instance by letting expensive generators buy energy from a cheap spot market if they are bound by contract to sell to a retailer. In this case an unidentified generator, with cheaper energy available, will provide the energy for the contract to be honoured, and will benefit from the sale, as will the generator holding the contract, who will save variable generation costs.

Figure 10.34 ▷ Merit order curve based on power plant operating costs in China, 2030



Competitive spot markets can bring efficiency gains to the operation of systems, favouring the most efficient sources

Note: GW = gigawatts; Gas GT = gas turbine; CCGT = combined-cycle gas turbine; Other RE = other renewable energy technologies (bioenergy, geothermal, marine and concentrating solar power).

The benefits of competitive wholesale markets are now widely acknowledged, and such market designs are being considered in a number of new places. Under reforms initiated in 2015, for example, China has ordered the establishment of provincial power exchanges, along with other elements related to wholesale market design and new mechanisms for electricity trade, power generation and distribution. As the share of energy traded increases, so will the benefits for power systems in China. Consider the merit order curve for power plants in the New Policies Scenario in China in 2030 (Figure 10.34). For a given level of demand, it would be most efficient to first ensure the uptake of all the zero marginal cost wind and solar PV production available, plus other renewables and nuclear power, before looking to the most efficient coal-fired power plants and so on until demand is met. Compare this to operations today, where about 10% of wind and solar PV output was curtailed in 2017 and all types of coal-fired power plants are operated more or less equally, regardless of their operating costs. As this demonstrates, adopting markets principles offers opportunities for cost savings, as well as emissions reductions.

PART C

WEO INSIGHT

Oil and gas look set to remain in the energy system for some time, yet the environmental impact of extracting, processing and transporting oil and gas to consumers has frequently been overlooked when discussing energy transitions.

In this chapter we provide the first comprehensive assessment of the greenhouse gas emissions associated with supplying all sources of oil and gas globally. We therefore provide an estimate of the full contribution of the global oil and gas industries to energy sector emissions.

Oil and gas that are produced in a clean and environmentally conscious manner are likely to enjoy advantages over other sources of supply. We examine some of the key innovations and technologies that could be used to reduce these emissions, including electrification, carbon capture, utilisation and storage, low-carbon hydrogen and options to reduce methane leaks.

Many of the available technologies could be deployed at relatively low costs and would have a material impact on future emissions trends. There are also potential spill-over benefits: the knowledge, practices and strengths of oil and gas companies could help overcome some of the hurdles to developing and deploying low-carbon technologies at large scale.

Innovation and the environmental performance of oil and gas supply

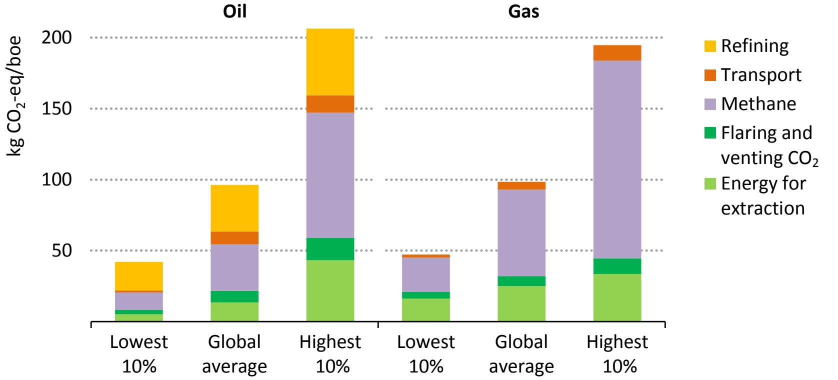
The under-explored side of energy transitions

S U M M A R Y

- Oil and natural gas are set to remain part of the energy system for decades to come. Minimising air pollution, water use and contamination, and local disruption are key to reducing immediate social and environmental impacts. But attention is increasing on the indirect emissions from producing, transporting and processing oil and gas. We provide here the first comprehensive global assessment of these emissions.

- There is a very broad range in the indirect emissions intensity of different sources of oil and gas (Figure 11.1). Supplying the most-emitting sources of oil and gas results in more than four-times the indirect emissions than the least-emitting sources. Indirect emissions of oil are between 10% and 30% of its full lifecycle emissions intensity; indirect emissions of natural gas are between 15% and 40% of its full lifecycle emissions intensity. Total indirect greenhouse gas (GHG) emissions from oil and gas operations today are around 5 200 million tonnes (Mt) of carbon-dioxide equivalent (CO_2-eq), 15% of total energy sector GHG emissions.

Figure 11.1 ▷ **Emissions intensities of oil and gas supply globally**

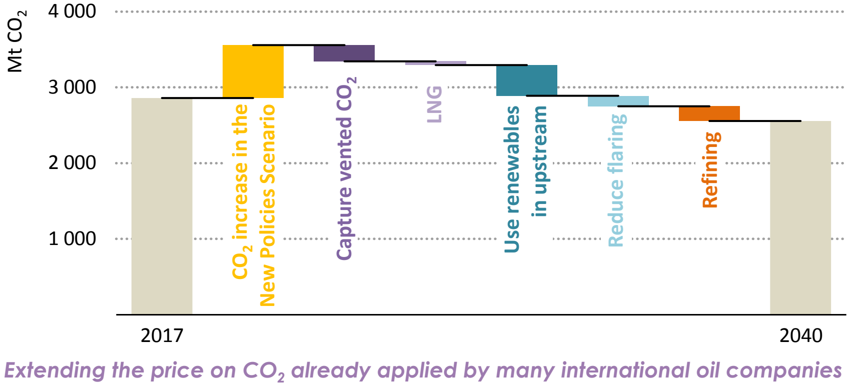


The supply of the most emissions-intensive sources of oil and gas results in four-times more indirect GHG emissions than the cleanest sources

- Around 97% of gas consumed today has a lower lifecycle emissions intensity than coal. Electricity produced from gas that has been transported as liquefied natural gas (LNG) on average has 45% fewer emissions than coal. But the aim for the future should be to focus on cost-effective ways to minimise the gap between gas and zero-carbon technologies rather than focus on the gap between coal and gas.

- Eliminating methane leaks is one of the most the cost-effective measures to provide drastic reductions to the emissions intensity of oil and gas supply. Deploying just those methane emissions reduction measures that have positive net present values would avoid around 1 500 Mt CO_2-eq emissions annually by 2040.
- Combining CO_2 capture facilities with enhanced oil recovery projects is one way to reduce the emissions intensity of oil. It could also help reduce the costs of future carbon capture, utilisation and storage (CCUS) projects. Injecting CO_2 in EOR projects can produce "negative emissions" oil if the CO_2 is captured from the atmosphere.
- Multiple upstream projects are being developed today that use renewable-generated steam or electricity to replace gas use. New LNG facilities can also electrify operations or use CCUS: doing so could provide imported gas at a lower emissions intensity than domestically produced gas in many regions.
- The use of low-emissions hydrogen is central to reducing emissions in the refining sector. Steam methane reforming with CCUS is likely to remain cheaper than using electricity to produce hydrogen.
- Deploying these technologies could yield important spill-over benefits. If the oil and gas industry can mobilise its vast knowledge, institutional and capital resources to support the development of zero-carbon technologies, this would provide a major boost to energy transitions.
- A carbon price of \$50 per tonne (t) of CO_2 is already used by some companies when screening projects. Applied across the oil and gas supply chains, this would cut CO_2 emissions in 2040 by over 1 000 Mt CO_2 (Figure 11.2). Combined with reductions in methane emissions, total savings of over 2 500 Mt CO_2-eq could be realised in 2040; this is equivalent to the current energy-sector GHG emissions of India.

Figure 11.2 ▷ Impact of a \$50/t CO_2 tax on indirect oil and gas CO_2 emissions in the New Policies Scenario



Extending the price on CO_2 already applied by many international oil companies to the oil and gas supply chains could yield reductions of 1 000 Mt CO_2 by 2040

11.1 Introduction

This edition of the *World Energy Outlook (WEO)* explores some major changes on the horizon in the types of energy that are produced and consumed. Electrifying end-use sectors, a shift towards low-carbon electricity generation and enhanced efficiency efforts are all central to this. Yet some elements of the traditional hydrocarbon-based energy system are set to remain for decades to come. In the New Policies Scenario, despite a 230% rise in renewable energy between 2017 and 2040, oil and natural gas are the two largest fuels in 2040. In the Sustainable Development Scenario, which contains concerted action to mitigate greenhouse gas (GHG) emissions in line with the Paris Agreement, achieves universal energy access by 2030 and ensures a substantial reduction in air pollutants, oil and gas still satisfy just under half of global energy demand in 2040.

Progress with energy transitions requires that this oil and gas is supplied in a way that minimises adverse social and environmental impacts. Some aspects of this have already received considerable attention, including potential hazards relating to air pollution, water use and contamination, noise and other local disruptions, and the risk of earthquakes. Less attention has been paid to the GHG emissions associated with the supply of oil and gas. But this situation is changing. An increasing number of countries, jurisdictions, and companies have announced targets or goals to ensure that oil and gas meet certain environmental targets (Table 11.1). The rising number of carbon dioxide (CO_2) pricing mechanisms around the world and increasing investor awareness of the various market and reputational risks attached to different fossil fuel investments could dampen the future prospects of the most emissions-intensive sources of production. There is also societal pressure to block new fossil fuel projects and associated infrastructure in a number of countries, often accompanied by legal challenges. While fossil fuels will remain in the energy system for some time, oil and gas that is produced in a clean and environmentally conscious manner is likely to enjoy advantages over other sources of supply.

The first task of this chapter is to examine the level and the origin of GHG emissions arising along the oil and gas supply chain. This enables a comparison of the indirect CO_2 and methane (CH_4) emissions[1] from the production, processing and transport of all sources of oil and gas globally to end-use consumers. We examine how these emissions evolve in the New Policies Scenario, and then discuss some of the key opportunities to reduce them. We conclude by illustrating the impact these technologies could have on energy and emissions trends, and by considering the implications for policy makers and industry.

1. We use a factor of 30 to convert a tonne of methane to a tonne of CO_2 equivalent (the 100-year global warming potential); see the *WEO-2017* for a detailed discussion on the use of global warming potentials. We report intensities in carbon-dioxide equivalent (CO_2-eq) when considering total GHG emissions and in CO_2 when considering CO_2 only.

Table 11.1 ▷ Announced goals and targets to reduce the GHG emissions intensity of oil and gas production

Jurisdiction	Low-carbon fuel standards and announcements
European Union	6% reduction in GHG intensity of transport fuels by 2020 (2010 baseline).
British Columbia (Canada)	10% reduction in GHG intensity of transport fuels by 2020; 15% reduction by 2030 (2010 baseline).
California (United States)	10% reduction in GHG intensity of transport fuels by 2020 (2010 baseline).
Oregon (United States)	10% reduction in GHG intensity of transport fuels by 2025 (2015 baseline).
Washington State (United States)	Announced plan for 10% reduction in GHG intensity of transport fuels by 2028 (2017 baseline).
Company	**GHG reduction targets**
BP	3.5 Mt reduction in annual GHG emissions by 2025 (2015 baseline).
Eni	43% reduction in upstream GHG emissions intensity by 2025 (2014 baseline).
Equinor	Reduction in upstream CO_2 emissions intensity to 8 kg CO_2/boe by 2030. 3 Mt reduction in annual CO_2 emissions by 2030 (2017 baseline).
Repsol	1.9 Mt reduction in annual GHG emissions by 2020 (2014 baseline).
Shell	20% reduction in CO_2-eq emissions intensity of energy products by 2035*; 50% reduction by 2050 (2017 baseline).

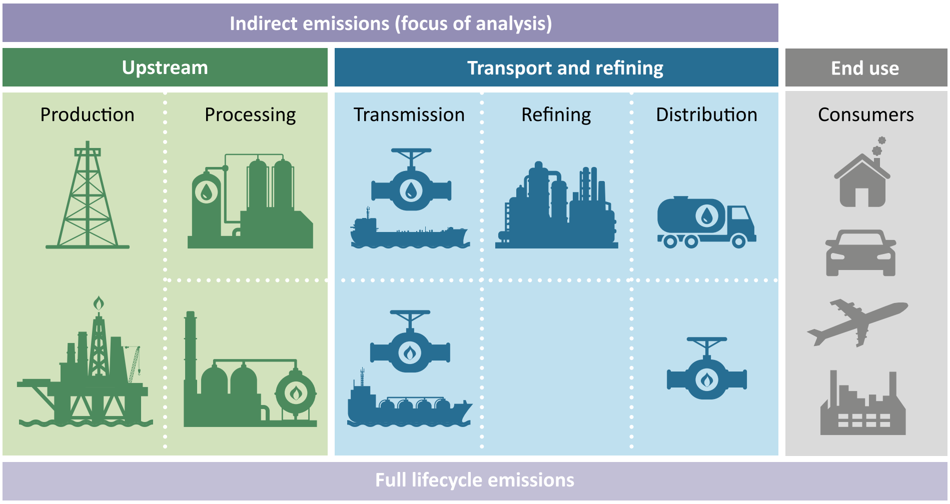
Note: kg CO_2/boe = kilogrammes of CO_2 per barrel of oil equivalent; *Includes emissions from both the production and consumption of the oil and gas produced.

11.2 Energy use and emissions from the oil and gas industry

Getting oil and gas out of the ground, processing it and bringing it to consumers is the business of energy supply. It is also an important component of global energy demand that produces CO_2 emissions from the fossil energy consumed in those processes. Leaks of CO_2 and methane to the atmosphere along this chain are an additional important element in global GHG emissions. As we shall see, there are wide variations in energy use and emissions across different sources of oil and gas supply.

In examining energy use and the indirect GHG emissions intensity of different sources of oil and gas, the starting point is to define the scope of emissions. We focus here predominantly on energy use and emissions that occur up to and including delivery of the product to the end-use consumer (Figure 11.3). These emissions are often referred to as the "well-to-tank", "well-to-meter" or "indirect" emissions as they exclude emissions that occur during combustion of the fuel itself. The emissions that occur during combustion of the fuel are generally well understood. There is a small degree of variation in CO_2 emissions from the combustion of natural gas (depending on its methane content), but on average, emissions are 1.9 tonnes CO_2 per thousand cubic metres (kcm) (or 320 kg CO_2 per barrel of oil equivalent [boe]). Combustion emissions from oil can vary to a much greater extent, depending on the oil product in question but, as a global average, are 405 kg CO_2/boe (Box 11.1).

Figure 11.3 ▷ Scope of greenhouse gas emissions included in the analysis



Our analysis focuses on the indirect GHG emissions associated with the production, processing, transmission, refining, and distribution of oil and gas

Box 11.1 ▷ Modelling emissions intensities in the *WEO-2018*

The World Energy Model tracks a barrel of oil or cubic metre of natural gas from where it is produced to where it is refined or processed and finally to where it is consumed. For upstream emissions, we generate country-specific energy intensities for each type of oil and gas production that take into account the various production processes used. For oil, the intensities are based on a field-by-field dataset produced by the King Abdullah Petroleum Research Center (KAPSARC) using the Oil Production Greenhouse Gas Emissions Estimator (OPGEE, version 2.0b).[2] For gas, there are a number of sources available that discuss the energy intensity of gas production, for example S&T Squared (2012) and figures from the International Energy Agency's World Energy Balances. But there is currently no comparable, comprehensive model to OPGEE, which means that there is more uncertainty about the energy intensities of various sources of gas production. Intensities are projected into the future taking into account continued technological improvements (which tend to reduce the energy intensity of production) and resource depletion (which tend to increase the energy intensity). Transportation energy use and emissions take into account the different trade routes and whether the transport is by ship or pipeline. Refining emissions take into account the different qualities of oil used as feedstock and the level of the processing required to provide the end-use products demanded by consumers. Hydrogen needs in refining operations are estimated using the Petroleum Refinery Life Cycle Inventory Model (PRELIM).

2. Multiple pioneering scientific papers have been published using the model OPGEE (Masnadi, et al., 2018; Masnadi & Brandt, 2017; Cooney, et al., 2017; Gordon, et al., 2017), and it is used to estimate the baseline emissions intensity of oil-based transport fuels for the Low-Carbon Fuel Standard in California.

Different oil products result in very different level of emissions when combusted: liquefied petroleum gases emit around 360 kg CO_2/boe, while heavy fuel oil emits around 440 kg CO_2/boe. The global average array of oil products produced from a barrel of oil equivalent in 2017 (the "product slate") results in around 405 kg CO_2 when combusted. Some oil products are used as feedstocks and not combusted, and this reduces the current global average emissions associated with all oil use to 360 kg CO_2/boe. The product slate can vary substantially between different individual refineries. However, refineries generally try to limit the production of heavier products, and so at a regional level there is only a slight variation in the emissions from combusting a barrel of oil equivalent. The additional emissions associated with refining a barrel of heavy oil in a complex refinery are captured in our modelling as refining emissions.

Another important consideration is how to distinguish between the energy used in the primary process and that used to produce any co-products. Gas is produced in association with oil from a single well, while some facilities generate electricity or heat that can be sold or exported to be used in other sectors. Our approach here is to allocate energy and emissions on the basis of "co-product displacement". This applies an emissions credit to the primary operation equal to the energy that would have otherwise been required to produce the co-product.

Our analysis does not consider all emissions that could be included in a full lifecycle assessment. We do not include the energy used in manufacturing the drilling rigs or the steel used in wells or pipelines; these amounts are not easily available in energy statistics and are likely to be dwarfed by the direct use of energy. We also do not consider land-use CO_2 emissions from clearing areas for production facilities in onshore areas. Previous assessments have indicated that these are likely to be relatively small – less than 1% of total lifecycle emissions of a barrel of conventional crude oil (Yeh, et al., 2010) – although emissions can be very site specific, depending on how the land was used prior to construction of the facility, and are subject to large uncertainty ranges.

11.2.1 Oil

Upstream

Extracting oil from the subsurface requires energy to power the engines of drilling rigs, the pumps that lift oil out of the ground or inject water to maintain pressure in the reservoir, and the auxiliary equipment used at production sites. There is variation between countries in the energy sources used to provide these services, but oil is often used to provide the energy required before production has started (i.e. during the drilling and development stage), and natural gas or electricity is often used during the production phase. The total amount of energy expended in this way has led to the concept of the "energy return on energy invested" (EROI), and this can be used to examine how the energy intensity of extracting oil has changed over time (Box 11.2). There is a wide degree of variation in the energy required for different types of oil production around the world, but in aggregate we estimate that oil production today results in just under 400 Mt CO_2 a year.

As well as combustion emissions of energy used to extract the oil, there can also be emissions from flaring associated gas. Natural gas is often produced as a by-product when extracting oil, and it is sometimes uneconomic to build infrastructure to bring the gas to market. An operator must therefore choose whether to use it on site, reinject it into the ground, vent it as methane to the atmosphere, or to flare it. Flared volumes of associated gas were around 180 billion cubic metres (bcm) during the mid-1970s, but the amount of gas flared dropped significantly during the early 1980s as more routes to market were established, larger volumes were reinjected, and policies were established to cut the volumes of gas wasted in this way. Annual volumes of gas flared subsequently started to creep upwards again, but have dropped marginally since the mid-2000s given a renewed policy focus on this issue. In 2017 around 140 bcm were flared, which resulted in emissions of around 270 Mt CO_2.[3] Flares are not perfectly efficient and so a small portion of the gas is often not combusted: just over 3 Mt of methane (100 Mt CO_2-eq) was released to the atmosphere in this way in 2017. There are also other sources of fugitive and vented methane emissions that occur during oil production. These are highly variable across regions, supply chain routes, processes and equipment, but we estimate that a further 33 Mt methane (1 000 Mt CO_2-eq) was emitted from global oil operations in 2017.

Box 11.2 ▷ A barrel over a barrel: the energy return on energy invested

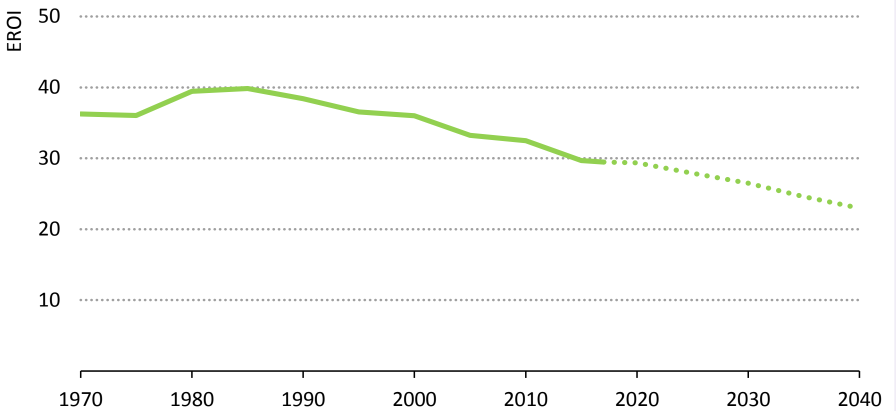
The EROI for oil is the ratio of the energy content of oil extracted from the ground on one hand and the amount of energy that was expended in doing so on the other. The higher the number, the better: a fall in the number shows that more energy is being consumed for the production of a given quantity of oil.

More complex resources, such as bitumen in Canada and extra-heavy oil in Venezuela, are generally more energy intensive to extract than conventional oil. These require heat to reduce the density and viscosity of the oil in the subsurface (to allow it to flow more easily) or the use of mining processes. The EROI can vary substantially depending on a variety of characteristics including the gas-to-oil ratio, production technique, field size, location and depth, the density of the produced oil and the age of the field. After a field passes its peak in production, while the volume of produced oil declines, the volume of water that is extracted can remain the same or even increase.[4] The energy use per barrel of oil produced from that field will therefore rise as the operator processes this produced water and seeks to maintain pressure in the reservoir.

3. CO_2 emissions from flaring and venting are not included in the IEA publication *"CO_2 Emissions from Fuel Combustion 2017"* since the gas is not used for any productive purpose.

4. Conventional crude oil fields generally produce some water with the produced oil, the ratio of water to total liquids extracted is often known as the "water-cut".

Figure 11.4 ▷ **Historical and projected EROI in the New Policies Scenario**



The historic downward trend in the global oil EROI continues as a result of resource depletion and a shift towards more complex resources

The variety of factors affecting the EROI means that generating a reliable history is a complex task. It is made more complicated by data gaps and problems: many of the world's largest producers do not provide a reliable historical record of the energy consumed in oil and gas extraction, and most statistical databases do not distinguish between energy use for oil extraction and for gas extraction. Our approach therefore relies on the EROI of fields today (as discussed above) and projects this backwards and forwards using the World Energy Model. Today, the EROI is around 30, having declined from around 40 in the 1980s (Figure 11.4). In the New Policies Scenario this trend continues and the average EROI of a barrel of oil produced in 2040 is around 20% lower than the value today. This occurs partly because of the continued shift towards heavier and more unconventional oil and partly because of resource depletion that tends to make the remaining oil more difficult to extract.

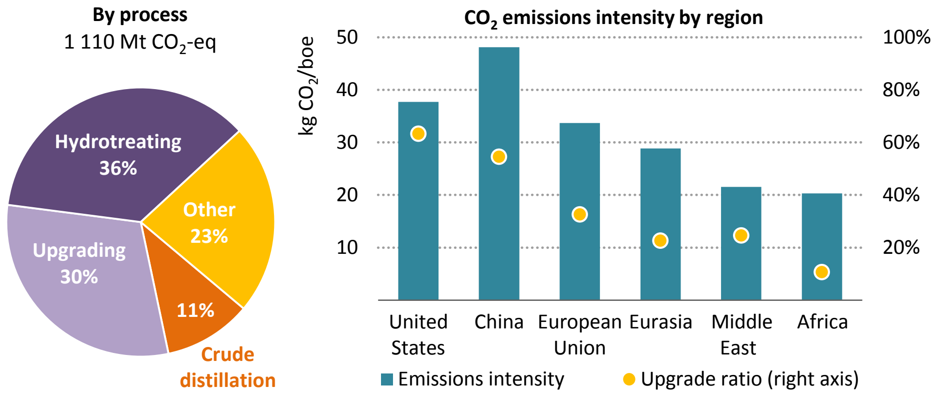
Transport

Most crude oil or oil product transport takes place via pipelines and ships. Both of these processes are relatively cost efficient – long-distance transportation represents only a fraction of the costs incurred along the oil value chain – but they still make an important contribution to the indirect emissions intensity of oil. The choice of transport mode depends on infrastructure availability and the distances and routes involved, but generally pipelines perform better over shorter distances, while ships are more flexible and mean lower costs over longer distances. Oil can also be moved by rail or road, but the inferior economics of these options compared with pipelines and ships mean that they are typically relied upon only when there are infrastructure bottlenecks. Oil pipelines require pumps and sometimes heaters along their length to maintain pressure and allow the flow of the oil: a variety of fuels can be used to provide the energy required by this equipment, but oil and gas are the most common. Most long-distance crude oil transport by ship relies on Very Large Crude Carriers, the majority of which consume low-quality heavy fuel oil for propulsion. Long-distance trade is less common for oil products than for crude oil because refineries are often set up to provide the products demanded by nearby consumers, but there are nevertheless still some transport requirements. For crude oil, taking all modes together, transport results in annual emissions of just over 200 Mt CO_2. For oil products, transport results in annual emissions of around 90 Mt CO_2 globally.

Refineries

Oil refining is a vital step to convert crude oil into useful oil products. This process can be energy intensive and can therefore result in large levels of GHG emissions. The oil refining process broadly consists of three major steps. The first is to separate crude oil into various hydrocarbon fractions ("crude distillation"). This usually results in a large volume of low-value oil products such as heavy fuel oil, especially when processing heavy crude oil. This leads to the second step, which is to convert low-value oil products into higher value ones ("upgrading"). The third step removes sulfur and other undesirable contaminants from the refined products ("hydrotreating"). Many jurisdictions have introduced regulations seeking to reduce the sulfur content of fuels.

Figure 11.5 ▷ Sources of refining emissions and emissions intensity in selected regions, 2017



Upgrading and hydrotreating processes account for the lion's share of refinery emissions, implying that the level of the required processing determines emissions intensity

Notes: "Other" includes emissions from other units (e.g. catalytic reforming, isomerisation) and a small level of emissions from natural gas liquids (NGL) fractionation. Although not strictly an oil refining process, NGL fractionation is included here since it converts liquids into usable oil products. Emissions intensity shows intensities of core refining operations only. The upgrade ratio is the sum of upgrading capacity (hydrocracking, fluid catalytic cracking, coking etc.) divided by primary distillation capacity.

Around two-thirds of CO_2 emissions from refinery operations comes from upgrading and hydrotreating (Figure 11.5). The complexity of a refinery is therefore the most important factor that determines its emissions intensity. Simple refineries that only involve crude distillation and a limited level of hydrotreating have relatively low-emissions intensities. More complex refineries that undertake an extensive upgrading process and a higher degree of hydrotreating have much higher emissions intensities. The different qualities of crude oil used as feedstock also affect the level of emissions: these are closely correlated with the configuration of refineries. Light crude oil is usually consumed by simple refineries, whereas heavy crude oil is mostly processed by complex refineries.

The fuels consumed in refineries also have impacts on emissions intensities. While refinery gas (hydrocarbon stream obtained during the refining process) is the dominant source of energy for refineries, more emissions-intensive fuels such as residual fuel oil or petroleum coke are also widely used. Petroleum coke accounts for around 12% of total energy use and over 15% of total emissions in refineries, although there is considerable uncertainty concerning the reporting of these data. Petroleum coke is a residue produced when refining heavy crude oils, and it emits more CO_2 and other air pollutants than coal when combusted. When used as a fuel, it results in a significant increase in emissions intensity. Petroleum coke is increasingly used in refineries in China as a cheaper alternative to coal, which explains the higher emissions intensity of Chinese refineries compared with others.

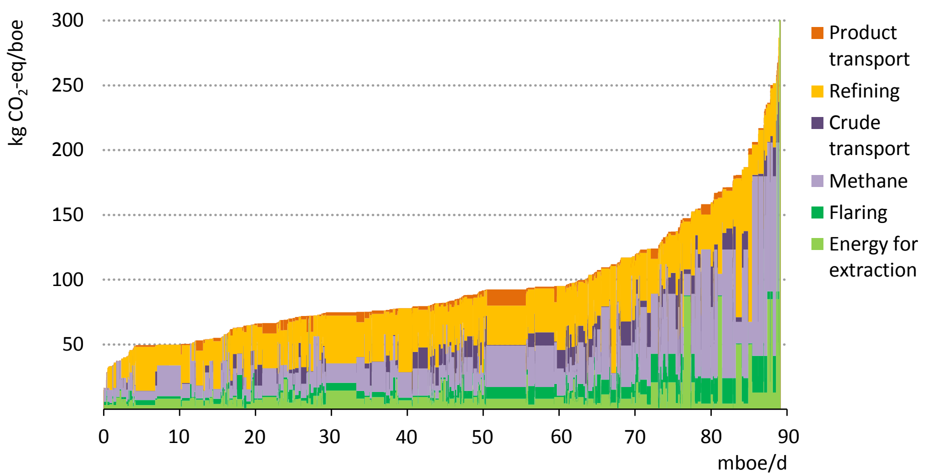
Overall, refining emissions range from 20 kg CO_2/boe to almost 80 kg CO_2/boe depending on the region, resulting in global emissions of around 1 100 Mt CO_2 a year. There is also a low level of methane emissions from refining but this is dwarfed by the emissions that occur during oil extraction (although estimates of emissions from refining are quite uncertain).

Indirect emissions for oil in 2017

Combining each of these elements and emissions sources for each barrel of oil produced in 2017 gives us the picture shown in Figure 11.6. Two points stand out. The first is that, on average, over 95 kg CO_2-eq is emitted in bringing a barrel of oil to end-use consumers. Since combustion results in around 405 kg CO_2/boe, this means that transport and refining processes account for almost 20% of the full lifecycle emissions intensity of oil. The second is that there is a strikingly broad range of emissions for different types of oil. The lowest 10% production has an average emissions intensity of less than 45 kg CO_2-eq/boe. The highest 10% has an emissions intensity of over 200 kg CO_2-eq/boe. Switching from consuming the most emissions-intensive oils to the least emissions-intensive oils would therefore reduce total emissions by over 25%. This percentage is broadly equivalent to the GHG emissions reductions that would be realised by switching from using the average diesel car on the road today to using a new hybrid car.

Sources of oil situated towards the left side of the spectrum are easy to extract, have low methane emissions, tend to be light oil or NGLs (and so can be processed by simple refineries or bypass the refining sector entirely), and are refined and consumed close to where they are extracted. Sources towards the right side of the spectrum require a great deal of effort to extract, result in a high level of fugitive or vented methane emissions, need to undergo complex refining operations and travel a long distance from production to refining and to consumption. Of course, most sources of oil lie somewhere in between these extreme cases: for example, some sources that require a large amount of heat and energy to extract and refine have a relatively low level of methane emissions.

Figure 11.6 ▷ Indirect emissions intensity of global oil production, 2017



Indirect oil emissions are over 95 kg CO_2-eq/boe, but a broad spectrum exists: the emissions intensity of the top 10% of barrels is over four-times that of the lowest 10%

Note: mboe/d = million barrels of oil equivalent per day.

11.2.2 Gas

Upstream

Many of the sources of energy use and upstream emissions for gas are the same as for oil. Energy is required to power the drilling equipment, maintain pressure in the reservoir and power auxiliary services. However one difference is that the level of flaring in natural gas operations is negligible – some flaring may take place during drilling, but operators will aim to minimise the volumes wasted in this way, since the whole point of the operation is to produce gas for sale. Another key difference is that the natural gas extracted can contain numerous impurities such as CO_2, hydrogen sulphide or sulfur dioxide: the volume of CO_2 can be as much as 50% of the volume of gas extracted. Natural gas that contains a high proportion of impurities is often referred to as "acid gas". These impurities must be extracted before the gas is transported long distances because they can lead to pipeline corrosion and because the gas must meet certain quality specifications before distribution to end-users. Processing to remove these impurities requires energy, and any CO_2 that is removed is often simply vented to the atmosphere. Venting CO_2 results in over 150 Mt of emissions every year.

As with oil, the natural gas value chain also results in significant quantities of methane being released to the atmosphere. However, unlike oil, emissions from gas are generally not confined to the upstream sector but can also occur during transmission and distribution, since the natural gas being transported is predominantly methane. We estimate that there are 29 Mt of methane emissions from upstream natural gas operations today (860 Mt CO_2-eq).

Transport

Transporting natural gas to end-use consumers relies on pipelines or on liquefied natural gas (LNG) carriers for seaborne shipments. In LNG, the liquefaction of natural gas prior to transport is an energy-intensive process requiring the gas to be cooled to minus 162 °C. The gas flowing to the (often remote) liquefaction facility is generally used to provide the energy for this and the other auxiliary services required by the LNG facility. The percentage consumed in this way averages around 9% globally, but it varies markedly depending on the composition of the incoming natural gas, the liquefaction technology and the ambient temperature (naturally enough, the energy requirements for liquefaction are lower for Novatek's Yamal LNG project, situated well above the Arctic Circle, than for projects in tropical climates). Steam and gas turbines were historically the most widely used drivers for liquefaction operations, but recently more modern aero-derivative gas turbines have been growing in popularity: these are around 25% more efficient than conventional gas turbines. There is also one large-scale facility that uses electricity rather than the incoming gas to power the liquefaction process (the Snøhvit LNG terminal in Norway), and this is also an option being considered for some planned projects in North America.

There are further (albeit smaller) energy losses during shipping. Up to 0.15% of the LNG cargo "boils off" each day, which means that the total amount consumed depends on the transport distance. This gas is often used to power the LNG tanker, and so produces CO_2 emissions. A 7 500 kilometre (km) journey from the United States to Europe takes around nine days and about 1.3% of the LNG cargo would be consumed and emitted as CO_2 during the voyage. Taking into account liquefaction and regasification, around 11% of the gas originally arriving at the liquefaction terminal would therefore be consumed. The vast majority of this is combusted and so is emitted as CO_2 rather than methane.

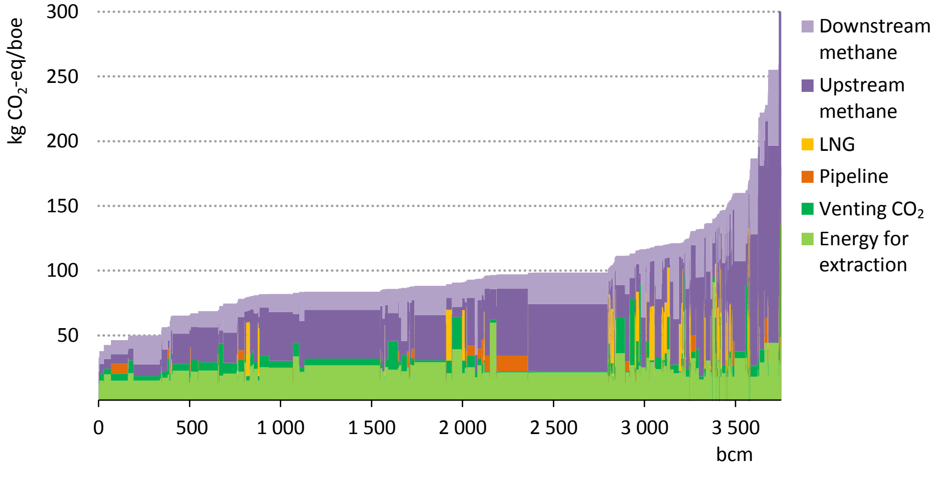
Gas transport by pipeline is less flexible than transport as LNG, but is more efficient. Pipelines are also usually used to transport gas over shorter distances than is the case for LNG. Nevertheless, compressor stations along a pipeline are needed to maintain pressure and allow the flow of the gas, and these require energy. In some locations these compressors are powered using electricity from the grid, but it is more common for a portion of the gas transported in the pipeline to be used. The number and power requirement of compressors needed for a pipeline vary depending on its capacity, length and geography. A 2 000 km pipeline with a 30 bcm capacity on average would consume around 4.5% of the gas transported.

In addition to these CO_2 emissions, the transportation and distribution of natural gas involves some methane emissions. LNG transport involves some methane emissions, but these estimates are currently subject to a very high degree of uncertainty. In gas pipelines, compressors are a major source of both fugitive and vented emissions. In total we estimate that 15 Mt of methane (450 Mt CO_2-eq) are emitted during gas transport today.

Indirect emissions for natural gas in 2017

The spectrum combining the emissions sources for gas in 2017 is shown in Figure 11.7. The average emissions intensity of all sources of gas is just under 100 kg CO_2-eq/boe (around 600 kg CO_2-eq/kcm), which means that the production, processing and transport of gas account on average for around 25% of the full lifecycle emissions of gas. As with oil, there is a large spread between different sources of gas and different trade routes. The highest 10% of production is around four-times more emissions intensive than the lowest 10%. Switching from consuming the most emissions-intensive gas to the least emissions-intensive gas would reduce emissions from gas consumption by nearly 30%. This percentage is broadly equivalent to the GHG emissions reductions that would be realised by switching from a classic gas boiler (with an efficiency of around 70%) to a new condensing gas boiler (with an efficiency of over 90%).

Figure 11.7 ▷ Indirect emissions intensity of global gas production, 2017



The average indirect emissions intensity of natural gas is just under 100 kg CO_2-eq/boe; methane emissions dominate the overall picture

Box 11.3 ▷ Comparing the full lifecycle emissions intensities of gas and coal

An oft-heard charge made against natural gas is that methane emissions along the gas value chain mean that gas has a lifecycle emissions intensity that is worse than coal. Based on the analysis in the *WEO-2017* and the additional elements included above, it is possible to examine this issue with much greater granularity than previously. Comparing the full lifecycle emissions of gas and coal depends on a variety of factors: the CO_2 emissions from the combustion of gas compared to coal; the emissions associated with coal extraction and transport; and, as is clear from Figure 11.7, the origin and destination of the gas in question. A number of other assumptions are also critical, including whether we are interested in the production of electricity or heat (electricity generation from natural gas tends to be more efficient than coal) and the conversion factor between a tonne of methane and a tonne of CO_2 (Ocko, et al., 2017).

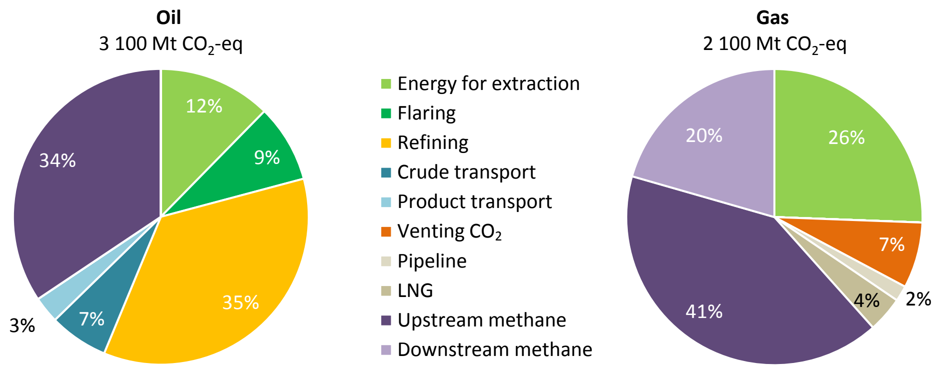
Assuming that 1 tonne of methane is equal to 30 tonnes of CO_2-equivalent (the 100-year global warming potential) and that we are interested in the production of electricity, then indirect emissions from natural gas must be below 500 kg CO_2-eq/boe for natural gas to have a lower full lifecycle emissions intensity than the average unit of coal produced globally. This means that over 99.7% of gas produced and consumed today is cleaner than coal when producing electricity. Further, even though LNG is a relatively energy-intensive process, electricity produced from gas that has been transported as LNG results on average in 45% fewer GHG emissions than coal. If one tonne of methane is equal to 85 tonnes of CO_2-equivalent (the 20-year global warming potential) then the spectrum illustrated in Figure 11.7 would shift upwards since methane would make a larger contribution to the overall emissions intensity. But over 97% of gas produced today would still be cleaner than coal when producing electricity. However, this simple comparison with coal sets the bar far too low for natural gas. Rather than focus on the gap in emissions intensity between coal and gas, the aim of the gas industry should be to minimise the gap with zero-carbon sources of electricity, by ensuring that all sources of emissions throughout the entire gas value chain are minimised or eliminated to the greatest extent possible.

11.2.3 Summary of indirect oil and gas GHG emissions

This comprehensive overview of the indirect emissions intensity of all sources of oil and gas produced and consumed globally indicates that combustion is the largest source of GHG emissions in the full lifecycle of nearly all sources of both oil and gas. It also indicates, however, that the extraction, processing and transporting of oil and gas to end-users represents on average around 20% of the full lifecycle emissions of oil and 25% of the full lifecycle emissions of gas. It is clear that there is a very wide distribution in the GHG emissions intensity of different types and sources of oil and gas from around the world: the most-emitting sources have an indirect emissions intensity that is over four-times higher than the least-emitting sources.

In total, oil results in nearly 50% more indirect GHG emissions than gas (Figure 11.8). Collectively, the indirect emissions from the supply of oil and gas are 5 200 Mt CO_2-eq today. This is nearly 15% of global energy sector GHG emissions. Our analysis shows that it is above-ground operational practices (namely methane emissions, venting CO_2 and flaring) that are responsible for the majority of GHG emissions from oil and gas operations worldwide, rather than the type of oil and gas that is produced and processed. Regarding CO_2 emissions only, the energy required for gas extraction and processing is responsible for the majority of emissions for natural gas, while the refining sector is the largest single source of CO_2 emissions for oil.

Figure 11.8 ▷ Breakdown of GHG emissions by element for oil and gas, 2017

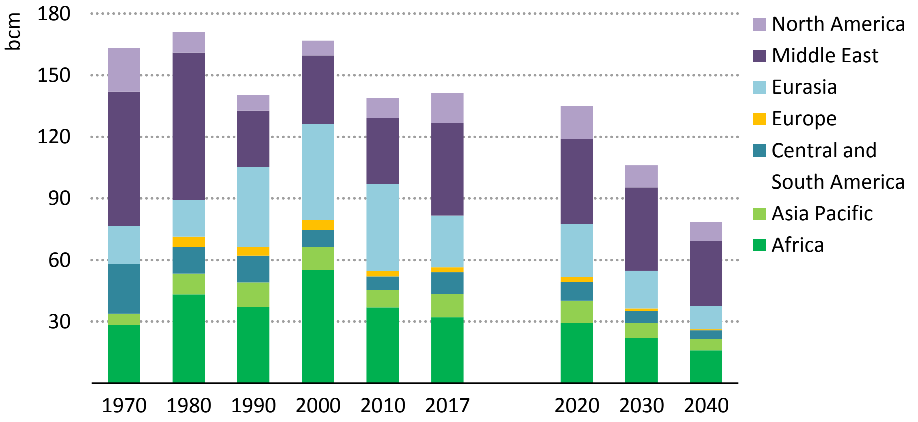


The extraction, processing and transportation of oil and gas is responsible for nearly 15% of global energy sector GHG emissions today

11.3 Indirect emissions in the New Policies Scenario

The previous section looked at emissions from different sources of oil and gas today. The key question in this section is how this could evolve in the future. In the New Policies Scenario, the use of new technologies and technological innovation reduces energy use and GHG emissions, as well as providing cost savings and efficiencies that improve the economics of production. Efficiency measures that have positive net present value are assumed to be adopted gradually around the world to 2040. There are also various efforts underway to reduce flaring: these efforts result in a continuing drop in volumes flared to under 80 bcm in 2040 (Figure 11.9). Existing and announced policy measures targeting the upstream, transportation or refining sectors also have an impact. For example, Canada's Alberta Province has a 100 Mt CO_2-eq limit on annual GHG emissions from upstream oil sands operations (excluding emissions from cogeneration) plus a 10 Mt CO_2-eq annual allowance for emissions from new upgrader facilities; there are also various targets and initiatives, primarily in North America, to reduce methane emissions from oil and gas operations.

Figure 11.9 ▷ **Historical and projected flaring volumes by region in the New Policies Scenario**



Although well below historical highs, around 140 bcm of natural gas was flared in 2017; flared volumes fall to under 80 bcm by 2040

Emissions from refining operations increase marginally to the mid-2020s in the New Policies Scenario. During this period, refiners add large amounts of upgrading capacity to reduce the yields of heavier oil products, and regulations on the sulfur content of fuels also trigger large additions of hydrotreating capacity. These two developments offset the impact of energy efficiency improvements. After 2025, continued efficiency improvements and slower growth in upgrading and hydrotreating capacity additions bend the curve backwards, and emissions slowly decline to 2040.

There is also a shift in the New Policies Scenario towards exploiting more energy-intensive resources to meet rising demand and offset declines from currently producing sources. As a result, CO_2 emissions from the oil and gas value chains rise from just under 2 900 Mt CO_2 in 2017 to nearly 3 600 Mt CO_2 in 2040 (Table 11.2). Various "game-changing" options are available that could have more fundamental impacts on the CO_2 emissions trend. These include both technologies that are well established today, but which could play a much greater role in the future, and more novel options that have recently risen to prominence. We investigate the potential of some of these technologies in the following section.

If there were no explicit efforts to tackle methane emissions in the New Policies Scenario, emissions would rise from 79 Mt methane in 2017 (2 400 Mt CO_2-eq) to over 105 Mt methane in 2040 (3 200 Mt CO_2-eq). The New Policies Scenario assumes that methane mitigation technologies and measures that consistently have positive net present values are gradually adopted over time (see section 11.4.1). Combined with existing methane reduction policies, methane emissions from oil and gas operations fall to around 55 Mt methane (1 650 Mt CO_2-eq) in 2040: around 1 500 Mt CO_2-eq annual emissions are therefore avoided in 2040.

Table 11.2 ▷ Indirect oil and gas GHG emissions in the New Policies Scenario (Mt CO_2-eq)

	2017	2025	2030	2035	2040
Oil	3 140	3 030	2 930	2 820	2 810
Energy for extraction	390	440	490	560	700
Flaring	270	220	200	170	150
Refining	1 110	1 150	1 150	1 130	1 130
Transport	290	290	280	270	260
Methane	1 080	930	810	690	570
Gas	2 100	2 140	2 240	2 340	2 420
Energy for extraction	540	620	680	760	850
Venting CO_2	150	170	190	220	240
Transport	120	160	200	210	240
Upstream methane	860	770	740	710	650
Downstream methane	430	420	430	440	440
Total indirect GHG emissions	**5 240**	**5 170**	**5 170**	**5 160**	**5 230**
of which: CO_2 emissions	2 870	3 050	3 190	3 320	3 570

Note: Refining includes emissions from refineries, heavy oil upgraders and NGL fractionation plants.

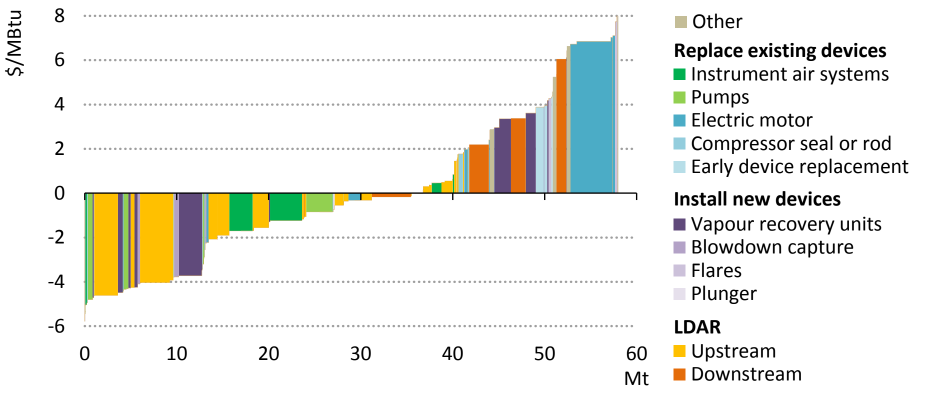
11.4 Reducing the emissions intensity of oil and gas

11.4.1 Tackling methane emissions

Understanding of the scale of methane emissions from the oil and gas supply chain continues to evolve but, on the basis of the work carried out in the *WEO-2017*, we estimate that around 36 Mt of methane emissions come from oil production and processing today, and 43 Mt from the production, processing and transport of natural gas. There is a wide variety of technologies and measures available to reduce these emissions. If all options were to be deployed across the oil and gas value chains, we estimate that this would avoid around 75% of these emissions. Importantly, however, since methane is a valuable product and in many cases can be sold if it is captured, we also estimate that around 45% of the 79 Mt total emissions could be avoided with measures that would have no net cost (assuming 2017 natural gas prices). There is a large degree of variation between countries given different gas prices and capital and labour costs, but the global averages for the key options in the marginal abatement cost curve are shown in Figure 11.10.

Leak detection and repair (LDAR) programmes are one of the key instruments to reduce methane emissions in a cost-effective manner. We include varying frequencies of these programs from monthly to yearly: the more frequent LDAR programmes are, the less the amount of gas that tends to be saved as a result of each programme, while the costs remain stable. This is what one would expect from effective programmes. However, monthly LDAR programs can still have net-negative cost in regions with high wellhead gas prices. Further, if LDAR programmes are discontinued, emissions can quickly increase again. LDAR programmes tend to be more cost effective for upstream operations since it takes longer to inspect a compressor on a transmission pipeline than in a production facility.

Figure 11.10 ▷ Marginal abatement cost curve for oil- and gas-related methane emissions by mitigation measure, 2017



Leak detection and repair in upstream operations and vapour recovery units on tanks offer some of the lowest cost options to reduce oil- and gas-related methane emissions

Note: MBtu = million British thermal units; Mt = million tonnes.

Another low-cost mitigation option is to install vapour recovery units on crude oil and condensate storage tanks.[5] In the absence of these units, dissolved methane can evaporate and be vented to the atmosphere. Measures such as replacing pneumatic devices and compressors with electric motors or finding alternative uses for associated gas (e.g. in mini-compressed natural gas units) are towards the more expensive end of the spectrum; yet in some regions these options too might have negative costs.

11.4.2 Electrification of operations

Once oil and gas projects reach their production phase, operators aim to keep facilities running on a continual basis. This is important to maximise output from the field, generate positive cash flows and recuperate upfront investment as quickly as possible. A continuous supply of fuel to provide the energy required for operations is therefore essential. Today, this power and heat is usually generated by combusting a portion of the extracted hydrocarbons (most often diesel and natural gas, and in some cases crude oil). However, generating electricity in this way is quite inefficient: small-scale onsite natural gas generators have an electricity generation efficiency that is often less than 35% (although some heat loss can be used in onsite processes to increase the efficiency). In addition, generating electricity in this way can use some of the valuable products that could otherwise be sold. As a result, there is increasing interest in the potential for electrifying upstream operations, using either electricity from a centralised grid or off-grid renewable energy sources. The costs of wind and solar energy have dropped dramatically in recent years, making off-grid

5. See https://www.iea.org/weo/weomodel/ for detail on these technologies.

renewables an increasingly attractive option. But the variable character of these energy sources, coupled with the need for a constant level of generation to maintain oil and gas operations, raises important questions about how much reliable energy these sources can provide, what level of energy and CO_2 emission savings can be realised, and what are the associated costs.

Electrification of upstream operations from the grid

The use of grid-based electricity would increase the efficiency of nearly all upstream operations. Large-scale, centralised electricity generators tend to have higher conversion efficiencies than smaller, more localised electricity generators and electric motors have very high efficiencies. Purchasing electricity would eliminate emissions from onsite electricity generation, but the impact on the total indirect emissions intensity would depend on the emissions intensity of the grid-based electricity. Broadly speaking, electricity would need to have an emissions intensity of less than 500 grammes of CO_2 per kilowatt-hour (g CO_2/kWh) for there to be a real reduction in the overall indirect emissions intensity of operations.

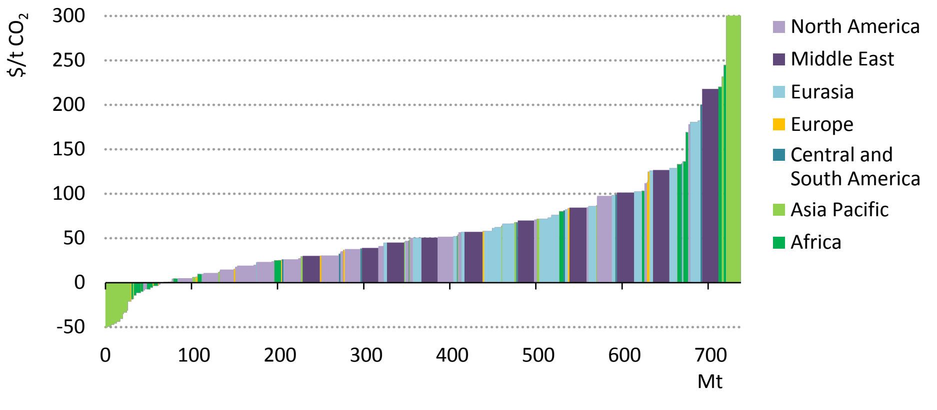
The emissions intensity of grid-based electricity varies widely according to local circumstances. For example, electricity generated today in the Middle East is around 670 g CO_2/kWh, in the United States it is around 480 g CO_2/kWh and in Norway it is less than 10 g CO_2/kWh. We estimate that just over 50% of global oil production today could in theory reduce emissions from energy extraction by connecting to the power grid. Grid-based electricity is already used in certain upstream operations, most notably in some tight oil developments in the United States. However, there has been minimal electrification of most facilities to date. There are a number of possible reasons for this. First, there are often large volumes of extracted gas available at the production site and there is often a large discount attached to this gas (it can even be considered to have a negative cost if there is no way to bring it to market). Onsite gas generation therefore can sometimes be much cheaper than buying electricity from the grid. Second, the majority of oil and gas fields are in remote places (including offshore), far from cities or a centralised power plant. Third, in many countries the centralised grid may not have full stability and reliability, and the risk of electricity outages deters companies that look to ensure continuous operations.

There are additional opportunities and challenges when it comes to electrifying offshore facilities via the grid. On one hand, offshore facilities are constrained by space: grid-based electrification removes the need for an onsite generator, freeing up space for other services (or allowing for a smaller platform). Similarly, powering subsea installations with direct connections to the grid can obviate the need for an offshore structure. On the other hand, many platforms are far from the coast, are located in deep waters and operate in harsh environments. The first offshore oil field electrified using an onshore grid connection was Saudi Arabia's Abu Safah development in 2003, situated around 50 km from the shore in a water depth of 33 metres. The technology has evolved rapidly and today it is possible to electrify fields up to around 200 km from shore in water depths up to around 100 metres. Despite this, only 15 offshore projects have been electrified to date via the grid. Most of these are in Norway, which has introduced a number of policy incentives to encourage electrification in this manner.

Electrification of upstream operations from decentralised renewables

Another option to reduce the emissions intensity of oil and gas operations is to develop off-grid renewables close to where extraction is taking place. To estimate the potential size of this opportunity we have examined the costs and emissions savings of installing different sizes of hybrid solar photovoltaic (PV), wind and battery storage systems at new oil and gas facilities that are developed in the New Policies Scenario.[6] This assessment takes into account the energy intensities of different production techniques across various regions, the levels of new resources developed each year, the cost of deploying decentralised renewables (and how these change over time), geographic data such as hourly wind and solar PV intensity profiles and whether the fields are onshore or offshore, different ratios of solar PV, wind and battery capacities, and the value of gas that is not to be combusted and that can be sold on the market.[7] The changes in power requirements over the lifetime of a field are an important consideration in this analysis. This is a function of both the production profile over time and the increase in energy intensity per unit of production as a field matures (see Box 11.1).

Figure 11.11 ▷ CO_2 abatement cost curve for decentralised renewables to power oil and gas facilities in the New Policies Scenario, 2040



Energy use in upstream operations result in just over 1 500 Mt CO_2 emissions in 2040; around 25% of these emissions can be avoided at \$50/t CO_2

Note: Marginal abatement costs here assume that the renewable systems are installed when fields are first developed in the New Policies Scenario.

6. Besides the use of batteries, a mini-grid between upstream facilities could be a viable option to help reduce possible curtailment in regions with clusters of nearby fields.

7. We focus here on hybrid wind and solar PV systems with varying levels of battery storage. Other renewable sources, such as geothermal energy, could also be used, but these are likely only available close to oil and gas facilities in a limited number of regions. The use of waste heat from produced water or oil (a form of geothermal energy) is considered as an efficiency measure.

On this basis, we have generated a global marginal abatement cost curve that describes the amount of CO_2 that can be saved at different costs (Figure 11.11). In 2040, total emissions arising from energy use in the upstream oil and gas sectors in the New Policies Scenario are just over 1 500 Mt CO_2. We estimate that it is technically possible to reduce these emissions by almost 750 Mt CO_2 by installing decentralised renewable systems when resources are first developed. Only a fraction of these would come with no net cost (where the value of the gas saved is greater than the cost of deploying renewables). However, at $50/t CO_2, the carbon price that many major oil companies have indicated they currently integrate into new investment decisions, around 25% of CO_2 emissions from the energy used for oil and gas production could be avoided. Besides electricity generation, providing low-carbon heat through the use of renewables could also be a viable option to help reduce emissions from some operations: one possibility is to use solar thermal energy to generate heat for thermal enhanced oil recovery operations, which is of particular interest in countries where solar is plentiful but gas is relatively scarce (Box 11.4).

Box 11.4 ▷ Solar enhanced oil recovery

Even with modern production techniques, a large share of the oil in a reservoir is often not produced during primary and secondary recovery. Some of this oil can be accessed only through the use of more complex and energy-intensive extraction techniques, called enhanced oil recovery (EOR). One of these techniques, thermal EOR, uses steam to heat the oil in the ground in order to increase its mobility. Around 1 million barrels per day (mb/d) oil is produced in this way today, with major operations in Canada, China, Indonesia, Oman and the United States. The steam required is mostly generated using natural gas: around 40 bcm of natural gas is consumed worldwide for thermal EOR today.

An alternative approach is to use large mirrors to concentrate the sun's energy to boil water and generate steam. This can generate the same quality of steam as natural gas (temperatures can reach up to 400 °C). Solar thermal EOR is very attractive for countries which have a scarcity of domestic natural gas resources and high solar capacity factors, including Kuwait, Oman and the United Arab Emirates. While it is difficult to eliminate the use of natural gas entirely (steam is generally also needed at night), gas consumption, and therefore emissions from energy extraction, can be reduced by up to 80%.

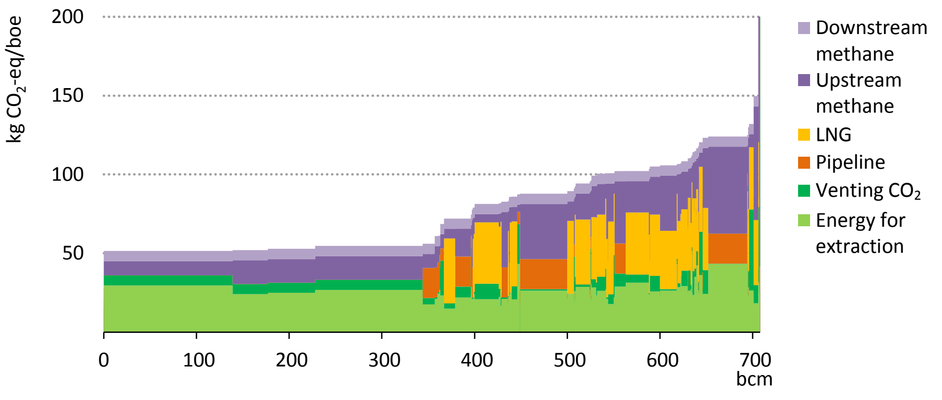
Interest in solar thermal EOR has risen dramatically in recent years. Pilot projects were launched in California in 2011 and in Oman in 2013. In 2015, one of the world's largest solar fields by peak capacity was announced in Oman: it will soon be operating at a capacity of 1 gigawatt (GW) and should provide around 20 thousand barrels per day (kb/d) production. A number of major projects have also been announced recently in Kuwait and California.

Reducing emissions from LNG

There are some opportunities to increase the efficiency of existing LNG plants: while LNG project developers already have commercial incentives to maximise the efficiency of their operations, there are currently no minimum efficiency standards for LNG plants. The wider use of waste heat recovery units, for example, could provide a real improvement in efficiency. Many existing facilities also use older, less efficient liquefaction equipment, and replacing this equipment with more modern aero-derivative gas turbines would reduce energy use (although this would entail significant upfront capital investment and disruption to operations). However, there are some options available that can provide a more radical reduction in the emissions profile of LNG facilities:

- Use electric motors to power the liquefaction process. There is one electric LNG plant currently in operation (the Snøhvit LNG facility in Norway) and another under construction in the United States. There are some barriers to the widespread adoption of this approach, including the need for LNG projects to be located near a reliable source of low-emissions power and the need to overcome technical challenges surrounding integration with the existing grid.[8] Off-grid renewable sources of energy could again be a viable option for new facilities located far from an existing grid.
- Equip the LNG facilities with carbon capture, utilisation and storage (CCUS) (see section 11.4.3).

Figure 11.12 ▷ Indirect emissions of natural gas consumed in China in the New Policies Scenario, 2040



Gas produced domestically in China has the lowest emissions intensity, but it could be undercut by electrifying LNG operations or using CCUS

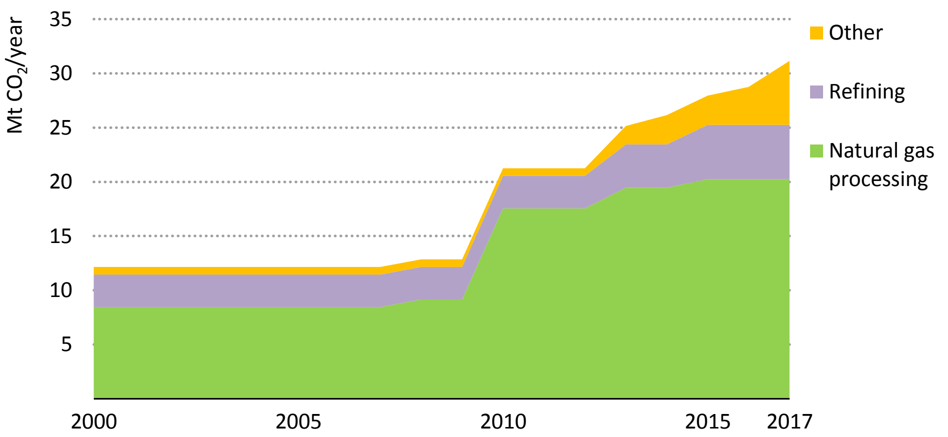
8. The Snøhvit facility in Norway has faced difficulties, including plant shutdowns, as a result of a weaker than expected connection to the grid. The Freeport project under construction in the United States includes an upgrade to the existing electricity grid.

The value of eliminating the emissions associated with liquefaction operations can be illustrated by looking at the spectrum of emissions for natural gas consumed in China in 2040 in the New Policies Scenario (Figure 11.12). Some sources of LNG (from North America and Australia) are already less GHG emissions-intensive than gas imports by pipeline because of the lower levels of energy required during their extraction and the tight controls placed on their methane emissions. However, they remain above that of domestic production within China. For LNG imports to be the cleanest source of gas consumed in China, emissions from the LNG process would need to be reduced by around 70-80%. Energy efficiency improvements could provide some of this reduction, but electrifying LNG operations (assuming the electricity itself has a low-emissions intensity) or producing the LNG in facilities equipped with CCUS would likely be necessary. Ensuring that methane emissions are kept as low as possible would also be essential.

11.4.3 Carbon capture, utilisation and storage

The oil and gas industry is already one of the global leaders in developing and deploying CO_2 capture. Of the 30 Mt CO_2 captured today from industrial activities in large-scale CCUS facilities, nearly 70% is captured from oil and gas operations (Figure 11.13). Around 4 Mt of the CO_2 captured today is injected into geological storage simply to reduce the emissions intensity of operations. However, the oil and gas industry is also active in this area because it can often make use of the CO_2 that is captured: either by selling it to industrial facilities or by injecting it into the subsurface to boost oil recovery (see section 11.4.4). A number of oil and gas processes produce highly concentrated streams of CO_2 that are relatively easy and cost-efficient to capture.

Figure 11.13 ▷ Historical volumes of CO_2 captured globally



Nearly 70% of the 30 Mt CO_2 emissions captured today is from oil and gas operations

One of the key opportunities to capture CO_2 emissions from the gas value chain is during natural gas processing. As discussed in section 11.2.2, underground deposits of natural gas can contain significant quantities of naturally occurring CO_2 – for example, the raw natural gas extracted from the Dulang field in Malaysia is over 50% CO_2 – and this must be removed to meet technical specifications before the gas can be sold or used. Requirements vary between countries, but natural gas transported in pipelines is often less than 0.5% CO_2, and gas transported as LNG must be less than 0.005% CO_2. One key advantage of capturing CO_2 from gas processing is that the separation process results in a very concentrated stream of CO_2 that can easily be purified prior to transport and storage. CO_2 emissions captured from natural gas processing represent the majority of total emissions captured today, but around 150 Mt CO_2 is still vented globally.

Since the CO_2 content of gas that is transported as LNG has to be very low, liquefaction facilities are another stage along the gas value chain where highly concentrated CO_2 emissions could potentially be captured. There is also a second stream of CO_2 open to potential capture at this stage arising from the combustion of natural gas to power the liquefaction process. These flue gas streams generally have low CO_2 concentrations, and so are more expensive to purify, but they represent a major source of emissions for LNG. There is one major LNG facility in operation today that is equipped with a CCUS unit to capture CO_2 at the point of liquefaction: the Gorgon LNG project in Australia. The natural gas flowing to this facility contains around 15% CO_2, which has to be removed prior to liquefaction: the aim is to capture these CO_2 emissions that would otherwise be vented. The LNG facility has been operating since 2016, although the capture facilities have yet to be brought online. There are currently no plans at any facility to capture the CO_2 emissions in the flue gas from the liquefaction process.

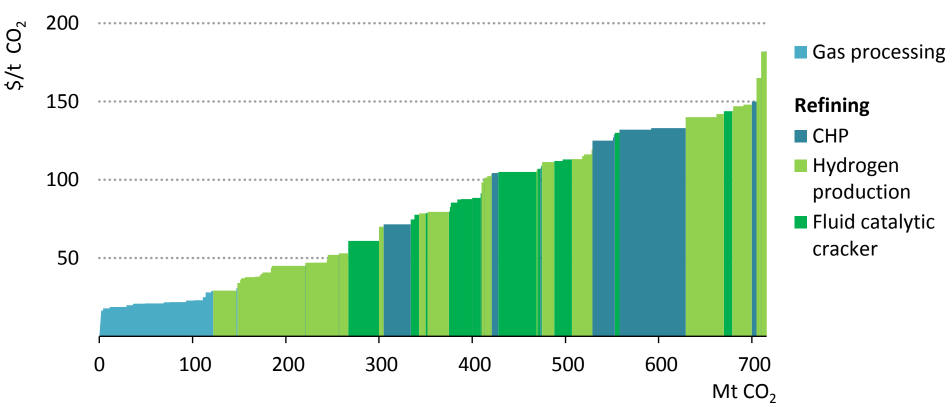
Refining offers an important opportunity to apply CCUS in the oil value chain. Refineries tend to consist of a variety of scattered CO_2-emission sources across different processing units, making it difficult to capture all emissions from a plant. However there are some units and systems that could be equipped with capture units. This includes hydrogen production units using steam methane reforming[9] (which are the source of around 30% of total CO_2 emissions from a refinery), fluid catalytic cracking units (around 15%) and combined heat and power systems (around 10%). Hydrogen production units result in highly concentrated CO_2 streams, while fluid catalytic cracking units generate a flue gas containing CO_2 in relatively high concentrations. The adoption of combined heat and power systems in refineries not only generate energy efficiency benefits but also centralises emissions sources, making CO_2 capture more viable. A number of refineries have installed units to capture CO_2 emissions. For example, emissions from the 400 kb/d Pernis refinery in Rotterdam are captured, transported and used in nearby greenhouses, and there are a number of other demonstration CCUS projects in refineries elsewhere.

9. In steam methane reforming, natural gas reacts with steam in the presence of a catalyst to produce hydrogen, carbon monoxide and CO_2. The carbon monoxide and steam are then combined to produce CO_2 and more hydrogen. The CO_2 and any other impurities are removed to leave a pure stream of hydrogen. This is then used to upgrade and hydrotreat the oil products (see Box 11.5).

The upgrading process used to transform extra-heavy oil and bitumen (EHOB) to lighter synthetic crude oil is another major point source of emissions. Just over 1 mb/d of EHOB is upgraded in Canada today, the vast majority of which comes from mining processes rather than underground in situ extraction techniques. The upgrading process accounts for around one-third of the total indirect emissions associated with mined EHOB and so capturing these emissions would provide a significant reduction in the emissions intensity of EHOB. There is one upgrader equipped with CCUS in operation today – the Quest project in Canada – which captures around 20% of the emissions from the 255 kb/d upgrader. There are other opportunities to capture CO_2 emissions from EHOB operations too, for example from the steam generation units required for in situ extraction, but no such projects are in operation or under development today.

Globally, we estimate that just over 700 Mt CO_2 indirect emissions from oil and gas operations could be avoided using CCUS (Figure 11.14). Many of these reductions could be realised at relatively low cost, particularly emissions from natural gas processing and refining processes that yield highly concentrated CO_2 streams. Over 250 Mt CO_2 emissions could be avoided at a cost of less than \$50/t CO_2. While some of the elements used in CCUS are relatively mature, limiting future cost reduction possibilities, there remain a number of novel aspects – particularly the combination of capture, transport and storage technologies – whose cost could fall substantially in the future. Increased investment in and deployment of CCUS, especially where there are opportunities to act at low cost, could help to trigger these reductions. Costs would also be reduced if the CO_2 could be monetised and/or utilised in other activities, such as enhanced oil recovery.

Figure 11.14 ▷ Opportunities and costs of using CCUS to reduce indirect oil and gas CO_2 emissions, 2017



Only around 20 Mt of CO_2 emissions are captured from oil and gas operations today. A \$50/t CO_2 price could reduce indirect emissions by around 250 Mt through CCUS.

Note: CHP = combined heat and power.

11.4.4 Enhanced oil recovery using CO_2

Overview and status of CO_2-EOR today

For carbon capture to lead to emissions reductions, the captured CO_2 must be stored permanently in underground geological sites or integrated into materials. One way to store it underground is to inject CO_2 into existing oil fields. This is a well-known EOR technique, as the addition of CO_2 increases the overall reservoir pressure to force the oil towards production wells; it can also blend with the oil, improving its mobility and so allowing it to flow more easily towards production wells. Some portion of the CO_2 remains below the ground during this process, while the remainder returns to the surface as the oil is extracted. If this CO_2 is separated and reinjected to form a closed loop, it results in permanent storage of CO_2. Today most CO_2-EOR projects recycle CO_2 returning to the surface as it is an expensive input to the production process.

Today the majority of injected CO_2 in CO_2-EOR projects is produced from naturally occurring underground CO_2 deposits. This may appear a somewhat ironic situation, given the wide efforts to reduce CO_2 emissions from the global energy system, but it results from the absence of available CO_2 close to oil fields. In the United States, for example, less than 30% of the near 70 Mt CO_2 injected each year for CO_2-EOR is captured from anthropogenic sources.

Oil produced through the injection of naturally sourced CO_2 will end up with a relatively high indirect emissions intensity. While over 95% of the purchased CO_2 will be stored underground, there will be no net reduction in CO_2 emissions if the CO_2 has been extracted from a nearby natural source (DOE/NETL, 2013; Cooney, et al., 2015; Azzolina, et al., 2015). In addition, recycling CO_2 requires electricity for the separation and compression of the CO_2, which tends to increase the overall energy intensity. For CO_2-EOR to provide a real reduction in upstream oil emissions, the CO_2 must be captured from anthropogenic sources or directly captured from the air. Capturing CO_2 from the atmosphere has been demonstrated at small scale, but is still in the early stages of development and consequently is a high cost option, although some have estimated that costs could be as low as $100 per tonne of CO_2 captured (Keith, et al., 2018).

As CO_2 is a costly input to the EOR process, CO_2-EOR operators currently seek to minimise its use. Today, between 0.3 t CO_2 and 0.6 t CO_2 is injected in EOR processes per barrel of oil produced in the United States, although this varies between fields and across the life of projects. Higher utilisation rates are possible – injection of 0.9 t CO_2 per barrel produced could be technically possible in some fields – and this would not only boost production to a higher degree, but also ensure that a greater level of CO_2 is stored per barrel of oil produced. Depending on the sources and quantities of CO_2 injected, the full lifecycle emissions intensity of CO_2-EOR could be as low as minus 350 kg CO_2/boe (see Spotlight). However, higher rates of utilisation are only likely to be economically attractive if policy measures create a value for storing CO_2. Globally, an estimated 190-430 billion barrels of oil are technically recoverable with CO_2-EOR. This would require injecting between 60 and 390 billion tonnes of CO_2: for comparison, total global energy-related emissions of CO_2

are currently around 32 billion tonnes each year (IEA, 2015). The United States holds the largest potential, but there are also good prospects in Central Asia, Middle East and Russia.

Today nearly all CO_2-EOR production is undertaken by independent or mid-sized oil companies. The availability of a reliable source of CO_2 at a suitable cost is a critical consideration when assessing whether or not to apply CO_2-EOR. Three-quarters of all CO_2-EOR production in the United States is carried out by three companies, all with substantial holdings of natural CO_2 resources. For others, the supply of CO_2 generally relies on a long-term take-or-pay contract between the producer of the CO_2 and the CO_2-EOR operator. The cost is generally linked to the oil price and can range from around \$15-30/t CO_2: injecting 0.5 t CO_2/bbl oil would therefore cost around \$7.5-15/bbl.

S P O T L I G H T

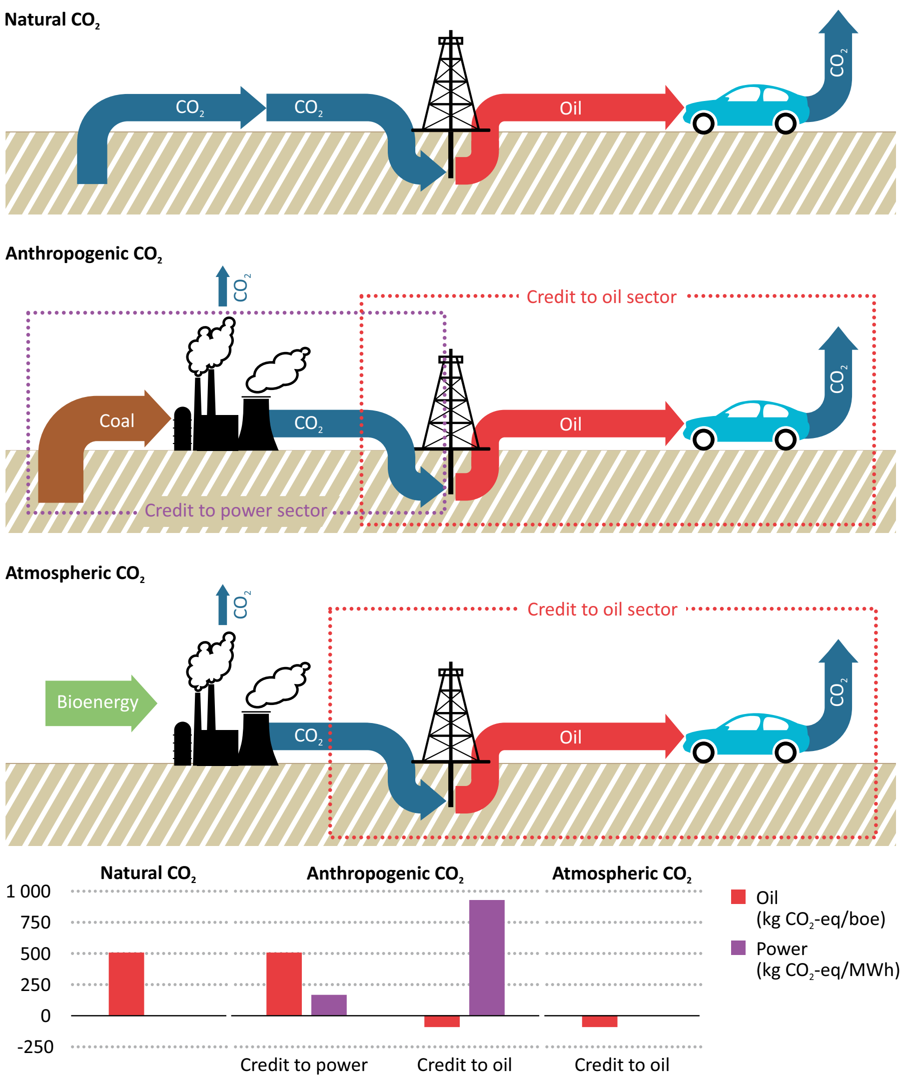
Can CO_2-EOR provide carbon-negative oil?

If enough anthropogenic CO_2 is injected during CO_2-EOR (the threshold depends on the level of indirect CO_2 emissions but is around 0.6 t CO_2/boe), the amount of CO_2 that ends up stored in the ground could exceed the CO_2 emissions from the production and combustion of the oil itself. The full lifecycle emissions intensity of the oil therefore would be negative and the oil could be described as net "carbon-negative". However this logic critically depends on the boundaries of the analysis and from where the anthropogenic CO_2 originated. A credit associated with storing CO_2 underground can only be counted once: either it can reduce the emissions from the original source when it was captured or it can reduce the emissions from oil production. It cannot do both.

For example, if a capture unit is attached to a coal-fired power plant and the captured CO_2 is transported to and injected in a CO_2-EOR site, it is not possible for both the electricity generated and the CO_2-EOR to be low-carbon. To put this another way, if a coal-fired power plant operator were to pay a CO_2-EOR operator to store captured CO_2, the CO_2-EOR operator could not claim that the oil produced has negative emissions. For CO_2-EOR to produce negative emissions – that is reduce the stock of CO_2 in the atmosphere – EOR projects would need to inject CO_2 that has either come from the combustion or conversion of biomass or has been captured directly from the air (Figure 11.15).

Ensuring the integrity of CO_2 storage is also important for validating the emissions reductions available through CO_2-EOR. There are certain steps operators can take to ensure and demonstrate the permanency of CO_2 storage, including: identifying sites with suitable geology that traps CO_2; avoiding abandoned wells that could create a conduit for CO_2 to reach the surface (or ensuring that these are plugged); and introducing monitoring and field surveillance to detect potential leakage. These measures reduce the risk of the injected CO_2 migrating back to the surface and adding to the atmospheric concentration of CO_2.

Figure 11.15 ▷ CO_2 emissions from CO_2-enhanced oil recovery



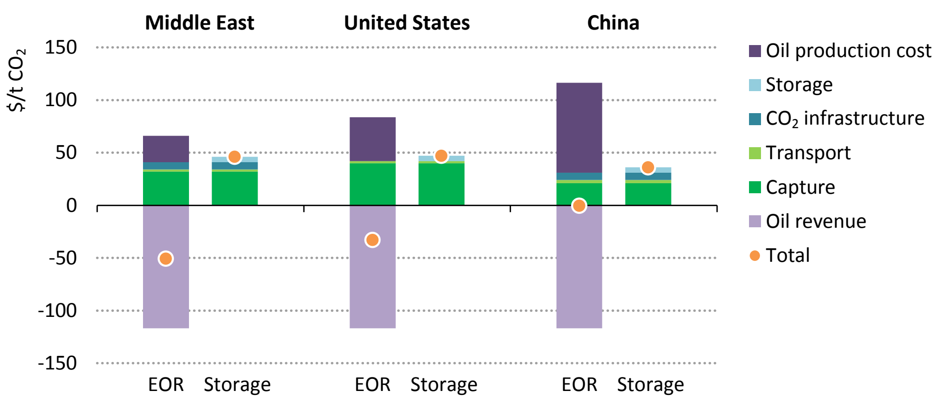
CO_2-EOR can provide net negative emissions oil, but careful accounting is essential unless the CO_2 used is captured from the atmosphere

Outlook for CO_2-EOR in the New Policies and Sustainable Development scenarios

In the New Policies Scenario, increases in EOR production are relatively subdued between 2017 and 2025 since there are lower cost investment opportunities for oil production. After 2025, as prices rise and as the growth in other sources of supply slows, EOR production grows by 2 mb/d to reach 4.7 mb/d in 2040. CO_2-EOR increases in tandem, but it does not enjoy any real advantage over the other EOR technologies: it remains around 35% of total EOR production throughout the projection period. The CO_2-EOR that does occur relies on the use of natural sources of CO_2 (similar to the situation today) or CO_2 captured from upstream activities (e.g. from natural gas processing). Production increases in the United States and the Middle East account for most of the CO_2-EOR production growth that does occur, while uptake in other regions remains limited.

The value proposition of CO_2-EOR projects is greatly enhanced in the Sustainable Development Scenario. A CO_2 price is introduced that increases to \$140/t CO_2 in 2040 in advanced economies and \$125/t CO_2 in 2040 in many developing economies. While today CO_2-EOR operators must pay for CO_2 that is injected, once the CO_2 price rises above the cost of capturing the CO_2, operators would start to be paid to take and store CO_2. For example, with a CO_2 price of \$35/t CO_2, a facility with a \$20/t CO_2 cost of capture would be willing to pay a CO_2-EOR operator up to \$15/t CO_2 for the transport and storage of CO_2. As a result CO_2-EOR production in the Sustainable Development Scenario grows to around 2.1 mb/d in 2040 (0.5 mb/d higher than in the New Policies Scenario). The CO_2 price is a critical enabler of this production, but the rise in the price of CO_2 throughout the Sustainable Development Scenario does not mean that CO_2-EOR operators receive ever-higher payments to transport and store CO_2. Geological storage operators can provide storage services for around \$15/t CO_2 in many regions, so a CO_2-EOR operator is unlikely to be paid much more than this.

Figure 11.16 ▷ Costs of CO_2-EOR projects compared with geologic storage



CO_2 storage in CO_2-EOR projects has a lower overall cost than geological storage. Focussing early stage CCUS deployment on CO_2-EOR projects would boost learning.

Notes: EOR = enhanced oil recovery. Assumes a \$70/bbl oil price.

Besides the increase in oil production, another important point about CO_2-EOR is that it offers a low-cost opportunity to deploy CCUS projects (Figure 11.16). CCUS from both power generation and industrial facilities grows over the course of the Sustainable

Development Scenario: total CO_2 captured worldwide rises from 150 Mt CO_2 in 2025 to nearly 2 400 Mt CO_2 in 2040. Combining CCUS facilities with CO_2-EOR operations would provide a cost-effective way to deploy CCUS in these circumstances. The oil revenues generated would reduce project costs and expand the amount-of CO_2 stored per unit of investment. If a number of projects of this kind can be developed, this would be likely to reduce the costs of CCUS more generally over time through learning by doing.

11.4.5 Hydrogen as an alternative fuel

The use of low-carbon hydrogen (H_2) is one way to reduce or bypass the emissions associated with the production and use of oil and gas.[10] Hydrogen and hydrogen-based fuels do not cause any CO_2 or air pollutant emissions when used and so they can act as zero-emissions energy carriers, be used as feedstocks to reduce the emissions intensity of industrial processes, or be consumed as end-user fuels. For example, hydrogen is a key input to the refining process, and current methods of production result in a large level of CO_2 emissions (Box 11.5).

Box 11.5 ▷ Reducing emissions from the refining sector

Two of the key measures to curb energy use and emissions in refineries are to improve energy efficiency and to change the fuels consumed. Regarding efficiency, waste heat recovery and combined heat and power systems are already used in many refineries in advanced economies, but there are a number of opportunities for them to be adopted more widely in developing economies.[11] Regarding fuel consumption, many refineries could switch away from the use of emissions-intensive fuels (e.g. fuel oil, petroleum coke) towards less polluting alternatives to provide some emissions reductions at the refinery (although to reduce emissions at a global level, such efforts would need to be accompanied by policies that ensure the displaced fuel is not sold to be combusted elsewhere).[12]

While these measures all contribute to emissions reductions in refineries in the New Policies Scenario, more fundamental reductions require tackling the two most energy-intensive processes – upgrading and hydrotreating. These processes use a large amount of hydrogen and producing this in a clean way would provide a major reduction in emissions. Around 35 Mt of hydrogen are consumed in refineries today, growing to 39 Mt in 2040 in the New Policies Scenario. Around 30% of this is currently met by hydrogen production from operations within the refineries themselves. For

10. The terms "green" and "low-carbon" are sometimes used to distinguish between hydrogen generated from renewable sources and from fossil fuels equipped with CCUS units; here we use low-carbon to refer to both production methods.

11. The adoption of combined heat and power systems can result in emissions reductions of 3-10% depending on the type of engine and process design (Motazedi, et al., 2017). As refinery consumption of electricity is small, surplus electricity can be provided to the grid.

12. In recent years, as US refineries sought to reduce emissions by limiting the use of petroleum coke, growing amounts of petroleum coke have been exported to China, India and other developing economies.

example, catalytic naphtha reforming – a process that converts naphtha into gasoline blending stocks – generates hydrogen as a by-product which can then be used elsewhere. A further 40% of hydrogen use in refineries is produced by splitting natural gas using SMR. The final 30% is procured from external suppliers, either from adjacent industrial facilities or by independent SMR facilities.

In the New Policies Scenario, emissions from hydrogen production in refineries in 2040 are around 220 Mt CO_2; the additional emissions from external procurement add another 140 Mt CO_2. Total hydrogen-related emissions are therefore around 360 Mt CO_2, over 30% of total refining CO_2 emissions. The use of zero-carbon hydrogen produced via SMR equipped with CCUS units or electrolysers using renewables would avoid these emissions entirely and provide a wholesale reduction to the emissions intensity of many types of oil. There are also efforts to separate hydrogen from refinery off-gas using technologies such as pressure swing adsorption. Exchanging non-monetised products through "outside-gate collaboration" is another way to avoid some of these emissions (CIEP, 2018). Steam crackers used to produce petrochemicals in industrial facilities tend to generate a surplus of hydrogen that could be used in refineries; conversely, the low-value fuel gases produced by refineries can be used in steam crackers.

One option being considered to reduce the emissions intensity of natural gas consumption is to blend low-carbon hydrogen into existing natural gas networks. The amount of hydrogen that could safely be injected in this way varies from around 10% to 20% by volume (depending on the end-use equipment). However, many current regulatory blending limits are much lower than these levels, and there could be scope to increase them.[13] Blending of this kind should be possible without any major infrastructure upgrades and could have a material impact on CO_2 emissions reductions: a 20% blend of hydrogen in the European natural gas grid would reduce current CO_2 emissions by around 60 Mt (a 7% reduction in CO_2 emissions from gas consumption).

In some countries, hydrogen blending is being considered as a transitional step towards the development of a pure hydrogen network. This hydrogen could be used to provide heat or could be converted to electricity using a fuel cell (e.g. in cars or residences). A related option would be to use a hydrogen-based fuel such as ammonia. Ammonia can be liquefied relatively easily, and there has been increasing interest in its potential both as an energy carrier and as a fuel for use in internal combustion engines, gas turbines, industrial ovens and in some fuel cells.

For hydrogen to provide a real reduction in global emissions, it must be produced in a low- or zero-carbon manner. Hydrogen can be produced using a broad range of processes and a number of different feedstocks, including fossil fuels, biomass and water. Today,

13. The regulatory blending limits for hydrogen currently range from 0.1% (in Belgium, New Zealand, the United Kingdom and the United States) to 10% in Germany and 12% in the Netherlands. Higher (or maximum) limits of safe blending have not yet been determined in most countries.

around 50% of total hydrogen production globally is generated from natural gas through steam methane reforming (SMR); 30% is produced by cracking oil products in the refining and chemical sectors and 18% is produced using coal gasification (mainly in China).[14] The remainder is produced from electrolysis of water, usually as a by-product of chlorine production. A range of different electrolysis processes exist, but all of them use electricity to separate water into oxygen and a pure stream of hydrogen.

SMR and coal gasification are well established and economically competitive methods of hydrogen production: costs range from around \$1-2/kg H_2 depending on natural gas and coal costs.[15] However, both processes result in large amounts of CO_2 emissions – SMR produces around 10 kg CO_2 per kg H_2 – and so they would need to be equipped with CCUS units to make low-carbon hydrogen. Another option would be to split natural gas into hydrogen and a solid carbon residue called "carbon black" through a process called "methane splitting". Carbon black can be used in tires, ink, paints and electrical equipment and, if sold, could help lower the overall costs of low-carbon hydrogen production. However, this is still a technology at the early stages of development and a number of challenges have yet to be resolved.

Electrolysis results in no direct CO_2 emissions, but production costs today are much higher at \$4-6/kg H_2. This is partly because of the high cost of electrolysers and partly because of the cost of electricity. The cost of electrolysers declines over the course of the New Policies Scenario, but the price of grid-based electricity remains relatively high. Generating hydrogen by running an electrolyser with grid-based electricity therefore looks expensive. An alternative option would be to run electrolysers only when electricity prices are very low, for example if there is cheap excess electricity from variable renewable sources available that would otherwise be curtailed. While the availability of such inexpensive electricity is far from certain, a bigger problem is that if the electrolysis facilities can only operate intermittently, the high capital cost of electrolysers would mean that this would be an expensive way to produce low-carbon hydrogen.

Another option would be to use an electrolyser in combination with a dedicated, off-grid renewable system in regions of high solar and wind resources. As the cost of renewables continue to decline and because an off-grid system could potentially avoid the relatively high costs associated with grid connection, it could generate electricity at low cost, and therefore power an electrolyser to generate hydrogen at low cost. This option is most likely to be viable in areas with high solar PV and wind resources but with little local demand for electricity. Possible candidates include areas in Australia (see Chapter 9), North Africa, Chile and South Peru, among others.

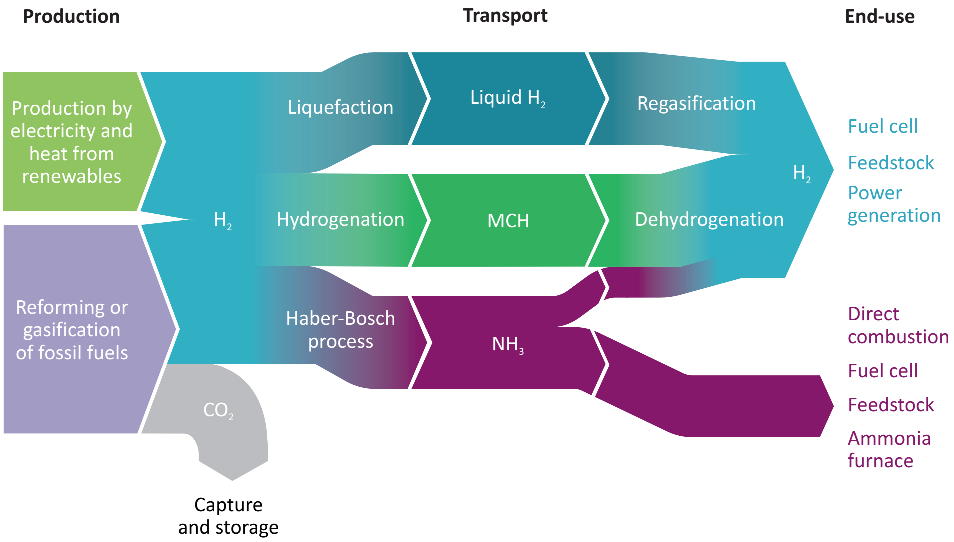
While hydrogen provides the opportunity to convert electricity into a storable fuel that can be used domestically for seasonal storage or transported overseas, cost-effective ways of transporting the hydrogen need to be developed. Various options exist (Figure 11.17). Liquefying pure hydrogen is a costly process because the hydrogen must be cooled to

14. Coal gasification involves a similar process to SMR, except that in the first step, the coal is converted into mixture of hydrogen, carbon monoxide and CO_2.

15. Costs for hydrogen are given in terms of its net calorific value.

minus 253 °C (significantly lower than the minus 162 °C required to produce LNG). If the hydrogen itself is used to provide this energy, around 30% would be consumed in the process. An alternative option might be to convert the hydrogen into a hydrogen-based fuel such as ammonia (NH_3, a combination of hydrogen and nitrogen). Ammonia is a gas at room temperature, but it can be liquefied by cooling to minus 33 °C (or at room temperature if pressured slightly), so transportation would be far less costly than for pure hydrogen. Once it has reached its final destination, ammonia could then be converted back into a pure stream of hydrogen. There are drawbacks however. This "dehydrogenation" process is still a relatively immature technology, and it requires energy, meaning that around 25% of the hydrogen would be lost. Further, ammonia is a toxic chemical: while safety measures could be put in place when it is used in centralised applications, its toxicity may limit its use in some forms of transport. There is also a risk that uncombusted ammonia fractions could escape, which are a precursor to tropospheric ozone formation, an air pollutant and a powerful GHG. Another long-distance transport option under consideration is to convert the hydrogen into chemicals (such as methylcyclohexane) that are liquid at room temperature and pressure.

Figure 11.17 ▷ Supply routes for low-carbon hydrogen



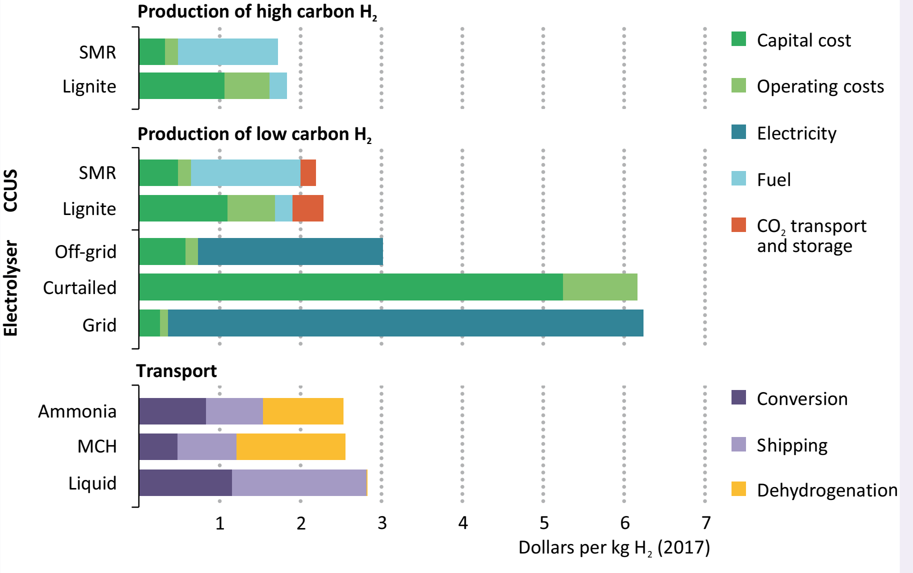
There are multiple options for the production, transportation and consumption of zero-carbon hydrogen and hydrogen-based fuels

The conclusion is that while there are many opportunities to use hydrogen across the energy sector (and reduce the emissions intensity of oil and gas), in the absence of stringent decarbonisation policies or generous financial incentives for electrolysers, SMR is likely to remain the cheapest option for producing hydrogen. Box 11.6 illustrates what this might mean in the case of Japan.

Box 11.6 ▷ Japan considers its low-carbon hydrogen options

In 2017, Japan released its Basic Hydrogen Strategy that aims to create new supply chains for producing and transporting low-carbon hydrogen. Japan's options to produce low-carbon hydrogen domestically are relatively constrained: potential storage areas for captured CO_2 are limited, restricting its availability to equip SMR units with CCUS, and its onshore renewables potential is limited by its mountainous terrain. If CCUS is ruled out, the cheapest way to produce low-carbon hydrogen in Japan would be by using a dedicated renewable hybrid system which would result in a cost for hydrogen of around \$5/kg H_2 in 2040 in the New Policies Scenario.

Figure 11.18 ▷ Costs of selected options to produce hydrogen in Australia and transport to Japan in the New Policies Scenario, 2040



SMR equipped with CCUS is the cheapest source of low-carbon hydrogen, but electrolysers using off-grid renewables could provide hydrogen for \$3/kg H_2 in 2040

Notes: SMR = Steam methane reforming; CCUS = carbon capture, utilisation and storage; MCH = methylcyclohexane. Electrolyser capital cost = \$550/kW of electricity input. Grid-based electrolyser: capacity factor = 100%, electricity price = \$123/megawatt-hour (MWh). Electrolyser relying on curtailed electricity: capacity factor = 5%, electricity price \$0/MWh. Off-grid electrolyser: capacity factor = 45%, electricity cost = \$50/MWh (based on the costs and capacity factors of hybrid solar and wind systems located in the best resource areas). All systems have a discount rate of 8%.

One option under consideration is to produce low-carbon hydrogen in a resource-rich region such as Australia and transport it to Japan. In Australia, the cheapest way to produce low-carbon hydrogen is by using SMR equipped with CCUS, whose projected cost in the New Policies Scenario in 2040 is just over \$2/kg H_2 (Figure 11.18). Hybrid off-grid renewables and electrolyser systems in Australia could potentially also be deployed. However the cost of hydrogen produced in this way would be about 40% higher than SMR equipped with CCUS. This is despite rapid cost reductions in renewables and electrolysers, and positioning these systems in the best locations for wind and solar resources.

The least expensive way to transport the hydrogen from Australia would be in the form of ammonia rather than as liquid hydrogen.[16] Low-carbon ammonia could be delivered to Japan for just over \$3.5/kg H_2 in 2040, including the \$2.2/kg H_2 cost of producing the hydrogen. This would be around a third cheaper than the cost of producing the low-carbon ammonia in Japan. If pure hydrogen were to be required in Japan then dehydrogenation and additional storage for hydrogen would be necessary: this would add another \$1/kg H_2 to total costs, but the imported hydrogen would still be marginally cheaper than domestically produced hydrogen.

11.5 Implications for policy makers and industry

Oil and natural gas are set to remain part of the energy system for decades to come in all of our scenarios, and there is likely to be increasing attention paid not only to their combustion emissions but also to emissions that occur along their supply chains. Increasing awareness by policy makers, industry and consumers of the need to minimise the environmental footprint of oil and gas production, processing and transport presents a number of opportunities for resource holders. Countries and companies that can credibly demonstrate that they are taking action in these areas could reasonably argue that these resources should be preferred over higher-emission options in a carbon-constrained world. Therefore it is important for the oil and gas industry to be proactive in limiting, in all ways possible, the environmental impact of oil and gas supply, and for policy makers to recognise that this is a pivotal element of energy transitions.

11.5.1 Policy options to encourage emissions reductions in oil and gas

Tackling the emissions that arise from oil and gas operations will require co-ordinated action between policy makers and industry. The previous sections demonstrated that the options and measures available to tackle emissions from oil and gas operations could lead to substantial reductions, and that many of these reductions could be achieved at relatively low costs. A core aim of policy makers in this area should therefore be to incentivise investment in these low-carbon technologies, particularly because many are closely connected with the core expertise of the oil and gas industries.

Increased attention to addressing indirect oil and gas emissions has led to the establishment of a number of voluntary industry partnerships (such as the Oil and Gas Climate Initiative

16. All costs are subject to a high degree of uncertainty and certain technologies have greater cost reduction potentials than others; for example while ammonia transport is already well established today, liquid hydrogen transport is at a much earlier stage of its development cycle.

[OGCI]). Many of these initiatives focus on broadening the use of best practices, promoting awareness of emissions reductions measures, and in some cases investing in new emissions reduction opportunities. While voluntary partnerships provide a basis for continuing dialogue and can help to inform government decision making, there are limits to what they can achieve. Policies are therefore critical. Here we identify five key issues for policy makers to inform the design of policies and strategies to reduce the environmental impact of oil and gas supply.

Improve data quality and measurement, increase transparency and engage with the public. Transparency is helpful to policy makers and regulators, as well as in informing the public. A public record system of emissions could be developed to help build trust in emissions data from the industry and the actions that are taken.

Establish a step-by-step policy and regulatory process towards a long-term goal. This would increase the confidence of the industry in the overall aims of the policy and help to foster innovation across the supply chain. The emissions reduction options and technologies available are at very different stages of their development cycles, but some of the largest emissions reductions can be achieved with measures that are already well understood and widely available. Policies that focus initially on these "low-hanging fruits" can enable or reduce the costs of technologies that are currently less well established.

Target policy support on options that fit within a wider emissions reduction agenda. Investment in measures that reduce emissions from the oil and gas value chains can also facilitate reductions in the wider energy system. Directing policy efforts and research, development and deployment investment towards the options that fit within system-wide decarbonisation plans would maximise spill-over benefits. The prospects for CCUS provide a useful illustration of this (Box 11.7).

Raise awareness within industry. Measures to increase awareness of the most cost-effective options would likely help accelerate their deployment.

Incentivise cross-industry collaboration. This would encourage companies to share best practices on emissions reductions and could help improve economies of scale (e.g. for CCUS or the use of decentralised renewables in upstream operations). In the latter case, if the installation of renewable systems at a number of fields over a wide geographic area is co-ordinated and connected, this would spread out the electricity load curve, increase the amount of time useful electricity is generated, and reduce costs for all participants.

Box 11.7 ▹ Policy support for CO_2-EOR

Enhanced oil recovery using CO_2 provides a lower cost option for injecting CO_2 into the subsurface than geological storage (section 11.4.4). CO_2-EOR could therefore be a helpful transitional step towards developing a full-fledged CO_2 capture, transportation and storage market. CO_2-EOR has gained limited traction except in the United States, which accounts for two thirds of global CO_2-EOR production today, although even in the United States it accounts for less than 3% of its total oil production.

There are many reasons for this: CO_2-EOR projects have higher upfront costs and longer payback periods, and are generally less flexible than other production options; CO_2-EOR often relies on infrastructure spread over a wide geographic area; and CO_2-EOR needs a reliable supply of CO_2. Long-term and sustained policy support was therefore essential to develop the CO_2-EOR industry in the United States. Policies were first established in the 1980s, when CO_2-EOR was seen as crucial to stemming the decline in domestic production, and more recently, the tax credit incentive for CO_2-EOR was increased and extended (the Section 45Q tax credit).

While most CO_2-EOR in the United States today relies on natural sources of CO_2 (which yields no emissions reductions benefits), the CO_2-EOR industry has established a network that can transport and store CO_2 over long distances. This provides a valuable platform for possible future use of CO_2 captured from anthropogenic sources (or CO_2 extracted from the atmosphere).

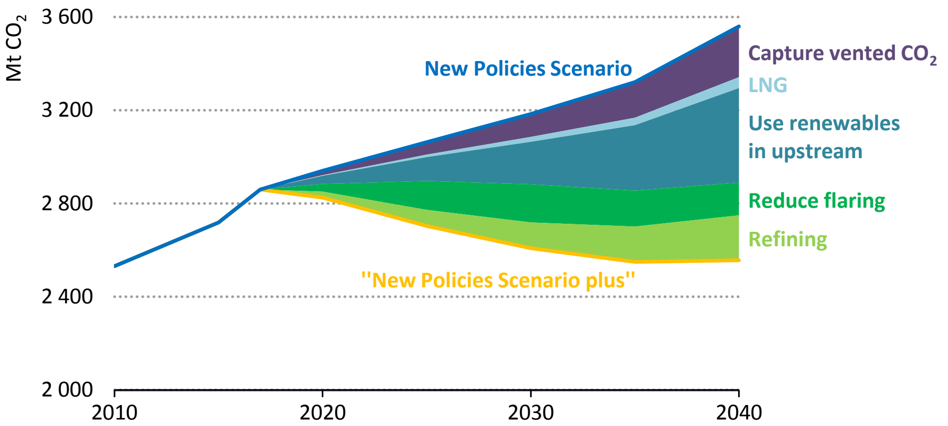
11.5.2 Bending the indirect emissions curve

Around 45% of the methane emissions that occur today from oil and gas operations could be avoided just by using measures that would pay for themselves through the value of the captured methane. As these are adopted in the New Policies Scenario, emissions are around 1 500 Mt CO_2-eq lower than they would have been otherwise in 2040.

However in the absence of any explicit policies to reduce indirect oil and gas CO_2 emissions beyond what has already been announced by governments, total CO_2 emissions from the oil and gas value chains increase from just under 2 900 Mt CO_2 in 2017 to nearly 3 600 Mt CO_2 in 2040 in the New Policies Scenario. To explore how this increase in CO_2 emissions could be averted, we consider what might happen if all companies along the supply chain were to factor in a cost for CO_2 emissions of \$50/t CO_2 across both new and existing infrastructure. This is a CO_2 price in line with the level that a number of major oil and gas companies have stated they already use when considering new capital investment decisions.

This CO_2 price stimulates a number of changes in indirect CO_2 emissions: by 2025 emissions are over 350 Mt lower than they would otherwise have been and by 2040 they are over 1 000 Mt lower (Figure 11.19). Large emissions reductions come through strengthened efforts to eliminate flaring, and capturing and reinjecting CO_2 that is extracted with natural gas. There is wider adoption of some efficiency improvements in existing facilities and the various "game-changing" measures are incorporated into the design of new facilities. This includes electrifying LNG facilities or equipping them with CCUS units, capturing and storing emissions from refining, and co-locating renewables with new upstream operations. This CO_2 price would also be sufficient to encourage CO_2-EOR operators to inject anthropogenic rather than just natural sources of CO_2. However the absence of captured CO_2 from outside the oil and gas sector means that CO_2-EOR cannot generate any real emissions reductions in this scenario.

Figure 11.19 ▷ **Emissions reductions with and without a \$50/t CO_2 tax across the oil and gas supply chains in the New Policies Scenario**

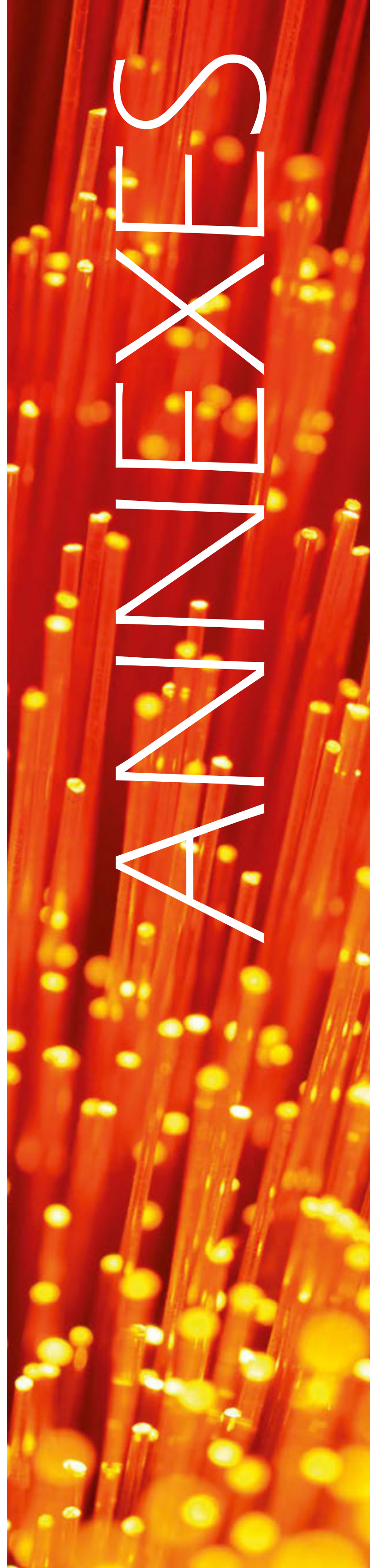


Placing a CO_2 price at a level that many international oil companies use in planning to the entire oil and gas supply chain could reduce emissions by over 1 000 Mt CO_2 in 2040

Note: The "New Policies Scenario plus" is identical to the New Policies Scenario with the addition of a \$50/t CO_2 price that is immediately introduced for all sources of indirect CO_2 emissions from the oil and gas supply chains.

When combined with the reductions in methane emissions, the total reduction in indirect emissions from the oil and gas sector would be over 2 500 Mt CO_2-eq. This is equal to the entire energy sector GHG emissions of India today. The spill-over benefits of avoiding these emissions could be just as important. The fossil fuel industry has vast knowledge, institutional and capital resources at its disposal: mobilising these to support the development of zero-carbon technologies would lead to greater cost reductions in the future, encourage more widespread deployment and accelerate energy transitions.

ANNEXES



Box A.1 ▷ *World Energy Outlook* links

WEO homepage

General information: www.iea.org/weo/
***WEO-2018* information:** www.iea.org/weo2018/

Modelling

Documentation and methodology / Investment costs
www.iea.org/weo/weomodel/

Recent WEO Special Reports

(Available to download free. Full listing at: www.iea.org/weo/specialreports/)

Outlook for Producer Economies
www.iea.org/weo/ProducerEconomies/

Offshore Energy Outlook
www.iea.org/weo/offshore/

Energy Access Outlook 2017: from Poverty to Prosperity
www.iea.org/access2017/

Southeast Asia Energy Outlook 2017
www.iea.org/southeastasia/

Energy and Air Pollution
www.iea.org/weo/airpollution/

Water-Energy Nexus
www.iea.org/water/

Databases

Sustainable Development Goal 7
www.iea.org/SDG/

Policy Databases
www.iea.org/policiesandmeasures/

Tables for scenario projections

General note to the tables

This annex includes historical and projected data for the New Policies, Current Policies and Sustainable Development scenarios for the following four data sets:

- A.1. Fossil fuel production and demand by region.
- A.2. Power sector overview by region covering gross electricity generation and installed capacity; cumulative retirements, additions and investments for 2018-2040. Global carbon dioxide (CO_2) emissions and intensity from power plants are also included.
- A.3. Energy demand, gross electricity generation and power generation capacity, and CO_2 emissions from fossil fuel combustion by region.
- A.4. Global emissions of pollutants by energy sector and fuel.

Geographical coverage for Tables A.1, A.2 and A.3 include: World, North America, Central and South America, Europe, Africa, Middle East, Eurasia, and Asia Pacific. In addition, Table A.3 covers: Brazil, China, European Union, India, Japan, Russia, South Africa, Southeast Asia and United States.

The definitions for regions, fuels and sectors are in Annex C. By convention, in the table headings, CPS refers to the Current Policies Scenario and SDS refers to the Sustainable Development Scenario.

Both in the text of this book and in the tables, rounding may lead to minor differences between totals and the sum of their individual components. Growth rates are calculated on a compound average annual basis and are marked "n.a." when the base year is zero or the value exceeds 200%. Nil values are marked "-".

Please see Box A.1 for details on where to download the *World Energy Outlook (WEO)* tables in Excel format. In addition, Box A.1 lists the links relating to the main *WEO* website, documentation and methodology of the World Energy Model (WEM), investment costs, recent *WEO* special reports and databases.

Data sources

Data for fossil fuel production, energy demand, gross electricity generation and CO_2 emissions from fuel combustion up to 2016 are based on IEA statistics, (www.iea.org/statistics) published in *World Energy Balances*, *CO_2 Emissions from Fuel Combustion* and *Monthly Oil Data Service*. Historical data for gross power generation capacity are drawn from the S&P Global Platts World Electric Power Plants Database (March 2018 version) and the International Atomic Energy Agency PRIS database (www.iaea.org/pris).

The formal base year for this year's projections is 2016, as this is the last year for which a complete picture of energy demand and production is in place. However, we have used more recent data wherever available, and we include our 2017 estimates (marked as 2017e) for energy production and demand in this annex (Tables A.1 to A.3). Estimates for the year 2017 are derived from a number of sources, including the latest monthly data submissions to the IEA's Energy Data Centre, other statistical releases from national administrations, and recent market data from the IEA *Market Report Series* that cover coal, oil, natural gas, renewables and power.

This annex also includes projections for primary air pollutant emissions that are emitted directly as a result of human activity. The focus is on anthropogenic emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X) and fine particulate matter ($PM_{2.5}$). Only emissions related to energy activities are reported. The base year of the projections is 2015. Base year air pollutant emissions estimates and scenario projections stem from a coupling of sectoral activity and associated energy demand of the WEM with the Greenhouse Gas and Air Pollution Interactions and Synergies (GAINS) model of the International Institute for Applied Systems Analysis (IIASA).[1]

Definitional note: A.1. Fossil fuel production and demand tables

Oil production and demand is expressed in million barrels per day (mb/d). Tight oil includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids). Processing gains covers volume increases that occur during crude oil refining. Biofuels and their inclusion in liquids demand is expressed in energy-equivalent volumes of gasoline and diesel. Natural gas production and demand is expressed in billion cubic metres (bcm). Coal production and demand is expressed in million tonnes of coal equivalent (Mtce). Differences between historical production and demand volumes for oil, gas and coal are due to changes in stocks. Bunkers include both international marine and aviation fuels.

Definitional note: A.2. Power sector overview tables

Included for the first time in the *WEO-2018*, the power sector summary tables provide a high-level snapshot of the electricity system by region. Electricity generation and installed power generation capacity data are provided on a gross basis (i.e. includes own use by the generator), with more detailed data broken down by fuel and region in the A.3 tables. The emission intensity is calculated based on electricity-only plants and the electricity component of combined heat and power (CHP) plants.[2] For retirements and additions, the category "other" includes bioenergy, geothermal, concentrating solar power (CSP), marine, and battery storage systems. For the investments table, "total plant" and "total" include

1. See: www.iiasa.ac.at/web/home/research/researchPrograms/air/GAINS.html for details.

2. We assume that the heat component of a CHP plant is 90% efficient and the remainder of the fuel input is allocated to electricity to derive the associated electricity-only emissions.

investment for batteries. The following abbreviations are used in the tables: Renew. = renewables; T&D = transmission and distribution.

Definitional note: A.3. Energy demand, electricity and CO_2 emissions tables

Total primary energy demand (TPED) is equivalent to power generation plus "other energy sector" excluding electricity and heat, plus total final consumption (TFC) excluding electricity and heat. TPED does not include ambient heat from heat pumps or electricity trade. Sectors comprising TFC include industry, transport, buildings (residential, services and non-specified other) and other (agriculture and non-energy use). Projected gross electrical capacity is the sum of existing capacity and additions, less retirements. While not itemised separately, other sources are included in total electricity generation, and batteries in total power generation capacity.

Total CO_2 includes emissions from "other energy sector" in addition to the power generation and TFC sectors shown in the tables. CO_2 emissions and energy demand from international marine and aviation bunkers are included only at the world transport level. Gas use in international bunkers is not itemised separately. CO_2 emissions do not include emissions from industrial waste and non-renewable municipal waste. Please visit www.iea.org/statistics/topics/CO2emissions for more information.

Definitional note: A.4. Emissions of air pollutant tables

Emissions of all air pollutants are expressed in million tonnes (Mt) per year and are reported by sector. The energy sector is broken down into power generation, industry and other transformation (i.e. other energy sector excluding electricity and heat), transport, buildings and agriculture. Emissions are reported separately for all energy activities and for combustion activities; the difference between these two relates to energy processes, including, for example, cement production in the industry sector or abrasion, tyres and brakes in road transport.

New Policies Scenario

	Production							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Oil production and supply (mb/d)										
North America	14.2	19.5	20.3	26.2	26.3	26.1	25.3	22	24	1.0
Central & South America	7.0	7.6	7.3	7.3	8.0	8.9	9.9	8	10	1.3
Europe	7.1	3.7	3.7	4.0	3.5	3.1	2.8	4	3	-1.2
Africa	7.7	7.8	8.2	8.0	8.1	8.3	8.7	9	8	0.3
Middle East	23.5	31.7	31.3	32.8	34.7	35.8	37.2	34	36	0.8
Eurasia	7.9	14.1	14.3	14.6	14.2	13.3	12.6	15	12	-0.5
Asia Pacific	7.8	8.0	7.7	7.0	6.7	6.6	6.8	8	7	-0.6
World production	**75.2**	**92.4**	**92.8**	**99.9**	**101.6**	**102.1**	**103.4**	**100**	**100**	**0.5**
Conventional crude oil	*64.8*	*67.7*	*66.9*	*65.6*	*65.7*	*64.1*	*63.8*	*70*	*60*	*-0.2*
Tight oil	-	*4.4*	*4.8*	*9.8*	*10.0*	*10.4*	*11.0*	*5*	*10*	*3.7*
Natural gas liquids	*8.9*	*16.2*	*16.7*	*19.0*	*19.9*	*20.8*	*21.1*	*18*	*20*	*1.0*
Extra-heavy oil & bitumen	*1.0*	*3.4*	*3.7*	*4.2*	*4.5*	*5.0*	*5.5*	*4*	*5*	*1.8*
Processing gains	1.8	2.3	2.3	2.5	2.7	2.8	2.9	2	3	1.1
World supply	**77.0**	**94.7**	**95.1**	**102.4**	**104.3**	**104.9**	**106.3**	**100**	**100**	**0.5**
Natural gas production (bcm)										
North America	763	966	976	1 185	1 225	1 274	1 328	26	25	1.3
Central & South America	102	177	183	189	212	251	293	5	5	2.1
Europe	338	289	291	227	207	205	203	8	4	-1.6
Africa	124	204	216	280	354	422	498	6	9	3.7
Middle East	198	600	620	709	817	925	1 025	16	19	2.2
Eurasia	691	837	886	974	1 016	1 069	1 104	24	20	1.0
Asia Pacific	290	565	596	730	810	877	950	16	18	2.0
World	**2 507**	**3 637**	**3 769**	**4 293**	**4 641**	**5 025**	**5 399**	**100**	**100**	**1.6**
Shale gas	*22*	*458*	*495*	*884*	*993*	*1 109*	*1 267*	*13*	*23*	*4.2*
Coal production (Mtce)										
North America	824	551	582	465	433	417	406	11	7	-1.6
Central & South America	48	90	88	85	86	87	88	2	2	-0.0
Europe	397	264	237	176	133	102	93	4	2	-4.0
Africa	187	216	224	218	222	217	228	4	4	0.1
Middle East	1	1	1	1	1	1	1	0	0	1.0
Eurasia	234	368	384	390	390	403	408	7	8	0.3
Asia Pacific	1 564	3 735	3 844	4 049	4 140	4 192	4 217	72	78	0.4
World	**3 255**	**5 225**	**5 360**	**5 383**	**5 405**	**5 419**	**5 441**	**100**	**100**	**0.1**
Steam coal	*2 504*	*3 979*	*4 134*	*4 201*	*4 280*	*4 350*	*4 412*	*77*	*81*	*0.3*
Coking coal	*449*	*956*	*960*	*918*	*887*	*846*	*806*	*18*	*15*	*-0.8*

Current Policies and Sustainable Development Scenarios

	Production						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Oil production and supply (mb/d)										
North America	27.2	27.9	27.6	24.3	22.4	18.5	24	27	1.3	-0.4
Central & South America	7.4	8.6	11.8	6.5	6.0	5.1	10	8	2.1	-1.5
Europe	4.1	3.6	2.9	3.8	3.1	2.2	3	3	-1.0	-2.2
Africa	8.3	9.0	10.6	7.1	6.5	5.4	9	8	1.1	-1.8
Middle East	34.0	36.7	41.6	30.5	30.0	24.8	35	36	1.2	-1.0
Eurasia	14.8	14.8	14.6	13.1	11.3	7.8	12	11	0.1	-2.6
Asia Pacific	7.1	7.1	8.1	6.3	5.5	4.1	7	6	0.2	-2.7
World production	**102.9**	**107.7**	**117.2**	**91.6**	**84.7**	**68.0**	**100**	**100**	**1.0**	**-1.3**
Conventional crude oil	*67.2*	*69.5*	*72.6*	*59.8*	*54.2*	*40.2*	*60*	*58*	*0.4*	*-2.2*
Tight oil	*10.3*	*10.5*	*12.1*	*9.1*	*8.3*	*7.3*	*10*	*10*	*4.1*	*1.8*
Natural gas liquids	*19.8*	*21.2*	*22.9*	*17.5*	*17.2*	*15.6*	*19*	*22*	*1.4*	*-0.3*
Extra-heavy oil & bitumen	*4.3*	*4.9*	*7.0*	*3.9*	*3.8*	*3.5*	*6*	*5*	*2.8*	*-0.2*
Processing gains	2.6	2.8	3.3	2.3	2.2	1.9	3	3	1.6	-0.8
World supply	**105.5**	**110.5**	**120.5**	**93.9**	**86.9**	**69.9**	**100**	**100**	**1.0**	**-1.3**
Natural gas production (bcm)										
North America	1 190	1 271	1 370	1 161	1 141	916	23	22	1.5	-0.3
Central & South America	198	246	340	183	187	196	6	5	2.7	0.3
Europe	227	211	207	226	206	197	4	5	-1.5	-1.7
Africa	291	380	568	274	326	372	10	9	4.3	2.4
Middle East	727	847	1 103	673	726	727	19	17	2.5	0.7
Eurasia	986	1 041	1 206	941	923	858	21	21	1.3	-0.1
Asia Pacific	769	863	1 054	730	809	919	18	22	2.5	1.9
World	**4 386**	**4 860**	**5 847**	**4 189**	**4 318**	**4 184**	**100**	**100**	**1.9**	**0.5**
Shale gas	*885*	*1 058*	*1 451*	*752*	*815*	*919*	*25*	*22*	*4.8*	*2.7*
Coal production (Mtce)										
North America	486	477	502	284	143	99	7	4	-0.6	-7.4
Central & South America	93	99	110	67	66	14	2	1	1.0	-7.6
Europe	192	165	135	138	62	31	2	1	-2.4	-8.5
Africa	243	280	337	207	168	128	5	6	1.8	-2.4
Middle East	1	1	1	1	1	1	0	0	1.0	0.4
Eurasia	407	429	473	334	263	210	7	9	0.9	-2.6
Asia Pacific	4 288	4 623	5 255	3 320	2 750	1 799	77	79	1.4	-3.2
World	**5 711**	**6 074**	**6 813**	**4 350**	**3 452**	**2 282**	**100**	**100**	**1.0**	**-3.6**
Steam coal	*4 486*	*4 872*	*5 655*	*3 313*	*2 587*	*1 609*	*83*	*71*	*1.4*	*-4.0*
Coking coal	*937*	*919*	*869*	*837*	*747*	*579*	*13*	*25*	*-0.4*	*-2.2*

New Policies Scenario

	Demand							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Oil and liquids demand (mb/d)										
North America	23.5	22.2	22.3	22.0	21.0	19.9	19.3	23	18	-0.6
Central & South America	4.5	5.8	5.8	5.9	6.0	6.2	6.3	6	6	0.4
Europe	14.9	13.0	13.2	12.1	10.9	9.6	8.7	14	8	-1.8
Africa	2.2	4.0	4.0	4.8	5.3	5.8	6.3	4	6	2.0
Middle East	4.3	7.4	7.4	8.4	9.0	9.7	10.6	8	10	1.6
Eurasia	3.1	3.6	3.7	4.1	4.2	4.2	4.2	4	4	0.5
Asia Pacific	19.4	29.6	30.5	35.8	38.0	39.0	39.5	32	37	1.1
International bunkers	5.4	7.8	8.0	9.2	9.9	10.6	11.4	8	11	1.6
World oil demand	**77.3**	**93.4**	**94.8**	**102.4**	**104.3**	**104.9**	**106.3**	**100**	**100**	**0.5**
World biofuels	0.2	1.7	1.8	2.8	3.4	4.0	4.7	2	4	4.1
World liquids demand	**77.5**	**95.1**	**96.6**	**105.2**	**107.7**	**108.9**	**110.9**	**100**	**100**	**0.6**
Natural gas demand (bcm)										
North America	800	979	969	1 078	1 101	1 136	1 170	26	22	0.8
Central & South America	97	169	174	183	204	236	271	5	5	1.9
Europe	606	587	613	622	611	601	592	16	11	-0.1
Africa	56	139	145	175	211	258	308	4	6	3.3
Middle East	174	487	501	560	646	731	794	13	15	2.0
Eurasia	471	553	575	592	601	617	635	15	12	0.4
Asia Pacific	313	732	775	1 073	1 248	1 413	1 579	21	29	3.1
International bunkers	-	0	0	10	20	33	49	0	1	32.7
World	**2 516**	**3 647**	**3 752**	**4 293**	**4 641**	**5 025**	**5 399**	**100**	**100**	**1.6**
Coal demand (Mtce)										
North America	818	530	513	396	372	356	341	10	6	-1.8
Central & South America	29	47	48	52	53	52	54	1	1	0.5
Europe	578	477	475	363	290	251	240	9	4	-2.9
Africa	117	143	145	150	149	146	142	3	3	-0.1
Middle East	2	5	5	8	9	11	13	0	0	4.5
Eurasia	202	217	224	228	219	214	211	4	4	-0.3
Asia Pacific	1 551	3 895	3 948	4 186	4 312	4 388	4 439	74	82	0.5
World	**3 298**	**5 314**	**5 357**	**5 383**	**5 405**	**5 419**	**5 441**	**100**	**100**	**0.1**

Current Policies and Sustainable Development Scenarios

	Demand						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Oil and liquids demand (mb/d)										
North America	22.2	21.7	21.3	20.2	17.4	12.1	18	17	-0.2	-2.6
Central & South America	6.1	6.4	7.1	5.4	4.9	4.0	6	6	0.9	-1.6
Europe	12.6	11.8	10.8	11.1	8.9	5.1	9	7	-0.9	-4.1
Africa	4.9	5.6	7.2	4.6	4.8	5.0	6	7	2.6	1.0
Middle East	8.5	9.2	11.4	7.6	7.2	7.2	9	10	1.9	-0.1
Eurasia	4.2	4.3	4.5	3.9	3.8	3.4	4	5	0.9	-0.3
Asia Pacific	37.3	40.7	45.0	33.4	32.5	26.7	37	38	1.7	-0.6
International bunkers	9.7	10.7	13.2	7.7	7.5	6.4	11	9	2.2	-0.9
World oil demand	**105.5**	**110.5**	**120.5**	**93.9**	**86.9**	**69.9**	**100**	**100**	**1.0**	**-1.3**
World biofuels	2.5	2.8	3.5	4.4	5.9	7.3	3	9	2.9	6.2
World liquids demand	**108.0**	**113.3**	**124.1**	**98.3**	**92.8**	**77.2**	**100**	**100**	**1.1**	**-1.0**
Natural gas demand (bcm)										
North America	1 097	1 146	1 229	1 066	1 016	814	21	19	1.0	-0.8
Central & South America	194	224	311	170	172	184	5	4	2.5	0.2
Europe	640	669	711	596	555	450	12	11	0.6	-1.3
Africa	177	220	334	166	182	201	6	5	3.7	1.4
Middle East	575	672	850	528	569	545	15	13	2.3	0.4
Eurasia	600	622	691	574	538	485	12	12	0.8	-0.7
Asia Pacific	1 099	1 297	1 699	1 081	1 271	1 491	29	36	3.5	2.9
International bunkers	5	10	23	9	14	15	0	0	28.3	25.9
World	**4 386**	**4 860**	**5 847**	**4 189**	**4 318**	**4 184**	**100**	**100**	**1.9**	**0.5**
Coal demand (Mtce)										
North America	432	414	422	204	83	64	6	3	-0.9	-8.7
Central & South America	54	57	62	43	34	28	1	1	1.1	-2.3
Europe	414	390	358	276	163	112	5	5	-1.2	-6.1
Africa	160	182	220	128	107	83	3	4	1.8	-2.4
Middle East	8	10	14	7	7	7	0	0	4.9	1.9
Eurasia	234	230	233	183	146	105	3	5	0.2	-3.3
Asia Pacific	4 408	4 792	5 506	3 509	2 912	1 884	81	83	1.5	-3.2
World	**5 711**	**6 074**	**6 813**	**4 350**	**3 452**	**2 282**	**100**	**100**	**1.1**	**-3.6**

New Policies Scenario

	2016	2017e	2025	2030	2035	2040	Shares (%) 2017e	Shares (%) 2040	CAAGR (%) 2017e-40
Electricity generation (TWh)									
North America	5 287	5 237	5 464	5 628	5 821	6 059	20	15	0.6
Central & South America	1 307	1 358	1 606	1 805	2 029	2 283	5	6	2.3
Europe	4 079	4 164	4 340	4 452	4 616	4 807	16	12	0.6
Africa	801	833	1 088	1 327	1 629	2 001	3	5	3.9
Middle East	1 082	1 106	1 326	1 591	1 889	2 167	4	5	3.0
Eurasia	1 338	1 354	1 475	1 559	1 651	1 756	5	4	1.1
Asia Pacific	11 024	11 627	14 953	17 148	19 284	21 369	45	53	2.7
World	**24 919**	**25 679**	**30 253**	**33 510**	**36 919**	**40 443**	**100**	**100**	**2.0**
Power generation capacity (GW)									
North America	1 393	1 409	1 567	1 647	1 715	1 788	20	14	1.0
Central & South America	333	345	438	493	549	622	5	5	2.6
Europe	1 261	1 284	1 445	1 588	1 645	1 701	18	14	1.2
Africa	209	226	334	413	501	622	3	5	4.5
Middle East	309	318	408	478	566	648	5	5	3.1
Eurasia	322	327	348	359	378	409	5	3	1.0
Asia Pacific	2 864	3 052	4 305	5 094	5 891	6 676	44	54	3.5
World	**6 690**	**6 961**	**8 845**	**10 073**	**11 244**	**12 466**	**100**	**100**	**2.6**
Global power sector CO_2 emissions and CO_2 intensity from electricity generation									
CO_2 emissions (Mt)	13 247	13 587	13 384	13 480	13 652	13 855	n.a.	n.a.	0.1
Intensity (g CO_2/kWh)	487	484	404	368	339	315	n.a.	n.a.	-1.8

	Coal	Gas	Oil	Nuclear	Hydro	Wind	Solar PV	Other	Total
Cumulative retirements, 2018-2040 (GW)									
North America	106	142	66	27	34	93	39	39	546
Central & South America	3	13	19	1	9	13	3	9	72
Europe	180	59	46	80	43	157	102	38	706
Africa	33	17	21	-	3	4	4	7	89
Middle East	0	42	43	-	0	0	1	0	87
Eurasia	55	101	8	20	1	0	0	3	189
Asia Pacific	181	86	91	32	41	180	141	87	840
World	**559**	**461**	**295**	**161**	**132**	**448**	**291**	**184**	**2 529**
Cumulative additions, 2018-2040 (GW)									
North America	2	279	10	6	50	211	267	98	925
Central & South America	8	91	4	7	97	59	54	28	348
Europe	61	172	1	46	74	387	279	103	1 123
Africa	31	135	20	3	65	39	139	52	485
Middle East	6	210	31	14	7	37	90	21	417
Eurasia	37	136	0	32	21	26	4	15	271
Asia Pacific	584	482	28	159	387	881	1 600	344	4 465
World	**730**	**1 506**	**95**	**267**	**701**	**1 640**	**2 433**	**662**	**8 034**

	Coal	Gas	Oil	Nuclear	Renewables	Total Plant	T&D	Total
Cumulative investments, 2018-2040 (billion dollars, 2017)								
North America	57	249	6	127	1 023	1 516	918	2 434
Central & South America	11	59	2	27	443	547	465	1 012
Europe	129	133	2	278	1 493	2 059	1 138	3 197
Africa	52	89	9	14	557	740	767	1 507
Middle East	10	160	27	47	285	531	308	839
Eurasia	85	128	0	124	144	483	260	743
Asia Pacific	748	310	17	472	4 050	5 787	4 452	10 239
World	**1 092**	**1 129**	**64**	**1 088**	**7 995**	**11 662**	**8 308**	**19 970**

							Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Electricity generation (TWh)										
North America	5 557	5 773	6 281	5 221	5 282	5 671	15	15	0.8	0.3
Central & South America	1 655	1 896	2 458	1 526	1 653	1 989	6	5	2.6	1.7
Europe	4 455	4 641	5 063	4 244	4 388	5 036	12	14	0.9	0.8
Africa	1 101	1 352	2 046	1 063	1 319	2 003	5	5	4.0	3.9
Middle East	1 379	1 677	2 329	1 269	1 459	1 833	5	5	3.3	2.2
Eurasia	1 507	1 616	1 881	1 388	1 393	1 467	4	4	1.4	0.3
Asia Pacific	15 318	17 799	22 697	14 148	15 666	19 115	53	52	3.0	2.2
World	**30 971**	**34 755**	**42 755**	**28 859**	**31 160**	**37 114**	**100**	**100**	**2.2**	**1.6**
Power generation capacity (GW)										
North America	1 555	1 625	1 795	1 576	1 730	2 120	15	14	1.1	1.8
Central & South America	442	501	640	433	484	610	5	4	2.7	2.5
Europe	1 448	1 504	1 631	1 458	1 620	1 951	14	13	1.0	1.8
Africa	334	397	570	359	497	844	5	6	4.1	5.9
Middle East	406	477	635	437	500	772	5	5	3.0	3.9
Eurasia	351	362	422	342	363	434	4	3	1.1	1.2
Asia Pacific	4 254	4 935	6 289	4 581	5 658	7 924	52	54	3.2	4.2
World	**8 789**	**9 802**	**11 981**	**9 187**	**10 850**	**14 655**	**100**	**100**	**2.4**	**3.3**
Global power sector CO_2 emissions and CO_2 intensity from electricity generation										
CO_2 emissions (Mt)	14 219	15 296	17 610	10 656	7 839	3 292	n.a.	n.a.	1.1	-6.0
Intensity (g CO_2/kWh)	420	405	383	332	221	69	n.a.	n.a.	-1.0	-8.1

	Current Policies					Sustainable Development				
	Coal	Gas	Nuclear	Renew.	Total	Coal	Gas	Nuclear	Renew.	Total
Cumulative retirements, 2018-2040 (GW)										
North America	76	142	25	187	501	258	145	19	188	698
Central & South America	3	13	1	33	72	7	14	1	33	77
Europe	162	59	77	330	687	214	59	57	333	721
Africa	33	17	-	11	89	35	17	-	13	94
Middle East	0	42	-	2	84	0	42	-	2	84
Eurasia	55	101	21	4	190	61	102	20	4	196
Asia Pacific	181	86	38	380	839	675	86	18	386	1 321
World	**511**	**461**	**161**	**947**	**2 463**	**1 250**	**464**	**115**	**959**	**3 191**
Cumulative additions, 2018-2040 (GW)										
North America	3	344	6	504	887	15	245	20	1 046	1 409
Central & South America	9	117	7	224	367	3	39	8	279	341
Europe	103	195	45	651	1 034	27	171	56	1 085	1 388
Africa	66	130	2	191	433	24	70	6	566	713
Middle East	7	213	12	128	400	3	103	23	382	538
Eurasia	51	157	34	41	285	9	103	40	148	302
Asia Pacific	899	541	141	2 266	4 077	222	445	228	5 030	6 194
World	**1 138**	**1 697**	**248**	**4 005**	**7 484**	**302**	**1 176**	**381**	**8 536**	**10 886**

	Current Policies					Sustainable Development				
	Fossil fuels	Nuclear	Renew.	T&D	Total	Fossil fuels	Nuclear	Renew.	T&D	Total
Cumulative investments, 2018-2040 (billion dollars, 2017)										
North America	365	128	926	968	2 405	413	180	1 865	1 061	3 584
Central & South America	90	27	436	523	1 083	31	31	505	374	949
Europe	369	272	1 183	1 086	2 941	228	339	1 859	1 411	3 875
Africa	197	7	417	767	1 409	100	24	1 019	914	2 090
Middle East	212	43	231	339	828	121	79	677	270	1 151
Eurasia	261	133	98	286	780	141	157	307	201	808
Asia Pacific	1 447	415	3 168	4 659	9 879	1 083	677	6 537	4 984	13 508
World	**2 941**	**1 025**	**6 459**	**8 628**	**19 325**	**2 117**	**1 487**	**12 768**	**9 214**	**25 965**

World: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**10 027**	**13 708**	**13 972**	**15 388**	**16 167**	**16 926**	**17 715**	**100**	**100**	**1.0**
Coal	2 308	3 720	3 750	3 768	3 783	3 793	3 809	27	22	0.1
Oil	3 665	4 364	4 435	4 754	4 830	4 842	4 894	32	28	0.4
Gas	2 071	3 022	3 107	3 539	3 820	4 132	4 436	22	25	1.6
Nuclear	675	679	688	805	848	918	971	5	5	1.5
Hydro	225	348	353	415	458	496	531	3	3	1.8
Bioenergy	1 022	1 350	1 385	1 590	1 691	1 776	1 851	10	10	1.3
Other renewables	60	224	254	516	736	968	1 223	2	7	7.1
Power sector	**3 660**	**5 208**	**5 357**	**5 826**	**6 215**	**6 668**	**7 137**	**100**	**100**	**1.3**
Coal	1 565	2 316	2 390	2 339	2 342	2 346	2 353	45	33	-0.1
Oil	341	247	252	205	179	158	141	5	2	-2.5
Gas	746	1 241	1 256	1 341	1 426	1 532	1 642	23	23	1.2
Nuclear	675	679	688	805	848	918	971	13	14	1.5
Hydro	225	348	353	415	458	496	531	7	7	1.8
Bioenergy	57	194	211	283	329	380	433	4	6	3.2
Other renewables	51	181	206	438	633	838	1 065	4	15	7.4
Other energy sector	**951**	**1 457**	**1 478**	**1 649**	**1 716**	**1 769**	**1 826**	**100**	**100**	**0.9**
Electricity	*239*	*352*	*364*	*397*	*426*	*459*	*494*	*25*	*27*	*1.3*
TFC	**7 036**	**9 530**	**9 696**	**10 871**	**11 474**	**12 018**	**12 581**	**100**	**100**	**1.1**
Coal	542	1 034	1 004	1 029	1 027	1 021	1 020	10	8	0.1
Oil	3 123	3 877	3 940	4 297	4 405	4 458	4 541	41	36	0.6
Gas	1 118	1 449	1 503	1 790	1 964	2 139	2 299	16	18	1.9
Electricity	1 090	1 792	1 846	2 206	2 457	2 717	2 985	19	24	2.1
Heat	248	283	289	301	302	303	302	3	2	0.2
Bioenergy	908	1 052	1 066	1 171	1 215	1 249	1 277	11	10	0.8
Other renewables	9	44	47	78	103	130	157	0	1	5.4
Industry	**1 863**	**2 821**	**2 855**	**3 265**	**3 460**	**3 648**	**3 833**	**100**	**100**	**1.3**
Coal	400	826	803	858	876	890	902	28	24	0.5
Oil	326	321	321	337	335	331	327	11	9	0.1
Gas	412	595	618	768	851	936	1 025	22	27	2.2
Electricity	462	743	768	913	987	1 057	1 123	27	29	1.7
Heat	101	136	140	149	148	146	143	5	4	0.1
Bioenergy	162	199	204	239	258	279	300	7	8	1.7
Other renewables	0	1	1	3	5	9	14	0	0	11.9
Transport	**1 958**	**2 745**	**2 794**	**3 144**	**3 313**	**3 447**	**3 617**	**100**	**100**	**1.1**
Oil	1 871	2 530	2 567	2 806	2 880	2 908	2 965	92	82	0.6
Of which: bunkers	*274*	*398*	*404*	*465*	*499*	*535*	*571*	*14*	*16*	*1.5*
Electricity	19	31	33	57	86	122	160	1	4	7.2
Biofuels	10	82	86	130	161	188	220	3	6	4.2
Other fuels	58	102	109	151	187	229	272	4	8	4.1
Buildings	**2 450**	**2 991**	**3 047**	**3 276**	**3 439**	**3 602**	**3 759**	**100**	**100**	**0.9**
Coal	109	130	127	86	65	44	31	4	1	-5.9
Oil	346	315	319	293	277	263	257	10	7	-0.9
Gas	535	644	665	735	780	820	840	22	22	1.0
Electricity	579	957	982	1 156	1 296	1 445	1 602	32	43	2.2
Heat	143	144	145	149	152	154	156	5	4	0.3
Bioenergy	731	761	766	786	777	761	734	25	20	-0.2
Traditional biomass	*646*	*655*	*658*	*666*	*649*	*624*	*591*	*22*	*16*	*-0.5*
Other renewables	8	41	44	71	93	115	137	1	4	5.1
Other	**765**	**973**	**999**	**1 187**	**1 260**	**1 320**	**1 373**	**100**	**100**	**1.4**
Petrochem. Feedstock	*439*	*509*	*535*	*667*	*720*	*767*	*813*	*54*	*59*	*1.8*

World: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**15 782**	**16 943**	**19 328**	**14 146**	**13 820**	**13 715**	**100**	**100**	**1.4**	**-0.1**
Coal	3 998	4 252	4 769	3 045	2 416	1 597	25	12	1.1	-3.6
Oil	4 902	5 128	5 570	4 334	3 985	3 156	29	23	1.0	-1.5
Gas	3 616	4 000	4 804	3 454	3 554	3 433	25	25	1.9	0.4
Nuclear	803	844	951	861	1 013	1 293	5	9	1.4	2.8
Hydro	413	449	514	431	492	601	3	4	1.6	2.3
Bioenergy	1 572	1 649	1 771	1 373	1 277	1 504	9	11	1.1	0.4
Other renewables	479	620	948	648	1 083	2 132	5	16	5.9	9.7
Power sector	**6 009**	**6 574**	**7 811**	**5 371**	**5 416**	**5 946**	**100**	**100**	**1.7**	**0.5**
Coal	2 515	2 718	3 140	1 714	1 161	513	40	9	1.2	-6.5
Oil	208	184	160	168	118	63	2	1	-2.0	-5.9
Gas	1 383	1 534	1 845	1 329	1 305	1 051	24	18	1.7	-0.8
Nuclear	803	844	951	861	1 013	1 293	12	22	1.4	2.8
Hydro	413	449	514	431	492	601	7	10	1.6	2.3
Bioenergy	278	311	378	324	400	570	5	10	2.6	4.4
Other renewables	410	533	823	545	926	1 856	11	31	6.2	10.0
Other energy sector	**1 699**	**1 819**	**2 063**	**1 470**	**1 398**	**1 290**	**100**	**100**	**1.5**	**-0.6**
Electricity	*415*	*457*	*553*	*365*	*367*	*390*	*27*	*30*	*1.8*	*0.3*
TFC	**11 103**	**11 911**	**13 510**	**10 126**	**10 007**	**9 958**	**100**	**100**	**1.5**	**0.1**
Coal	1 076	1 102	1 147	962	895	754	8	8	0.6	-1.2
Oil	4 431	4 680	5 163	3 936	3 667	2 962	38	30	1.2	-1.2
Gas	1 814	2 008	2 392	1 741	1 871	2 032	18	20	2.0	1.3
Electricity	2 249	2 532	3 125	2 117	2 313	2 802	23	28	2.3	1.8
Heat	308	315	325	287	275	245	2	2	0.5	-0.7
Bioenergy	1 157	1 187	1 234	979	828	888	9	9	0.6	-0.8
Other renewables	69	86	125	103	157	276	1	3	4.3	8.0
Industry	**3 327**	**3 581**	**4 087**	**3 121**	**3 155**	**3 197**	**100**	**100**	**1.6**	**0.5**
Coal	879	916	979	799	760	665	24	21	0.9	-0.8
Oil	343	346	347	319	303	272	8	9	0.3	-0.7
Gas	778	874	1 081	741	788	866	26	27	2.5	1.5
Electricity	929	1 021	1 197	872	896	945	29	30	1.9	0.9
Heat	152	155	157	141	131	108	4	3	0.5	-1.1
Bioenergy	242	266	318	240	259	298	8	9	1.9	1.7
Other renewables	2	3	8	8	19	42	0	1	9.0	17.5
Transport	**3 210**	**3 451**	**3 964**	**2 945**	**2 895**	**2 640**	**100**	**100**	**1.5**	**-0.2**
Oil	2 908	3 101	3 494	2 500	2 243	1 581	88	60	1.3	-2.1
Of which: bunkers	*488*	*541*	*663*	*390*	*376*	*322*	*17*	*12*	*2.2*	*-1.0*
Electricity	47	61	94	66	130	364	2	14	4.7	11.1
Biofuels	115	130	165	208	280	351	4	13	2.9	6.3
Other fuels	140	160	211	172	242	344	5	13	2.9	5.1
Buildings	**3 374**	**3 605**	**4 053**	**2 905**	**2 755**	**2 860**	**100**	**100**	**1.2**	**-0.3**
Coal	109	96	74	81	55	13	2	0	-2.3	-9.3
Oil	315	313	311	280	252	201	8	7	-0.1	-2.0
Gas	761	829	939	696	703	672	23	23	1.5	0.0
Electricity	1 190	1 358	1 724	1 101	1 205	1 405	43	49	2.5	1.6
Heat	152	157	165	143	141	134	4	5	0.5	-0.4
Bioenergy	784	773	728	515	270	213	18	7	-0.2	-5.4
Traditional biomass	*666*	*649*	*591*	*396*	*144*	*77*	*15*	*3*	*-0.5*	*-8.9*
Other renewables	64	79	113	90	131	222	3	8	4.2	7.3
Other	**1 192**	**1 273**	**1 408**	**1 155**	**1 201**	**1 261**	**100**	**100**	**1.5**	**1.0**
Petrochem. Feedstock	*667*	*721*	*822*	*648*	*686*	*751*	*58*	*60*	*1.9*	*1.5*

World: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**15 441**	**24 919**	**25 679**	**30 253**	**33 510**	**36 919**	**40 443**	**100**	**100**	**2.0**
Coal	6 001	9 575	9 858	9 896	10 016	10 172	10 335	38	26	0.2
Oil	1 212	926	940	763	676	597	527	4	1	-2.5
Gas	2 747	5 781	5 855	6 829	7 517	8 265	9 071	23	22	1.9
Nuclear	2 591	2 605	2 637	3 089	3 253	3 520	3 726	10	9	1.5
Renewables	2 868	5 997	6 351	9 645	12 017	14 333	16 753	25	41	4.3
Hydro	2 618	4 049	4 109	4 821	5 330	5 774	6 179	16	15	1.8
Bioenergy	164	569	623	890	1 057	1 238	1 427	2	4	3.7
Wind	31	957	1 085	2 304	3 157	3 960	4 690	4	12	6.6
Geothermal	52	82	87	129	190	261	343	0	1	6.1
Solar PV	1	328	435	1 463	2 197	2 935	3 839	2	9	9.9
CSP	1	10	11	34	75	138	222	0	1	14.0
Marine	1	1	1	3	12	27	52	0	0	18.2

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**6 690**	**6 961**	**8 845**	**10 073**	**11 244**	**12 466**	**100**	**100**	**2.6**
Coal	2 025	2 067	2 130	2 143	2 184	2 238	30	18	0.3
Oil	446	447	350	307	278	246	6	2	-2.6
Gas	1 644	1 695	2 113	2 334	2 526	2 740	24	22	2.1
Nuclear	413	413	448	464	495	518	6	4	1.0
Renewables	2 159	2 337	3 744	4 718	5 600	6 504	34	52	4.6
Hydro	1 244	1 270	1 462	1 604	1 728	1 839	18	15	1.6
Bioenergy	129	136	186	216	247	278	2	2	3.2
Wind	467	515	953	1 250	1 498	1 707	7	14	5.4
Geothermal	13	14	20	29	39	51	0	0	5.8
Solar PV	300	398	1 109	1 589	2 033	2 540	6	20	8.4
CSP	5	5	13	25	44	68	0	1	12.1
Marine	1	1	1	5	11	21	0	0	17.3

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**23 123**	**32 053**	**32 580**	**33 902**	**34 576**	**35 157**	**35 881**	**100**	**100**	**0.4**
Coal	8 951	14 233	14 448	14 284	14 235	14 182	14 170	44	39	-0.1
Oil	9 620	11 204	11 339	11 862	11 949	11 904	11 980	35	33	0.2
Gas	4 551	6 616	6 794	7 757	8 393	9 072	9 731	21	27	1.6
Power sector	**9 305**	**13 247**	**13 587**	**13 384**	**13 480**	**13 652**	**13 855**	**100**	**100**	**0.1**
Coal	6 458	9 515	9 822	9 574	9 553	9 543	9 542	72	69	-0.1
Oil	1 093	796	805	651	571	503	448	6	3	-2.5
Gas	1 754	2 937	2 961	3 159	3 357	3 606	3 865	22	28	1.2
TFC	**12 632**	**17 223**	**17 382**	**18 707**	**19 217**	**19 578**	**20 029**	**100**	**100**	**0.6**
Coal	2 306	4 412	4 320	4 356	4 321	4 272	4 255	25	21	-0.1
Oil	7 951	9 806	9 922	10 619	10 793	10 828	10 962	57	55	0.4
Transport	*5 619*	*7 610*	*7 730*	*8 453*	*8 678*	*8 768*	*8 940*	*44*	*45*	*0.6*
Of which: bunkers	*854*	*1 236*	*1 258*	*1 445*	*1 549*	*1 659*	*1 769*	*7*	*9*	*1.5*
Gas	2 374	3 004	3 140	3 731	4 103	4 478	4 813	18	24	1.9

World: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total generation	**30 971**	**34 755**	**42 755**	**28 859**	**31 160**	**37 114**	**100**	**100**	**2.2**	**1.6**
Coal	10 694	11 722	13 910	7 193	4 847	1 982	33	5	1.5	-6.7
Oil	779	697	610	605	413	197	1	1	-1.9	-6.6
Gas	7 072	8 172	10 295	6 810	6 830	5 358	24	14	2.5	-0.4
Nuclear	3 079	3 239	3 648	3 303	3 888	4 960	9	13	1.4	2.8
Renewables	9 316	10 894	14 261	10 917	15 151	24 585	33	66	3.6	6.1
Hydro	4 801	5 223	5 973	5 012	5 722	6 990	14	19	1.6	2.3
Bioenergy	873	992	1 228	1 039	1 325	1 968	3	5	3.0	5.1
Wind	2 151	2 668	3 679	2 707	4 355	7 730	9	21	5.5	8.9
Geothermal	125	170	277	162	282	555	1	1	5.1	8.4
Solar PV	1 334	1 782	2 956	1 940	3 268	6 409	7	17	8.7	12.4
CSP	30	52	119	54	184	855	0	2	10.9	20.8
Marine	2	8	29	4	15	78	0	0	15.3	20.3

	Power generation capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total capacity	**8 789**	**9 802**	**11 981**	**9 187**	**10 850**	**14 655**	**100**	**100**	**2.4**	**3.3**
Coal	2 219	2 348	2 693	1 945	1 633	1 119	22	8	1.2	-2.6
Oil	353	314	264	339	289	228	2	2	-2.3	-2.9
Gas	2 154	2 415	2 930	1 996	2 103	2 406	24	16	2.4	1.5
Nuclear	446	459	498	467	542	678	4	5	0.8	2.2
Renewables	3 565	4 171	5 395	4 385	6 174	9 914	45	68	3.7	6.5
Hydro	1 452	1 565	1 769	1 531	1 738	2 096	15	14	1.5	2.2
Bioenergy	182	203	241	213	266	379	2	3	2.5	4.6
Wind	891	1 066	1 345	1 122	1 712	2 819	11	19	4.3	7.7
Geothermal	19	26	41	26	43	82	0	1	4.9	8.1
Solar PV	1 008	1 290	1 951	1 472	2 346	4 240	16	29	7.2	10.8
CSP	11	18	36	20	62	267	0	2	9.0	18.9
Marine	1	3	11	2	6	31	0	0	14.2	19.3

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total CO_2	**35 454**	**37 748**	**42 475**	**29 535**	**25 482**	**17 647**	**100**	**100**	**1.2**	**-2.6**
Coal	15 207	16 099	17 930	11 335	8 335	3 855	42	22	0.9	-5.6
Oil	12 303	12 831	13 984	10 657	9 501	6 886	33	39	0.9	-2.1
Gas	7 945	8 818	10 561	7 543	7 645	6 906	25	39	1.9	0.1
Power sector	**14 219**	**15 296**	**17 610**	**10 656**	**7 839**	**3 292**	**100**	**100**	**1.1**	**-6.0**
Coal	10 300	11 097	12 758	6 995	4 456	930	72	28	1.1	-9.7
Oil	662	587	510	534	377	202	3	6	-2.0	-5.8
Gas	3 257	3 612	4 342	3 128	3 006	2 160	25	66	1.7	-1.4
TFC	**19 371**	**20 461**	**22 617**	**17 227**	**16 113**	**13 091**	**100**	**100**	**1.2**	**-1.2**
Coal	4 548	4 630	4 778	4 012	3 570	2 646	21	20	0.4	-2.1
Oil	11 029	11 622	12 816	9 590	8 665	6 357	57	49	1.1	-1.9
Transport	*8 764*	*9 348*	*10 539*	*7 528*	*6 758*	*4 768*	*47*	*36*	*1.4*	*-2.1*
Of which: bunkers	*1 517*	*1 681*	*2 057*	*1 214*	*1 169*	*999*	*9*	*8*	*2.2*	*-1.0*
Gas	3 793	4 209	5 023	3 624	3 878	4 088	22	31	2.1	1.2

North America: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**2 678**	**2 632**	**2 624**	**2 675**	**2 667**	**2 661**	**2 693**	**100**	**100**	**0.1**
Coal	572	371	359	277	260	249	239	14	9	-1.8
Oil	1 048	974	977	976	934	879	851	37	32	-0.6
Gas	657	814	805	895	915	944	971	31	36	0.8
Nuclear	229	248	247	224	216	206	204	9	8	-0.8
Hydro	55	59	64	67	68	70	72	2	3	0.5
Bioenergy	96	123	124	144	158	173	190	5	7	1.9
Other renewables	20	43	47	92	116	141	167	2	6	5.7
Power sector	**1 099**	**1 030**	**1 012**	**960**	**958**	**966**	**984**	**100**	**100**	**-0.1**
Coal	533	340	331	247	232	217	205	33	21	-2.1
Oil	84	18	18	6	5	4	2	2	0	-8.3
Gas	155	299	282	302	302	311	317	28	32	0.5
Nuclear	229	248	247	224	216	206	204	24	21	-0.8
Hydro	55	59	64	67	68	70	72	6	7	0.5
Bioenergy	24	26	25	30	32	35	39	3	4	1.8
Other renewables	18	40	44	84	104	124	145	4	15	5.4
Other energy sector	**171**	**242**	**244**	**287**	**297**	**307**	**318**	**100**	**100**	**1.2**
Electricity	*61*	*63*	*62*	*62*	*63*	*64*	*65*	*26*	*20*	*0.2*
TFC	**1 833**	**1 828**	**1 831**	**1 910**	**1 907**	**1 898**	**1 921**	**100**	**100**	**0.2**
Coal	37	22	20	20	19	18	18	1	1	-0.5
Oil	935	912	916	915	872	820	794	50	41	-0.6
Gas	426	396	399	438	450	463	475	22	25	0.8
Electricity	355	391	388	407	421	437	456	21	24	0.7
Heat	6	7	7	7	7	6	6	0	0	-1.1
Bioenergy	72	97	99	114	126	138	151	5	8	1.9
Other renewables	2	3	3	9	13	17	22	0	1	8.4
Industry	**420**	**342**	**338**	**372**	**375**	**379**	**389**	**100**	**100**	**0.6**
Coal	34	21	19	19	18	18	18	6	5	-0.4
Oil	44	33	32	31	29	28	27	9	7	-0.6
Gas	168	151	151	173	174	176	179	45	46	0.7
Electricity	123	96	95	104	107	110	115	28	30	0.8
Heat	5	6	6	6	5	5	5	2	1	-0.9
Bioenergy	45	36	35	38	40	41	44	10	11	0.9
Other renewables	0	0	0	0	1	1	1	0	0	21.1
Transport	**676**	**736**	**741**	**737**	**717**	**693**	**692**	**100**	**100**	**-0.3**
Oil	652	673	675	654	614	567	542	91	78	-0.9
Electricity	1	2	2	4	7	12	18	0	3	10.7
Biofuels	3	40	42	52	60	68	77	6	11	2.7
Other fuels	20	21	21	27	36	46	55	3	8	4.2
Buildings	**540**	**554**	**553**	**565**	**573**	**580**	**589**	**100**	**100**	**0.3**
Coal	2	1	0	0	0	0	-	0	-	n.a.
Oil	67	40	40	33	28	23	18	7	3	-3.4
Gas	215	200	202	206	206	206	206	37	35	0.1
Electricity	230	289	286	294	302	309	317	52	54	0.5
Heat	1	1	1	1	1	1	1	0	0	-2.2
Bioenergy	24	20	20	23	24	26	27	4	5	1.4
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	2	3	3	8	12	15	19	1	3	7.9
Other	**197**	**196**	**200**	**236**	**243**	**247**	**252**	**100**	**100**	**1.0**
Petrochem. Feedstock	*120*	*70*	*77*	*103*	*107*	*109*	*112*	*38*	*44*	*1.6*

North America: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**2 718**	**2 750**	**2 872**	**2 498**	**2 343**	**2 106**	**100**	**100**	**0.4**	**-1.0**
Coal	302	290	295	143	58	45	10	2	-0.9	-8.7
Oil	987	969	949	885	757	518	33	25	-0.1	-2.7
Gas	911	952	1 021	885	844	676	36	32	1.0	-0.8
Nuclear	224	216	208	237	239	243	7	12	-0.7	-0.1
Hydro	67	69	73	67	69	73	3	3	0.6	0.6
Bioenergy	142	152	182	172	201	225	6	11	1.7	2.6
Other renewables	84	103	144	108	174	328	5	16	5.0	8.8
Power sector	**989**	**1 001**	**1 049**	**876**	**824**	**838**	**100**	**100**	**0.2**	**-0.8**
Coal	273	261	257	116	34	22	24	3	-1.1	-11.2
Oil	7	5	3	6	4	2	0	0	-7.5	-8.6
Gas	309	323	337	323	286	157	32	19	0.8	-2.5
Nuclear	224	216	208	237	239	243	20	29	-0.7	-0.1
Hydro	67	69	73	67	69	73	7	9	0.6	0.6
Bioenergy	30	32	39	31	38	53	4	6	1.9	3.3
Other renewables	79	95	132	96	154	289	13	34	4.9	8.6
Other energy sector	**294**	**315**	**359**	**262**	**251**	**218**	**100**	**100**	**1.7**	**-0.5**
Electricity	*64*	*66*	*70*	*57*	*54*	*52*	*19*	*24*	*0.5*	*-0.8*
TFC	**1 925**	**1 942**	**2 013**	**1 820**	**1 731**	**1 544**	**100**	**100**	**0.4**	**-0.7**
Coal	20	19	18	18	16	13	1	1	-0.3	-1.8
Oil	923	901	883	831	708	483	44	31	-0.2	-2.7
Gas	444	457	482	419	418	398	24	26	0.8	-0.0
Electricity	414	431	470	391	400	436	23	28	0.8	0.5
Heat	7	7	6	7	6	4	0	0	-0.9	-2.4
Bioenergy	112	120	142	141	163	172	7	11	1.6	2.4
Other renewables	6	7	12	13	21	38	1	2	5.6	11.1
Industry	**376**	**383**	**405**	**356**	**345**	**332**	**100**	**100**	**0.8**	**-0.1**
Coal	19	19	18	18	16	13	4	4	-0.3	-1.7
Oil	31	30	28	28	25	21	7	6	-0.5	-1.7
Gas	175	178	186	165	157	143	46	43	0.9	-0.2
Electricity	105	109	119	100	97	97	29	29	1.0	0.1
Heat	6	6	5	6	5	4	1	1	-0.8	-1.8
Bioenergy	39	41	48	39	42	49	12	15	1.4	1.4
Other renewables	0	0	1	1	2	6	0	2	20.4	29.6
Transport	**738**	**725**	**733**	**702**	**638**	**494**	**100**	**100**	**-0.0**	**-1.7**
Oil	661	639	624	582	467	258	85	52	-0.3	-4.1
Electricity	2	3	5	8	21	61	1	12	4.9	16.8
Biofuels	49	54	67	79	98	98	9	20	2.0	3.7
Other fuels	25	29	38	32	52	76	5	15	2.5	5.7
Buildings	**577**	**593**	**626**	**532**	**515**	**480**	**100**	**100**	**0.5**	**-0.6**
Coal	0	0	0	0	0	-	0	-	-2.6	n.a.
Oil	37	34	27	31	24	12	4	2	-1.6	-5.2
Gas	211	216	222	190	176	144	36	30	0.4	-1.5
Electricity	300	312	339	278	277	273	54	57	0.8	-0.2
Heat	1	1	1	1	1	0	0	0	-1.2	-6.8
Bioenergy	22	23	25	21	20	21	4	4	0.9	0.2
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	5	7	10	11	17	31	2	6	5.1	10.1
Other	**234**	**241**	**249**	**230**	**234**	**237**	**100**	**100**	**1.0**	**0.7**
Petrochem. Feedstock	*103*	*106*	*111*	*100*	*102*	*104*	*44*	*44*	*1.6*	*1.3*

North America: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**4 837**	**5 287**	**5 237**	**5 464**	**5 628**	**5 821**	**6 059**	**100**	**100**	**0.6**
Coal	2 266	1 451	1 416	1 080	1 021	966	920	27	15	-1.9
Oil	227	77	77	29	23	18	11	1	0	-8.0
Gas	712	1 672	1 569	1 789	1 842	1 928	2 003	30	33	1.1
Nuclear	879	952	950	861	828	790	783	18	13	-0.8
Renewables	754	1 130	1 219	1 704	1 912	2 117	2 341	23	39	2.9
Hydro	645	687	740	778	796	814	833	14	14	0.5
Bioenergy	82	93	90	109	120	131	142	2	2	2.0
Wind	6	271	291	528	614	710	796	6	13	4.5
Geothermal	21	25	24	30	38	47	55	0	1	3.6
Solar PV	0	50	70	254	335	400	490	1	8	8.8
CSP	1	4	3	5	7	10	18	0	0	7.6
Marine	0	0	0	0	3	5	7	0	0	27.8

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**1 393**	**1 409**	**1 567**	**1 647**	**1 715**	**1 788**	**100**	**100**	**1.0**
Coal	303	291	225	209	197	188	21	10	-1.9
Oil	80	80	37	31	28	24	6	1	-5.1
Gas	521	529	610	637	654	666	38	37	1.0
Nuclear	121	121	111	106	102	101	9	6	-0.8
Renewables	366	386	573	644	704	766	27	43	3.0
Hydro	196	196	202	205	209	213	14	12	0.3
Bioenergy	22	23	25	27	29	31	2	2	1.4
Wind	97	105	170	191	209	223	7	12	3.3
Geothermal	5	4	5	6	7	8	0	0	2.7
Solar PV	44	55	169	211	244	284	4	16	7.4
CSP	2	2	2	3	3	5	0	0	4.3
Marine	0	0	0	1	2	2	0	0	22.1

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**6 565**	**5 798**	**5 727**	**5 453**	**5 283**	**5 115**	**5 031**	**100**	**100**	**-0.6**
Coal	2 324	1 475	1 432	1 094	1 026	964	914	25	18	-1.9
Oil	2 762	2 510	2 513	2 386	2 239	2 071	1 976	44	39	-1.0
Gas	1 479	1 813	1 782	1 972	2 018	2 080	2 140	31	43	0.8
Power sector	**2 777**	**2 127**	**2 056**	**1 723**	**1 654**	**1 612**	**1 573**	**100**	**100**	**-1.2**
Coal	2 144	1 365	1 333	993	928	869	821	65	52	-2.1
Oil	269	60	60	21	16	13	8	3	1	-8.3
Gas	364	702	663	709	710	730	744	32	47	0.5
TFC	**3 428**	**3 260**	**3 257**	**3 235**	**3 116**	**2 977**	**2 914**	**100**	**100**	**-0.5**
Coal	175	99	90	91	87	84	82	3	3	-0.4
Oil	2 305	2 283	2 286	2 197	2 057	1 894	1 804	70	62	-1.0
Transport	*1 927*	*1 990*	*1 999*	*1 936*	*1 817*	*1 677*	*1 605*	*61*	*55*	*-0.9*
Gas	948	878	881	947	971	999	1 027	27	35	0.7

North America: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**5 557**	**5 773**	**6 281**	**5 221**	**5 282**	**5 671**	**100**	**100**	**0.8**	**0.3**
Coal	1 189	1 149	1 150	506	151	92	18	2	-0.9	-11.2
Oil	31	26	13	29	20	10	0	0	-7.3	-8.3
Gas	1 828	1 956	2 121	1 934	1 746	915	34	16	1.3	-2.3
Nuclear	861	828	800	909	917	933	13	16	-0.7	-0.1
Renewables	1 647	1 812	2 195	1 841	2 446	3 719	35	66	2.6	5.0
Hydro	778	800	847	778	802	845	13	15	0.6	0.6
Bioenergy	108	118	140	114	148	220	2	4	2.0	4.0
Wind	498	569	713	622	960	1 599	11	28	4.0	7.7
Geothermal	30	39	56	30	44	79	1	1	3.7	5.2
Solar PV	227	277	417	289	452	778	7	14	8.0	11.0
CSP	4	6	15	7	37	184	0	3	6.8	19.2
Marine	0	2	7	0	2	14	0	0	27.3	31.7

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**1 555**	**1 625**	**1 795**	**1 576**	**1 730**	**2 120**	**100**	**100**	**1.1**	**1.8**
Coal	230	220	219	202	120	49	12	2	-1.2	-7.5
Oil	38	35	27	36	29	22	1	1	-4.7	-5.5
Gas	626	660	731	574	595	630	41	30	1.4	0.8
Nuclear	111	106	103	117	118	122	6	6	-0.7	0.0
Renewables	545	597	703	634	845	1 244	39	59	2.6	5.2
Hydro	202	206	215	203	208	217	12	10	0.4	0.4
Bioenergy	25	27	31	27	34	49	2	2	1.3	3.4
Wind	162	178	201	201	290	441	11	21	2.9	6.4
Geothermal	5	6	9	5	7	12	0	1	2.8	4.4
Solar PV	150	176	242	196	292	466	13	22	6.6	9.7
CSP	2	2	4	3	12	54	0	3	3.4	16.0
Marine	0	1	2	0	1	5	0	0	21.6	26.0

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**5 640**	**5 605**	**5 658**	**4 631**	**3 714**	**2 305**	**100**	**100**	**-0.1**	**-3.9**
Coal	1 197	1 145	1 127	556	197	74	20	3	-1.0	-12.1
Oil	2 425	2 347	2 279	2 136	1 736	1 010	40	44	-0.4	-3.9
Gas	2 018	2 113	2 252	1 939	1 781	1 221	40	53	1.0	-1.6
Power sector	**1 843**	**1 821**	**1 831**	**1 242**	**757**	**209**	**100**	**100**	**-0.5**	**-9.5**
Coal	1 094	1 045	1 030	464	120	22	56	11	-1.1	-16.3
Oil	22	18	10	21	14	8	1	4	-7.5	-8.6
Gas	727	759	791	757	623	179	43	86	0.8	-5.5
TFC	**3 290**	**3 237**	**3 215**	**2 948**	**2 552**	**1 790**	**100**	**100**	**-0.1**	**-2.6**
Coal	93	89	85	83	69	46	3	3	-0.2	-2.9
Oil	2 231	2 154	2 081	1 965	1 592	913	65	51	-0.4	-3.9
Transport	*1 956*	*1 892*	*1 845*	*1 723*	*1 383*	*763*	*57*	*43*	*-0.3*	*-4.1*
Gas	967	994	1 049	900	891	831	33	46	0.8	-0.3

United States: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**2 271**	**2 161**	**2 148**	**2 185**	**2 162**	**2 139**	**2 149**	**100**	**100**	**0.0**
Coal	534	342	330	265	251	242	231	15	11	-1.5
Oil	871	787	793	790	745	691	662	37	31	-0.8
Gas	548	653	637	708	722	738	753	30	35	0.7
Nuclear	208	219	219	201	190	180	176	10	8	-0.9
Hydro	22	23	26	26	27	28	29	1	1	0.5
Bioenergy	73	102	103	119	131	145	160	5	7	1.9
Other renewables	15	36	40	75	95	116	138	2	6	5.6
Power sector	**960**	**868**	**846**	**807**	**801**	**801**	**809**	**100**	**100**	**-0.2**
Coal	502	316	308	241	229	215	203	36	25	-1.8
Oil	58	8	7	3	3	2	2	1	0	-6.3
Gas	137	248	230	244	244	248	250	27	31	0.4
Nuclear	208	219	219	201	190	180	176	26	22	-0.9
Hydro	22	23	26	26	27	28	29	3	4	0.5
Bioenergy	21	21	20	23	25	28	31	2	4	1.9
Other renewables	13	33	37	68	84	101	119	4	15	5.2
Other energy sector	**121**	**166**	**164**	**193**	**196**	**199**	**201**	**100**	**100**	**0.9**
Electricity	*48*	*47*	*47*	*47*	*47*	*47*	*48*	*28*	*24*	*0.1*
TFC	**1 546**	**1 515**	**1 518**	**1 578**	**1 565**	**1 548**	**1 560**	**100**	**100**	**0.1**
Coal	33	18	15	15	14	14	14	1	1	-0.4
Oil	793	744	751	748	705	656	631	49	40	-0.8
Gas	360	336	338	370	379	388	397	22	25	0.7
Electricity	301	327	321	335	343	353	365	21	23	0.6
Heat	5	7	7	7	6	5	5	0	0	-1.3
Bioenergy	52	81	83	96	106	117	129	5	8	2.0
Other renewables	2	2	3	8	11	15	19	0	1	8.3
Industry	**336**	**264**	**261**	**287**	**287**	**288**	**293**	**100**	**100**	**0.5**
Coal	30	17	15	15	14	14	14	6	5	-0.3
Oil	29	20	20	20	19	18	17	8	6	-0.6
Gas	138	123	124	140	140	139	141	47	48	0.6
Electricity	98	69	67	75	76	78	81	26	28	0.8
Heat	4	5	5	5	5	4	4	2	1	-1.0
Bioenergy	36	30	30	32	33	34	36	11	12	0.8
Other renewables	0	-	-	0	0	1	1	-	0	n.a.
Transport	**588**	**622**	**628**	**622**	**600**	**577**	**575**	**100**	**100**	**-0.4**
Oil	569	565	569	547	507	461	437	91	76	-1.1
Electricity	0	1	1	3	6	11	15	0	3	12.6
Biofuels	3	39	41	49	57	65	73	6	13	2.6
Other fuels	15	17	17	23	31	41	49	3	8	4.6
Buildings	**459**	**473**	**469**	**477**	**481**	**485**	**490**	**100**	**100**	**0.2**
Coal	2	1	0	0	0	0	-	0	-	n.a.
Oil	49	27	27	22	18	13	9	6	2	-4.7
Gas	189	175	176	179	178	178	177	38	36	0.0
Electricity	202	254	250	254	259	262	267	53	55	0.3
Heat	1	1	1	1	1	1	1	0	0	-2.8
Bioenergy	13	11	11	14	15	16	18	2	4	2.1
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	2	2	3	7	11	14	18	1	4	8.0
Other	**163**	**157**	**160**	**193**	**196**	**199**	**202**	**100**	**100**	**1.0**
Petrochem. Feedstock	*101*	*55*	*61*	*84*	*86*	*88*	*90*	*38*	*45*	*1.7*

United States: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**2 211**	**2 214**	**2 264**	**2 037**	**1 893**	**1 683**	**100**	**100**	**0.2**	**-1.1**
Coal	282	274	284	133	51	37	13	2	-0.6	-9.1
Oil	794	767	731	710	593	386	32	23	-0.4	-3.1
Gas	722	746	768	719	686	536	34	32	0.8	-0.8
Nuclear	201	190	181	214	213	213	8	13	-0.8	-0.1
Hydro	26	27	29	26	28	30	1	2	0.5	0.7
Bioenergy	118	127	154	147	173	193	7	11	1.8	2.8
Other renewables	68	83	117	89	149	289	5	17	4.8	9.0
Power sector	**827**	**831**	**858**	**734**	**684**	**689**	**100**	**100**	**0.1**	**-0.9**
Coal	258	251	252	111	32	18	29	3	-0.9	-11.6
Oil	3	3	2	3	3	2	0	0	-5.4	-6.4
Gas	252	258	256	278	248	126	30	18	0.5	-2.6
Nuclear	201	190	181	214	213	213	21	31	-0.8	-0.1
Hydro	26	27	29	26	28	30	3	4	0.5	0.7
Bioenergy	23	25	32	24	30	45	4	6	2.0	3.5
Other renewables	63	76	107	78	131	255	12	37	4.8	8.8
Other energy sector	**197**	**206**	**216**	**177**	**168**	**143**	**100**	**100**	**1.2**	**-0.6**
Electricity	*48*	*48*	*50*	*43*	*41*	*38*	*23*	*27*	*0.3*	*-0.9*
TFC	**1 586**	**1 585**	**1 623**	**1 503**	**1 418**	**1 250**	**100**	**100**	**0.3**	**-0.8**
Coal	15	15	14	14	12	10	1	1	-0.3	-1.8
Oil	752	723	696	673	560	367	43	29	-0.3	-3.1
Gas	374	383	400	353	352	333	25	27	0.7	-0.1
Electricity	339	350	374	322	328	355	23	28	0.7	0.4
Heat	7	6	5	6	5	4	0	0	-1.0	-2.7
Bioenergy	94	102	122	123	143	148	8	12	1.7	2.6
Other renewables	5	6	10	11	18	33	1	3	5.5	11.0
Industry	**290**	**293**	**306**	**274**	**264**	**251**	**100**	**100**	**0.7**	**-0.2**
Coal	15	14	14	14	12	10	5	4	-0.2	-1.7
Oil	20	19	18	18	16	14	6	6	-0.5	-1.6
Gas	142	143	147	133	125	111	48	44	0.7	-0.5
Electricity	75	77	83	72	69	68	27	27	0.9	0.0
Heat	5	5	4	5	4	3	1	1	-0.9	-1.8
Bioenergy	32	34	39	33	35	40	13	16	1.2	1.3
Other renewables	0	0	1	1	2	4	0	2	n.a.	n.a.
Transport	**620**	**602**	**602**	**591**	**531**	**404**	**100**	**100**	**-0.2**	**-1.9**
Oil	550	523	499	481	375	193	83	48	-0.6	-4.6
Electricity	2	2	4	7	19	55	1	14	6.3	19.0
Biofuels	48	52	65	75	91	89	11	22	2.1	3.5
Other fuels	21	24	33	28	46	68	5	17	2.8	6.1
Buildings	**486**	**497**	**517**	**450**	**435**	**404**	**100**	**100**	**0.4**	**-0.6**
Coal	0	0	0	0	0	-	0	-	-2.6	n.a.
Oil	25	23	16	20	14	4	3	1	-2.2	-7.6
Gas	183	186	190	165	152	125	37	31	0.3	-1.5
Electricity	259	267	285	240	238	231	55	57	0.6	-0.3
Heat	1	1	1	1	1	0	0	0	-1.6	-9.3
Bioenergy	13	14	16	13	14	16	3	4	1.5	1.6
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	5	6	9	10	16	28	2	7	5.0	10.2
Other	**190**	**194**	**199**	**187**	**189**	**191**	**100**	**100**	**0.9**	**0.8**
Petrochem. Feedstock	*84*	*86*	*89*	*82*	*83*	*85*	*45*	*44*	*1.7*	*1.5*

United States: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**4 026**	**4 300**	**4 220**	**4 375**	**4 471**	**4 590**	**4 743**	**100**	**100**	**0.5**
Coal	2 130	1 354	1 320	1 056	1 009	958	912	31	19	-1.6
Oil	118	35	31	16	15	12	7	1	0	-6.2
Gas	634	1 418	1 309	1 458	1 483	1 531	1 574	31	33	0.8
Nuclear	798	840	839	771	730	691	676	20	14	-0.9
Renewables	346	647	714	1 072	1 232	1 395	1 571	17	33	3.5
Hydro	253	270	302	305	314	325	337	7	7	0.5
Bioenergy	72	79	75	89	99	109	119	2	3	2.0
Wind	6	229	249	443	508	587	659	6	14	4.3
Geothermal	15	19	18	22	29	38	46	0	1	4.0
Solar PV	0	47	66	208	274	323	390	2	8	8.0
CSP	1	4	3	5	7	10	16	0	0	7.3
Marine	-	-	-	0	2	3	5	-	0	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**1 169**	**1 182**	**1 290**	**1 343**	**1 383**	**1 424**	**100**	**100**	**0.8**
Coal	288	277	215	203	194	184	23	13	-1.8
Oil	58	58	23	22	21	18	5	1	-4.9
Gas	468	474	532	542	543	542	40	38	0.6
Nuclear	105	105	98	93	88	86	9	6	-0.9
Renewables	248	266	413	469	514	560	23	39	3.3
Hydro	103	103	104	106	109	111	9	8	0.3
Bioenergy	18	18	19	21	23	25	2	2	1.4
Wind	81	88	140	154	168	179	7	13	3.1
Geothermal	4	4	4	5	6	7	0	1	3.1
Solar PV	41	52	143	179	204	233	4	16	6.7
CSP	2	2	2	3	3	4	0	0	4.0
Marine	-	-	0	1	1	2	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**5 690**	**4 813**	**4 742**	**4 514**	**4 343**	**4 159**	**4 047**	**100**	**100**	**-0.7**
Coal	2 172	1 356	1 314	1 048	991	935	886	28	22	-1.7
Oil	2 283	1 992	2 004	1 902	1 760	1 602	1 511	42	37	-1.2
Gas	1 234	1 464	1 424	1 565	1 591	1 622	1 650	30	41	0.6
Power sector	**2 520**	**1 877**	**1 802**	**1 553**	**1 498**	**1 451**	**1 406**	**100**	**100**	**-1.1**
Coal	2 014	1 270	1 239	969	916	862	814	69	58	-1.8
Oil	185	26	23	11	10	8	5	1	0	-6.3
Gas	322	582	540	574	572	582	587	30	42	0.4
TFC	**2 910**	**2 684**	**2 689**	**2 653**	**2 531**	**2 396**	**2 332**	**100**	**100**	**-0.6**
Coal	156	79	70	71	68	66	65	3	3	-0.3
Oil	1 950	1 859	1 873	1 786	1 649	1 496	1 412	70	61	-1.2
Transport	*1 682*	*1 670*	*1 684*	*1 618*	*1 498*	*1 363*	*1 294*	*63*	*55*	*-1.1*
Gas	805	746	747	796	814	834	856	28	37	0.6

United States: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**4 441**	**4 568**	**4 871**	**4 189**	**4 230**	**4 515**	**100**	**100**	**0.6**	**0.3**
Coal	1 129	1 107	1 128	486	141	77	23	2	-0.7	-11.6
Oil	17	17	9	16	14	7	0	0	-5.2	-6.2
Gas	1 501	1 573	1 607	1 673	1 516	732	33	16	0.9	-2.5
Nuclear	771	730	693	820	817	816	14	18	-0.8	-0.1
Renewables	1 021	1 140	1 432	1 192	1 740	2 881	29	64	3.1	6.3
Hydro	306	315	340	307	322	352	7	8	0.5	0.7
Bioenergy	89	98	117	93	125	195	2	4	2.0	4.2
Wind	416	469	583	530	841	1 418	12	31	3.8	7.9
Geothermal	22	30	47	22	35	69	1	2	4.2	5.9
Solar PV	184	221	326	234	379	660	7	15	7.2	10.5
CSP	4	6	14	6	35	176	0	4	6.5	18.9
Marine	0	1	4	0	1	11	0	0	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**1 276**	**1 320**	**1 426**	**1 297**	**1 431**	**1 769**	**100**	**100**	**0.8**	**1.8**
Coal	218	210	212	192	114	44	15	3	-1.1	-7.7
Oil	23	23	20	22	20	16	1	1	-4.5	-5.5
Gas	547	565	598	502	517	543	42	31	1.0	0.6
Nuclear	98	93	88	104	104	106	6	6	-0.8	0.0
Renewables	388	425	502	465	657	1 010	35	57	2.8	6.0
Hydro	104	107	111	105	109	115	8	6	0.3	0.5
Bioenergy	19	21	24	20	27	42	2	2	1.3	3.7
Wind	132	144	159	168	249	383	11	22	2.6	6.6
Geothermal	4	5	7	4	6	11	1	1	3.2	4.9
Solar PV	126	146	196	165	254	404	14	23	5.9	9.3
CSP	2	2	4	3	12	51	0	3	3.0	15.8
Marine	0	0	1	0	1	4	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**4 643**	**4 570**	**4 503**	**3 780**	**2 942**	**1 697**	**100**	**100**	**-0.2**	**-4.4**
Coal	1 117	1 082	1 086	515	170	54	24	3	-0.8	-12.9
Oil	1 922	1 832	1 734	1 683	1 329	716	39	42	-0.6	-4.4
Gas	1 604	1 656	1 682	1 582	1 443	927	37	55	0.7	-1.8
Power sector	**1 640**	**1 623**	**1 618**	**1 107**	**654**	**129**	**100**	**100**	**-0.5**	**-10.8**
Coal	1 037	1 005	1 011	445	111	16	62	12	-0.9	-17.3
Oil	11	11	6	11	9	5	0	4	-5.4	-6.4
Gas	591	607	601	652	533	108	37	84	0.5	-6.8
TFC	**2 689**	**2 616**	**2 559**	**2 399**	**2 040**	**1 389**	**100**	**100**	**-0.2**	**-2.8**
Coal	73	70	68	64	54	35	3	3	-0.1	-2.9
Oil	1 804	1 715	1 622	1 578	1 240	660	63	48	-0.6	-4.4
Transport	*1 626*	*1 548*	*1 477*	*1 423*	*1 109*	*570*	*58*	*41*	*-0.6*	*-4.6*
Gas	813	831	869	756	746	694	34	50	0.7	-0.3

Central and South America: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**449**	**655**	**667**	**730**	**784**	**847**	**916**	**100**	**100**	**1.4**
Coal	20	33	34	37	37	36	38	5	4	0.5
Oil	214	273	274	280	285	292	296	41	32	0.3
Gas	83	142	147	154	172	199	228	22	25	1.9
Nuclear	3	6	7	9	14	15	17	1	2	4.2
Hydro	47	60	61	76	84	93	101	9	11	2.2
Bioenergy	80	132	135	152	161	172	183	20	20	1.3
Other renewables	1	9	10	22	31	41	53	2	6	7.5
Power sector	**105**	**192**	**200**	**214**	**237**	**266**	**301**	**100**	**100**	**1.8**
Coal	7	18	18	17	16	14	14	9	5	-1.1
Oil	21	31	31	21	17	16	14	16	5	-3.4
Gas	22	51	54	47	50	61	73	27	24	1.3
Nuclear	3	6	7	9	14	15	17	3	6	4.2
Hydro	47	60	61	76	84	93	101	30	34	2.2
Bioenergy	4	19	20	23	26	30	34	10	11	2.3
Other renewables	1	8	9	20	28	37	48	5	16	7.5
Other energy sector	**62**	**88**	**89**	**96**	**104**	**112**	**120**	**100**	**100**	**1.3**
Electricity	*13*	*23*	*24*	*27*	*29*	*33*	*36*	*27*	*30*	*1.8*
TFC	**351**	**488**	**496**	**558**	**598**	**644**	**692**	**100**	**100**	**1.5**
Coal	10	11	12	14	16	17	18	2	3	1.9
Oil	179	229	229	243	250	259	265	46	38	0.6
Gas	41	61	62	76	87	100	114	13	16	2.6
Electricity	56	90	93	112	126	142	160	19	23	2.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	65	96	98	111	117	123	131	20	19	1.3
Other renewables	0	1	1	2	3	4	5	0	1	6.9
Industry	**120**	**152**	**155**	**178**	**192**	**207**	**225**	**100**	**100**	**1.6**
Coal	10	11	11	14	15	16	18	7	8	1.9
Oil	34	32	32	33	33	33	33	21	14	0.1
Gas	20	27	28	38	44	52	60	18	27	3.5
Electricity	26	36	38	44	49	54	59	24	26	2.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	31	46	46	49	51	53	55	30	24	0.7
Other renewables	-	0	0	0	0	0	0	0	0	42.8
Transport	**105**	**170**	**171**	**190**	**201**	**215**	**228**	**100**	**100**	**1.3**
Oil	96	144	144	153	157	163	167	84	73	0.6
Electricity	0	0	0	1	1	2	3	0	2	9.7
Biofuels	6	18	19	28	33	38	44	11	19	3.7
Other fuels	3	8	8	8	10	12	14	5	6	2.7
Buildings	**82**	**116**	**119**	**132**	**142**	**153**	**165**	**100**	**100**	**1.4**
Coal	0	0	0	0	0	0	0	0	0	-3.5
Oil	18	22	22	22	23	23	24	18	14	0.4
Gas	9	15	15	17	19	20	22	13	13	1.6
Electricity	29	50	52	62	71	81	91	43	55	2.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	26	29	29	28	27	25	23	25	14	-1.0
Traditional biomass	*23*	*26*	*27*	*25*	*23*	*21*	*19*	*22*	*12*	*-1.4*
Other renewables	0	1	1	2	3	3	4	1	3	6.5
Other	**44**	**49**	**50**	**58**	**63**	**69**	**74**	**100**	**100**	**1.7**
Petrochem. Feedstock	*20*	*20*	*21*	*24*	*27*	*30*	*32*	*41*	*44*	*2.0*

Central & South America: Current Policies & Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**745**	**816**	**983**	**683**	**688**	**733**	**100**	**100**	**1.7**	**0.4**
Coal	38	40	43	30	24	20	4	3	1.1	-2.3
Oil	290	303	333	253	228	185	34	25	0.9	-1.7
Gas	163	189	262	143	145	155	27	21	2.5	0.2
Nuclear	9	14	17	9	15	20	2	3	4.2	4.8
Hydro	77	86	105	77	86	103	11	14	2.4	2.3
Bioenergy	148	156	177	148	153	180	18	24	1.2	1.3
Other renewables	20	28	46	24	37	71	5	10	6.8	8.8
Power sector	**223**	**252**	**329**	**196**	**205**	**246**	**100**	**100**	**2.2**	**0.9**
Coal	19	19	19	12	6	1	6	1	0.3	-10.6
Oil	23	19	16	14	7	3	5	1	-2.9	-10.1
Gas	54	63	97	39	31	18	30	7	2.6	-4.5
Nuclear	9	14	17	9	15	20	5	8	4.2	4.8
Hydro	77	86	105	77	86	103	32	42	2.4	2.3
Bioenergy	23	26	32	23	27	37	10	15	2.1	2.7
Other renewables	19	25	42	22	33	63	13	26	6.9	8.8
Other energy sector	**99**	**111**	**133**	**91**	**92**	**92**	**100**	**100**	**1.8**	**0.2**
Electricity	*28*	*31*	*40*	*25*	*26*	*30*	*30*	*32*	*2.2*	*1.0*
TFC	**566**	**616**	**733**	**528**	**534**	**567**	**100**	**100**	**1.7**	**0.6**
Coal	14	16	18	13	14	14	2	2	1.9	0.8
Oil	251	265	298	225	207	172	41	30	1.1	-1.3
Gas	77	89	116	75	86	110	16	19	2.7	2.5
Electricity	115	132	172	106	116	142	23	25	2.7	1.8
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	107	112	126	107	108	123	17	22	1.1	1.0
Other renewables	2	2	4	2	4	7	1	1	5.9	9.0
Industry	**180**	**196**	**234**	**170**	**173**	**182**	**100**	**100**	**1.8**	**0.7**
Coal	14	15	18	13	14	14	8	8	1.9	0.8
Oil	33	33	33	31	29	25	14	14	0.2	-1.1
Gas	38	45	63	35	39	44	27	24	3.6	2.1
Electricity	45	50	61	42	43	48	26	26	2.1	1.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	50	52	59	49	49	50	25	27	1.0	0.3
Other renewables	0	0	0	0	1	1	0	1	40.5	51.8
Transport	**192**	**208**	**247**	**184**	**183**	**181**	**100**	**100**	**1.6**	**0.2**
Oil	160	171	197	139	121	89	80	49	1.4	-2.1
Electricity	1	1	1	1	2	5	0	3	4.0	11.2
Biofuels	24	27	36	35	45	58	14	32	2.8	5.0
Other fuels	8	10	13	10	15	29	5	16	2.4	5.9
Buildings	**135**	**148**	**178**	**118**	**117**	**136**	**100**	**100**	**1.8**	**0.6**
Coal	0	0	0	0	0	0	0	0	-1.9	-8.5
Oil	23	24	25	22	22	21	14	15	0.6	-0.2
Gas	17	19	23	17	18	20	13	15	1.8	1.2
Electricity	65	77	103	60	67	83	58	61	3.0	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	28	27	23	18	7	6	13	4	-1.0	-6.7
Traditional biomass	*25*	*23*	*19*	*15*	*4*	*2*	*11*	*2*	*-1.4*	*-10.5*
Other renewables	2	2	4	2	3	6	2	4	5.6	7.9
Other	**58**	**64**	**75**	**57**	**61**	**68**	**100**	**100**	**1.7**	**1.3**
Petrochem. Feedstock	*24*	*27*	*32*	*23*	*25*	*30*	*43*	*44*	*2.0*	*1.6*

Central and South America: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**803**	**1 307**	**1 358**	**1 606**	**1 805**	**2 029**	**2 283**	**100**	**100**	**2.3**
Coal	24	73	74	74	69	62	63	5	3	-0.7
Oil	104	144	149	102	83	77	69	11	3	-3.3
Gas	97	244	258	260	298	372	452	19	20	2.5
Nuclear	12	24	26	35	54	57	66	2	3	4.2
Renewables	566	822	851	1 135	1 300	1 460	1 633	63	72	2.9
Hydro	551	698	709	882	983	1 081	1 177	52	52	2.2
Bioenergy	12	69	77	86	97	109	122	6	5	2.0
Wind	0	45	54	124	159	183	210	4	9	6.0
Geothermal	2	4	4	8	12	17	24	0	1	7.6
Solar PV	0	5	7	34	48	65	92	0	4	12.0
CSP	-	-	-	1	3	5	8	-	0	n.a.
Marine	-	-	-	0	0	0	0	-	0	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**333**	**345**	**438**	**493**	**549**	**622**	**100**	**100**	**2.6**
Coal	13	13	16	16	16	17	4	3	1.3
Oil	48	49	42	37	35	33	14	5	-1.7
Gas	61	63	88	104	119	141	18	23	3.6
Nuclear	4	4	5	7	8	9	1	2	4.1
Renewables	207	217	286	328	368	417	63	67	2.9
Hydro	170	174	199	220	240	263	51	42	1.8
Bioenergy	19	19	23	25	27	29	6	5	1.8
Wind	14	17	40	50	56	64	5	10	5.8
Geothermal	1	1	1	2	3	4	0	1	7.2
Solar PV	3	5	23	30	40	55	1	9	11.2
CSP	-	-	0	1	2	2	-	0	n.a.
Marine	-	-	0	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**829**	**1 184**	**1 205**	**1 229**	**1 271**	**1 342**	**1 418**	**100**	**100**	**0.7**
Coal	80	127	133	139	139	136	141	11	10	0.2
Oil	579	760	765	768	770	785	791	63	56	0.1
Gas	171	297	307	322	362	422	487	25	34	2.0
Power sector	**150**	**297**	**308**	**254**	**244**	**257**	**279**	**100**	**100**	**-0.4**
Coal	31	81	82	77	71	63	63	27	23	-1.2
Oil	67	97	99	67	55	50	45	32	16	-3.4
Gas	52	119	126	110	118	143	171	41	61	1.3
TFC	**595**	**790**	**798**	**872**	**913**	**965**	**1 009**	**100**	**100**	**1.0**
Coal	44	44	47	58	64	68	74	6	7	1.9
Oil	477	630	632	667	679	698	709	79	70	0.5
Transport	*288*	*432*	*432*	*461*	*472*	*490*	*501*	*54*	*50*	*0.6*
Gas	74	116	118	147	171	198	227	15	22	2.9

Central & South America: Current Policies & Sustainable Development Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total generation	**1 655**	**1 896**	**2 458**	**1 526**	**1 653**	**1 989**	**100**	**100**	**2.6**	**1.7**
Coal	80	82	86	48	24	6	3	0	0.6	-10.3
Oil	109	92	77	67	34	12	3	1	-2.8	-10.2
Gas	303	381	610	220	188	121	25	6	3.8	-3.2
Nuclear	36	54	67	35	58	76	3	4	4.2	4.8
Renewables	1 127	1 287	1 618	1 155	1 349	1 773	66	89	2.8	3.2
Hydro	892	1 000	1 217	890	997	1 200	50	60	2.4	2.3
Bioenergy	86	95	117	87	99	134	5	7	1.9	2.4
Wind	112	141	186	127	170	266	8	13	5.5	7.1
Geothermal	7	11	21	8	14	30	1	2	7.1	8.7
Solar PV	29	38	68	41	63	124	3	6	10.6	13.5
CSP	1	2	8	2	6	18	0	1	n.a.	n.a.
Marine	0	0	0	0	0	1	0	0	n.a.	n.a.

	Power generation capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total capacity	**442**	**501**	**640**	**433**	**484**	**610**	**100**	**100**	**2.7**	**2.5**
Coal	16	17	18	15	13	9	3	1	1.6	-1.5
Oil	42	37	33	42	37	33	5	5	-1.7	-1.7
Gas	95	116	167	77	79	88	26	14	4.3	1.4
Nuclear	5	7	9	5	8	10	1	2	4.1	4.6
Renewables	282	321	408	293	344	463	64	76	2.8	3.4
Hydro	202	225	275	200	220	262	43	43	2.0	1.8
Bioenergy	23	25	28	23	26	32	4	5	1.7	2.1
Wind	36	44	57	41	54	84	9	14	5.3	7.1
Geothermal	1	2	3	1	2	4	1	1	6.7	8.3
Solar PV	20	24	42	27	40	75	6	12	9.8	12.6
CSP	0	1	2	1	2	5	0	1	n.a.	n.a.
Marine	0	0	0	0	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total CO_2	**1 286**	**1 379**	**1 629**	**1 090**	**974**	**815**	**100**	**100**	**1.3**	**-1.7**
Coal	146	152	163	108	79	54	10	7	0.9	-3.8
Oil	797	825	902	687	601	459	55	56	0.7	-2.2
Gas	343	402	563	295	294	302	35	37	2.7	-0.1
Power sector	**283**	**293**	**364**	**187**	**119**	**57**	**100**	**100**	**0.7**	**-7.0**
Coal	84	84	85	50	23	6	23	10	0.1	-11.0
Oil	72	60	50	45	23	9	14	15	-2.9	-10.1
Gas	126	148	228	92	73	43	63	75	2.6	-4.5
TFC	**897**	**964**	**1 116**	**811**	**768**	**684**	**100**	**100**	**1.5**	**-0.7**
Coal	58	64	74	54	53	46	7	7	2.0	-0.1
Oil	690	726	809	613	551	429	73	63	1.1	-1.7
Transport	*481*	*513*	*591*	*417*	*365*	*267*	*53*	*39*	*1.4*	*-2.1*
Gas	149	174	233	144	165	209	21	31	3.0	2.5

Brazil: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**184**	**281**	**285**	**315**	**338**	**363**	**391**	**100**	**100**	**1.4**
Coal	13	16	17	16	16	16	17	6	4	-0.1
Oil	88	109	110	117	121	124	127	39	32	0.6
Gas	8	30	31	28	33	43	52	11	13	2.3
Nuclear	2	4	4	7	8	8	10	1	3	4.0
Hydro	26	33	32	40	44	47	51	11	13	2.1
Bioenergy	47	85	87	98	103	109	115	30	29	1.2
Other renewables	0	4	4	9	12	15	19	2	5	6.5
Power sector	**37**	**69**	**71**	**76**	**85**	**96**	**110**	**100**	**100**	**1.9**
Coal	3	6	7	4	4	4	4	9	4	-2.3
Oil	4	3	3	1	1	1	1	4	1	-5.0
Gas	1	11	12	5	6	10	14	17	12	0.6
Nuclear	2	4	4	7	8	8	10	6	9	4.0
Hydro	26	33	32	40	44	47	51	44	47	2.1
Bioenergy	2	9	10	11	12	13	14	14	13	1.5
Other renewables	0	3	3	8	10	13	15	5	14	6.7
Other energy sector	**27**	**41**	**41**	**46**	**50**	**54**	**57**	**100**	**100**	**1.5**
Electricity	*6*	*11*	*11*	*13*	*14*	*16*	*17*	*27*	*30*	*1.9*
TFC	**153**	**224**	**227**	**256**	**273**	**293**	**313**	**100**	**100**	**1.4**
Coal	6	7	7	8	8	9	9	3	3	1.0
Oil	80	101	102	110	113	117	120	45	38	0.7
Gas	5	13	12	15	19	22	26	5	8	3.2
Electricity	28	42	43	51	57	64	71	19	23	2.3
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	35	61	61	71	75	79	84	27	27	1.4
Other renewables	0	1	1	1	2	2	3	0	1	5.5
Industry	**56**	**77**	**79**	**89**	**95**	**101**	**108**	**100**	**100**	**1.4**
Coal	6	7	7	8	8	8	9	9	8	1.0
Oil	14	10	11	11	11	11	11	13	10	0.2
Gas	4	9	9	12	15	17	19	11	18	3.5
Electricity	13	17	17	20	22	24	26	22	24	1.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	20	35	35	38	39	41	43	45	39	0.8
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**47**	**83**	**84**	**94**	**98**	**104**	**109**	**100**	**100**	**1.1**
Oil	41	64	64	69	70	72	72	77	67	0.5
Electricity	0	0	0	0	1	1	2	0	2	10.0
Biofuels	6	17	17	23	26	28	32	20	29	2.8
Other fuels	0	2	2	2	2	2	3	3	3	0.6
Buildings	**29**	**38**	**38**	**43**	**47**	**52**	**57**	**100**	**100**	**1.7**
Coal	-	-	-	-	-	-	-	-	-	n.a.
Oil	8	7	7	8	8	8	9	19	15	0.8
Gas	0	1	1	1	1	2	2	1	4	6.7
Electricity	14	23	23	28	31	36	41	60	71	2.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	7	7	6	6	4	3	2	17	4	-4.3
Traditional biomass	*7*	*6*	*6*	*5*	*4*	*3*	*2*	*16*	*4*	*-4.6*
Other renewables	0	1	1	1	2	2	3	2	5	5.2
Other	**21**	**26**	**26**	**30**	**33**	**36**	**39**	**100**	**100**	**1.8**
Petrochem. Feedstock	*9*	*11*	*11*	*13*	*15*	*16*	*18*	*43*	*47*	*2.2*

Brazil: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**321**	**351**	**417**	**300**	**303**	**320**	**100**	**100**	**1.7**	**0.5**
Coal	17	17	18	14	11	10	4	3	0.1	-2.3
Oil	122	130	141	106	96	75	34	23	1.1	-1.7
Gas	31	39	62	24	27	37	15	12	3.1	0.8
Nuclear	7	8	10	7	8	11	2	3	4.1	4.3
Hydro	41	46	56	40	41	45	14	14	2.6	1.5
Bioenergy	95	100	113	100	108	122	27	38	1.1	1.5
Other renewables	8	10	16	9	13	20	4	6	5.7	6.9
Power sector	**81**	**92**	**120**	**71**	**76**	**92**	**100**	**100**	**2.3**	**1.1**
Coal	5	5	5	2	0	-	4	-	-1.4	n.a.
Oil	3	3	2	1	1	1	2	1	-1.0	-7.0
Gas	7	10	19	2	3	5	16	5	2.1	-3.8
Nuclear	7	8	10	7	8	11	9	12	4.1	4.3
Hydro	41	46	56	40	41	45	47	49	2.6	1.5
Bioenergy	11	12	14	11	12	15	11	16	1.3	1.6
Other renewables	7	9	13	8	11	16	11	17	6.0	6.9
Other energy sector	**47**	**53**	**63**	**44**	**45**	**46**	**100**	**100**	**1.9**	**0.5**
Electricity	*13*	*15*	*19*	*12*	*12*	*14*	*30*	*30*	*2.3*	*1.0*
TFC	**259**	**280**	**329**	**246**	**248**	**259**	**100**	**100**	**1.6**	**0.6**
Coal	8	8	9	8	7	7	3	3	1.0	-0.1
Oil	113	120	133	100	90	71	40	28	1.2	-1.5
Gas	16	19	26	15	17	24	8	9	3.3	2.9
Electricity	53	60	76	49	53	63	23	24	2.6	1.7
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	68	72	82	73	78	90	25	35	1.3	1.7
Other renewables	1	2	3	1	2	4	1	2	4.6	6.7
Industry	**90**	**97**	**113**	**86**	**86**	**88**	**100**	**100**	**1.6**	**0.5**
Coal	8	8	9	8	7	7	8	8	1.0	-0.1
Oil	11	11	11	11	10	9	10	10	0.3	-0.7
Gas	13	15	20	11	12	13	18	15	3.7	1.6
Electricity	20	22	27	19	20	21	24	24	2.0	1.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	38	40	45	37	37	38	40	43	1.1	0.3
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**94**	**101**	**115**	**90**	**89**	**84**	**100**	**100**	**1.4**	**0.0**
Oil	72	76	84	60	49	30	73	35	1.2	-3.3
Electricity	0	0	1	0	1	2	0	3	3.6	10.7
Biofuels	20	22	28	28	35	44	24	53	2.2	4.3
Other fuels	2	2	3	2	3	8	2	9	0.2	5.2
Buildings	**45**	**50**	**63**	**40**	**41**	**50**	**100**	**100**	**2.2**	**1.2**
Coal	-	-	-	-	-	-	-	-	n.a.	n.a.
Oil	8	8	9	7	7	7	14	14	1.0	-0.1
Gas	1	1	2	1	1	2	4	4	6.9	6.5
Electricity	29	34	46	27	30	37	74	74	3.1	2.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	6	4	2	4	1	1	4	1	-4.2	-10.0
Traditional biomass	*5*	*4*	*2*	*3*	*1*	*0*	*3*	*1*	*-4.6*	*-12.6*
Other renewables	1	2	2	1	2	3	4	7	4.3	5.9
Other	**30**	**33**	**39**	**30**	**32**	**37**	**100**	**100**	**1.8**	**1.5**
Petrochem. Feedstock	*13*	*15*	*18*	*13*	*14*	*17*	*47*	*46*	*2.2*	*1.8*

Brazil: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	2000	**2016**	**2017e**	**2025**	**2030**	**2035**	**2040**	**2017e**	**2040**	**2017e-40**
Total generation	**349**	**579**	**586**	**700**	**784**	**880**	**990**	**100**	**100**	**2.3**
Coal	11	26	28	19	18	17	17	5	2	-2.2
Oil	15	15	15	5	5	5	5	3	0	-5.0
Gas	4	56	62	32	35	63	87	11	9	1.5
Nuclear	6	16	16	26	31	31	39	3	4	4.0
Renewables	312	465	464	618	695	763	843	79	85	2.6
Hydro	304	381	367	468	510	552	597	63	60	2.1
Bioenergy	8	51	57	60	64	67	71	10	7	1.0
Wind	0	33	40	80	102	118	137	7	14	5.5
Geothermal	-	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	0	0	11	18	24	34	0	3	25.5
CSP	-	-	-	-	1	2	3	-	0	n.a.
Marine	-	-	-	-	-	-	0	-	0	n.a.

	Power generation capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2016	**2017e**	**2025**	**2030**	**2035**	**2040**	**2017e**	**2040**	**2017e-40**
Total capacity	**149**	**156**	**192**	**212**	**230**	**259**	**100**	**100**	**2.2**
Coal	4	4	5	4	4	4	3	2	-0.3
Oil	8	8	7	7	7	7	5	3	-0.8
Gas	12	12	18	19	19	23	8	9	2.8
Nuclear	2	2	3	4	4	5	1	2	4.4
Renewables	122	129	159	177	195	219	83	85	2.3
Hydro	97	100	112	120	129	141	64	54	1.5
Bioenergy	15	15	17	18	19	20	10	8	1.2
Wind	10	12	22	28	31	36	8	14	4.8
Geothermal	-	-	-	-	-	-	-	-	n.a.
Solar PV	0	1	8	11	14	20	1	8	13.5
CSP	-	-	-	0	1	1	-	0	n.a.
Marine	-	-	-	-	-	0	-	0	n.a.

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	2000	**2016**	**2017e**	**2025**	**2030**	**2035**	**2040**	**2017e**	**2040**	**2017e-40**
Total CO_2	**292**	**417**	**428**	**426**	**444**	**472**	**495**	**100**	**100**	**0.6**
Coal	46	61	67	59	58	58	59	16	12	-0.6
Oil	230	290	293	305	312	319	322	68	65	0.4
Gas	16	66	68	62	74	95	114	16	23	2.3
Power sector	**31**	**69**	**75**	**40**	**40**	**48**	**56**	**100**	**100**	**-1.2**
Coal	17	34	37	24	23	22	22	49	38	-2.3
Oil	12	10	10	3	3	3	3	13	5	-5.0
Gas	2	25	28	12	14	23	32	37	56	0.6
TFC	**242**	**321**	**326**	**355**	**369**	**384**	**396**	**100**	**100**	**0.8**
Coal	26	25	28	32	33	34	35	9	9	1.0
Oil	206	267	271	289	294	301	304	83	77	0.5
Transport	*125*	*193*	*194*	*207*	*211*	*216*	*218*	*60*	*55*	*0.5*
Gas	10	28	28	35	42	49	58	9	15	3.2

Brazil: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**722**	**825**	**1 068**	**668**	**717**	**851**	**100**	**100**	**2.6**	**1.6**
Coal	24	23	21	11	1	-	2	-	-1.2	n.a.
Oil	12	12	12	3	3	3	1	0	-1.0	-7.0
Gas	44	60	120	15	18	31	11	4	2.9	-2.9
Nuclear	26	31	39	26	31	42	4	5	4.1	4.3
Renewables	615	698	875	613	664	774	82	91	2.8	2.3
Hydro	478	535	657	460	477	520	62	61	2.6	1.5
Bioenergy	59	63	69	61	65	73	6	9	0.8	1.0
Wind	69	88	119	80	103	141	11	17	4.9	5.6
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	8	12	26	12	19	38	2	4	24.1	26.1
CSP	-	1	3	-	1	3	0	0	n.a.	n.a.
Marine	-	-	0	-	-	0	0	0	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**192**	**214**	**269**	**191**	**204**	**238**	**100**	**100**	**2.4**	**1.9**
Coal	5	5	4	5	4	-	2	-	-0.2	n.a.
Oil	7	7	7	7	7	7	3	3	-0.7	-0.9
Gas	19	21	24	18	19	19	9	8	3.0	2.0
Nuclear	3	4	5	3	4	5	2	2	4.5	4.5
Renewables	157	177	226	157	169	201	84	85	2.5	2.0
Hydro	115	127	158	109	110	120	59	50	2.0	0.8
Bioenergy	17	18	20	18	19	21	7	9	1.1	1.3
Wind	19	24	32	22	28	37	12	16	4.2	4.9
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	6	8	16	8	12	23	6	10	12.4	14.1
CSP	-	0	1	-	0	1	0	0	n.a.	n.a.
Marine	-	-	0	-	-	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**454**	**491**	**568**	**372**	**326**	**266**	**100**	**100**	**1.2**	**-2.0**
Coal	65	64	64	46	32	24	11	9	-0.2	-4.4
Oil	322	340	369	274	237	166	65	62	1.0	-2.4
Gas	68	87	135	52	58	76	24	29	3.0	0.5
Power sector	**55**	**59**	**79**	**22**	**10**	**13**	**100**	**100**	**0.3**	**-7.2**
Coal	30	29	27	14	1	-	34	-	-1.4	n.a.
Oil	8	8	8	2	2	2	10	14	-1.0	-7.0
Gas	17	22	45	6	7	11	56	86	2.1	-3.8
TFC	**367**	**391**	**438**	**324**	**291**	**232**	**100**	**100**	**1.3**	**-1.5**
Coal	32	33	35	30	28	22	8	10	1.0	-0.9
Oil	300	315	343	260	224	157	78	68	1.0	-2.3
Transport	*218*	*231*	*254*	*183*	*149*	*90*	*58*	*39*	*1.2*	*-3.3*
Gas	35	42	59	33	39	52	14	23	3.4	2.8

Europe: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**2 028**	**1 966**	**2 008**	**1 934**	**1 845**	**1 779**	**1 752**	**100**	**100**	**-0.6**
Coal	405	334	332	254	203	176	168	17	10	-2.9
Oil	712	619	632	572	512	449	407	31	23	-1.9
Gas	496	483	504	511	501	493	486	25	28	-0.2
Nuclear	273	246	243	216	192	187	186	12	11	-1.2
Hydro	52	55	52	62	64	65	67	3	4	1.1
Bioenergy	80	170	179	210	226	237	246	9	14	1.4
Other renewables	10	59	66	109	146	172	193	3	11	4.8
Power sector	**837**	**835**	**847**	**804**	**777**	**780**	**799**	**100**	**100**	**-0.3**
Coal	279	235	232	157	113	92	90	27	11	-4.0
Oil	52	19	19	10	8	7	5	2	1	-5.7
Gas	154	159	170	176	175	174	174	20	22	0.1
Nuclear	273	246	243	216	192	187	186	29	23	-1.2
Hydro	52	55	52	62	64	65	67	6	8	1.1
Bioenergy	19	68	71	85	95	102	107	8	13	1.8
Other renewables	8	53	60	97	130	153	170	7	21	4.7
Other energy sector	**189**	**177**	**182**	**172**	**162**	**153**	**148**	**100**	**100**	**-0.9**
Electricity	*55*	*52*	*54*	*50*	*49*	*48*	*49*	*30*	*33*	*-0.4*
TFC	**1 395**	**1 385**	**1 417**	**1 411**	**1 368**	**1 320**	**1 295**	**100**	**100**	**-0.4**
Coal	76	56	57	53	49	45	42	4	3	-1.3
Oil	616	559	570	525	474	417	380	40	29	-1.7
Gas	313	300	309	308	300	292	285	22	22	-0.4
Electricity	260	298	304	323	334	349	364	21	28	0.8
Heat	67	65	65	66	65	65	64	5	5	-0.0
Bioenergy	61	101	106	123	130	133	136	7	11	1.1
Other renewables	3	6	7	12	16	20	23	0	2	5.5
Industry	**383**	**328**	**338**	**343**	**339**	**336**	**336**	**100**	**100**	**-0.0**
Coal	55	36	36	36	34	33	32	11	9	-0.5
Oil	61	31	31	29	28	27	26	9	8	-0.9
Gas	118	101	106	107	105	102	101	32	30	-0.2
Electricity	110	111	113	117	117	118	119	34	36	0.2
Heat	21	22	21	22	21	21	20	6	6	-0.2
Bioenergy	18	27	29	32	33	34	35	9	10	0.8
Other renewables	0	0	0	1	1	2	2	0	1	7.7
Transport	**345**	**382**	**391**	**389**	**364**	**335**	**320**	**100**	**100**	**-0.9**
Oil	333	355	362	344	310	270	244	93	76	-1.7
Electricity	7	7	7	11	16	24	32	2	10	7.0
Biofuels	1	14	16	26	29	30	31	4	10	2.9
Other fuels	4	6	6	7	8	10	12	1	4	3.3
Buildings	**505**	**532**	**540**	**534**	**524**	**513**	**507**	**100**	**100**	**-0.3**
Coal	18	17	17	14	11	8	7	3	1	-4.0
Oil	92	57	57	38	26	16	10	11	2	-7.2
Gas	169	179	182	178	172	164	156	34	31	-0.7
Electricity	138	174	178	188	194	200	205	33	41	0.6
Heat	45	43	43	43	43	43	43	8	9	0.1
Bioenergy	41	57	58	62	64	66	66	11	13	0.5
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	2	5	5	10	13	17	19	1	4	5.8
Other	**161**	**144**	**149**	**145**	**141**	**137**	**133**	**100**	**100**	**-0.5**
Petrochem. Feedstock	*88*	*87*	*90*	*82*	*78*	*73*	*69*	*60*	*52*	*-1.1*

Europe: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**2 001**	**1 985**	**1 999**	**1 843**	**1 710**	**1 533**	**100**	**100**	**-0.0**	**-1.2**
Coal	290	273	250	194	114	78	13	5	-1.2	-6.1
Oil	593	559	511	520	416	233	26	15	-0.9	-4.2
Gas	525	549	583	489	455	368	29	24	0.6	-1.4
Nuclear	223	208	204	225	235	257	10	17	-0.7	0.3
Hydro	61	63	65	63	66	71	3	5	1.0	1.3
Bioenergy	206	216	235	229	253	265	12	17	1.2	1.7
Other renewables	103	118	150	123	171	261	7	17	3.6	6.1
Power sector	**838**	**846**	**887**	**768**	**751**	**818**	**100**	**100**	**0.2**	**-0.2**
Coal	192	180	168	104	36	20	19	2	-1.4	-10.1
Oil	10	8	5	10	7	4	1	0	-5.4	-6.6
Gas	176	194	214	170	156	117	24	14	1.0	-1.6
Nuclear	223	208	204	225	235	257	23	31	-0.7	0.3
Hydro	61	63	65	63	66	71	7	9	1.0	1.3
Bioenergy	83	88	98	90	103	125	11	15	1.4	2.5
Other renewables	93	106	133	107	147	224	15	27	3.6	5.9
Other energy sector	**177**	**171**	**167**	**163**	**146**	**123**	**100**	**100**	**-0.4**	**-1.7**
Electricity	*52*	*53*	*54*	*48*	*46*	*48*	*33*	*39*	*0.1*	*-0.5*
TFC	**1 452**	**1 449**	**1 462**	**1 352**	**1 264**	**1 090**	**100**	**100**	**0.1**	**-1.1**
Coal	54	51	45	49	42	31	3	3	-1.0	-2.6
Oil	546	517	476	478	384	215	33	20	-0.8	-4.1
Gas	322	328	338	293	274	229	23	21	0.4	-1.3
Electricity	331	346	381	316	331	385	26	35	1.0	1.0
Heat	67	68	69	63	61	56	5	5	0.3	-0.6
Bioenergy	121	126	136	137	148	138	9	13	1.1	1.2
Other renewables	10	12	17	16	24	36	1	3	4.1	7.6
Industry	**349**	**349**	**355**	**329**	**313**	**291**	**100**	**100**	**0.2**	**-0.7**
Coal	36	35	33	34	30	25	9	9	-0.4	-1.5
Oil	30	29	27	28	26	22	7	7	-0.7	-1.6
Gas	109	109	110	100	93	78	31	27	0.1	-1.3
Electricity	119	120	125	114	111	110	35	38	0.4	-0.2
Heat	22	22	22	21	19	16	6	6	0.1	-1.2
Bioenergy	32	34	38	31	32	34	11	12	1.2	0.7
Other renewables	1	1	1	1	2	5	0	2	4.8	11.8
Transport	**400**	**389**	**382**	**368**	**323**	**235**	**100**	**100**	**-0.1**	**-2.2**
Oil	359	345	328	303	232	101	86	43	-0.4	-5.4
Electricity	9	11	17	15	29	80	4	34	4.0	11.3
Biofuels	25	26	29	41	49	35	7	15	2.5	3.4
Other fuels	6	7	9	9	13	19	2	8	1.7	5.2
Buildings	**559**	**569**	**592**	**516**	**496**	**451**	**100**	**100**	**0.4**	**-0.8**
Coal	14	12	9	12	8	2	2	1	-2.9	-8.2
Oil	43	34	21	37	23	4	3	1	-4.3	-10.6
Gas	191	196	204	169	156	123	34	27	0.5	-1.7
Electricity	196	208	232	181	184	188	39	42	1.2	0.2
Heat	45	46	47	42	41	39	8	9	0.4	-0.3
Bioenergy	61	63	65	61	63	64	11	14	0.5	0.4
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	8	10	14	14	20	29	2	6	4.5	7.7
Other	**145**	**142**	**134**	**139**	**131**	**114**	**100**	**100**	**-0.5**	**-1.1**
Petrochem. Feedstock	*82*	*78*	*69*	*79*	*72*	*58*	*51*	*51*	*-1.1*	*-1.9*

Europe: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**3 652**	**4 079**	**4 164**	**4 340**	**4 452**	**4 616**	**4 807**	**100**	**100**	**0.6**
Coal	1 122	963	945	648	466	396	403	23	8	-3.6
Oil	208	64	67	33	24	21	14	2	0	-6.5
Gas	587	793	868	910	896	889	889	21	18	0.1
Nuclear	1 049	942	930	830	737	717	712	22	15	-1.2
Renewables	685	1 311	1 347	1 915	2 324	2 589	2 785	32	58	3.2
Hydro	607	645	608	717	742	760	775	15	16	1.1
Bioenergy	48	212	229	281	315	341	361	6	8	2.0
Wind	22	322	360	670	942	1 110	1 222	9	25	5.5
Geothermal	6	17	19	24	28	31	35	0	1	2.6
Solar PV	0	110	123	216	281	316	340	3	7	4.5
CSP	-	6	6	7	11	18	25	0	1	6.3
Marine	1	1	1	1	5	13	28	0	1	18.5

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**1 261**	**1 284**	**1 445**	**1 588**	**1 645**	**1 701**	**100**	**100**	**1.2**
Coal	231	228	181	144	115	108	18	6	-3.2
Oil	62	61	33	24	20	15	5	1	-5.8
Gas	264	265	307	343	363	378	21	22	1.6
Nuclear	145	142	125	111	109	108	11	6	-1.2
Renewables	559	588	795	956	1 023	1 071	46	63	2.6
Hydro	244	246	260	268	273	277	19	16	0.5
Bioenergy	44	46	57	63	67	70	4	4	1.9
Wind	162	178	275	358	390	407	14	24	3.7
Geothermal	2	3	3	4	4	5	0	0	2.6
Solar PV	105	114	196	257	276	291	9	17	4.2
CSP	2	2	3	4	6	8	0	0	5.6
Marine	0	0	1	2	6	13	0	1	18.8

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**4 514**	**3 945**	**4 007**	**3 520**	**3 119**	**2 812**	**2 652**	**100**	**100**	**-1.8**
Coal	1 577	1 293	1 280	948	737	628	601	32	23	-3.2
Oil	1 837	1 563	1 590	1 427	1 261	1 087	974	40	37	-2.1
Gas	1 100	1 089	1 137	1 145	1 121	1 097	1 077	28	41	-0.2
Power sector	**1 701**	**1 435**	**1 450**	**1 117**	**915**	**821**	**803**	**100**	**100**	**-2.5**
Coal	1 171	1 005	990	671	480	392	378	68	47	-4.1
Oil	167	58	60	32	24	21	16	4	2	-5.7
Gas	363	371	399	414	411	409	409	28	51	0.1
TFC	**2 594**	**2 312**	**2 358**	**2 220**	**2 036**	**1 838**	**1 705**	**100**	**100**	**-1.4**
Coal	354	245	249	234	215	196	185	11	11	-1.3
Oil	1 545	1 404	1 427	1 309	1 163	1 001	899	61	53	-2.0
Transport	*1 001*	*1 076*	*1 097*	*1 043*	*940*	*819*	*739*	*47*	*43*	*-1.7*
Gas	695	663	682	677	659	641	622	29	36	-0.4

Europe: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**4 455**	**4 641**	**5 063**	**4 244**	**4 388**	**5 036**	**100**	**100**	**0.9**	**0.8**
Coal	803	769	752	417	128	67	15	1	-1.0	-10.9
Oil	33	24	16	31	21	10	0	0	-6.0	-7.8
Gas	905	1 020	1 155	879	797	566	23	11	1.2	-1.8
Nuclear	855	796	784	862	900	986	15	20	-0.7	0.3
Renewables	1 854	2 027	2 351	2 052	2 538	3 403	46	68	2.5	4.1
Hydro	713	732	761	736	768	820	15	16	1.0	1.3
Bioenergy	273	293	328	298	345	429	6	9	1.6	2.8
Wind	632	741	929	741	1 051	1 558	18	31	4.2	6.6
Geothermal	23	25	30	25	32	47	1	1	1.9	3.9
Solar PV	206	223	271	242	319	468	5	9	3.5	6.0
CSP	7	9	20	9	17	45	0	1	5.2	9.0
Marine	1	3	13	1	6	36	0	1	14.5	19.8

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**1 448**	**1 504**	**1 631**	**1 458**	**1 620**	**1 951**	**100**	**100**	**1.0**	**1.8**
Coal	206	186	169	149	92	40	10	2	-1.3	-7.3
Oil	32	24	16	30	22	15	1	1	-5.7	-5.8
Gas	312	346	401	290	312	377	25	19	1.8	1.5
Nuclear	125	115	110	128	136	141	7	7	-1.1	-0.0
Renewables	765	820	909	856	1 045	1 340	56	69	1.9	3.6
Hydro	258	264	272	266	276	291	17	15	0.4	0.7
Bioenergy	56	59	63	61	69	82	4	4	1.4	2.6
Wind	260	290	325	302	400	535	20	27	2.7	4.9
Geothermal	3	3	4	3	4	6	0	0	1.9	4.0
Solar PV	185	199	232	220	287	395	14	20	3.1	5.6
CSP	3	4	6	3	6	14	0	1	4.6	8.2
Marine	0	1	6	1	3	16	0	1	14.8	20.0

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**3 774**	**3 669**	**3 534**	**3 075**	**2 356**	**1 433**	**100**	**100**	**-0.5**	**-4.4**
Coal	1 100	1 033	946	696	359	176	27	12	-1.3	-8.3
Oil	1 494	1 403	1 287	1 282	983	463	36	32	-0.9	-5.2
Gas	1 180	1 234	1 301	1 097	1 014	793	37	55	0.6	-1.6
Power sector	**1 264**	**1 246**	**1 227**	**872**	**535**	**318**	**100**	**100**	**-0.7**	**-6.4**
Coal	818	767	708	442	148	44	58	14	-1.4	-12.7
Oil	32	24	17	31	22	13	1	4	-5.4	-6.6
Gas	414	455	502	400	366	261	41	82	1.0	-1.8
TFC	**2 322**	**2 245**	**2 139**	**2 034**	**1 685**	**1 027**	**100**	**100**	**-0.4**	**-3.5**
Coal	239	224	198	215	178	109	9	11	-1.0	-3.5
Oil	1 374	1 298	1 195	1 174	903	417	56	41	-0.8	-5.2
Transport	*1 089*	*1 045*	*994*	*919*	*703*	*305*	*46*	*30*	*-0.4*	*-5.4*
Gas	710	723	746	646	605	501	35	49	0.4	-1.3

European Union: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**1 693**	**1 596**	**1 621**	**1 512**	**1 404**	**1 321**	**1 274**	**100**	**100**	**-1.0**
Coal	321	241	234	167	118	91	79	14	6	-4.6
Oil	625	522	532	466	405	341	299	33	23	-2.5
Gas	396	383	397	388	370	349	334	25	26	-0.7
Nuclear	246	219	216	180	153	150	150	13	12	-1.6
Hydro	31	30	27	33	34	35	36	2	3	1.2
Bioenergy	67	155	162	192	206	215	221	10	17	1.3
Other renewables	7	46	51	86	118	140	156	3	12	5.0
Power sector	**683**	**664**	**672**	**613**	**573**	**565**	**569**	**100**	**100**	**-0.7**
Coal	236	177	171	107	64	42	33	25	6	-6.9
Oil	44	16	17	9	6	5	4	2	1	-6.1
Gas	103	115	125	125	120	113	110	19	19	-0.5
Nuclear	246	219	216	180	153	150	150	32	26	-1.6
Hydro	31	30	27	33	34	35	36	4	6	1.2
Bioenergy	17	64	67	79	87	92	95	10	17	1.5
Other renewables	6	43	48	79	108	127	141	7	25	4.8
Other energy sector	**143**	**132**	**134**	**122**	**112**	**103**	**98**	**100**	**100**	**-1.4**
Electricity	*43*	*39*	*41*	*37*	*34*	*33*	*33*	*30*	*33*	*-0.9*
TFC	**1 179**	**1 138**	**1 158**	**1 123**	**1 065**	**1 004**	**964**	**100**	**100**	**-0.8**
Coal	51	34	34	30	27	24	22	3	2	-1.8
Oil	543	471	480	429	375	316	277	41	29	-2.4
Gas	272	252	255	246	234	222	210	22	22	-0.8
Electricity	217	239	244	251	256	263	271	21	28	0.4
Heat	45	48	48	48	47	46	45	4	5	-0.2
Bioenergy	49	90	94	111	117	121	124	8	13	1.2
Other renewables	1	3	3	7	10	12	15	0	2	7.5
Industry	**309**	**259**	**264**	**262**	**255**	**248**	**245**	**100**	**100**	**-0.3**
Coal	37	21	20	20	19	18	17	8	7	-0.8
Oil	52	24	24	23	22	20	19	9	8	-1.0
Gas	102	84	87	85	81	78	75	33	31	-0.6
Electricity	91	87	89	89	88	87	87	34	35	-0.1
Heat	11	16	16	16	15	14	14	6	6	-0.8
Bioenergy	17	26	27	29	30	31	32	10	13	0.7
Other renewables	0	0	0	0	0	1	1	0	1	17.6
Transport	**303**	**319**	**326**	**316**	**287**	**255**	**237**	**100**	**100**	**-1.4**
Oil	296	297	302	278	241	200	172	93	72	-2.4
Electricity	6	5	6	9	13	20	28	2	12	7.2
Biofuels	1	14	15	25	28	29	29	5	12	2.8
Other fuels	1	3	3	4	5	7	8	1	3	3.9
Buildings	**425**	**438**	**443**	**427**	**411**	**394**	**381**	**100**	**100**	**-0.6**
Coal	12	10	11	7	5	3	3	2	1	-6.0
Oil	81	50	51	34	23	13	8	11	2	-7.7
Gas	150	152	153	145	136	126	116	35	30	-1.2
Electricity	117	142	145	148	150	151	152	33	40	0.2
Heat	34	32	31	32	32	32	32	7	8	0.0
Bioenergy	31	48	49	54	56	58	58	11	15	0.8
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	1	2	3	6	9	11	13	1	3	7.4
Other	**141**	**121**	**125**	**118**	**112**	**106**	**100**	**100**	**100**	**-0.9**
Petrochem. Feedstock	*83*	*80*	*82*	*74*	*69*	*64*	*59*	*66*	*58*	*-1.5*

European Union: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**1 568**	**1 525**	**1 480**	**1 448**	**1 320**	**1 141**	**100**	**100**	**-0.4**	**-1.5**
Coal	193	169	127	128	71	49	9	4	-2.6	-6.6
Oil	485	445	387	422	325	164	26	14	-1.4	-5.0
Gas	403	418	428	373	337	256	29	22	0.3	-1.9
Nuclear	187	170	171	187	189	206	12	18	-1.0	-0.2
Hydro	33	34	35	33	35	37	2	3	1.1	1.3
Bioenergy	187	196	213	209	230	233	14	20	1.2	1.6
Other renewables	80	93	119	96	134	196	8	17	3.7	6.0
Power sector	**640**	**632**	**639**	**593**	**574**	**617**	**100**	**100**	**-0.2**	**-0.4**
Coal	133	113	80	72	24	15	12	2	-3.3	-10.1
Oil	9	6	4	8	6	3	1	1	-5.7	-7.0
Gas	127	142	152	123	109	78	24	13	0.9	-2.0
Nuclear	187	170	171	187	189	206	27	33	-1.0	-0.2
Hydro	33	34	35	33	35	37	6	6	1.1	1.3
Bioenergy	76	81	87	84	94	107	14	17	1.1	2.1
Other renewables	75	86	109	86	118	171	17	28	3.6	5.6
Other energy sector	**126**	**120**	**113**	**115**	**101**	**81**	**100**	**100**	**-0.8**	**-2.2**
Electricity	*38*	*38*	*37*	*35*	*33*	*34*	*33*	*41*	*-0.4*	*-0.8*
TFC	**1 157**	**1 135**	**1 108**	**1 078**	**988**	**816**	**100**	**100**	**-0.2**	**-1.5**
Coal	31	28	24	28	23	16	2	2	-1.6	-3.3
Oil	447	412	359	388	300	151	32	19	-1.3	-4.9
Gas	259	259	260	234	214	167	23	20	0.1	-1.8
Electricity	257	265	283	248	257	293	26	36	0.6	0.8
Heat	49	50	49	46	44	40	4	5	0.1	-0.8
Bioenergy	109	114	124	124	135	124	11	15	1.2	1.2
Other renewables	5	7	10	10	16	25	1	3	5.5	10.0
Industry	**266**	**263**	**260**	**251**	**236**	**213**	**100**	**100**	**-0.1**	**-0.9**
Coal	20	19	18	19	17	13	7	6	-0.7	-1.9
Oil	23	22	20	22	20	16	8	8	-0.9	-1.7
Gas	87	85	82	79	72	57	32	27	-0.2	-1.8
Electricity	90	90	91	87	84	81	35	38	0.1	-0.4
Heat	16	16	14	15	13	10	6	5	-0.5	-2.0
Bioenergy	30	31	35	29	29	31	13	15	1.1	0.6
Other renewables	0	0	1	1	1	3	0	2	13.5	22.2
Transport	**326**	**309**	**290**	**299**	**255**	**174**	**100**	**100**	**-0.5**	**-2.7**
Oil	291	271	243	242	176	63	84	36	-0.9	-6.6
Electricity	8	10	14	13	25	66	5	38	4.1	11.4
Biofuels	24	25	27	39	46	31	9	18	2.5	3.1
Other fuels	3	4	5	6	9	13	2	7	1.8	6.0
Buildings	**448**	**450**	**457**	**415**	**393**	**346**	**100**	**100**	**0.1**	**-1.1**
Coal	8	6	3	7	4	0	1	0	-5.1	-20.3
Oil	38	30	18	32	20	3	4	1	-4.5	-11.1
Gas	157	159	161	139	125	93	35	27	0.2	-2.2
Electricity	155	161	173	144	144	141	38	41	0.8	-0.1
Heat	33	34	35	31	31	29	8	8	0.5	-0.3
Bioenergy	53	55	58	53	56	58	13	17	0.7	0.7
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	5	6	9	9	14	21	2	6	5.5	9.6
Other	**118**	**112**	**101**	**112**	**103**	**84**	**100**	**100**	**-0.9**	**-1.7**
Petrochem. Feedstock	*74*	*69*	*58*	*71*	*63*	*48*	*58*	*58*	*-1.5*	*-2.3*

European Union: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	2000	**2016**	**2017e**	**2025**	**2030**	**2035**	**2040**	**2017e**	**2040**	**2017e-40**
Total generation	**3 006**	**3 228**	**3 299**	**3 332**	**3 354**	**3 423**	**3 515**	**100**	**100**	**0.3**
Coal	968	736	708	447	262	173	140	21	4	-6.8
Oil	181	60	62	30	22	19	13	2	0	-6.7
Gas	480	611	682	685	646	599	580	21	17	-0.7
Nuclear	945	840	829	691	587	574	574	25	16	-1.6
Renewables	431	977	1 012	1 476	1 835	2 055	2 205	31	63	3.4
Hydro	357	350	319	385	400	411	419	10	12	1.2
Bioenergy	46	206	223	267	294	314	325	7	9	1.6
Wind	22	303	338	618	864	1 008	1 105	10	31	5.3
Geothermal	5	7	8	7	10	12	14	0	0	2.8
Solar PV	0	105	118	191	253	281	292	4	8	4.0
CSP	-	6	6	6	10	15	22	0	1	5.6
Marine	1	1	1	1	5	13	28	0	1	18.5

	Power generation capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2016	**2017e**	**2025**	**2030**	**2035**	**2040**	**2017e**	**2040**	**2017e-40**
Total capacity	**1 024**	**1 040**	**1 151**	**1 266**	**1 295**	**1 320**	**100**	**100**	**1.0**
Coal	173	170	121	84	55	43	16	3	-5.8
Oil	51	50	27	20	16	12	5	1	-6.0
Gas	217	217	247	272	280	284	21	22	1.2
Nuclear	127	125	105	90	89	89	12	7	-1.4
Renewables	455	478	649	794	845	877	46	66	2.7
Hydro	154	155	160	165	169	171	15	13	0.4
Bioenergy	42	44	55	60	62	64	4	5	1.6
Wind	154	169	255	329	354	367	16	28	3.4
Geothermal	1	1	1	1	2	2	0	0	3.6
Solar PV	101	107	175	232	247	252	10	19	3.8
CSP	2	2	3	4	5	7	0	1	5.0
Marine	0	0	1	2	6	13	0	1	18.8

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	2000	**2016**	**2017e**	**2025**	**2030**	**2035**	**2040**	**2017e**	**2040**	**2017e-40**
Total CO_2	**3 758**	**3 125**	**3 148**	**2 663**	**2 249**	**1 917**	**1 719**	**100**	**100**	**-2.6**
Coal	1 274	938	911	624	422	313	263	29	15	-5.3
Oil	1 608	1 321	1 341	1 166	997	822	709	43	41	-2.7
Gas	876	866	897	873	830	782	747	28	43	-0.8
Power sector	**1 378**	**1 077**	**1 078**	**781**	**575**	**462**	**410**	**100**	**100**	**-4.1**
Coal	996	757	733	459	272	180	140	68	34	-7.0
Oil	140	50	52	27	20	17	12	5	3	-6.1
Gas	242	270	293	295	283	265	259	27	63	-0.5
TFC	**2 190**	**1 890**	**1 912**	**1 744**	**1 550**	**1 347**	**1 208**	**100**	**100**	**-2.0**
Coal	232	146	145	133	118	104	97	8	8	-1.8
Oil	1 356	1 184	1 201	1 067	916	753	649	63	54	-2.6
Transport	*889*	*902*	*917*	*844*	*732*	*606*	*522*	*48*	*43*	*-2.4*
Gas	602	559	566	544	517	489	462	30	38	-0.9

European Union: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**3 422**	**3 508**	**3 713**	**3 278**	**3 356**	**3 785**	**100**	**100**	**0.5**	**0.6**
Coal	560	483	347	293	83	52	9	1	-3.1	-10.7
Oil	30	22	14	28	20	9	0	0	-6.2	-7.8
Gas	689	784	856	669	578	393	23	10	1.0	-2.4
Nuclear	717	651	657	717	725	790	18	21	-1.0	-0.2
Renewables	1 423	1 565	1 835	1 569	1 947	2 537	49	67	2.6	4.1
Hydro	384	394	411	390	405	428	11	11	1.1	1.3
Bioenergy	259	274	299	282	318	371	8	10	1.3	2.2
Wind	583	681	850	669	917	1 279	23	34	4.1	6.0
Geothermal	7	9	12	8	12	20	0	1	2.0	4.4
Solar PV	182	196	234	211	275	368	6	10	3.0	5.1
CSP	6	8	17	7	14	36	0	1	4.5	8.0
Marine	1	3	13	1	6	36	0	1	14.5	19.8

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**1 150**	**1 182**	**1 259**	**1 162**	**1 280**	**1 478**	**100**	**100**	**0.8**	**1.5**
Coal	139	111	74	103	60	27	6	2	-3.6	-7.7
Oil	27	20	12	25	18	12	1	1	-5.9	-5.9
Gas	253	280	319	232	240	263	25	18	1.7	0.8
Nuclear	105	94	93	108	112	115	7	8	-1.3	-0.4
Renewables	622	667	739	691	841	1 034	59	70	1.9	3.4
Hydro	160	163	168	162	168	175	13	12	0.4	0.5
Bioenergy	53	55	58	58	64	72	5	5	1.2	2.2
Wind	241	267	298	273	350	439	24	30	2.5	4.2
Geothermal	1	1	2	1	2	3	0	0	2.7	5.2
Solar PV	165	176	202	193	250	317	16	21	2.8	4.8
CSP	3	3	6	3	5	12	0	1	4.0	7.3
Marine	0	1	6	1	3	16	0	1	14.8	20.0

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**2 868**	**2 701**	**2 406**	**2 343**	**1 742**	**967**	**100**	**100**	**-1.2**	**-5.0**
Coal	735	639	465	461	219	94	19	10	-2.9	-9.4
Oil	1 224	1 120	975	1 041	766	314	41	32	-1.4	-6.1
Gas	908	943	965	841	757	559	40	58	0.3	-2.0
Power sector	**893**	**837**	**704**	**624**	**369**	**202**	**100**	**100**	**-1.8**	**-7.0**
Coal	567	484	335	309	96	23	48	11	-3.4	-14.0
Oil	27	20	14	25	18	10	2	5	-5.7	-6.9
Gas	300	333	356	290	255	169	51	84	0.9	-2.4
TFC	**1 832**	**1 732**	**1 582**	**1 592**	**1 273**	**705**	**100**	**100**	**-0.8**	**-4.2**
Coal	135	123	103	121	97	53	7	7	-1.5	-4.3
Oil	1 123	1 033	902	950	699	279	57	40	-1.2	-6.1
Transport	*883*	*823*	*739*	*736*	*533*	*191*	*47*	*27*	*-0.9*	*-6.6*
Gas	574	576	578	520	477	373	37	53	0.1	-1.8

Africa: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**490**	**807**	**829**	**980**	**1 086**	**1 192**	**1 299**	**100**	**100**	**2.0**
Coal	82	100	101	105	105	102	100	12	8	-0.1
Oil	102	183	185	224	247	269	294	22	23	2.0
Gas	47	115	121	145	175	213	255	15	20	3.3
Nuclear	3	4	3	4	4	7	10	0	1	4.7
Hydro	6	10	10	18	23	29	35	1	3	5.3
Bioenergy	249	390	403	467	496	508	504	49	39	1.0
Other renewables	0	5	6	17	36	63	101	1	8	13.3
Power sector	**96**	**166**	**173**	**199**	**232**	**282**	**344**	**100**	**100**	**3.0**
Coal	52	67	68	71	68	61	54	39	16	-1.0
Oil	11	21	23	23	22	23	22	13	6	-0.2
Gas	22	58	61	65	76	95	117	35	34	2.9
Nuclear	3	4	3	4	4	7	10	2	3	4.7
Hydro	6	10	10	18	23	29	35	6	10	5.3
Bioenergy	1	1	1	2	5	8	10	1	3	9.7
Other renewables	0	5	6	16	34	60	96	3	28	13.2
Other energy sector	**65**	**111**	**116**	**157**	**178**	**188**	**191**	**100**	**100**	**2.2**
Electricity	*8*	*15*	*15*	*18*	*21*	*24*	*29*	*13*	*15*	*2.8*
TFC	**368**	**600**	**613**	**718**	**790**	**862**	**935**	**100**	**100**	**1.9**
Coal	19	19	19	19	20	21	22	3	2	0.8
Oil	89	165	165	201	224	245	271	27	29	2.2
Gas	14	41	44	56	70	86	101	7	11	3.7
Electricity	31	55	57	75	93	115	143	9	15	4.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	215	320	328	365	381	391	392	53	42	0.8
Other renewables	0	0	0	1	2	4	5	0	1	15.1
Industry	**57**	**96**	**98**	**116**	**131**	**150**	**173**	**100**	**100**	**2.5**
Coal	11	12	12	13	15	16	18	12	11	1.8
Oil	13	17	17	20	21	23	25	17	15	1.8
Gas	5	25	26	30	35	41	48	26	28	2.7
Electricity	15	22	22	27	31	36	42	23	24	2.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	13	21	21	25	29	34	40	22	23	2.8
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**54**	**117**	**116**	**144**	**161**	**175**	**191**	**100**	**100**	**2.2**
Oil	53	115	114	141	157	170	185	98	97	2.1
Electricity	1	0	0	1	1	1	2	0	1	5.7
Biofuels	-	0	0	0	1	1	1	0	1	15.5
Other fuels	1	1	1	2	2	3	3	1	2	4.3
Buildings	**237**	**362**	**374**	**428**	**465**	**501**	**533**	**100**	**100**	**1.6**
Coal	2	5	5	4	3	2	2	1	0	-3.8
Oil	15	19	20	23	27	32	40	5	8	3.0
Gas	4	11	13	19	27	36	43	3	8	5.5
Electricity	15	31	32	44	58	75	96	9	18	4.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	202	296	304	337	349	353	348	81	65	0.6
Traditional biomass	*197*	*285*	*292*	*325*	*335*	*336*	*328*	*78*	*62*	*0.5*
Other renewables	0	0	0	1	2	3	5	0	1	14.7
Other	**20**	**25**	**25**	**30**	**33**	**36**	**38**	**100**	**100**	**1.8**
Petrochem. Feedstock	*11*	*9*	*9*	*11*	*12*	*13*	*14*	*34*	*38*	*2.3*

Africa: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**997**	**1 127**	**1 400**	**756**	**688**	**810**	**100**	**100**	**2.3**	**-0.1**
Coal	112	127	154	90	75	58	11	7	1.8	-2.4
Oil	232	263	336	212	221	225	24	28	2.6	0.9
Gas	147	182	277	137	151	166	20	21	3.7	1.4
Nuclear	4	4	7	4	4	14	0	2	3.0	6.3
Hydro	17	21	31	20	25	40	2	5	4.8	6.0
Bioenergy	470	502	525	266	148	132	38	16	1.2	-4.7
Other renewables	16	28	69	27	63	174	5	21	11.4	16.0
Power sector	**204**	**246**	**370**	**186**	**206**	**304**	**100**	**100**	**3.4**	**2.5**
Coal	77	87	100	57	40	20	27	7	1.7	-5.2
Oil	23	22	25	19	15	9	7	3	0.4	-3.9
Gas	66	81	134	58	56	46	36	15	3.5	-1.2
Nuclear	4	4	7	4	4	14	2	5	3.0	6.3
Hydro	17	21	31	20	25	40	8	13	4.8	6.0
Bioenergy	2	4	9	3	6	13	2	4	9.0	10.9
Other renewables	15	26	65	25	59	162	18	53	11.3	15.8
Other energy sector	**160**	**187**	**222**	**90**	**75**	**82**	**100**	**100**	**2.9**	**-1.5**
Electricity	*19*	*22*	*31*	*17*	*19*	*25*	*14*	*30*	*3.2*	*2.2*
TFC	**727**	**811**	**983**	**572**	**520**	**596**	**100**	**100**	**2.1**	**-0.1**
Coal	20	21	26	18	18	18	3	3	1.4	-0.2
Oil	208	240	311	192	206	217	32	36	2.8	1.2
Gas	56	70	100	56	68	91	10	15	3.7	3.2
Electricity	76	94	145	74	94	147	15	25	4.1	4.2
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	366	383	397	229	130	110	40	19	0.8	-4.6
Other renewables	1	2	4	2	5	12	0	2	14.1	19.5
Industry	**117**	**134**	**180**	**111**	**121**	**147**	**100**	**100**	**2.7**	**1.8**
Coal	14	15	21	13	13	15	11	10	2.4	1.0
Oil	20	22	27	19	20	23	15	15	2.0	1.3
Gas	30	35	47	29	33	40	26	27	2.7	2.0
Electricity	28	32	43	26	28	34	24	23	2.9	1.8
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	25	30	43	24	27	35	24	24	3.1	2.2
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**149**	**173**	**218**	**139**	**148**	**152**	**100**	**100**	**2.8**	**1.2**
Oil	146	169	213	134	140	133	98	88	2.8	0.7
Electricity	1	1	1	1	1	3	0	2	2.7	8.6
Biofuels	0	0	1	2	3	6	0	4	14.3	25.0
Other fuels	2	2	3	2	4	9	1	6	3.6	8.7
Buildings	**430**	**470**	**544**	**293**	**220**	**261**	**100**	**100**	**1.6**	**-1.5**
Coal	4	4	3	3	3	1	1	0	-2.3	-5.9
Oil	24	29	48	24	29	42	9	16	3.8	3.2
Gas	19	27	43	19	25	35	8	13	5.5	4.5
Electricity	45	59	97	45	62	106	18	41	4.9	5.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	337	349	349	200	97	66	64	25	0.6	-6.4
Traditional biomass	*325*	*335*	*328*	*187*	*82*	*46*	*60*	*18*	*0.5*	*-7.7*
Other renewables	1	2	4	2	4	11	1	4	13.8	18.7
Other	**31**	**34**	**41**	**29**	**31**	**36**	**100**	**100**	**2.1**	**1.5**
Petrochem. Feedstock	*11*	*12*	*14*	*10*	*12*	*14*	*35*	*39*	*2.3*	*2.1*

Africa: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**442**	**801**	**833**	**1 088**	**1 327**	**1 629**	**2 001**	**100**	**100**	**3.9**
Coal	209	254	256	285	278	260	241	31	12	-0.3
Oil	51	86	92	97	95	97	95	11	5	0.1
Gas	92	308	324	374	450	569	708	39	35	3.5
Nuclear	13	15	13	14	14	26	39	2	2	4.7
Renewables	77	137	146	317	488	674	917	18	46	8.3
Hydro	75	116	122	210	272	332	403	15	20	5.3
Bioenergy	1	2	2	9	19	28	36	0	2	13.2
Wind	0	10	12	35	68	91	117	1	6	10.6
Geothermal	0	4	5	9	20	38	63	1	3	11.8
Solar PV	0	3	4	49	99	160	247	1	12	19.4
CSP	-	1	1	5	10	24	49	0	2	18.1
Marine	-	-	-	0	0	0	0	-	0	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**209**	**226**	**334**	**413**	**501**	**622**	**100**	**100**	**4.5**
Coal	45	47	55	53	50	46	21	7	-0.1
Oil	41	42	41	41	42	41	18	7	-0.1
Gas	82	91	132	153	175	209	40	34	3.7
Nuclear	2	2	2	2	4	5	1	1	4.4
Renewables	40	44	101	157	221	306	19	49	8.8
Hydro	32	34	52	64	79	96	15	15	4.6
Bioenergy	1	1	2	5	6	8	0	1	11.6
Wind	4	4	14	25	32	40	2	6	9.9
Geothermal	1	1	2	3	6	10	0	2	12.4
Solar PV	2	3	30	57	90	138	2	22	17.3
CSP	0	1	2	4	8	15	0	2	15.8
Marine	-	-	0	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**658**	**1 156**	**1 185**	**1 354**	**1 472**	**1 598**	**1 737**	**100**	**100**	**1.7**
Coal	262	376	383	398	387	366	345	32	20	-0.4
Oil	299	552	557	660	724	785	856	47	49	1.9
Gas	98	227	245	296	361	447	536	21	31	3.5
Power sector	**293**	**479**	**489**	**512**	**521**	**542**	**563**	**100**	**100**	**0.6**
Coal	206	267	270	283	269	245	216	55	38	-1.0
Oil	35	75	76	75	73	74	71	16	13	-0.3
Gas	52	137	143	153	178	224	276	29	49	2.9
TFC	**329**	**594**	**613**	**741**	**836**	**930**	**1 039**	**100**	**100**	**2.3**
Coal	55	68	71	73	75	78	85	12	8	0.7
Oil	251	466	471	571	636	695	768	77	74	2.2
Transport	*160*	*343*	*343*	*424*	*473*	*511*	*555*	*56*	*53*	*2.1*
Gas	23	60	71	96	125	157	186	12	18	4.3

Africa: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 101**	**1 352**	**2 046**	**1 063**	**1 319**	**2 003**	**100**	**100**	**4.0**	**3.9**
Coal	310	357	432	228	165	85	21	4	2.3	-4.7
Oil	98	96	109	80	65	39	5	2	0.7	-3.7
Gas	379	480	779	329	344	295	38	15	3.9	-0.4
Nuclear	14	14	26	14	16	54	1	3	3.0	6.3
Renewables	299	403	697	410	726	1 528	34	76	7.0	10.8
Hydro	202	249	357	232	296	470	17	23	4.8	6.0
Bioenergy	7	15	30	9	21	46	1	2	12.3	14.4
Wind	31	41	76	53	114	192	4	10	8.6	13.0
Geothermal	9	17	46	11	25	78	2	4	10.3	12.8
Solar PV	45	72	160	90	238	626	8	31	17.1	24.3
CSP	5	9	28	15	33	115	1	6	15.2	22.5
Marine	0	0	0	0	0	1	0	0	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**334**	**397**	**570**	**359**	**497**	**844**	**100**	**100**	**4.1**	**5.9**
Coal	59	66	80	50	46	37	14	4	2.3	-1.1
Oil	41	41	45	36	33	32	8	4	0.3	-1.2
Gas	132	155	203	125	131	144	36	17	3.5	2.0
Nuclear	2	2	4	2	2	8	1	1	2.7	6.1
Renewables	95	127	224	144	277	597	39	71	7.3	12.0
Hydro	50	59	84	56	71	113	15	13	4.0	5.3
Bioenergy	2	4	7	3	5	10	1	1	10.9	12.7
Wind	12	16	27	21	42	67	5	8	8.1	12.5
Geothermal	1	3	7	2	4	12	1	1	10.8	13.5
Solar PV	27	43	90	57	143	361	16	43	15.2	22.4
CSP	2	3	8	5	11	34	1	4	13.0	20.0
Marine	0	0	0	0	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**1 407**	**1 621**	**2 116**	**1 240**	**1 215**	**1 129**	**100**	**100**	**2.6**	**-0.2**
Coal	425	470	545	338	265	161	26	14	1.6	-3.7
Oil	682	772	984	623	644	639	47	57	2.5	0.6
Gas	300	378	587	279	306	329	28	29	3.9	1.3
Power sector	**539**	**611**	**797**	**428**	**341**	**193**	**100**	**100**	**2.1**	**-4.0**
Coal	307	347	402	228	158	56	51	29	1.8	-6.6
Oil	76	73	80	63	51	30	10	16	0.2	-4.0
Gas	156	191	314	137	132	108	39	56	3.5	-1.2
TFC	**765**	**889**	**1 168**	**711**	**766**	**826**	**100**	**100**	**2.8**	**1.3**
Coal	76	81	98	68	65	62	8	7	1.4	-0.6
Oil	592	683	884	548	581	599	76	72	2.8	1.1
Transport	*440*	*509*	*641*	*402*	*420*	*400*	*55*	*48*	*2.8*	*0.7*
Gas	97	126	186	96	120	166	16	20	4.3	3.8

South Africa: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**103**	**131**	**131**	**133**	**132**	**135**	**138**	**100**	**100**	**0.2**
Coal	74	90	91	86	77	69	60	69	44	-1.8
Oil	12	20	20	24	26	28	30	15	22	1.7
Gas	1	3	3	4	5	7	8	3	6	3.9
Nuclear	3	4	3	4	4	7	10	3	7	4.7
Hydro	0	0	0	0	0	0	0	0	0	9.4
Bioenergy	12	12	12	13	14	15	16	9	11	1.1
Other renewables	-	1	1	2	6	9	13	1	10	12.4
Power sector	**51**	**64**	**64**	**64**	**62**	**63**	**64**	**100**	**100**	**-0.1**
Coal	48	59	60	57	48	41	33	93	52	-2.6
Oil	-	0	0	0	0	0	0	0	0	7.4
Gas	-	-	-	1	2	3	4	-	6	n.a.
Nuclear	3	4	3	4	4	7	10	5	16	4.7
Hydro	0	0	0	0	0	0	0	0	1	9.4
Bioenergy	0	0	0	1	2	3	4	0	7	18.4
Other renewables	-	1	1	2	5	8	12	1	19	12.7
Other energy sector	**15**	**17**	**17**	**18**	**19**	**19**	**20**	**100**	**100**	**0.5**
Electricity	*4*	*4*	*4*	*4*	*5*	*5*	*5*	*25*	*26*	*0.8*
TFC	**56**	**70**	**70**	**75**	**78**	**82**	**87**	**100**	**100**	**1.0**
Coal	16	17	17	16	15	14	14	24	16	-0.8
Oil	16	26	26	29	30	32	34	37	39	1.2
Gas	-	2	2	2	2	2	3	3	3	1.7
Electricity	15	17	17	19	22	24	28	24	32	2.2
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	9	9	9	9	8	8	8	13	10	-0.3
Other renewables	-	0	0	0	1	1	1	0	1	10.1
Industry	**20**	**25**	**25**	**26**	**27**	**28**	**29**	**100**	**100**	**0.6**
Coal	9	10	10	10	10	10	10	40	35	0.0
Oil	1	2	2	2	1	1	1	7	5	-0.6
Gas	-	2	2	2	2	2	2	7	8	1.3
Electricity	8	10	10	11	11	12	12	41	43	0.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	2	2	2	2	2	2	2	6	8	1.7
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**12**	**19**	**18**	**22**	**24**	**26**	**28**	**100**	**100**	**1.9**
Oil	12	19	18	22	23	25	27	98	94	1.7
Electricity	0	0	0	0	0	1	1	2	3	4.2
Biofuels	-	-	-	0	0	1	1	-	3	n.a.
Other fuels	-	0	0	0	0	0	0	0	0	34.2
Buildings	**16**	**20**	**20**	**19**	**20**	**21**	**23**	**100**	**100**	**0.7**
Coal	2	5	5	4	3	2	2	25	9	-3.9
Oil	1	2	1	1	1	1	1	8	5	-1.3
Gas	-	0	0	0	0	0	0	0	1	22.9
Electricity	6	6	6	7	9	11	13	30	59	3.7
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	7	7	7	7	6	6	5	37	23	-1.5
Traditional biomass	*7*	*7*	*7*	*6*	*6*	*5*	*5*	*37*	*20*	*-2.0*
Other renewables	-	0	0	0	1	1	1	1	5	9.5
Other	**7**	**7**	**7**	**7**	**7**	**7**	**7**	**100**	**100**	**0.3**
Petrochem. Feedstock	*5*	*3*	*3*	*3*	*3*	*3*	*3*	*40*	*42*	*0.5*

South Africa: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**138**	**145**	**161**	**121**	**106**	**100**	**100**	**100**	**0.9**	**-1.2**
Coal	90	91	88	76	55	31	54	31	-0.1	-4.6
Oil	25	28	34	22	22	21	21	21	2.3	0.2
Gas	4	6	9	4	7	9	5	9	4.2	4.4
Nuclear	4	4	7	4	4	10	4	10	3.0	4.5
Hydro	0	0	0	0	0	0	0	0	9.4	9.3
Bioenergy	12	13	15	10	9	13	9	13	1.0	0.2
Other renewables	2	3	8	4	9	16	5	16	10.1	13.5
Power sector	**68**	**72**	**82**	**57**	**45**	**41**	**100**	**100**	**1.0**	**-2.0**
Coal	60	61	59	48	28	7	72	17	-0.1	-8.9
Oil	0	0	0	0	0	0	0	0	7.8	5.5
Gas	1	2	4	1	3	4	5	11	n.a.	n.a.
Nuclear	4	4	7	4	4	10	8	23	3.0	4.5
Hydro	0	0	0	0	0	0	0	1	9.4	9.3
Bioenergy	1	2	4	1	2	5	5	11	18.0	18.7
Other renewables	2	3	7	3	8	15	9	36	10.4	13.7
Other energy sector	**19**	**19**	**21**	**17**	**16**	**17**	**100**	**100**	**0.8**	**-0.2**
Electricity	*5*	*5*	*6*	*4*	*4*	*4*	*29*	*22*	*1.5*	*-0.6*
TFC	**76**	**81**	**94**	**69**	**66**	**67**	**100**	**100**	**1.3**	**-0.2**
Coal	16	16	16	15	13	11	17	16	-0.3	-2.0
Oil	29	32	37	27	27	25	40	37	1.7	-0.1
Gas	2	2	3	2	2	3	3	5	1.6	2.4
Electricity	20	22	29	18	18	21	31	31	2.4	0.9
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	8	8	8	7	5	6	9	9	-0.4	-1.9
Other renewables	0	0	1	0	1	2	1	3	8.3	11.8
Industry	**27**	**28**	**30**	**25**	**24**	**23**	**100**	**100**	**0.8**	**-0.3**
Coal	10	11	11	10	9	8	36	33	0.4	-1.2
Oil	2	1	1	1	1	1	5	5	-0.4	-1.1
Gas	2	2	2	2	2	2	8	9	1.4	0.7
Electricity	11	12	13	10	10	10	43	41	1.0	-0.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	2	2	2	2	2	2	8	11	1.9	2.1
Other renewables	0	0	0	0	0	0	0	1	n.a.	n.a.
Transport	**23**	**25**	**31**	**21**	**22**	**23**	**100**	**100**	**2.3**	**0.9**
Oil	22	24	30	20	20	19	96	84	2.2	0.2
Electricity	0	0	0	0	1	1	2	4	2.2	5.0
Biofuels	0	0	1	1	1	2	2	9	n.a.	n.a.
Other fuels	0	0	0	0	0	1	0	4	18.1	48.2
Buildings	**20**	**21**	**25**	**16**	**13**	**14**	**100**	**100**	**1.0**	**-1.4**
Coal	4	4	3	3	3	1	12	8	-2.3	-6.0
Oil	1	1	1	1	1	1	5	5	-0.8	-3.2
Gas	0	0	0	0	0	0	0	1	20.7	20.7
Electricity	8	9	14	7	7	10	59	68	4.0	2.2
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	7	6	5	4	2	1	21	9	-1.6	-7.3
Traditional biomass	*6*	*6*	*5*	*4*	*2*	*1*	*19*	*5*	*-2.0*	*-9.3*
Other renewables	0	0	1	0	1	1	3	9	8.0	10.6
Other	**7**	**7**	**8**	**7**	**7**	**7**	**100**	**100**	**0.5**	**-0.1**
Petrochem. Feedstock	*3*	*3*	*3*	*3*	*3*	*3*	*41*	*42*	*0.6*	*0.1*

South Africa: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**208**	**249**	**252**	**273**	**297**	**327**	**360**	**100**	**100**	**1.6**
Coal	193	226	228	227	200	176	150	91	42	-1.8
Oil	-	0	0	0	0	1	1	0	0	6.7
Gas	-	-	-	4	10	18	25	-	7	n.a.
Nuclear	13	15	13	14	14	26	39	5	11	4.7
Renewables	1	8	10	28	72	107	146	4	40	12.4
Hydro	1	1	1	2	3	4	5	0	1	9.4
Bioenergy	0	0	0	3	9	13	16	0	4	19.7
Wind	-	4	5	13	36	53	70	2	20	12.3
Geothermal	-	-	-	0	0	0	0	-	0	n.a.
Solar PV	-	3	3	8	24	34	46	1	13	11.9
CSP	-	1	1	2	2	4	9	0	2	11.8
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**52**	**56**	**67**	**84**	**98**	**115**	**100**	**100**	**3.2**
Coal	39	42	42	37	34	28	74	24	-1.7
Oil	4	4	4	4	4	3	7	3	-0.6
Gas	-	-	4	8	12	19	-	16	n.a.
Nuclear	2	2	2	2	4	5	3	5	4.4
Renewables	7	8	15	31	41	53	14	46	8.6
Hydro	3	4	4	4	4	4	6	4	0.9
Bioenergy	0	0	1	2	3	4	0	3	12.3
Wind	1	2	5	12	17	22	4	19	10.6
Geothermal	-	-	0	0	0	0	-	0	n.a.
Solar PV	1	2	5	12	16	21	3	18	11.3
CSP	0	0	1	1	1	3	1	2	9.9
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**281**	**412**	**415**	**408**	**381**	**356**	**329**	**100**	**100**	**-1.0**
Coal	231	337	340	323	289	256	222	82	67	-1.8
Oil	49	71	71	79	84	89	93	17	28	1.2
Gas	-	4	4	6	8	12	15	1	4	5.7
Power sector	**189**	**236**	**238**	**226**	**196**	**170**	**140**	**100**	**100**	**-2.3**
Coal	189	236	238	224	192	163	130	100	93	-2.6
Oil	-	0	0	0	0	1	1	0	1	7.4
Gas	-	-	-	1	4	6	9	-	6	n.a.
TFC	**89**	**132**	**134**	**139**	**140**	**142**	**145**	**100**	**100**	**0.4**
Coal	42	60	62	58	55	51	49	46	34	-1.0
Oil	47	68	68	76	81	85	90	51	62	1.2
Transport	*35*	*55*	*54*	*65*	*70*	*75*	*80*	*41*	*55*	*1.7*
Gas	-	4	4	4	5	5	6	3	4	1.7

South Africa: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**286**	**320**	**407**	**251**	**247**	**266**	**100**	**100**	**2.1**	**0.2**
Coal	242	252	256	191	119	27	63	10	0.5	-8.9
Oil	0	0	1	0	1	1	0	0	7.1	5.0
Gas	6	14	28	4	18	30	7	11	n.a.	n.a.
Nuclear	14	14	26	14	14	37	6	14	3.0	4.5
Renewables	25	39	96	41	95	171	24	64	10.4	13.2
Hydro	2	2	5	2	3	5	1	2	9.4	9.4
Bioenergy	3	7	14	3	9	17	3	6	19.0	19.9
Wind	11	15	37	19	47	76	9	28	9.2	12.7
Geothermal	0	0	0	0	0	0	0	0	n.a.	n.a.
Solar PV	7	13	35	13	31	61	9	23	10.7	13.4
CSP	2	2	6	4	6	12	1	4	9.8	13.4
Marine	-	-	-	0	0	0	-	0	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**70**	**81**	**114**	**71**	**90**	**114**	**100**	**100**	**3.1**	**3.1**
Coal	45	45	47	39	35	21	41	19	0.5	-2.9
Oil	4	4	3	3	3	3	3	3	-0.5	-0.7
Gas	5	9	17	4	6	9	15	8	n.a.	n.a.
Nuclear	2	2	4	2	2	5	3	5	2.7	4.4
Renewables	14	19	38	21	40	65	33	57	6.9	9.5
Hydro	4	4	4	4	4	4	4	4	0.9	0.9
Bioenergy	1	2	3	1	2	4	3	3	11.7	12.6
Wind	4	5	12	8	16	23	10	21	7.7	11.0
Geothermal	0	0	0	0	0	0	0	0	n.a.	n.a.
Solar PV	4	7	16	8	16	29	14	26	10.2	13.0
CSP	1	1	2	1	2	4	2	3	8.0	11.6
Marine	-	-	-	0	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**427**	**441**	**451**	**364**	**281**	**162**	**100**	**100**	**0.4**	**-4.0**
Coal	339	343	330	284	196	77	73	47	-0.1	-6.3
Oil	81	88	105	75	73	68	23	42	1.7	-0.2
Gas	7	10	16	6	11	17	3	11	6.0	6.4
Power sector	**240**	**248**	**242**	**191**	**115**	**14**	**100**	**100**	**0.1**	**-11.7**
Coal	238	243	232	189	108	3	96	20	-0.1	-17.6
Oil	0	0	1	0	0	0	0	3	7.8	5.5
Gas	2	5	10	1	6	10	4	76	n.a.	n.a.
TFC	**143**	**148**	**164**	**129**	**121**	**104**	**100**	**100**	**0.9**	**-1.1**
Coal	60	59	57	53	46	32	35	31	-0.4	-2.8
Oil	78	85	101	72	70	65	62	63	1.8	-0.2
Transport	*66*	*73*	*90*	*60*	*61*	*57*	*55*	*55*	*2.2*	*0.2*
Gas	4	5	6	5	5	7	4	6	1.6	2.1

Middle East: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**353**	**729**	**740**	**846**	**957**	**1 085**	**1 200**	**100**	**100**	**2.1**
Coal	2	3	3	6	7	8	9	0	1	4.5
Oil	205	320	319	353	378	407	446	43	37	1.5
Gas	145	401	412	464	535	605	658	56	55	2.1
Nuclear	-	2	2	12	14	23	25	0	2	12.3
Hydro	1	2	2	2	3	3	3	0	0	2.0
Bioenergy	0	1	1	3	4	8	11	0	1	11.4
Other renewables	0	0	1	6	16	31	47	0	4	19.5
Power sector	**114**	**274**	**280**	**294**	**324**	**363**	**396**	**100**	**100**	**1.5**
Coal	0	0	0	2	3	4	5	0	1	16.2
Oil	47	91	93	92	81	70	64	33	16	-1.6
Gas	65	179	182	181	211	237	257	65	65	1.5
Nuclear	-	2	2	12	14	23	25	1	6	12.3
Hydro	1	2	2	2	3	3	3	1	1	2.0
Bioenergy	-	0	0	1	2	4	6	0	2	35.1
Other renewables	0	0	1	4	10	21	35	0	9	19.9
Other energy sector	**36**	**69**	**71**	**95**	**107**	**118**	**130**	**100**	**100**	**2.6**
Electricity	*8*	*19*	*19*	*23*	*27*	*30*	*34*	*27*	*26*	*2.5*
TFC	**241**	**480**	**485**	**571**	**663**	**767**	**862**	**100**	**100**	**2.5**
Coal	0	3	3	3	3	3	3	1	0	-0.0
Oil	145	226	224	255	286	326	371	46	43	2.2
Gas	65	175	180	217	254	292	318	37	37	2.5
Electricity	29	75	77	92	111	133	153	16	18	3.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	0	1	1	2	3	3	4	0	1	7.2
Other renewables	0	0	0	3	6	9	12	0	1	18.6
Industry	**57**	**114**	**113**	**134**	**148**	**165**	**181**	**100**	**100**	**2.1**
Coal	0	3	3	3	3	3	3	2	1	-0.0
Oil	22	14	11	11	11	12	12	10	7	0.5
Gas	27	83	86	102	113	127	141	76	77	2.2
Electricity	7	14	14	18	20	22	24	12	13	2.3
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	-	-	0	1	1	2	2	0	1	14.5
Other renewables	0	0	0	0	0	0	0	0	0	23.2
Transport	**71**	**135**	**133**	**158**	**177**	**204**	**228**	**100**	**100**	**2.3**
Oil	71	128	126	147	165	190	213	95	93	2.3
Electricity	0	0	0	0	0	0	0	0	0	9.3
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	0	7	7	11	12	14	15	5	6	3.2
Buildings	**77**	**146**	**150**	**176**	**218**	**262**	**293**	**100**	**100**	**3.0**
Coal	0	0	0	0	0	0	0	0	0	-1.6
Oil	26	19	19	17	16	16	16	13	5	-0.7
Gas	29	68	70	86	108	130	140	47	48	3.0
Electricity	21	58	59	70	87	106	124	40	42	3.3
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	0	1	1	1	1	2	2	1	1	4.5
Traditional biomass	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.9*
Other renewables	0	0	0	3	6	9	11	0	4	18.2
Other	**36**	**85**	**89**	**104**	**120**	**136**	**160**	**100**	**100**	**2.6**
Petrochem. Feedstock	*23*	*68*	*71*	*84*	*98*	*113*	*135*	*81*	*85*	*2.8*

Middle East: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**863**	**986**	**1 271**	**791**	**835**	**955**	**100**	**100**	**2.4**	**1.1**
Coal	6	7	10	5	5	5	1	1	4.9	1.9
Oil	358	389	486	314	291	287	38	30	1.9	-0.5
Gas	476	556	704	437	472	451	55	47	2.3	0.4
Nuclear	12	13	23	13	18	45	2	5	12.0	15.3
Hydro	2	3	3	3	3	4	0	0	2.0	2.9
Bioenergy	2	4	10	4	7	14	1	1	10.7	12.5
Other renewables	6	14	36	15	39	150	3	16	18.1	25.7
Power sector	**304**	**339**	**425**	**263**	**266**	**285**	**100**	**100**	**1.8**	**0.1**
Coal	2	3	6	2	2	2	1	1	16.7	12.3
Oil	93	83	76	70	42	16	18	5	-0.8	-7.5
Gas	191	227	286	165	174	107	67	38	2.0	-2.3
Nuclear	12	13	23	13	18	45	5	16	12.0	15.3
Hydro	2	3	3	3	3	4	1	1	2.0	2.9
Bioenergy	1	1	5	2	4	9	1	3	33.5	36.9
Other renewables	3	9	25	8	22	102	6	36	18.3	25.6
Other energy sector	**98**	**113**	**146**	**86**	**88**	**90**	**100**	**100**	**3.2**	**1.0**
Electricity	*24*	*28*	*37*	*21*	*23*	*26*	*25*	*29*	*2.8*	*1.3*
TFC	**580**	**679**	**901**	**551**	**607**	**738**	**100**	**100**	**2.7**	**1.8**
Coal	3	3	3	3	2	2	0	0	0.1	-2.1
Oil	258	295	395	241	246	270	44	37	2.5	0.8
Gas	219	256	324	211	237	281	36	38	2.6	2.0
Electricity	96	117	164	89	103	133	18	18	3.4	2.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	2	3	4	2	3	5	0	1	7.2	7.7
Other renewables	2	5	10	7	17	48	1	6	17.7	25.8
Industry	**134**	**150**	**186**	**128**	**135**	**147**	**100**	**100**	**2.2**	**1.1**
Coal	3	3	3	2	2	2	1	1	0.1	-2.4
Oil	11	11	12	11	10	10	7	7	0.6	-0.4
Gas	102	114	144	97	102	108	77	74	2.3	1.0
Electricity	18	20	24	18	19	22	13	15	2.5	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	1	1	2	1	1	3	1	2	15.0	16.0
Other renewables	0	0	0	0	0	1	0	1	22.3	34.7
Transport	**160**	**181**	**245**	**150**	**155**	**174**	**100**	**100**	**2.7**	**1.2**
Oil	150	172	235	137	132	127	96	73	2.7	0.0
Electricity	0	0	0	0	0	1	0	0	2.8	12.6
Biofuels	-	-	-	-	-	0	-	0	n.a.	n.a.
Other fuels	9	9	10	13	23	46	4	27	1.4	8.5
Buildings	**183**	**228**	**311**	**172**	**204**	**271**	**100**	**100**	**3.2**	**2.6**
Coal	0	0	0	0	0	0	0	0	-1.6	-4.7
Oil	17	18	19	16	15	14	6	5	-0.1	-1.4
Gas	89	113	147	82	93	105	47	39	3.3	1.7
Electricity	74	92	134	67	80	105	43	39	3.6	2.5
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	1	1	2	1	1	2	1	1	4.0	3.7
Traditional biomass	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0.9*	*-7.3*
Other renewables	2	5	9	6	16	46	3	17	17.3	25.6
Other	**103**	**119**	**159**	**101**	**113**	**147**	**100**	**100**	**2.6**	**2.2**
Petrochem. Feedstock	*83*	*97*	*133*	*81*	*93*	*126*	*84*	*86*	*2.8*	*2.5*

Middle East: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**430**	**1 082**	**1 106**	**1 326**	**1 591**	**1 889**	**2 167**	**100**	**100**	**3.0**
Coal	0	0	0	11	15	21	27	0	1	19.0
Oil	175	305	311	329	306	271	249	28	11	-1.0
Gas	246	746	760	874	1 082	1 260	1 402	69	65	2.7
Nuclear	-	7	7	46	55	88	96	1	4	12.3
Renewables	8	23	28	65	133	249	394	3	18	12.2
Hydro	8	21	23	27	30	32	36	2	2	2.0
Bioenergy	-	0	0	2	6	14	23	0	1	35.1
Wind	0	1	1	9	27	56	100	0	5	20.2
Geothermal	-	-	-	0	0	0	0	-	0	n.a.
Solar PV	-	1	3	23	57	118	189	0	9	19.8
CSP	-	0	1	4	13	29	46	0	2	20.9
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**309**	**318**	**408**	**478**	**566**	**648**	**100**	**100**	**3.1**
Coal	0	0	3	4	5	7	0	1	14.2
Oil	88	88	95	87	81	76	28	12	-0.6
Gas	203	211	267	312	352	379	66	59	2.6
Nuclear	1	1	7	9	14	15	0	2	12.3
Renewables	18	18	37	66	113	171	6	26	10.2
Hydro	16	17	19	20	22	23	5	4	1.4
Bioenergy	0	0	0	1	2	4	0	1	26.2
Wind	0	0	3	10	21	37	0	6	21.7
Geothermal	-	-	0	0	0	0	-	0	n.a.
Solar PV	1	1	12	29	58	91	0	14	21.2
CSP	0	0	2	5	10	16	0	2	24.6
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**880**	**1 769**	**1 754**	**1 936**	**2 123**	**2 326**	**2 496**	**100**	**100**	**1.5**
Coal	4	14	13	22	25	30	34	1	1	4.3
Oil	556	884	848	913	938	982	1 034	48	41	0.9
Gas	320	871	893	1 001	1 161	1 314	1 428	51	57	2.1
Power sector	**304**	**708**	**720**	**723**	**763**	**795**	**826**	**100**	**100**	**0.6**
Coal	1	2	1	9	13	18	22	0	3	16.2
Oil	149	285	291	288	254	220	201	40	24	-1.6
Gas	154	421	428	426	496	557	603	60	73	1.5
TFC	**508**	**918**	**889**	**1 027**	**1 161**	**1 321**	**1 445**	**100**	**100**	**2.1**
Coal	2	11	11	11	11	11	11	1	1	-0.0
Oil	374	548	507	568	622	699	769	57	53	1.8
Transport	*211*	*382*	*378*	*441*	*494*	*569*	*636*	*43*	*44*	*2.3*
Gas	132	359	371	448	528	611	665	42	46	2.6

Middle East: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 379**	**1 677**	**2 329**	**1 269**	**1 459**	**1 833**	**100**	**100**	**3.3**	**2.2**
Coal	11	16	30	9	10	12	1	1	19.6	14.9
Oil	333	312	298	249	156	57	13	3	-0.2	-7.1
Gas	925	1 177	1 592	834	947	634	68	35	3.3	-0.8
Nuclear	46	51	89	52	70	174	4	9	12.0	15.3
Renewables	63	121	320	125	276	956	14	52	11.2	16.6
Hydro	27	30	36	32	36	45	2	2	2.0	2.9
Bioenergy	2	5	17	8	13	30	1	2	33.3	36.8
Wind	8	22	63	28	112	340	3	19	17.8	26.8
Geothermal	0	0	0	0	0	0	0	0	n.a.	n.a.
Solar PV	22	56	185	52	92	339	8	18	19.7	22.9
CSP	4	9	19	6	22	201	1	11	16.3	28.9
Marine	-	-	-	0	0	1	-	0	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**406**	**477**	**635**	**437**	**500**	**772**	**100**	**100**	**3.0**	**3.9**
Coal	3	4	7	3	3	3	1	0	14.7	10.0
Oil	96	89	85	93	80	72	13	9	-0.1	-0.8
Gas	264	313	382	271	279	272	60	35	2.6	1.1
Nuclear	7	8	13	7	10	24	2	3	11.9	14.7
Renewables	36	61	145	64	127	399	23	52	9.4	14.3
Hydro	19	20	23	22	24	28	4	4	1.5	2.3
Bioenergy	0	1	3	1	2	6	0	1	24.6	28.5
Wind	3	8	23	11	43	123	4	16	19.3	28.2
Geothermal	0	0	0	0	0	0	0	0	n.a.	n.a.
Solar PV	12	29	89	27	49	170	14	22	21.1	24.6
CSP	2	3	6	2	8	72	1	9	19.8	33.1
Marine	-	-	-	0	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**1 981**	**2 209**	**2 724**	**1 752**	**1 702**	**1 477**	**100**	**100**	**1.9**	**-0.7**
Coal	22	26	37	19	18	16	1	1	4.6	1.0
Oil	929	972	1 157	796	684	563	42	38	1.4	-1.8
Gas	1 030	1 211	1 530	937	1 000	898	56	61	2.4	0.0
Power sector	**747**	**806**	**936**	**614**	**548**	**296**	**100**	**100**	**1.1**	**-3.8**
Coal	9	13	24	8	9	10	3	3	16.7	12.3
Oil	291	259	239	218	132	49	26	17	-0.8	-7.5
Gas	447	533	672	388	407	238	72	80	2.0	-2.5
TFC	**1 043**	**1 194**	**1 536**	**972**	**998**	**1 041**	**100**	**100**	**2.4**	**0.7**
Coal	11	11	11	9	8	6	1	1	0.1	-2.9
Oil	580	649	847	530	509	482	55	46	2.3	-0.2
Transport	*450*	*515*	*702*	*410*	*396*	*379*	*46*	*36*	*2.7*	*0.0*
Gas	452	534	678	433	481	553	44	53	2.7	1.8

Eurasia: New Policies Scenario

	Energy demand (Mtoe)							**Shares** (%)		**CAAGR** (%)
	2000	**2016**	**2017e**	**2025**	**2030**	**2035**	**2040**	**2017e**	**2040**	**2017e-40**
TPED	**742**	**881**	**911**	**943**	**960**	**986**	**1 019**	**100**	**100**	**0.5**
Coal	141	152	157	160	154	150	148	17	15	-0.3
Oil	154	184	188	196	197	193	190	21	19	0.1
Gas	386	463	481	495	502	516	531	53	52	0.4
Nuclear	35	52	54	55	61	68	76	6	7	1.5
Hydro	18	21	22	23	25	26	28	2	3	1.1
Bioenergy	8	9	9	11	13	16	21	1	2	3.7
Other renewables	0	0	0	2	8	16	25	0	2	21.7
Power sector	**390**	**396**	**400**	**406**	**413**	**430**	**453**	**100**	**100**	**0.5**
Coal	96	82	82	84	78	75	73	21	16	-0.5
Oil	30	8	8	7	6	5	5	2	1	-2.0
Gas	208	228	229	230	228	231	234	57	52	0.1
Nuclear	35	52	54	55	61	68	76	13	17	1.5
Hydro	18	21	22	23	25	26	28	5	6	1.1
Bioenergy	4	4	4	5	7	9	14	1	3	5.0
Other renewables	0	0	0	2	8	15	24	0	5	22.0
Other energy sector	**107**	**189**	**195**	**194**	**191**	**190**	**192**	**100**	**100**	**-0.1**
Electricity	*26*	*34*	*35*	*34*	*33*	*33*	*34*	*18*	*18*	*-0.0*
TFC	**500**	**551**	**570**	**608**	**627**	**646**	**664**	**100**	**100**	**0.7**
Coal	22	23	24	25	25	26	26	4	4	0.4
Oil	109	141	144	158	162	163	163	25	25	0.5
Gas	156	188	203	212	218	225	233	36	35	0.6
Electricity	63	80	80	91	99	107	114	14	17	1.6
Heat	146	115	114	116	117	118	120	20	18	0.2
Bioenergy	4	4	5	5	6	7	7	1	1	1.9
Other renewables	0	0	0	0	0	1	1	0	0	17.3
Industry	**148**	**194**	**203**	**218**	**224**	**232**	**240**	**100**	**100**	**0.7**
Coal	11	17	18	19	20	21	22	9	9	0.9
Oil	19	28	28	28	27	26	25	14	10	-0.5
Gas	34	69	75	79	81	85	89	37	37	0.7
Electricity	31	35	35	39	42	44	45	17	19	1.1
Heat	53	45	45	50	51	53	55	22	23	0.9
Bioenergy	1	1	1	2	2	3	3	1	1	3.4
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**86**	**112**	**116**	**125**	**130**	**133**	**137**	**100**	**100**	**0.7**
Oil	51	72	73	80	82	82	83	63	60	0.5
Electricity	6	8	8	9	10	11	13	7	9	2.2
Biofuels	0	-	-	-	-	-	-	-	-	n.a.
Other fuels	30	33	35	37	38	40	41	31	30	0.7
Buildings	**207**	**200**	**205**	**210**	**215**	**220**	**225**	**100**	**100**	**0.4**
Coal	10	6	6	5	5	4	4	3	2	-2.2
Oil	11	17	17	19	20	20	20	8	9	0.8
Gas	73	74	79	81	82	84	85	38	38	0.3
Electricity	22	33	34	38	42	46	50	16	22	1.7
Heat	88	67	66	64	63	62	62	32	27	-0.3
Bioenergy	3	3	3	3	3	3	4	1	2	0.8
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	0	0	0	0	0	0	1	0	0	14.6
Other	**59**	**44**	**45**	**55**	**58**	**60**	**62**	**100**	**100**	**1.4**
Petrochem. Feedstock	*29*	*21*	*22*	*31*	*33*	*35*	*37*	*50*	*60*	*2.2*

Eurasia: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**959**	**989**	**1 081**	**902**	**876**	**855**	**100**	**100**	**0.8**	**-0.3**
Coal	164	161	163	128	102	73	15	9	0.2	-3.3
Oil	200	204	204	189	181	157	19	18	0.4	-0.8
Gas	501	520	578	480	450	405	53	47	0.8	-0.7
Nuclear	58	63	79	62	77	93	7	11	1.7	2.4
Hydro	23	25	28	25	30	39	3	5	1.2	2.6
Bioenergy	10	12	17	12	18	37	2	4	2.6	6.2
Other renewables	2	5	13	7	18	50	1	6	18.3	25.4
Power sector	**413**	**426**	**475**	**390**	**378**	**386**	**100**	**100**	**0.8**	**-0.2**
Coal	88	86	89	60	40	21	19	6	0.3	-5.7
Oil	7	6	5	7	6	4	1	1	-2.0	-2.8
Gas	230	235	253	224	197	153	53	40	0.4	-1.7
Nuclear	58	63	79	62	77	93	17	24	1.7	2.4
Hydro	23	25	28	25	30	39	6	10	1.2	2.6
Bioenergy	5	6	9	6	12	29	2	8	3.3	8.5
Other renewables	2	5	13	7	17	46	3	12	18.6	25.4
Other energy sector	**196**	**197**	**210**	**179**	**164**	**139**	**100**	**100**	**0.3**	**-1.5**
Electricity	*35*	*35*	*39*	*31*	*28*	*26*	*18*	*19*	*0.5*	*-1.3*
TFC	**618**	**646**	**702**	**584**	**577**	**566**	**100**	**100**	**0.9**	**-0.0**
Coal	25	26	27	23	22	20	4	4	0.4	-0.8
Oil	161	168	176	152	148	133	25	24	0.9	-0.3
Gas	216	226	248	205	205	206	35	36	0.9	0.1
Electricity	93	102	121	86	89	98	17	17	1.8	0.9
Heat	117	119	123	111	105	95	18	17	0.3	-0.8
Bioenergy	5	6	7	6	6	8	1	1	1.7	2.3
Other renewables	0	0	1	1	1	4	0	1	14.6	25.5
Industry	**220**	**229**	**250**	**209**	**204**	**201**	**100**	**100**	**0.9**	**-0.1**
Coal	19	20	22	18	18	18	9	9	0.9	0.0
Oil	28	27	25	28	27	26	10	13	-0.6	-0.3
Gas	81	86	98	75	73	70	39	35	1.1	-0.3
Electricity	40	42	46	38	38	38	19	19	1.2	0.4
Heat	50	52	56	47	44	41	22	20	0.9	-0.4
Bioenergy	2	2	3	2	3	5	1	3	3.8	5.5
Other renewables	0	0	0	0	0	2	0	1	n.a.	n.a.
Transport	**128**	**135**	**148**	**121**	**120**	**115**	**100**	**100**	**1.0**	**-0.0**
Oil	82	86	93	76	73	60	63	52	1.1	-0.9
Electricity	8	9	11	9	10	14	8	12	1.7	2.6
Biofuels	-	-	-	-	-	-	-	-	n.a.	n.a.
Other fuels	38	39	43	36	38	42	29	36	0.9	0.7
Buildings	**215**	**224**	**240**	**201**	**198**	**194**	**100**	**100**	**0.7**	**-0.3**
Coal	5	5	4	5	3	2	2	1	-1.8	-5.1
Oil	20	21	23	17	17	16	9	8	1.2	-0.4
Gas	82	85	90	79	79	79	38	41	0.6	-0.0
Electricity	40	45	56	35	37	41	23	21	2.2	0.9
Heat	65	65	64	61	58	52	27	27	-0.2	-1.1
Bioenergy	3	3	3	3	3	3	1	1	0.1	-0.6
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	0	0	0	0	1	2	0	1	11.5	21.8
Other	**55**	**59**	**64**	**53**	**55**	**56**	**100**	**100**	**1.5**	**0.9**
Petrochem. Feedstock	*31*	*33*	*37*	*30*	*31*	*34*	*58*	*61*	*2.2*	*1.8*

Eurasia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**1 046**	**1 338**	**1 354**	**1 475**	**1 559**	**1 651**	**1 756**	**100**	**100**	**1.1**
Coal	214	247	249	270	253	243	240	18	14	-0.1
Oil	54	13	13	7	5	3	2	1	0	-7.8
Gas	429	626	631	697	739	760	777	47	44	0.9
Nuclear	133	199	206	212	232	260	289	15	16	1.5
Renewables	216	254	255	289	331	386	447	19	25	2.5
Hydro	213	250	251	271	288	306	321	19	18	1.1
Bioenergy	3	3	3	5	10	20	35	0	2	11.9
Wind	0	0	1	9	23	43	65	0	4	23.1
Geothermal	0	0	1	2	7	13	21	0	1	17.1
Solar PV	-	1	1	2	3	4	5	0	0	8.6
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	0	0	0	-	0	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**322**	**327**	**348**	**359**	**378**	**409**	**100**	**100**	**1.0**
Coal	68	68	62	55	53	50	21	12	-1.3
Oil	9	9	6	3	1	1	3	0	-10.0
Gas	146	150	163	168	170	184	46	45	0.9
Nuclear	28	28	31	34	38	40	9	10	1.6
Renewables	71	72	86	98	115	132	22	32	2.6
Hydro	69	70	77	81	86	90	21	22	1.1
Bioenergy	1	1	2	3	5	8	0	2	7.8
Wind	0	0	4	10	18	26	0	6	22.2
Geothermal	0	0	0	1	2	3	0	1	17.1
Solar PV	0	0	2	3	3	4	0	1	12.3
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	0	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**1 761**	**1 851**	**1 927**	**1 980**	**1 975**	**1 980**	**1 999**	**100**	**100**	**0.2**
Coal	525	459	494	499	472	458	452	26	23	-0.4
Oil	391	405	424	438	442	436	433	22	22	0.1
Gas	845	987	1 008	1 043	1 061	1 086	1 114	52	56	0.4
Power sector	**993**	**920**	**910**	**913**	**884**	**873**	**872**	**100**	**100**	**-0.2**
Coal	409	340	341	349	324	310	302	38	35	-0.5
Oil	95	29	26	22	20	18	17	3	2	-1.9
Gas	488	551	542	543	540	546	553	60	63	0.1
TFC	**697**	**809**	**891**	**929**	**946**	**959**	**973**	**100**	**100**	**0.4**
Coal	113	113	146	143	141	141	143	16	15	-0.1
Oil	262	338	359	381	387	386	383	40	39	0.3
Transport	*151*	*213*	*217*	*236*	*243*	*244*	*245*	*24*	*25*	*0.5*
Gas	323	359	386	405	418	432	447	43	46	0.6

Eurasia: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 507**	**1 616**	**1 881**	**1 388**	**1 393**	**1 467**	**100**	**100**	**1.4**	**0.3**
Coal	285	287	315	166	94	36	17	2	1.0	-8.0
Oil	7	5	2	7	5	2	0	0	-7.9	-7.9
Gas	708	774	881	658	557	348	47	24	1.5	-2.6
Nuclear	221	239	301	236	293	356	16	24	1.7	2.4
Renewables	286	312	382	321	444	725	20	49	1.8	4.6
Hydro	271	288	327	290	344	455	17	31	1.2	2.6
Bioenergy	4	8	21	9	31	92	1	6	9.6	16.7
Wind	7	8	17	13	47	123	1	8	16.0	26.6
Geothermal	2	5	13	6	15	39	1	3	14.6	20.3
Solar PV	2	3	4	3	6	15	0	1	7.8	14.0
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	0	0	0	0	0	1	0	0	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**351**	**362**	**422**	**342**	**363**	**434**	**100**	**100**	**1.1**	**1.2**
Coal	66	61	63	52	35	16	15	4	-0.3	-6.2
Oil	6	3	1	6	3	1	0	0	-10.0	-10.0
Gas	164	171	205	153	149	151	49	35	1.4	0.0
Nuclear	32	35	41	35	40	49	10	11	1.7	2.4
Renewables	84	91	109	96	135	216	26	50	1.8	4.9
Hydro	77	81	92	83	97	126	22	29	1.2	2.6
Bioenergy	2	3	5	3	8	21	1	5	5.6	12.2
Wind	3	3	7	6	22	48	2	11	15.2	25.5
Geothermal	0	1	2	1	2	5	0	1	14.6	20.3
Solar PV	2	2	4	3	6	15	1	3	11.4	18.3
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	0	0	0	0	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**2 020**	**2 065**	**2 204**	**1 813**	**1 617**	**1 322**	**100**	**100**	**0.6**	**-1.6**
Coal	518	507	521	386	287	182	24	14	0.2	-4.3
Oil	447	460	476	419	397	336	22	25	0.5	-1.0
Gas	1 055	1 097	1 207	1 008	933	805	55	61	0.8	-1.0
Power sector	**933**	**933**	**981**	**799**	**640**	**445**	**100**	**100**	**0.3**	**-3.1**
Coal	367	357	367	247	163	84	37	19	0.3	-5.9
Oil	22	20	17	22	19	14	2	3	-1.9	-2.8
Gas	544	556	597	530	459	347	61	78	0.4	-1.9
TFC	**946**	**981**	**1 044**	**890**	**863**	**785**	**100**	**100**	**0.7**	**-0.6**
Coal	144	143	146	133	120	94	14	12	-0.0	-1.9
Oil	389	404	422	364	349	299	40	38	0.7	-0.8
Transport	*242*	*255*	*276*	*226*	*216*	*178*	*26*	*23*	*1.1*	*-0.8*
Gas	413	433	476	393	394	392	46	50	0.9	0.1

Russia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**621**	**705**	**730**	**745**	**744**	**754**	**769**	**100**	**100**	**0.2**
Coal	120	113	117	115	107	103	99	16	13	-0.7
Oil	126	149	152	156	154	148	143	21	19	-0.3
Gas	319	367	383	390	389	391	395	52	51	0.1
Nuclear	34	52	53	55	58	65	73	7	9	1.4
Hydro	14	16	16	17	18	19	19	2	3	0.9
Bioenergy	7	8	8	9	11	14	18	1	2	3.5
Other renewables	0	0	0	2	7	14	22	0	3	22.5
Power sector	**342**	**334**	**337**	**342**	**344**	**357**	**372**	**100**	**100**	**0.4**
Coal	80	61	61	61	54	51	49	18	13	-1.0
Oil	23	7	7	6	6	5	5	2	1	-1.3
Gas	186	195	196	197	195	193	191	58	51	-0.1
Nuclear	34	52	53	55	58	65	73	16	20	1.4
Hydro	14	16	16	17	18	19	19	5	5	0.9
Bioenergy	4	4	4	5	6	9	13	1	4	4.9
Other renewables	0	0	0	2	7	14	22	0	6	22.4
Other energy sector	**90**	**145**	**150**	**145**	**138**	**134**	**133**	**100**	**100**	**-0.5**
Electricity	*22*	*28*	*28*	*28*	*28*	*28*	*28*	*19*	*21*	*0.0*
TFC	**418**	**447**	**462**	**482**	**489**	**496**	**502**	**100**	**100**	**0.4**
Coal	18	12	12	12	11	11	10	3	2	-1.0
Oil	91	112	113	123	124	123	120	25	24	0.3
Gas	117	151	164	167	168	171	174	36	35	0.3
Electricity	52	64	64	71	77	82	86	14	17	1.3
Heat	137	105	104	105	104	105	106	23	21	0.0
Bioenergy	3	4	4	4	4	5	5	1	1	1.2
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Industry	**127**	**165**	**173**	**182**	**184**	**188**	**192**	**100**	**100**	**0.5**
Coal	7	8	9	9	9	9	8	5	4	-0.2
Oil	16	23	24	24	23	22	21	14	11	-0.6
Gas	26	62	68	69	70	72	75	39	39	0.4
Electricity	27	28	28	31	32	33	33	16	17	0.8
Heat	50	43	43	48	49	51	52	25	27	0.8
Bioenergy	1	1	1	2	2	2	2	1	1	2.2
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**74**	**94**	**98**	**103**	**105**	**105**	**106**	**100**	**100**	**0.3**
Oil	42	58	59	62	63	61	59	60	56	0.0
Electricity	5	7	7	8	9	10	11	7	11	2.1
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	27	30	32	33	33	34	35	33	33	0.4
Buildings	**165**	**152**	**156**	**153**	**154**	**154**	**154**	**100**	**100**	**-0.0**
Coal	10	3	3	2	2	1	1	2	1	-4.8
Oil	7	10	10	11	11	11	11	6	7	0.6
Gas	47	49	54	53	52	51	51	35	33	-0.2
Electricity	18	27	27	30	33	36	38	18	25	1.5
Heat	82	60	59	55	53	52	50	38	33	-0.7
Bioenergy	2	2	2	2	2	2	2	2	2	0.0
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Other	**51**	**36**	**36**	**44**	**46**	**48**	**49**	**100**	**100**	**1.4**
Petrochem. Feedstock	*28*	*18*	*19*	*26*	*28*	*30*	*32*	*52*	*65*	*2.4*

Russia: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**757**	**768**	**817**	**717**	**685**	**661**	**100**	**100**	**0.5**	**-0.4**
Coal	119	113	111	93	69	47	14	7	-0.2	-3.9
Oil	159	159	153	151	143	121	19	18	0.0	-1.0
Gas	394	403	431	378	348	304	53	46	0.5	-1.0
Nuclear	57	60	76	61	72	85	9	13	1.6	2.1
Hydro	17	18	20	18	21	27	2	4	1.1	2.4
Bioenergy	9	10	14	10	16	33	2	5	2.3	6.2
Other renewables	2	5	11	6	16	44	1	7	19.1	26.2
Power sector	**348**	**355**	**390**	**333**	**319**	**327**	**100**	**100**	**0.6**	**-0.1**
Coal	65	61	62	45	27	16	16	5	0.1	-5.7
Oil	6	6	5	6	6	4	1	1	-1.3	-2.1
Gas	196	201	207	191	166	126	53	38	0.2	-1.9
Nuclear	57	60	76	61	72	85	19	26	1.6	2.1
Hydro	17	18	20	18	21	27	5	8	1.1	2.4
Bioenergy	5	6	9	6	12	28	2	9	3.2	8.4
Other renewables	1	5	11	6	15	41	3	12	19.0	25.8
Other energy sector	**147**	**142**	**144**	**134**	**118**	**96**	**100**	**100**	**-0.2**	**-1.9**
Electricity	*29*	*29*	*32*	*26*	*24*	*21*	*22*	*22*	*0.5*	*-1.2*
TFC	**491**	**506**	**534**	**464**	**454**	**434**	**100**	**100**	**0.6**	**-0.3**
Coal	12	11	10	11	9	7	2	2	-1.0	-2.2
Oil	125	129	130	119	115	101	24	23	0.6	-0.5
Gas	171	176	189	162	159	157	35	36	0.6	-0.2
Electricity	73	79	91	67	69	75	17	17	1.6	0.7
Heat	106	106	109	101	95	85	20	20	0.2	-0.9
Bioenergy	4	4	5	4	5	5	1	1	1.1	1.2
Other renewables	0	0	0	0	1	3	0	1	n.a.	n.a.
Industry	**184**	**189**	**201**	**175**	**168**	**162**	**100**	**100**	**0.7**	**-0.3**
Coal	9	9	8	8	8	7	4	4	-0.3	-1.1
Oil	23	22	20	23	23	22	10	14	-0.7	-0.3
Gas	71	74	83	66	63	60	41	37	0.9	-0.5
Electricity	31	32	34	30	29	29	17	18	0.9	0.2
Heat	48	49	53	45	43	39	27	24	0.9	-0.4
Bioenergy	2	2	2	2	2	3	1	2	2.3	3.9
Other renewables	0	0	0	0	0	2	0	1	n.a.	n.a.
Transport	**105**	**109**	**115**	**99**	**97**	**89**	**100**	**100**	**0.7**	**-0.4**
Oil	64	66	67	60	56	43	59	49	0.6	-1.3
Electricity	8	9	10	8	9	13	9	14	1.6	2.5
Biofuels	-	-	-	-	-	-	-	-	n.a.	n.a.
Other fuels	34	35	37	31	32	33	32	37	0.6	0.2
Buildings	**157**	**161**	**167**	**147**	**144**	**137**	**100**	**100**	**0.3**	**-0.5**
Coal	2	2	1	2	1	0	1	0	-4.5	-12.6
Oil	11	12	13	10	10	9	8	6	1.2	-0.6
Gas	54	54	56	53	52	51	33	37	0.1	-0.2
Electricity	32	36	43	27	29	31	26	23	2.0	0.5
Heat	55	54	52	53	50	43	31	32	-0.5	-1.3
Bioenergy	2	2	2	2	2	2	1	1	-0.1	-1.6
Traditional biomass	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*n.a.*	*n.a.*
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Other	**45**	**47**	**51**	**43**	**44**	**45**	**100**	**100**	**1.5**	**1.0**
Petrochem. Feedstock	*26*	*28*	*32*	*26*	*27*	*29*	*62*	*65*	*2.3*	*2.0*

Russia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**876**	**1 076**	**1 087**	**1 173**	**1 226**	**1 284**	**1 346**	**100**	**100**	**0.9**
Coal	176	171	172	183	162	155	149	16	11	-0.6
Oil	33	8	8	6	5	3	2	1	0	-5.9
Gas	370	512	515	565	594	588	576	47	43	0.5
Nuclear	131	197	203	210	222	249	279	19	21	1.4
Renewables	167	188	189	209	244	290	341	17	25	2.6
Hydro	164	185	186	195	207	219	227	17	17	0.9
Bioenergy	3	2	2	5	9	19	34	0	3	12.1
Wind	0	0	0	7	19	38	58	0	4	28.3
Geothermal	0	0	1	2	6	12	19	0	1	16.6
Solar PV	-	0	1	1	2	3	4	0	0	8.4
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	0	0	0	-	0	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**259**	**262**	**268**	**273**	**285**	**304**	**100**	**100**	**0.7**
Coal	52	52	44	36	33	31	20	10	-2.2
Oil	4	4	2	2	1	1	1	0	-7.0
Gas	122	125	129	130	127	133	48	44	0.3
Nuclear	28	28	30	32	36	38	11	13	1.4
Renewables	53	54	62	73	86	100	21	33	2.7
Hydro	51	52	55	58	61	63	20	21	0.8
Bioenergy	1	1	2	3	5	8	1	3	7.7
Wind	0	0	3	9	16	23	0	8	26.7
Geothermal	0	0	0	1	2	3	0	1	16.6
Solar PV	0	0	1	2	2	3	0	1	13.0
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	0	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**1 456**	**1 407**	**1 462**	**1 477**	**1 437**	**1 408**	**1 384**	**100**	**100**	**-0.2**
Coal	443	324	356	347	312	296	281	24	20	-1.0
Oil	318	310	314	320	316	303	294	21	21	-0.3
Gas	695	773	792	810	809	809	810	54	59	0.1
Power sector	**860**	**754**	**741**	**742**	**709**	**691**	**674**	**100**	**100**	**-0.4**
Coal	347	257	257	256	228	217	206	35	31	-1.0
Oil	75	25	22	21	19	17	17	3	2	-1.3
Gas	438	472	462	465	462	457	452	62	67	-0.1
TFC	**541**	**591**	**654**	**660**	**656**	**646**	**638**	**100**	**100**	**-0.1**
Coal	94	63	94	85	79	74	70	14	11	-1.3
Oil	212	254	260	271	270	261	253	40	40	-0.1
Transport	*126*	*171*	*174*	*184*	*185*	*180*	*176*	*27*	*28*	*0.0*
Gas	235	274	299	304	306	310	315	46	49	0.2

Russia: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total generation	**1 196**	**1 269**	**1 445**	**1 102**	**1 095**	**1 139**	**100**	**100**	**1.2**	**0.2**
Coal	196	191	214	121	61	24	15	2	1.0	-8.3
Oil	6	5	2	6	5	2	0	0	-5.9	-5.9
Gas	568	617	655	509	418	228	45	20	1.1	-3.5
Nuclear	219	229	290	231	274	326	20	29	1.6	2.1
Renewables	207	228	283	236	337	560	20	49	1.8	4.8
Hydro	196	209	237	210	250	318	16	28	1.1	2.4
Bioenergy	4	7	20	8	30	89	1	8	9.7	16.9
Wind	4	5	11	9	41	106	1	9	19.2	31.7
Geothermal	2	5	12	6	13	36	1	3	14.3	19.8
Solar PV	1	2	3	2	4	10	0	1	7.3	13.2
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	0	0	0	0	0	1	0	0	n.a.	n.a.

	Power generation capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total capacity	**270**	**275**	**313**	**257**	**264**	**302**	**100**	**100**	**0.8**	**0.6**
Coal	46	41	42	37	23	9	14	3	-0.9	-7.3
Oil	2	2	1	2	2	1	0	0	-7.0	-7.0
Gas	129	132	149	114	99	83	48	27	0.8	-1.8
Nuclear	31	33	40	34	38	45	13	15	1.6	2.1
Renewables	60	66	80	70	102	164	25	54	1.7	4.9
Hydro	55	59	66	60	70	87	21	29	1.0	2.2
Bioenergy	2	2	5	3	8	20	2	7	5.5	12.1
Wind	2	2	4	5	19	41	1	14	17.9	29.9
Geothermal	0	1	2	1	2	5	1	2	14.2	19.8
Solar PV	1	2	3	2	3	10	1	3	11.8	18.6
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	0	0	0	0	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2025	**2030**	**2040**	**2025**	**2030**	**2040**	**2040**		**2017e-40**	
	Current Policies			**Sustainable Development**			**CPS**	**SDS**	**CPS**	**SDS**
Total CO_2	**1 508**	**1 509**	**1 544**	**1 365**	**1 179**	**921**	**100**	**100**	**0.2**	**-2.0**
Coal	363	341	337	272	180	101	22	11	-0.2	-5.3
Oil	326	329	324	307	288	230	21	25	0.1	-1.3
Gas	819	838	883	786	712	590	57	64	0.5	-1.3
Power sector	**757**	**749**	**766**	**662**	**518**	**357**	**100**	**100**	**0.1**	**-3.1**
Coal	272	256	260	189	113	62	34	17	0.1	-6.0
Oil	20	19	17	21	19	14	2	4	-1.3	-2.1
Gas	464	474	489	452	387	282	64	79	0.2	-2.1
TFC	**675**	**684**	**696**	**635**	**602**	**517**	**100**	**100**	**0.3**	**-1.0**
Coal	86	81	72	78	64	37	10	7	-1.2	-4.0
Oil	278	283	282	261	246	198	40	38	0.3	-1.2
Transport	*189*	*194*	*199*	*177*	*167*	*129*	*29*	*25*	*0.6*	*-1.3*
Gas	311	321	342	296	292	283	49	55	0.6	-0.2

Asia Pacific: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**3 012**	**5 639**	**5 789**	**6 803**	**7 344**	**7 798**	**8 201**	**100**	**100**	**1.5**
Coal	1 085	2 727	2 763	2 930	3 018	3 072	3 108	48	38	0.5
Oil	957	1 415	1 457	1 688	1 778	1 818	1 838	25	22	1.0
Gas	257	604	637	867	1 004	1 135	1 267	11	15	3.0
Nuclear	132	122	132	284	347	412	453	2	6	5.5
Hydro	45	140	142	166	191	211	227	2	3	2.0
Bioenergy	509	524	534	601	623	646	672	9	8	1.0
Other renewables	27	108	124	267	382	504	636	2	8	7.4
Power sector	**1 020**	**2 315**	**2 446**	**2 948**	**3 275**	**3 581**	**3 860**	**100**	**100**	**2.0**
Coal	598	1 575	1 658	1 759	1 832	1 882	1 912	68	50	0.6
Oil	96	60	60	46	40	33	28	2	1	-3.2
Gas	120	268	278	340	382	423	471	11	12	2.3
Nuclear	132	122	132	284	347	412	453	5	12	5.5
Hydro	45	140	142	166	191	211	227	6	6	2.0
Bioenergy	6	76	88	137	163	192	223	4	6	4.1
Other renewables	23	75	88	216	319	428	547	4	14	8.3
Other energy sector	**321**	**581**	**582**	**648**	**678**	**701**	**727**	**100**	**100**	**1.0**
Electricity	*68*	*146*	*155*	*183*	*204*	*226*	*247*	*27*	*34*	*2.0*
TFC	**2 074**	**3 801**	**3 880**	**4 619**	**4 994**	**5 302**	**5 577**	**100**	**100**	**1.6**
Coal	378	900	870	895	896	892	890	22	16	0.1
Oil	775	1 248	1 287	1 535	1 638	1 693	1 726	33	31	1.3
Gas	103	288	307	474	567	654	733	8	13	3.9
Electricity	295	803	847	1 106	1 273	1 435	1 593	22	29	2.8
Heat	30	96	103	112	114	114	113	3	2	0.4
Bioenergy	490	432	430	447	443	438	432	11	8	0.0
Other renewables	4	34	36	51	63	76	89	1	2	4.1
Industry	**678**	**1 595**	**1 610**	**1 905**	**2 052**	**2 179**	**2 289**	**100**	**100**	**1.5**
Coal	278	727	704	753	771	783	792	44	35	0.5
Oil	133	167	170	184	185	183	179	11	8	0.2
Gas	39	138	146	240	298	354	407	9	18	4.6
Electricity	151	429	450	562	622	674	718	28	31	2.1
Heat	21	63	68	71	70	67	63	4	3	-0.4
Bioenergy	55	69	71	93	104	113	120	4	5	2.4
Other renewables	0	1	1	2	3	6	9	0	0	12.5
Transport	**347**	**696**	**723**	**925**	**1 038**	**1 115**	**1 186**	**100**	**100**	**2.2**
Oil	342	647	669	821	895	932	961	93	81	1.6
Electricity	4	14	15	31	50	70	92	2	8	8.1
Biofuels	0	9	9	21	29	35	43	1	4	7.1
Other fuels	1	27	30	52	64	78	91	4	8	5.0
Buildings	**802**	**1 080**	**1 107**	**1 230**	**1 302**	**1 373**	**1 447**	**100**	**100**	**1.2**
Coal	77	102	98	63	46	29	19	9	1	-6.9
Oil	118	141	145	140	137	133	128	13	9	-0.5
Gas	36	97	104	148	166	180	189	9	13	2.6
Electricity	125	322	341	459	543	629	719	31	50	3.3
Heat	9	33	35	41	44	47	50	3	3	1.6
Bioenergy	435	355	351	332	309	286	264	32	18	-1.2
Traditional biomass	*426*	*343*	*339*	*316*	*290*	*266*	*243*	*31*	*17*	*-1.4*
Other renewables	3	32	34	47	57	68	78	3	5	3.7
Other	**246**	**430**	**440**	**559**	**602**	**635**	**655**	**100**	**100**	**1.7**
Petrochem. Feedstock	*148*	*234*	*245*	*333*	*365*	*393*	*412*	*56*	*63*	*2.3*

Asia Pacific: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**7 007**	**7 740**	**9 040**	**6 257**	**6 260**	**6 304**	**100**	**100**	**2.0**	**0.4**
Coal	3 086	3 354	3 854	2 456	2 038	1 318	43	21	1.5	-3.2
Oil	1 755	1 901	2 089	1 571	1 514	1 229	23	19	1.6	-0.7
Gas	888	1 044	1 362	875	1 026	1 198	15	19	3.4	2.8
Nuclear	272	327	412	311	426	620	5	10	5.1	7.0
Hydro	165	183	209	177	213	271	2	4	1.7	2.8
Bioenergy	594	607	624	524	464	567	7	9	0.7	0.3
Other renewables	248	324	490	344	580	1 100	5	17	6.2	10.0
Power sector	**3 038**	**3 464**	**4 275**	**2 692**	**2 786**	**3 069**	**100**	**100**	**2.5**	**1.0**
Coal	1 864	2 082	2 501	1 363	1 003	426	58	14	1.8	-5.7
Oil	46	41	30	42	36	25	1	1	-3.0	-3.7
Gas	356	411	525	349	404	452	12	15	2.8	2.1
Nuclear	272	327	412	311	426	620	10	20	5.1	7.0
Hydro	165	183	209	177	213	271	5	9	1.7	2.8
Bioenergy	135	153	186	168	210	304	4	10	3.3	5.5
Other renewables	199	266	413	282	494	970	10	32	7.0	11.0
Other energy sector	**675**	**725**	**826**	**599**	**583**	**546**	**100**	**100**	**1.5**	**-0.3**
Electricity	*194*	*223*	*283*	*165*	*169*	*185*	*34*	*34*	*2.6*	*0.8*
TFC	**4 744**	**5 218**	**6 033**	**4 303**	**4 353**	**4 432**	**100**	**100**	**1.9**	**0.6**
Coal	939	966	1 009	838	782	656	17	15	0.6	-1.2
Oil	1 596	1 753	1 962	1 427	1 393	1 149	33	26	1.8	-0.5
Gas	476	574	765	476	572	699	13	16	4.1	3.6
Electricity	1 126	1 310	1 671	1 054	1 180	1 461	28	33	3.0	2.4
Heat	116	121	127	106	103	90	2	2	0.9	-0.6
Bioenergy	443	437	420	340	238	247	7	6	-0.1	-2.4
Other renewables	48	57	77	63	86	129	1	3	3.4	5.8
Industry	**1 951**	**2 139**	**2 476**	**1 818**	**1 864**	**1 897**	**100**	**100**	**1.9**	**0.7**
Coal	774	809	865	702	668	579	35	31	0.9	-0.9
Oil	190	194	195	175	166	146	8	8	0.6	-0.7
Gas	243	306	434	239	292	382	18	20	4.8	4.3
Electricity	575	647	779	534	560	596	31	31	2.4	1.2
Heat	74	76	75	68	63	48	3	3	0.4	-1.5
Bioenergy	93	105	124	93	104	122	5	6	2.5	2.4
Other renewables	1	2	5	6	12	26	0	1	9.2	17.5
Transport	**952**	**1 092**	**1 308**	**866**	**908**	**865**	**100**	**100**	**2.6**	**0.8**
Oil	861	977	1 142	738	701	490	87	57	2.4	-1.3
Electricity	26	36	58	33	68	201	4	23	6.0	11.8
Biofuels	16	22	32	33	53	68	2	8	5.7	9.3
Other fuels	48	57	76	63	86	106	6	12	4.2	5.7
Buildings	**1 276**	**1 372**	**1 563**	**1 073**	**1 004**	**1 068**	**100**	**100**	**1.5**	**-0.2**
Coal	85	74	57	60	40	8	4	1	-2.3	-10.4
Oil	152	153	149	134	123	93	10	9	0.1	-1.9
Gas	151	174	210	140	156	166	13	16	3.1	2.1
Electricity	470	566	764	436	498	608	49	57	3.6	2.5
Heat	41	45	52	38	40	42	3	4	1.8	0.9
Bioenergy	331	307	260	211	78	52	17	5	-1.3	-8.0
Traditional biomass	*316*	*290*	*243*	*194*	*59*	*29*	*16*	*3*	*-1.4*	*-10.1*
Other renewables	46	54	70	54	70	98	4	9	3.3	4.8
Other	**565**	**615**	**686**	**546**	**577**	**602**	**100**	**100**	**1.9**	**1.4**
Petrochem. Feedstock	*333*	*368*	*425*	*325*	*351*	*384*	*62*	*64*	*2.4*	*2.0*

Asia Pacific: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**4 232**	**11 024**	**11 627**	**14 953**	**17 148**	**19 284**	**21 369**	**100**	**100**	**2.7**
Coal	2 166	6 588	6 918	7 529	7 914	8 225	8 442	59	40	0.9
Oil	392	235	231	166	140	110	87	2	0	-4.2
Gas	585	1 391	1 446	1 926	2 210	2 487	2 840	12	13	3.0
Nuclear	505	467	505	1 091	1 332	1 582	1 740	4	8	5.5
Renewables	563	2 320	2 504	4 220	5 529	6 858	8 237	22	39	5.3
Hydro	519	1 632	1 657	1 936	2 219	2 448	2 634	14	12	2.0
Bioenergy	18	190	222	399	491	595	708	2	3	5.2
Wind	3	308	365	928	1 324	1 767	2 180	3	10	8.1
Geothermal	23	32	34	58	86	114	145	0	1	6.5
Solar PV	1	158	226	885	1 375	1 874	2 477	2	12	11.0
CSP	-	0	- 0	12	30	52	76	0	0	n.a.
Marine	0	1	1	1	4	9	16	0	0	16.3

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**2 864**	**3 052**	**4 305**	**5 094**	**5 891**	**6 676**	**100**	**100**	**3.5**
Coal	1 365	1 420	1 589	1 661	1 747	1 823	47	27	1.1
Oil	119	119	97	85	70	55	4	1	-3.2
Gas	367	386	545	617	693	782	13	12	3.1
Nuclear	113	114	168	194	222	241	4	4	3.3
Renewables	899	1 012	1 866	2 469	3 057	3 642	33	55	5.7
Hydro	517	532	654	746	819	878	17	13	2.2
Bioenergy	42	46	75	91	109	127	2	2	4.5
Wind	189	210	446	606	772	910	7	14	6.6
Geothermal	5	5	9	13	17	22	0	0	6.4
Solar PV	145	219	677	1 002	1 321	1 678	7	25	9.3
CSP	0	-	4	9	15	22	-	0	n.a.
Marine	0	0	1	2	3	6	0	0	14.3

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**7 061**	**15 115**	**15 518**	**16 967**	**17 745**	**18 262**	**18 685**	**100**	**100**	**0.8**
Coal	4 179	10 489	10 713	11 185	11 449	11 600	11 682	69	63	0.4
Oil	2 343	3 294	3 383	3 825	4 026	4 099	4 147	22	22	0.9
Gas	539	1 332	1 421	1 958	2 271	2 563	2 857	9	15	3.1
Power sector	**3 087**	**7 283**	**7 655**	**8 142**	**8 499**	**8 752**	**8 940**	**100**	**100**	**0.7**
Coal	2 495	6 455	6 804	7 193	7 466	7 647	7 739	89	87	0.6
Oil	310	191	192	146	129	107	90	3	1	-3.2
Gas	282	637	660	804	903	998	1 111	9	12	2.3
TFC	**3 627**	**7 304**	**7 318**	**8 220**	**8 621**	**8 867**	**9 081**	**100**	**100**	**0.9**
Coal	1 564	3 833	3 705	3 746	3 729	3 693	3 676	51	40	-0.0
Oil	1 884	2 901	2 982	3 481	3 700	3 796	3 861	41	43	1.1
Transport	*1 028*	*1 939*	*2 007*	*2 466*	*2 690*	*2 802*	*2 891*	*27*	*32*	*1.6*
Gas	179	570	631	992	1 192	1 378	1 544	9	17	4.0

Asia Pacific: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**15 318**	**17 799**	**22 697**	**14 148**	**15 666**	**19 115**	**100**	**100**	**3.0**	**2.2**
Coal	8 018	9 062	11 145	5 818	4 275	1 683	49	9	2.1	-6.0
Oil	168	143	94	143	111	66	0	0	-3.8	-5.3
Gas	2 024	2 385	3 158	1 957	2 251	2 480	14	13	3.5	2.4
Nuclear	1 045	1 256	1 580	1 194	1 634	2 381	7	12	5.1	7.0
Renewables	4 040	4 930	6 697	5 013	7 373	12 481	30	65	4.4	7.2
Hydro	1 918	2 124	2 427	2 054	2 478	3 155	11	17	1.7	2.8
Bioenergy	393	458	573	513	667	1 016	3	5	4.2	6.8
Wind	863	1 145	1 694	1 123	1 901	3 651	7	19	6.9	10.5
Geothermal	54	72	111	81	152	283	0	1	5.3	9.7
Solar PV	803	1 113	1 852	1 222	2 099	4 060	8	21	9.6	13.4
CSP	9	15	30	17	69	292	0	2	0.0	0.0
Marine	1	3	10	2	6	24	0	0	13.6	18.3

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**4 254**	**4 935**	**6 289**	**4 581**	**5 658**	**7 924**	**100**	**100**	**3.2**	**4.2**
Coal	1 638	1 794	2 137	1 474	1 324	966	34	12	1.8	-1.7
Oil	98	86	58	97	84	54	1	1	-3.0	-3.4
Gas	561	653	841	506	559	744	13	9	3.4	2.9
Nuclear	165	186	217	174	226	324	3	4	2.8	4.6
Renewables	1 757	2 154	2 898	2 299	3 402	5 656	46	71	4.7	7.8
Hydro	644	710	807	702	842	1 059	13	13	1.8	3.0
Bioenergy	74	85	104	96	122	179	2	2	3.6	6.1
Wind	415	526	705	540	861	1 521	11	19	5.4	9.0
Geothermal	8	11	17	13	23	42	0	1	5.1	9.5
Solar PV	612	816	1 253	942	1 529	2 759	20	35	7.9	11.7
CSP	3	5	8	6	22	88	0	1	n.a.	n.a.
Marine	0	1	3	1	2	8	0	0	11.4	16.3

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**17 819**	**19 502**	**22 510**	**14 704**	**12 707**	**8 139**	**100**	**100**	**1.6**	**-2.8**
Coal	11 799	12 766	14 591	9 232	7 130	3 191	65	39	1.4	-5.1
Oil	4 012	4 371	4 842	3 501	3 286	2 417	22	30	1.6	-1.5
Gas	2 008	2 365	3 077	1 971	2 291	2 531	14	31	3.4	2.5
Power sector	**8 611**	**9 587**	**11 474**	**6 514**	**4 898**	**1 773**	**100**	**100**	**1.8**	**-6.2**
Coal	7 621	8 484	10 140	5 554	3 837	709	88	40	1.7	-9.4
Oil	148	132	96	136	116	80	1	5	-3.0	-3.7
Gas	842	971	1 239	824	945	984	11	56	2.8	1.8
TFC	**8 582**	**9 252**	**10 299**	**7 630**	**7 284**	**5 910**	**100**	**100**	**1.5**	**-0.9**
Coal	3 927	4 018	4 165	3 450	3 078	2 284	40	39	0.5	-2.1
Oil	3 658	4 027	4 521	3 183	3 011	2 218	44	38	1.8	-1.3
Transport	*2 588*	*2 937*	*3 433*	*2 217*	*2 106*	*1 476*	*33*	*25*	*2.4*	*-1.3*
Gas	997	1 207	1 612	996	1 195	1 408	16	24	4.2	3.6

China: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**1 143**	**2 974**	**3 051**	**3 509**	**3 684**	**3 787**	**3 858**	**100**	**100**	**1.0**
Coal	668	1 924	1 927	1 915	1 861	1 775	1 676	63	43	-0.6
Oil	227	551	577	690	719	719	721	19	19	1.0
Gas	23	172	198	361	432	490	543	7	14	4.5
Nuclear	4	56	65	147	196	247	276	2	7	6.5
Hydro	19	100	100	110	119	128	134	3	3	1.3
Bioenergy	198	113	114	137	149	162	178	4	5	2.0
Other renewables	3	59	69	150	207	267	330	2	9	7.1
Power sector	**380**	**1 286**	**1 364**	**1 643**	**1 786**	**1 901**	**1 984**	**100**	**100**	**1.6**
Coal	334	1 032	1 081	1 108	1 109	1 085	1 043	79	53	-0.2
Oil	16	8	8	7	6	6	5	1	0	-2.0
Gas	5	36	41	101	122	139	160	3	8	6.1
Nuclear	4	56	65	147	196	247	276	5	14	6.5
Hydro	19	100	100	110	119	128	134	7	7	1.3
Bioenergy	1	28	34	65	79	94	110	2	6	5.3
Other renewables	0	27	35	105	153	203	257	3	13	9.0
Other energy sector	**127**	**347**	**347**	**357**	**349**	**338**	**330**	**100**	**100**	**-0.2**
Electricity	*27*	*86*	*91*	*102*	*109*	*113*	*117*	*26*	*35*	*1.1*
TFC	**791**	**1 978**	**2 016**	**2 356**	**2 487**	**2 563**	**2 622**	**100**	**100**	**1.1**
Coal	274	711	676	619	567	511	458	34	17	-1.7
Oil	186	498	523	643	679	684	691	26	26	1.2
Gas	13	114	131	244	299	345	381	6	15	4.8
Electricity	92	449	476	627	711	784	845	24	32	2.5
Heat	26	90	96	105	107	107	106	5	4	0.4
Bioenergy	197	85	80	72	70	68	68	4	3	-0.7
Other renewables	2	32	33	45	54	64	73	2	3	3.5
Industry	**307**	**999**	**1 004**	**1 107**	**1 134**	**1 146**	**1 141**	**100**	**100**	**0.6**
Coal	189	554	527	493	456	415	371	53	32	-1.5
Oil	35	55	61	62	58	54	49	6	4	-1.0
Gas	4	44	51	109	143	175	202	5	18	6.2
Electricity	60	285	299	370	402	428	446	30	39	1.8
Heat	19	60	65	68	67	64	60	6	5	-0.3
Bioenergy	-	-	-	4	6	8	9	-	1	n.a.
Other renewables	0	0	0	1	1	3	5	0	0	10.8
Transport	**87**	**299**	**318**	**432**	**483**	**504**	**532**	**100**	**100**	**2.3**
Oil	85	270	284	364	389	388	392	89	74	1.4
Electricity	1	10	11	23	37	51	65	3	12	8.0
Biofuels	-	2	3	9	14	18	22	1	4	9.6
Other fuels	1	17	20	35	43	48	53	6	10	4.3
Buildings	**319**	**464**	**478**	**538**	**568**	**593**	**615**	**100**	**100**	**1.1**
Coal	64	86	82	48	33	18	9	17	2	-9.0
Oil	20	55	58	52	47	43	37	12	6	-1.9
Gas	4	43	50	87	98	106	109	10	18	3.5
Electricity	26	137	148	214	250	284	313	31	51	3.3
Heat	7	30	31	37	40	43	46	7	7	1.7
Bioenergy	197	83	78	58	48	41	34	16	6	-3.5
Traditional biomass	*197*	*83*	*78*	*56*	*45*	*36*	*29*	*16*	*5*	*-4.2*
Other renewables	2	30	32	43	51	59	67	7	11	3.3
Other	**77**	**216**	**216**	**280**	**302**	**320**	**333**	**100**	**100**	**1.9**
Petrochem. Feedstock	*42*	*114*	*118*	*169*	*189*	*208*	*223*	*55*	*67*	*2.8*

China: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**3 633**	**3 936**	**4 391**	**3 241**	**3 168**	**2 968**	**100**	**100**	**1.6**	**-0.1**
Coal	2 005	2 068	2 143	1 642	1 326	735	49	25	0.5	-4.1
Oil	733	795	855	637	590	448	19	15	1.7	-1.1
Gas	371	460	608	360	446	535	14	18	5.0	4.4
Nuclear	144	188	265	167	245	387	6	13	6.3	8.1
Hydro	109	116	129	114	130	149	3	5	1.1	1.7
Bioenergy	133	140	153	142	149	205	3	7	1.3	2.6
Other renewables	136	169	238	179	282	508	5	17	5.5	9.1
Power sector	**1 680**	**1 890**	**2 233**	**1 493**	**1 515**	**1 565**	**100**	**100**	**2.2**	**0.6**
Coal	1 152	1 242	1 377	891	680	300	62	19	1.1	-5.4
Oil	7	6	5	7	7	5	0	0	-2.0	-2.3
Gas	111	144	191	102	133	162	9	10	7.0	6.2
Nuclear	144	188	265	167	245	387	12	25	6.3	8.1
Hydro	109	116	129	114	130	149	6	10	1.1	1.7
Bioenergy	65	76	94	84	105	147	4	9	4.5	6.6
Other renewables	92	118	172	127	215	416	8	27	7.1	11.3
Other energy sector	**371**	**377**	**386**	**324**	**289**	**223**	**100**	**100**	**0.5**	**-1.9**
Electricity	*105*	*115*	*131*	*92*	*89*	*82*	*34*	*37*	*1.6*	*-0.4*
TFC	**2 444**	**2 641**	**2 926**	**2 223**	**2 218**	**2 128**	**100**	**100**	**1.6**	**0.2**
Coal	659	628	562	579	489	310	19	15	-0.8	-3.3
Oil	684	751	820	593	557	432	28	20	2.0	-0.8
Gas	244	303	409	245	306	378	14	18	5.1	4.7
Electricity	635	729	890	596	659	775	30	36	2.8	2.1
Heat	109	114	120	100	96	84	4	4	1.0	-0.6
Bioenergy	69	64	60	58	43	58	2	3	-1.3	-1.4
Other renewables	44	51	66	51	67	92	2	4	3.0	4.5
Industry	**1 142**	**1 202**	**1 294**	**1 051**	**1 023**	**925**	**100**	**100**	**1.1**	**-0.4**
Coal	511	487	432	458	388	239	33	26	-0.9	-3.4
Oil	64	63	57	57	50	34	4	4	-0.3	-2.6
Gas	111	149	224	112	149	208	17	22	6.7	6.3
Electricity	380	424	499	351	364	374	39	40	2.3	1.0
Heat	71	73	72	65	60	45	6	5	0.5	-1.5
Bioenergy	4	5	8	4	7	13	1	1	n.a.	n.a.
Other renewables	1	1	2	3	6	12	0	1	6.2	15.3
Transport	**450**	**516**	**595**	**404**	**420**	**397**	**100**	**100**	**2.8**	**1.0**
Oil	391	441	488	324	290	180	82	45	2.4	-2.0
Electricity	20	28	46	25	50	123	8	31	6.4	11.0
Biofuels	7	10	16	14	25	33	3	8	8.3	11.6
Other fuels	32	37	45	41	54	61	7	15	3.5	4.9
Buildings	**568**	**612**	**683**	**495**	**487**	**502**	**100**	**100**	**1.6**	**0.2**
Coal	69	59	45	47	29	3	7	1	-2.6	-13.9
Oil	60	58	48	50	41	23	7	5	-0.8	-4.0
Gas	88	102	124	78	89	93	18	19	4.0	2.8
Electricity	214	255	323	200	225	261	47	52	3.5	2.5
Heat	38	41	48	35	36	38	7	8	1.8	0.9
Bioenergy	57	47	33	38	8	8	5	2	-3.7	-9.2
Traditional biomass	*56*	*45*	*29*	*36*	*4*	*2*	*4*	*0*	*-4.2*	*-14.3*
Other renewables	42	49	63	46	57	76	9	15	3.0	3.9
Other	**284**	**310**	**355**	**273**	**287**	**304**	**100**	**100**	**2.2**	**1.5**
Petrochem. Feedstock	*170*	*193*	*237*	*165*	*181*	*207*	*67*	*68*	*3.1*	*2.5*

China: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**1 387**	**6 225**	**6 594**	**8 485**	**9 534**	**10 434**	**11 187**	**100**	**100**	**2.3**
Coal	1 079	4 267	4 446	4 646	4 686	4 616	4 463	67	40	0.0
Oil	47	11	11	6	5	4	3	0	0	-6.2
Gas	18	184	217	595	722	833	962	3	9	6.7
Nuclear	17	213	248	565	754	947	1 058	4	9	6.5
Renewables	226	1 551	1 672	2 674	3 367	4 033	4 701	25	42	4.6
Hydro	222	1 163	1 168	1 274	1 388	1 483	1 557	18	14	1.3
Bioenergy	2	76	94	208	259	313	371	1	3	6.1
Wind	1	237	286	667	899	1 139	1 387	4	12	7.1
Geothermal	0	0	0	1	3	7	15	0	0	21.6
Solar PV	0	75	123	514	793	1 050	1 313	2	12	10.8
CSP	-	0	0	10	24	40	56	0	1	37.3
Marine	0	0	0	0	1	1	2	0	0	24.6

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**1 628**	**1 755**	**2 497**	**2 925**	**3 294**	**3 598**	**100**	**100**	**3.2**
Coal	946	981	1 045	1 069	1 073	1 054	56	29	0.3
Oil	9	9	8	7	7	4	0	0	-3.0
Gas	68	75	159	185	208	232	4	6	5.0
Nuclear	34	37	89	115	136	148	2	4	6.0
Renewables	571	653	1 178	1 519	1 831	2 111	37	59	5.2
Hydro	332	344	409	450	484	510	20	14	1.7
Bioenergy	12	15	32	40	49	58	1	2	6.0
Wind	149	164	324	418	508	590	9	16	5.7
Geothermal	0	0	0	0	1	2	0	0	20.9
Solar PV	78	131	408	602	776	935	7	26	8.9
CSP	0	0	3	7	12	16	0	0	33.6
Marine	0	0	0	0	1	1	0	0	23.5

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**3 139**	**9 071**	**9 255**	**9 689**	**9 647**	**9 374**	**9 054**	**100**	**100**	**-0.1**
Coal	2 549	7 385	7 438	7 243	6 975	6 594	6 161	80	68	-0.8
Oil	547	1 308	1 385	1 597	1 644	1 604	1 582	15	17	0.6
Gas	43	377	433	849	1 028	1 175	1 311	5	14	4.9
Power sector	**1 450**	**4 356**	**4 565**	**4 812**	**4 849**	**4 772**	**4 625**	**100**	**100**	**0.1**
Coal	1 382	4 246	4 441	4 550	4 540	4 424	4 232	97	92	-0.2
Oil	56	26	27	23	21	20	17	1	0	-2.0
Gas	12	84	96	239	288	328	376	2	8	6.1
TFC	**1 542**	**4 429**	**4 389**	**4 531**	**4 442**	**4 238**	**4 053**	**100**	**100**	**-0.3**
Coal	1 083	3 002	2 856	2 516	2 250	1 978	1 729	65	43	-2.2
Oil	439	1 185	1 254	1 481	1 534	1 501	1 484	29	37	0.7
Transport	*258*	*810*	*854*	*1 094*	*1 171*	*1 167*	*1 181*	*19*	*29*	*1.4*
Gas	19	243	279	534	657	759	840	6	21	4.9

China: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**8 604**	**9 821**	**11 883**	**7 996**	**8 695**	**9 970**	**100**	**100**	**2.6**	**1.8**
Coal	4 865	5 313	6 025	3 729	2 831	1 143	51	11	1.3	-5.7
Oil	6	5	3	8	6	2	0	0	-6.2	-7.9
Gas	645	846	1 125	564	670	701	9	7	7.4	5.2
Nuclear	554	721	1 017	640	940	1 485	9	15	6.3	8.1
Renewables	2 533	2 936	3 713	3 055	4 247	6 640	31	67	3.5	6.2
Hydro	1 269	1 352	1 499	1 331	1 511	1 738	13	17	1.1	1.7
Bioenergy	207	248	311	273	353	501	3	5	5.3	7.5
Wind	604	739	1 010	740	1 145	2 070	8	21	5.6	9.0
Geothermal	1	2	7	2	5	20	0	0	18.0	23.2
Solar PV	446	582	863	698	1 180	2 134	7	21	8.8	13.2
CSP	7	12	22	11	53	174	0	2	31.8	44.3
Marine	0	0	2	0	1	3	0	0	22.9	26.6

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**2 436**	**2 760**	**3 278**	**2 659**	**3 231**	**4 231**	**100**	**100**	**2.7**	**3.9**
Coal	1 072	1 140	1 231	990	892	671	38	16	1.0	-1.6
Oil	8	7	4	8	7	4	0	0	-3.0	-3.0
Gas	169	207	269	147	169	191	8	5	5.7	4.2
Nuclear	87	109	139	92	130	198	4	5	5.7	7.3
Renewables	1 085	1 268	1 585	1 404	1 998	3 091	48	73	3.9	7.0
Hydro	406	435	488	436	499	578	15	14	1.5	2.3
Bioenergy	32	39	48	43	56	79	1	2	5.2	7.4
Wind	294	347	428	361	528	875	13	21	4.3	7.6
Geothermal	0	0	1	0	1	3	0	0	17.2	22.4
Solar PV	350	443	612	560	897	1 506	19	36	6.9	11.2
CSP	2	4	6	4	17	48	0	1	28.4	40.3
Marine	0	0	1	0	0	1	0	0	21.8	25.5

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**10 187**	**10 732**	**11 385**	**8 401**	**6 811**	**3 248**	**100**	**100**	**0.9**	**-4.5**
Coal	7 591	7 778	7 971	6 108	4 492	1 286	70	40	0.3	-7.3
Oil	1 722	1 859	1 950	1 449	1 278	802	17	25	1.5	-2.3
Gas	874	1 095	1 463	844	1 041	1 159	13	36	5.4	4.4
Power sector	**5 015**	**5 443**	**6 075**	**3 907**	**2 888**	**698**	**100**	**100**	**1.3**	**-7.8**
Coal	4 731	5 083	5 607	3 643	2 558	367	92	53	1.0	-10.3
Oil	23	21	17	24	22	16	0	2	-2.0	-2.3
Gas	261	339	451	240	308	315	7	45	7.0	5.3
TFC	**4 811**	**4 905**	**4 885**	**4 178**	**3 630**	**2 292**	**100**	**100**	**0.5**	**-2.8**
Coal	2 679	2 503	2 147	2 302	1 778	769	44	34	-1.2	-5.5
Oil	1 600	1 739	1 836	1 342	1 187	742	38	32	1.7	-2.3
Transport	*1 177*	*1 326*	*1 467*	*975*	*874*	*544*	*30*	*24*	*2.4*	*-1.9*
Gas	532	663	901	535	665	780	18	34	5.2	4.6

India: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**441**	**862**	**898**	**1 238**	**1 465**	**1 683**	**1 880**	**100**	**100**	**3.3**
Coal	146	380	400	561	668	773	868	45	46	3.4
Oil	112	217	223	300	350	392	421	25	22	2.8
Gas	23	47	49	81	104	126	147	5	8	4.8
Nuclear	4	10	11	28	43	58	71	1	4	8.6
Hydro	6	12	12	17	22	26	30	1	2	3.9
Bioenergy	149	192	195	220	222	224	224	22	12	0.6
Other renewables	0	6	7	32	55	85	119	1	6	13.1
Power sector	**133**	**329**	**358**	**490**	**595**	**699**	**801**	**100**	**100**	**3.6**
Coal	103	255	276	346	394	441	481	77	60	2.5
Oil	9	8	9	9	9	8	7	2	1	-1.3
Gas	9	14	16	28	39	48	56	4	7	5.5
Nuclear	4	10	11	28	43	58	71	3	9	8.6
Hydro	6	12	12	17	22	26	30	3	4	3.9
Bioenergy	1	25	28	31	35	40	44	8	6	2.1
Other renewables	0	5	6	29	52	80	113	2	14	13.4
Other energy sector	**43**	**89**	**88**	**117**	**140**	**161**	**181**	**100**	**100**	**3.2**
Electricity	*17*	*32*	*34*	*45*	*55*	*66*	*77*	*39*	*42*	*3.5*
TFC	**314**	**572**	**592**	**841**	**998**	**1 152**	**1 290**	**100**	**100**	**3.4**
Coal	33	99	104	173	220	265	309	17	24	4.9
Oil	94	182	187	266	317	364	395	32	31	3.3
Gas	10	32	33	51	63	76	89	6	7	4.4
Electricity	32	95	104	165	212	263	316	18	24	4.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	144	163	163	184	182	179	175	28	14	0.3
Other renewables	0	1	1	2	3	5	7	0	1	9.3
Industry	**83**	**206**	**211**	**337**	**418**	**495**	**567**	**100**	**100**	**4.4**
Coal	26	87	92	162	210	256	302	43	53	5.3
Oil	17	29	25	35	40	44	48	12	8	2.8
Gas	2	21	22	33	39	44	47	10	8	3.4
Electricity	14	36	40	64	80	96	110	19	19	4.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	26	32	32	44	49	54	58	15	10	2.6
Other renewables	0	0	0	0	1	2	2	0	0	18.4
Transport	**32**	**90**	**92**	**147**	**187**	**230**	**263**	**100**	**100**	**4.7**
Oil	31	85	87	135	168	201	223	95	85	4.1
Electricity	1	1	2	3	6	10	14	2	5	10.0
Biofuels	0	1	0	3	4	5	7	0	3	12.9
Other fuels	0	3	3	6	9	13	19	3	7	9.0
Buildings	**156**	**216**	**222**	**261**	**281**	**304**	**330**	**100**	**100**	**1.7**
Coal	7	12	12	12	11	9	7	5	2	-2.0
Oil	19	31	32	36	40	43	46	14	14	1.6
Gas	0	2	2	4	5	7	9	1	3	7.5
Electricity	11	41	45	71	95	123	154	20	47	5.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	119	131	131	137	128	119	109	59	33	-0.8
Traditional biomass	*113*	*124*	*124*	*128*	*119*	*110*	*101*	*56*	*31*	*-0.9*
Other renewables	0	1	1	2	2	3	4	0	1	7.3
Other	**42**	**60**	**67**	**96**	**111**	**122**	**130**	**100**	**100**	**2.9**
Petrochem. Feedstock	*20*	*19*	*24*	*36*	*44*	*49*	*55*	*35*	*42*	*3.7*

India: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**1 277**	**1 532**	**2 024**	**1 107**	**1 185**	**1 358**	**100**	**100**	**3.6**	**1.8**
Coal	595	728	1 009	454	439	376	50	28	4.1	-0.3
Oil	310	370	469	284	309	295	23	22	3.3	1.2
Gas	82	104	145	97	129	211	7	16	4.8	6.5
Nuclear	25	38	56	27	49	78	3	6	7.4	9.0
Hydro	17	21	25	18	24	35	1	3	3.2	4.7
Bioenergy	219	220	217	180	144	162	11	12	0.5	-0.8
Other renewables	31	51	103	47	90	201	5	15	12.4	15.7
Power sector	**518**	**637**	**888**	**427**	**462**	**547**	**100**	**100**	**4.0**	**1.9**
Coal	377	446	604	252	193	56	68	10	3.5	-6.7
Oil	9	10	7	9	9	6	1	1	-0.9	-1.4
Gas	31	41	60	43	62	122	7	22	5.9	9.2
Nuclear	25	38	56	27	49	78	6	14	7.4	9.0
Hydro	17	21	25	18	24	35	3	6	3.2	4.7
Bioenergy	31	33	37	35	41	61	4	11	1.3	3.5
Other renewables	29	48	98	43	83	188	11	34	12.8	16.0
Other energy sector	**125**	**152**	**204**	**110**	**123**	**147**	**100**	**100**	**3.7**	**2.3**
Electricity	*52*	*65*	*93*	*40*	*45*	*58*	*46*	*40*	*4.4*	*2.3*
TFC	**855**	**1 025**	**1 351**	**767**	**840**	**1 001**	**100**	**100**	**3.7**	**2.3**
Coal	176	227	323	162	195	251	24	25	5.1	3.9
Oil	275	336	441	251	279	276	33	28	3.8	1.7
Gas	50	61	83	53	65	86	6	9	4.1	4.3
Electricity	169	217	325	157	194	278	24	28	5.1	4.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	183	182	174	141	98	96	13	10	0.3	-2.3
Other renewables	2	3	5	4	7	14	0	1	8.0	12.8
Industry	**342**	**427**	**582**	**325**	**384**	**482**	**100**	**100**	**4.5**	**3.7**
Coal	164	215	312	151	186	246	54	51	5.5	4.4
Oil	37	43	52	35	38	43	9	9	3.2	2.3
Gas	32	37	44	33	38	45	7	9	3.1	3.2
Electricity	64	81	112	60	69	84	19	17	4.6	3.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	45	51	61	45	50	58	10	12	2.8	2.6
Other renewables	0	1	2	1	3	6	0	1	16.9	23.1
Transport	**149**	**194**	**283**	**137**	**165**	**188**	**100**	**100**	**5.0**	**3.2**
Oil	140	180	257	123	137	124	91	66	4.8	1.5
Electricity	3	3	6	3	9	35	2	18	5.9	14.3
Biofuels	1	2	4	5	8	14	1	7	9.8	16.3
Other fuels	5	8	17	7	10	16	6	9	8.5	8.3
Buildings	**266**	**290**	**348**	**210**	**183**	**209**	**100**	**100**	**2.0**	**-0.3**
Coal	12	12	11	11	9	5	3	2	-0.6	-4.0
Oil	38	42	51	35	37	36	15	17	2.1	0.6
Gas	4	5	9	4	7	11	2	5	7.3	8.5
Electricity	74	100	165	67	86	126	48	60	5.9	4.6
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	137	128	109	90	40	24	31	11	-0.8	-7.1
Traditional biomass	*128*	*119*	*101*	*82*	*31*	*16*	*29*	*8*	*-0.9*	*-8.6*
Other renewables	2	2	3	3	4	7	1	3	6.1	9.9
Other	**98**	**115**	**137**	**95**	**108**	**122**	**100**	**100**	**3.1**	**2.6**
Petrochem. Feedstock	*36*	*44*	*55*	*36*	*43*	*52*	*40*	*43*	*3.7*	*3.5*

India: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**570**	**1 478**	**1 605**	**2 431**	**3 098**	**3 810**	**4 553**	**100**	**100**	**4.6**
Coal	390	1 105	1 194	1 541	1 760	1 989	2 194	74	48	2.7
Oil	29	23	26	28	29	24	21	2	0	-0.9
Gas	56	71	80	155	223	280	336	5	7	6.4
Nuclear	17	38	41	107	167	221	273	3	6	8.6
Renewables	77	240	263	600	919	1 296	1 728	16	38	8.5
Hydro	74	138	142	199	254	300	343	9	8	3.9
Bioenergy	1	44	49	61	74	89	106	3	2	3.4
Wind	2	45	50	158	254	386	493	3	11	10.4
Geothermal	-	-	-	0	1	1	1	-	0	n.a.
Solar PV	0	14	22	181	333	512	770	1	17	16.8
CSP	-	-	- 0	1	3	7	14	0	0	n.a.
Marine	-	-	-	-	0	0	1	-	0	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**353**	**379**	**641**	**848**	**1 116**	**1 420**	**100**	**100**	**5.9**
Coal	214	224	273	297	355	421	59	30	2.8
Oil	8	8	10	12	10	9	2	1	0.8
Gas	29	29	47	60	77	94	8	7	5.2
Nuclear	7	7	16	24	31	39	2	3	8.1
Renewables	96	111	280	428	599	796	29	56	8.9
Hydro	47	48	67	83	96	109	13	8	3.6
Bioenergy	11	11	15	18	21	24	3	2	3.3
Wind	29	33	80	120	172	209	9	15	8.4
Geothermal	-	-	0	0	0	0	-	0	n.a.
Solar PV	9	19	118	206	307	449	5	32	14.7
CSP	-	-	0	1	3	5	-	0	n.a.
Marine	-	-	-	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**885**	**2 075**	**2 195**	**3 076**	**3 673**	**4 242**	**4 738**	**100**	**100**	**3.4**
Coal	572	1 468	1 568	2 182	2 593	2 993	3 360	71	71	3.4
Oil	277	534	527	726	860	982	1 066	24	23	3.1
Gas	36	73	100	169	221	267	312	5	7	5.1
Power sector	**459**	**1 071**	**1 160**	**1 471**	**1 685**	**1 887**	**2 062**	**100**	**100**	**2.5**
Coal	409	1 013	1 095	1 376	1 564	1 750	1 911	94	93	2.5
Oil	28	25	28	28	29	24	21	2	1	-1.3
Gas	22	33	38	67	93	112	131	3	6	5.5
TFC	**393**	**965**	**995**	**1 560**	**1 937**	**2 299**	**2 614**	**100**	**100**	**4.3**
Coal	159	452	469	799	1 021	1 232	1 438	47	55	5.0
Oil	230	476	465	662	792	917	999	47	38	3.4
Transport	*95*	*259*	*266*	*410*	*512*	*612*	*677*	*27*	*26*	*4.1*
Gas	5	38	61	99	124	150	176	6	7	4.7

India: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**2 560**	**3 270**	**4 849**	**2 281**	**2 776**	**3 903**	**100**	**100**	**4.9**	**3.9**
Coal	1 678	1 999	2 745	1 134	884	253	57	6	3.7	-6.5
Oil	28	30	23	28	29	20	0	1	-0.6	-1.1
Gas	167	233	367	235	361	767	8	20	6.8	10.3
Nuclear	95	145	215	102	188	299	4	8	7.4	9.0
Renewables	593	863	1 499	782	1 315	2 563	31	66	7.9	10.4
Hydro	198	241	295	213	284	409	6	10	3.2	4.7
Bioenergy	59	67	80	73	94	170	2	4	2.1	5.5
Wind	157	244	426	205	370	749	9	19	9.7	12.4
Geothermal	0	0	1	0	2	5	0	0	n.a.	n.a.
Solar PV	177	309	693	287	554	1 125	14	29	16.3	18.7
CSP	1	2	4	3	11	105	0	3	0.0	0.0
Marine	-	-	1	0	0	1	0	0	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**652**	**862**	**1 400**	**711**	**992**	**1 647**	**100**	**100**	**5.8**	**6.6**
Coal	289	333	485	247	228	166	35	10	3.4	-1.3
Oil	11	12	10	10	11	9	1	1	1.1	0.4
Gas	47	63	102	49	77	197	7	12	5.6	8.7
Nuclear	14	21	31	15	27	47	2	3	7.2	9.1
Renewables	278	408	709	382	633	1 165	51	71	8.4	10.7
Hydro	66	78	93	71	93	130	7	8	2.9	4.4
Bioenergy	15	16	19	17	22	35	1	2	2.4	5.1
Wind	80	116	181	104	173	312	13	19	7.7	10.3
Geothermal	0	0	0	0	0	1	0	0	n.a.	n.a.
Solar PV	117	197	414	189	342	651	30	40	14.3	16.6
CSP	0	1	1	1	4	36	0	2	n.a.	n.a.
Marine	-	-	0	0	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**3 239**	**3 967**	**5 421**	**2 641**	**2 686**	**2 447**	**100**	**100**	**4.0**	**0.5**
Coal	2 316	2 831	3 909	1 755	1 670	1 300	72	53	4.1	-0.8
Oil	753	916	1 204	680	740	693	22	28	3.7	1.2
Gas	171	219	308	206	276	454	6	19	5.0	6.8
Power sector	**1 597**	**1 899**	**2 563**	**1 130**	**934**	**462**	**100**	**100**	**3.5**	**-3.9**
Coal	1 496	1 772	2 400	1 002	761	157	94	34	3.5	-8.1
Oil	29	30	22	28	29	20	1	4	-0.9	-1.4
Gas	72	96	141	100	145	286	6	62	5.9	9.2
TFC	**1 596**	**2 014**	**2 790**	**1 467**	**1 709**	**1 943**	**100**	**100**	**4.6**	**3.0**
Coal	813	1 051	1 498	747	902	1 133	54	58	5.2	3.9
Oil	687	845	1 130	619	681	647	41	33	3.9	1.5
Transport	*425*	*549*	*780*	*373*	*417*	*377*	*28*	*19*	*4.8*	*1.5*
Gas	96	118	162	102	126	163	6	8	4.3	4.4

Japan: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
TPED	**518**	**426**	**428**	**415**	**403**	**390**	**379**	**100**	**100**	**-0.5**
Coal	97	114	115	94	90	84	78	27	21	-1.7
Oil	255	177	174	148	129	112	97	41	26	-2.5
Gas	66	102	101	81	82	85	86	24	23	-0.7
Nuclear	84	5	9	53	56	58	61	2	16	8.9
Hydro	7	7	7	8	8	9	9	2	2	1.1
Bioenergy	5	14	14	18	18	18	18	3	5	1.0
Other renewables	4	7	8	13	19	25	30	2	8	5.8
Power sector	**221**	**189**	**194**	**195**	**198**	**200**	**202**	**100**	**100**	**0.2**
Coal	48	72	74	53	52	49	47	38	23	-2.0
Oil	29	17	16	10	6	4	2	8	1	-8.7
Gas	48	75	73	48	46	46	44	38	22	-2.2
Nuclear	84	5	9	53	56	58	61	4	30	8.9
Hydro	7	7	7	8	8	9	9	4	4	1.1
Bioenergy	2	7	8	11	11	11	11	4	5	1.5
Other renewables	3	7	8	12	18	23	29	4	14	5.7
Other energy sector	**57**	**33**	**33**	**36**	**35**	**34**	**34**	**100**	**100**	**0.2**
Electricity	*10*	*7*	*7*	*7*	*7*	*8*	*8*	*23*	*23*	*0.3*
TFC	**331**	**294**	**294**	**276**	**263**	**250**	**238**	**100**	**100**	**-0.9**
Coal	21	21	20	19	18	16	14	7	6	-1.5
Oil	202	150	148	129	116	102	90	50	38	-2.1
Gas	22	32	33	35	36	37	38	11	16	0.7
Electricity	81	83	85	84	85	85	86	29	36	0.0
Heat	1	1	1	1	1	1	1	0	0	0.6
Bioenergy	3	6	6	7	7	7	7	2	3	0.3
Other renewables	1	0	0	1	1	2	2	0	1	7.1
Industry	**98**	**82**	**82**	**80**	**76**	**72**	**68**	**100**	**100**	**-0.8**
Coal	21	21	20	19	17	16	14	24	21	-1.5
Oil	32	16	16	15	13	11	10	20	14	-2.2
Gas	8	11	11	13	14	13	13	14	20	0.7
Electricity	34	30	30	29	28	27	26	37	39	-0.6
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	3	4	4	4	4	4	4	5	6	0.0
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**86**	**72**	**70**	**59**	**53**	**48**	**44**	**100**	**100**	**-2.0**
Oil	84	70	68	56	49	42	38	97	85	-2.6
Electricity	2	2	2	2	3	4	5	2	11	5.0
Biofuels	-	0	0	1	1	1	1	1	2	3.9
Other fuels	0	0	0	0	1	1	1	0	2	14.1
Buildings	**100**	**99**	**100**	**98**	**98**	**97**	**97**	**100**	**100**	**-0.1**
Coal	0	0	0	-	-	-	-	0	-	n.a.
Oil	39	23	23	21	19	17	15	23	15	-1.9
Gas	15	21	21	21	22	23	24	21	24	0.5
Electricity	45	52	53	53	53	54	54	53	56	0.1
Heat	1	1	1	1	1	1	1	1	1	0.6
Bioenergy	0	2	2	2	2	2	2	2	2	-0.3
Traditional biomass	-	-	-	-	-	-	-	-	-	*n.a.*
Other renewables	1	0	0	1	1	1	2	0	2	7.0
Other	**47**	**42**	**42**	**38**	**35**	**33**	**29**	**100**	**100**	**-1.6**
Petrochem. Feedstock	*33*	*22*	*23*	*22*	*21*	*19*	*17*	*54*	*59*	*-1.2*

Japan: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**419**	**410**	**392**	**388**	**357**	**314**	**100**	**100**	**-0.4**	**-1.3**
Coal	102	100	93	76	50	32	24	10	-0.9	-5.5
Oil	150	133	107	133	105	59	27	19	-2.1	-4.6
Gas	82	86	95	76	77	54	24	17	-0.3	-2.7
Nuclear	48	48	46	56	64	78	12	25	7.6	10.1
Hydro	8	8	9	8	10	12	2	4	0.9	2.5
Bioenergy	18	18	16	22	23	24	4	8	0.4	2.3
Other renewables	12	17	27	17	27	55	7	17	5.3	8.5
Power sector	**198**	**200**	**206**	**184**	**177**	**182**	**100**	**100**	**0.3**	**-0.3**
Coal	61	63	62	38	16	5	30	3	-0.8	-10.7
Oil	10	6	3	7	3	1	1	0	-7.6	-12.2
Gas	49	48	51	45	45	21	25	11	-1.6	-5.3
Nuclear	48	48	46	56	64	78	22	43	7.6	10.1
Hydro	8	8	9	8	10	12	4	7	0.9	2.5
Bioenergy	11	11	10	14	15	17	5	9	1.2	3.4
Other renewables	12	17	26	15	23	48	13	26	5.3	8.2
Other energy sector	**36**	**36**	**35**	**33**	**32**	**28**	**100**	**100**	**0.3**	**-0.6**
Electricity	*7*	*8*	*8*	*7*	*6*	*6*	*24*	*23*	*0.6*	*-0.6*
TFC	**280**	**270**	**250**	**260**	**235**	**190**	**100**	**100**	**-0.7**	**-1.9**
Coal	20	18	14	18	16	12	6	6	-1.5	-2.4
Oil	131	119	99	118	95	55	40	29	-1.7	-4.2
Gas	35	37	40	33	32	29	16	15	0.9	-0.5
Electricity	86	87	89	81	79	80	36	42	0.2	-0.3
Heat	1	1	1	0	0	0	0	0	0.3	-0.1
Bioenergy	7	7	5	7	7	7	2	4	-1.0	0.4
Other renewables	1	1	1	2	4	7	1	3	5.3	12.9
Industry	**81**	**77**	**70**	**77**	**71**	**59**	**100**	**100**	**-0.7**	**-1.4**
Coal	19	17	14	18	16	11	20	19	-1.5	-2.4
Oil	15	13	10	14	12	8	14	13	-2.1	-3.1
Gas	13	14	14	13	13	11	20	19	0.9	-0.1
Electricity	29	29	27	28	26	24	39	40	-0.5	-1.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	4	4	4	4	4	4	6	7	0.3	-0.1
Other renewables	0	0	0	0	1	1	0	2	n.a.	n.a.
Transport	**60**	**55**	**49**	**54**	**44**	**29**	**100**	**100**	**-1.5**	**-3.8**
Oil	57	52	45	50	38	16	91	57	-1.8	-6.1
Electricity	2	2	3	2	4	9	7	31	3.3	7.9
Biofuels	1	1	1	1	2	2	2	6	3.1	6.6
Other fuels	0	0	0	1	1	2	1	7	9.1	17.4
Buildings	**100**	**101**	**101**	**91**	**86**	**77**	**100**	**100**	**0.1**	**-1.1**
Coal	0	-	-	-	-	-	-	-	n.a.	n.a.
Oil	21	19	15	18	14	6	15	8	-1.7	-5.5
Gas	22	23	25	19	18	16	25	21	0.8	-1.2
Electricity	54	56	59	50	49	47	58	61	0.5	-0.5
Heat	1	1	1	0	0	0	1	1	0.3	-0.1
Bioenergy	2	2	0	2	2	1	0	2	-21.7	-1.3
Traditional biomass	-	-	-	-	-	-	-	-	*n.a.*	*n.a.*
Other renewables	0	1	1	2	3	6	1	7	5.5	13.1
Other	**38**	**36**	**29**	**37**	**33**	**25**	**100**	**100**	**-1.5**	**-2.1**
Petrochem. Feedstock	*22*	*20*	*17*	*21*	*19*	*15*	*58*	*59*	*-1.2*	*-1.8*

Japan: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**1 058**	**1 052**	**1 077**	**1 065**	**1 072**	**1 080**	**1 088**	**100**	**100**	**0.0**
Coal	230	349	360	265	264	252	240	33	22	-1.8
Oil	140	84	77	52	33	20	10	7	1	-8.5
Gas	248	406	400	290	287	294	285	37	26	-1.5
Nuclear	322	18	33	205	216	222	233	3	21	8.9
Renewables	98	172	186	232	250	271	298	17	27	2.1
Hydro	84	79	80	91	95	99	103	7	9	1.1
Bioenergy	10	34	35	48	48	48	48	3	4	1.4
Wind	0	6	6	13	19	25	31	1	3	7.2
Geothermal	3	3	2	6	11	16	21	0	2	9.7
Solar PV	0	51	61	74	76	81	88	6	8	1.6
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	1	2	7	-	1	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**325**	**333**	**330**	**323**	**323**	**329**	**100**	**100**	**-0.0**
Coal	50	50	49	49	46	43	15	13	-0.6
Oil	46	46	28	17	10	5	14	2	-8.8
Gas	83	84	83	84	83	83	25	25	-0.1
Nuclear	42	41	34	31	30	32	12	10	-0.9
Renewables	103	111	134	140	150	162	33	49	1.7
Hydro	50	50	51	53	54	55	15	17	0.4
Bioenergy	7	8	9	10	10	10	2	3	1.3
Wind	3	4	6	8	10	12	1	4	5.6
Geothermal	1	0	1	2	3	4	0	1	9.0
Solar PV	42	49	66	67	72	78	15	24	2.1
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	0	0	1	3	-	1	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**1 123**	**1 114**	**1 109**	**884**	**824**	**761**	**704**	**100**	**100**	**-2.0**
Coal	353	441	450	354	341	318	296	41	42	-1.8
Oil	605	412	401	330	283	241	209	36	30	-2.8
Gas	165	261	259	201	199	202	199	23	28	-1.1
Power sector	**430**	**553**	**558**	**385**	**366**	**345**	**322**	**100**	**100**	**-2.4**
Coal	227	316	329	236	234	221	209	59	65	-2.0
Oil	91	55	50	32	20	12	6	9	2	-8.7
Gas	112	183	179	117	111	112	107	32	33	-2.2
TFC	**645**	**524**	**514**	**468**	**430**	**391**	**359**	**100**	**100**	**-1.6**
Coal	106	107	103	100	91	82	73	20	20	-1.5
Oil	487	342	336	287	254	222	197	65	55	-2.3
Transport	*251*	*207*	*204*	*167*	*146*	*126*	*112*	*40*	*31*	*-2.6*
Gas	52	75	76	81	85	87	89	15	25	0.7

Japan: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 089**	**1 106**	**1 140**	**1 019**	**999**	**1 004**	**100**	**100**	**0.2**	**-0.3**
Coal	305	316	319	194	83	23	28	2	-0.5	-11.2
Oil	52	33	13	35	17	4	1	0	-7.4	-12.1
Gas	299	308	335	276	284	128	29	13	-0.8	-4.8
Nuclear	182	185	176	214	247	299	15	30	7.6	10.1
Renewables	229	243	275	279	347	528	24	53	1.7	4.7
Hydro	91	93	100	95	111	142	9	14	0.9	2.5
Bioenergy	47	47	46	62	66	75	4	7	1.2	3.3
Wind	13	18	28	24	51	125	2	12	6.6	13.9
Geothermal	5	10	19	6	11	28	2	3	9.4	11.1
Solar PV	74	75	81	93	107	148	7	15	1.2	3.9
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	0	1	0	1	11	0	1	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**334**	**331**	**330**	**342**	**349**	**407**	**100**	**100**	**-0.0**	**0.9**
Coal	51	54	52	42	29	7	16	2	0.2	-8.0
Oil	28	17	7	28	17	5	2	1	-7.9	-8.9
Gas	87	91	93	75	70	70	28	17	0.4	-0.8
Nuclear	34	29	24	34	35	41	7	10	-2.1	0.2
Renewables	133	138	149	162	196	280	45	69	1.3	4.1
Hydro	51	52	53	53	60	71	16	18	0.3	1.6
Bioenergy	9	9	10	12	13	15	3	4	1.2	2.9
Wind	6	8	11	11	22	48	3	12	5.1	12.1
Geothermal	1	2	3	1	2	5	1	1	8.7	10.5
Solar PV	65	67	71	84	98	137	22	34	1.6	4.6
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	0	0	0	0	4	0	1	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**929**	**889**	**821**	**758**	**567**	**299**	**100**	**100**	**-1.3**	**-5.5**
Coal	389	387	363	280	162	75	44	25	-0.9	-7.5
Oil	335	295	238	288	218	108	29	36	-2.2	-5.6
Gas	205	208	220	190	187	117	27	39	-0.7	-3.4
Power sector	**423**	**417**	**408**	**303**	**185**	**50**	**100**	**100**	**-1.4**	**-9.9**
Coal	272	279	276	171	65	2	68	5	-0.8	-19.3
Oil	32	20	8	22	10	3	2	5	-7.6	-12.2
Gas	119	118	123	111	109	46	30	90	-1.6	-5.8
TFC	**475**	**444**	**390**	**426**	**357**	**230**	**100**	**100**	**-1.2**	**-3.4**
Coal	100	91	74	92	82	61	19	26	-1.4	-2.3
Oil	292	266	223	257	200	101	57	44	-1.8	-5.1
Transport	*171*	*155*	*134*	*150*	*112*	*48*	*34*	*21*	*-1.8*	*-6.1*
Gas	83	87	93	76	75	68	24	30	0.9	-0.5

Southeast Asia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	**2016**	**2017e**	**2025**	**2030**	**2035**	**2040**	**2017e**	**2040**	**2017e-40**
TPED	**383**	**644**	**664**	**826**	**923**	**1 018**	**1 110**	**100**	**100**	**2.3**
Coal	32	120	126	176	208	244	278	19	25	3.5
Oil	154	218	225	286	308	323	329	34	30	1.7
Gas	74	139	141	170	191	215	241	21	22	2.4
Nuclear	-	-	-	-	-	1	4	-	0	n.a.
Hydro	4	10	11	16	22	26	30	2	3	4.5
Bioenergy	101	128	131	130	130	131	133	20	12	0.1
Other renewables	18	28	30	48	64	79	95	5	9	5.1
Power sector	**95**	**217**	**229**	**304**	**360**	**421**	**485**	**100**	**100**	**3.3**
Coal	19	85	91	129	153	181	209	40	43	3.7
Oil	18	6	7	6	6	5	5	3	1	-1.4
Gas	34	75	77	89	96	104	113	34	23	1.7
Nuclear	-	-	-	-	-	1	4	-	1	n.a.
Hydro	4	10	11	16	22	26	30	5	6	4.5
Bioenergy	1	12	14	18	21	26	32	6	7	3.8
Other renewables	18	28	30	47	63	78	93	13	19	5.0
Other energy sector	**47**	**54**	**55**	**67**	**74**	**82**	**89**	**100**	**100**	**2.1**
Electricity	*4*	*8*	*9*	*13*	*16*	*19*	*23*	*16*	*26*	*4.3*
TFC	**273**	**453**	**464**	**572**	**632**	**686**	**737**	**100**	**100**	**2.0**
Coal	13	35	35	46	53	60	66	7	9	2.8
Oil	124	200	206	260	282	294	300	44	41	1.6
Gas	17	40	40	57	70	84	100	9	14	4.0
Electricity	28	72	76	105	127	151	178	16	24	3.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	92	106	107	103	99	95	91	23	12	-0.7
Other renewables	-	-	-	0	1	1	2	-	0	n.a.
Industry	**76**	**139**	**140**	**182**	**207**	**233**	**260**	**100**	**100**	**2.7**
Coal	13	33	33	45	52	58	64	24	25	2.9
Oil	24	24	24	27	29	29	29	17	11	0.9
Gas	9	32	31	44	54	65	78	22	30	4.1
Electricity	12	30	31	42	49	56	62	22	24	3.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	18	21	21	23	24	25	26	15	10	0.8
Other renewables	-	-	-	0	0	0	0	-	0	n.a.
Transport	**61**	**121**	**124**	**161**	**179**	**190**	**197**	**100**	**100**	**2.0**
Oil	61	113	116	148	163	170	174	94	88	1.8
Electricity	0	0	0	1	2	3	5	0	2	12.8
Biofuels	-	5	5	8	9	11	12	4	6	3.9
Other fuels	0	3	3	4	5	6	7	2	3	4.1
Buildings	**108**	**143**	**146**	**157**	**167**	**179**	**195**	**100**	**100**	**1.3**
Coal	1	1	1	2	2	2	2	1	1	0.7
Oil	19	18	19	20	21	22	23	13	12	0.9
Gas	0	0	0	1	2	4	5	0	2	11.1
Electricity	15	42	44	61	75	91	110	30	56	4.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	73	81	81	72	66	59	54	56	28	-1.8
Traditional biomass	*73*	*80*	*81*	*71*	*65*	*58*	*53*	*55*	*27*	*-1.8*
Other renewables	-	-	-	0	1	1	1	-	1	n.a.
Other	**28**	**51**	**53**	**73**	**79**	**83**	**85**	**100**	**100**	**2.1**
Petrochem. Feedstock	*17*	*33*	*36*	*52*	*56*	*60*	*61*	*67*	*72*	*2.4*

Southeast Asia: Current Policies and Sustainable Development Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
TPED	**848**	**965**	**1 201**	**767**	**804**	**902**	**100**	**100**	**2.6**	**1.3**
Coal	190	246	360	143	112	76	30	8	4.7	-2.2
Oil	293	323	366	267	272	237	31	26	2.1	0.2
Gas	173	193	245	166	185	212	20	24	2.4	1.8
Nuclear	-	-	4	-	-	5	0	1	n.a.	n.a.
Hydro	15	19	24	19	27	45	2	5	3.5	6.4
Bioenergy	130	129	130	105	83	97	11	11	-0.0	-1.3
Other renewables	46	55	72	68	124	229	6	25	3.9	9.2
Power sector	**317**	**384**	**530**	**293**	**335**	**439**	**100**	**100**	**3.7**	**2.9**
Coal	143	189	286	99	64	25	54	6	5.1	-5.5
Oil	6	6	5	5	4	3	1	1	-1.1	-3.1
Gas	90	95	113	84	92	97	21	22	1.7	1.0
Nuclear	-	-	4	-	-	5	1	1	n.a.	n.a.
Hydro	15	19	24	19	27	45	4	10	3.5	6.4
Bioenergy	18	21	28	20	26	42	5	10	3.2	5.0
Other renewables	45	54	71	66	121	222	13	51	3.8	9.1
Other energy sector	**69**	**78**	**100**	**65**	**68**	**74**	**100**	**100**	**2.6**	**1.3**
Electricity	*13*	*17*	*25*	*12*	*13*	*19*	*25*	*26*	*4.7*	*3.4*
TFC	**583**	**653**	**784**	**522**	**533**	**578**	**100**	**100**	**2.3**	**1.0**
Coal	47	55	68	43	46	49	9	8	3.0	1.5
Oil	267	294	332	243	250	216	42	37	2.1	0.2
Gas	58	72	102	57	69	91	13	16	4.1	3.6
Electricity	109	133	188	101	118	170	24	29	4.0	3.6
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	103	99	92	76	48	46	12	8	-0.7	-3.6
Other renewables	0	1	1	1	3	6	0	1	n.a.	n.a.
Industry	**185**	**213**	**269**	**173**	**186**	**214**	**100**	**100**	**2.9**	**1.8**
Coal	45	53	66	42	45	48	25	23	3.0	1.7
Oil	28	29	30	26	25	24	11	11	1.0	0.0
Gas	45	56	81	42	48	62	30	29	4.2	3.1
Electricity	43	50	65	40	44	52	24	24	3.3	2.2
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	24	25	27	23	24	25	10	12	1.1	0.7
Other renewables	0	0	0	0	1	3	0	1	n.a.	n.a.
Transport	**164**	**187**	**220**	**151**	**161**	**150**	**100**	**100**	**2.5**	**0.8**
Oil	153	174	203	134	136	101	92	68	2.4	-0.6
Electricity	0	1	1	1	3	21	1	14	6.2	20.5
Biofuels	7	8	10	10	13	15	5	10	3.3	5.1
Other fuels	4	5	6	6	9	12	3	8	3.5	6.6
Buildings	**161**	**174**	**208**	**126**	**109**	**135**	**100**	**100**	**1.6**	**-0.3**
Coal	2	2	2	1	1	0	1	0	1.5	-5.4
Oil	21	22	25	20	21	23	12	17	1.3	0.8
Gas	1	2	5	2	3	6	2	5	11.2	12.6
Electricity	64	81	121	59	71	96	58	71	4.5	3.5
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	72	66	54	42	11	6	26	4	-1.8	-10.7
Traditional biomass	*71*	*65*	*53*	*42*	*10*	*5*	*26*	*4*	*-1.8*	*-11.6*
Other renewables	0	0	1	1	1	3	0	3	n.a.	n.a.
Other	**73**	**79**	**86**	**72**	**76**	**80**	**100**	**100**	**2.1**	**1.8**
Petrochem. Feedstock	*52*	*56*	*61*	*51*	*55*	*58*	*71*	*72*	*2.3*	*2.1*

Southeast Asia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total generation	**370**	**914**	**961**	**1 349**	**1 640**	**1 960**	**2 318**	**100**	**100**	**3.9**
Coal	79	333	355	542	655	794	933	37	40	4.3
Oil	72	25	27	22	22	20	17	3	1	-2.0
Gas	154	386	397	480	531	589	674	41	29	2.3
Nuclear	-	-	-	-	-	2	16	-	1	n.a.
Renewables	65	170	181	306	433	555	679	19	29	5.9
Hydro	47	119	124	187	256	307	344	13	15	4.5
Bioenergy	1	22	26	40	54	70	89	3	4	5.4
Wind	-	1	2	13	22	34	50	0	2	16.2
Geothermal	16	22	23	40	55	68	80	2	3	5.6
Solar PV	0	5	6	25	46	76	115	1	5	13.7
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	0	0	0	-	0	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)
	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total capacity	**240**	**248**	**365**	**443**	**529**	**628**	**100**	**100**	**4.1**
Coal	67	71	114	132	153	175	29	28	4.0
Oil	26	26	24	22	19	14	10	2	-2.7
Gas	92	93	124	141	163	193	38	31	3.2
Nuclear	-	-	-	-	1	2	-	0	n.a.
Renewables	56	58	101	145	189	236	23	38	6.3
Hydro	40	41	59	80	95	105	17	17	4.2
Bioenergy	7	8	11	13	15	18	3	3	3.8
Wind	1	1	6	10	15	21	1	3	13.0
Geothermal	3	4	6	8	10	12	1	2	5.2
Solar PV	4	4	19	34	54	80	2	13	13.6
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	0	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2016	2017e	2025	2030	2035	2040	2017e	2040	2017e-40
Total CO_2	**693**	**1 283**	**1 323**	**1 695**	**1 915**	**2 136**	**2 340**	**100**	**100**	**2.5**
Coal	134	484	507	707	832	974	1 111	38	47	3.5
Oil	413	512	525	640	694	724	739	40	32	1.5
Gas	146	287	292	348	389	438	491	22	21	2.3
Power sector	**217**	**539**	**569**	**744**	**857**	**989**	**1 121**	**100**	**100**	**3.0**
Coal	78	344	366	518	614	728	840	64	75	3.7
Oil	58	19	21	18	19	17	15	4	1	-1.4
Gas	81	176	182	208	224	244	267	32	24	1.7
TFC	**410**	**684**	**693**	**886**	**992**	**1 075**	**1 145**	**100**	**100**	**2.2**
Coal	55	140	140	189	218	245	271	20	24	2.9
Oil	333	477	487	601	653	681	696	70	61	1.6
Transport	*185*	*338*	*347*	*442*	*487*	*509*	*519*	*50*	*45*	*1.8*
Gas	21	67	65	97	121	148	178	9	16	4.4

Southeast Asia: Current Policies and Sustainable Development Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total generation	**1 398**	**1 720**	**2 462**	**1 292**	**1 509**	**2 174**	**100**	**100**	**4.2**	**3.6**
Coal	596	800	1 258	413	270	112	51	5	5.7	-4.9
Oil	23	23	18	18	13	11	1	0	-1.7	-4.1
Gas	491	531	676	463	516	579	27	27	2.3	1.7
Nuclear	-	-	14	-	-	20	1	1	n.a.	n.a.
Renewables	288	366	496	398	710	1 452	20	67	4.5	9.5
Hydro	178	223	274	218	314	519	11	24	3.5	6.4
Bioenergy	40	51	77	47	70	126	3	6	4.8	7.0
Wind	13	19	31	43	131	312	1	14	13.8	25.8
Geothermal	38	47	63	58	108	185	3	9	4.5	9.5
Solar PV	20	27	50	32	87	308	2	14	9.7	18.7
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	0	0	0	0	0	2	0	0	n.a.	n.a.

	Power generation capacity (GW)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total capacity	**357**	**426**	**586**	**378**	**494**	**814**	**100**	**100**	**3.8**	**5.3**
Coal	116	144	218	96	88	65	37	8	5.0	-0.4
Oil	24	23	14	24	22	13	2	2	-2.6	-2.8
Gas	122	138	184	119	123	151	31	19	3.0	2.1
Nuclear	-	-	2	-	-	3	0	0	n.a.	n.a.
Renewables	93	117	158	138	258	568	27	70	4.5	10.4
Hydro	55	69	84	70	99	161	14	20	3.2	6.1
Bioenergy	11	12	16	12	16	25	3	3	3.2	5.3
Wind	5	8	13	20	59	134	2	16	10.7	22.5
Geothermal	6	7	9	9	16	27	2	3	4.1	9.1
Solar PV	15	20	36	26	68	220	6	27	9.8	18.7
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	0	0	0	0	0	1	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2017e-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
Total CO_2	**1 780**	**2 109**	**2 770**	**1 499**	**1 408**	**1 164**	**100**	**100**	**3.3**	**-0.6**
Coal	766	982	1 431	573	442	263	52	23	4.6	-2.8
Oil	659	734	840	589	593	483	30	41	2.1	-0.4
Gas	355	393	498	337	374	418	18	36	2.4	1.6
Power sector	**805**	**1 002**	**1 432**	**612**	**486**	**307**	**100**	**100**	**4.1**	**-2.6**
Coal	574	758	1 151	399	258	70	80	23	5.1	-7.0
Oil	19	20	16	15	12	10	1	3	-1.0	-3.1
Gas	212	224	265	198	216	227	19	74	1.7	1.0
TFC	**909**	**1 038**	**1 255**	**826**	**864**	**807**	**100**	**100**	**2.6**	**0.7**
Coal	192	224	281	175	184	193	22	24	3.1	1.4
Oil	619	690	793	553	561	456	63	57	2.1	-0.3
Transport	*457*	*518*	*606*	*401*	*407*	*303*	*48*	*38*	*2.4*	*-0.6*
Gas	98	124	182	98	119	158	14	20	4.5	3.9

World: New Policies Scenario

	Emissions of pollutants by energy sector					Shares (%)		CAAGR (%)
	2015	2025	2030	2035	2040	2015	2040	2015-40
SO_2 emissions from all energy activities (Mt)								
Total	**72.9**	**51.9**	**48.4**	**48.4**	**48.9**	**100**	**100**	**-1.6**
Power	26.3	16.5	13.2	13.0	13.4	36	27	-2.6
Industry*	30.0	26.4	26.7	27.2	27.6	41	56	-0.3
Transport	10.2	3.8	4.0	4.2	4.3	14	9	-3.4
Buildings	4.7	4.0	3.4	2.8	2.6	6	5	-2.4
Agriculture	1.8	1.2	1.2	1.1	1.0	2	2	-2.1
NO_X emissions from all energy activities (Mt)								
Total	**108.0**	**96.2**	**92.2**	**91.6**	**93.0**	**100**	**100**	**-0.6**
Power	16.4	12.3	11.8	11.5	11.9	15	13	-1.3
Industry*	25.9	25.1	25.1	26.0	27.0	24	29	0.2
Transport	57.5	51.5	48.2	47.0	47.3	53	51	-0.8
Buildings	4.6	4.7	4.6	4.6	4.5	4	5	-0.1
Agriculture	3.6	2.7	2.5	2.4	2.3	3	2	-1.8
$PM_{2.5}$ emissions from all energy activities (Mt)								
Total	**32.1**	**29.3**	**28.4**	**28.3**	**28.3**	**100**	**100**	**-0.5**
Power	1.8	1.3	1.1	1.1	1.1	6	4	-1.9
Industry*	8.5	8.8	9.2	9.8	10.4	26	37	0.8
Transport	3.6	2.8	2.6	2.7	2.8	11	10	-1.0
Buildings	17.1	15.6	14.8	14.0	13.3	53	47	-1.0
Agriculture	1.2	0.7	0.7	0.7	0.7	4	2	-2.3

** Industry also includes other transformation.*

	Emissions of pollutants by fuel					Shares (%)		CAAGR (%)
	2015	2025	2030	2035	2040	2015	2040	2015-40
SO_2 emissions from combustion activities (Mt)								
Total	**54.5**	**34.9**	**30.9**	**30.1**	**30.3**	**100**	**100**	**-2.3**
Coal	31.1	18.8	14.7	14.2	14.3	57	47	-3.1
Oil	20.7	13.4	13.3	12.7	12.3	38	41	-2.0
Gas	0.3	0.4	0.5	0.5	0.6	1	2	2.3
Bioenergy	2.3	2.3	2.5	2.7	3.1	4	10	1.2
NO_X emissions from combustion activities (Mt)								
Total	**95.9**	**84.9**	**80.5**	**79.4**	**80.3**	**100**	**100**	**-0.7**
Coal	16.9	11.1	10.3	9.6	9.6	18	12	-2.2
Oil	66.2	60.0	55.8	54.3	54.2	69	67	-0.8
Gas	9.2	9.7	10.1	10.9	11.7	10	15	1.0
Bioenergy	3.6	4.2	4.5	4.7	5.0	4	6	1.2
$PM_{2.5}$ emissions from combustion activities (Mt)								
Total	**25.4**	**22.2**	**20.8**	**20.2**	**19.6**	**100**	**100**	**-1.0**
Coal	4.3	2.9	2.4	2.1	1.9	17	10	-3.1
Oil	4.7	3.7	3.4	3.4	3.4	18	17	-1.2
Gas	0.1	0.1	0.1	0.2	0.2	0	1	1.5
Bioenergy	16.3	15.5	14.9	14.5	14.0	64	72	-0.6

World: Current Policies and Sustainable Development Scenarios

	Emissions of pollutants by energy sector						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2015-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
SO_2 emissions from all energy activities (Mt)										
Total	**54.2**	**51.7**	**55.1**	**42.9**	**32.7**	**17.0**	**100**	**100**	**-1.1**	**-5.7**
Power	17.7	14.9	16.9	12.1	7.2	1.7	31	10	-1.7	-10.5
Industry*	26.6	27.0	28.3	23.3	19.8	12.2	51	72	-0.2	-3.5
Transport	4.1	4.5	5.3	3.1	2.8	1.9	10	11	-2.6	-6.4
Buildings	4.5	4.1	3.5	3.4	2.1	0.9	6	5	-1.2	-6.5
Agriculture	1.3	1.3	1.1	1.0	0.8	0.3	2	2	-1.7	-7.1
NO_X emissions from all energy activities (Mt)										
Total	**100.9**	**101.0**	**109.3**	**81.7**	**68.2**	**45.4**	**100**	**100**	**0.0**	**-3.4**
Power	12.9	13.0	14.5	9.7	7.2	2.2	13	5	-0.5	-7.8
Industry*	25.4	25.6	28.1	21.6	18.5	12.7	26	28	0.3	-2.8
Transport	55.1	54.8	59.2	44.3	37.7	27.0	54	59	0.1	-3.0
Buildings	4.9	4.9	5.0	3.6	2.7	1.8	5	4	0.3	-3.7
Agriculture	2.8	2.6	2.6	2.5	2.2	1.8	2	4	-1.3	-2.7
$PM_{2.5}$ emissions from all energy activities (Mt)										
Total	**29.9**	**29.6**	**30.2**	**19.6**	**12.0**	**5.3**	**100**	**100**	**-0.2**	**-6.9**
Power	1.3	1.2	1.4	1.0	0.6	0.1	5	2	-1.0	-10.2
Industry*	8.9	9.3	10.6	7.1	5.5	2.1	35	39	0.9	-5.4
Transport	3.2	3.3	3.7	2.5	2.2	1.8	12	34	0.2	-2.6
Buildings	15.8	15.0	13.7	8.5	3.2	1.0	45	19	-0.9	-10.7
Agriculture	0.7	0.7	0.7	0.6	0.5	0.3	2	5	-1.9	-5.5

** Industry also includes other transformation.*

	Emissions of pollutants by fuel						Shares (%)		CAAGR (%)	
	2025	2030	2040	2025	2030	2040	2040		2015-40	
	Current Policies			Sustainable Development			CPS	SDS	CPS	SDS
SO_2 emissions from combustion activities (Mt)										
Total	**37.2**	**34.2**	**36.4**	**27.4**	**19.1**	**8.2**	**100**	**100**	**-1.6**	**-7.3**
Coal	20.6	17.1	18.7	14.5	8.5	2.5	51	31	-2.0	-9.5
Oil	13.9	14.2	14.3	10.4	8.0	3.3	39	41	-1.5	-7.0
Gas	0.4	0.5	0.7	0.4	0.5	0.5	2	6	2.7	1.7
Bioenergy	2.3	2.4	2.8	2.1	2.1	1.8	8	22	0.7	-1.0
NO_X emissions from combustion activities (Mt)										
Total	**89.6**	**89.3**	**96.6**	**71.6**	**58.9**	**38.1**	**100**	**100**	**0.0**	**-3.6**
Coal	11.7	11.5	12.1	8.5	5.8	1.8	12	5	-1.3	-8.6
Oil	63.9	62.9	67.2	51.5	43.1	30.8	70	81	0.1	-3.0
Gas	9.8	10.4	12.5	8.2	7.1	3.2	13	8	1.2	-4.1
Bioenergy	4.2	4.5	4.9	3.5	2.9	2.3	5	6	1.2	-1.8
$PM_{2.5}$ emissions from combustion activities (Mt)										
Total	**22.8**	**21.9**	**21.4**	**13.8**	**7.2**	**3.2**	**100**	**100**	**-0.7**	**-7.9**
Coal	3.2	2.8	2.7	2.2	1.3	0.3	13	8	-1.8	-10.7
Oil	4.0	4.0	4.5	3.2	2.6	2.0	21	61	-0.2	-3.4
Gas	0.1	0.2	0.2	0.1	0.1	0.1	1	4	1.9	0.1
Bioenergy	15.4	14.9	14.0	8.2	3.2	0.9	65	27	-0.6	-11.1

Design of the scenarios

The *World Energy Outlook-2018* (*WEO-2018*) presents projections for three core scenarios, which are differentiated primarily by their underlying assumptions about the evolution of energy-related government policies.

The **New Policies Scenario** (NPS) is the central scenario of this *Outlook*, and aims to provide a sense of the direction in which the most recent policy ambitions could take the energy sector. In addition to incorporating policies and measures that governments around the world have already put in place, it also takes into account the effects of announced policies, as expressed in official targets and plans. The Nationally Determined Contributions of the Paris Agreement provide important guidance regarding policy intentions, although some have been supplemented or superseded by more recent announcements. Given that "new policies" are by definition not yet fully reflected in legislation or regulation, the prospects and timing for their full realisation are based upon our assessment of the relevant political, regulatory, market, infrastructural and financial constraints.

The **Current Policies Scenario** (CPS) considers the impact of only those policies and measures that are firmly enshrined in legislation as of mid-2018. In addition, where existing policies target a range of outcomes, it is assumed that the lower end of the range is achieved. In this way, CPS provides a cautious assessment of where existing policies might lead the energy sector in the absence of additional impetus from governments. It provides a benchmark against which the impact of "new policies" can be measured.

The **Sustainable Development Scenario** (SDS) was introduced for the first time in the *WEO-2017.* Unlike the other main scenarios, it starts from the objectives to be achieved and then assesses what combination of actions would deliver them. These objectives are derived from the Sustainable Development Goals (SDGs) of the United Nations, providing an energy sector pathway that achieves: universal access to affordable, reliable and modern energy services by 2030 (SDG 7.1); a substantial reduction in air pollution (SDG 3.9); and effective action to combat climate change (SDG 13). On the latter point, the Sustainable Development Scenario is fully aligned with the goal of the Paris Agreement to hold the increase in the global average temperature to well below 2 °C above pre-industrial levels. This scenario lays out an integrated strategy for the achievement of these important policy objectives, while also having a strong accent on energy security.

This annex presents some key elements of the design of the three core scenarios, starting with population, economic growth and fossil fuel resources, which are held constant across the scenarios, and prices for fossil fuels and carbon dioxide (CO_2) emissions, which are not. The annex also includes the key policies assumed to be adopted in each of the main scenarios of *WEO-2018,* presented by sector and region. The assumptions related to the **Future is Electric Scenario** (FiES), introduced in Part B of this *Outlook*, are included in Chapter 9.

Population

Table B.1 ▷ Population assumptions by region

	Compound average annual growth rate			Population (million)		Urbanisation share	
	2000-17	2017-25	2017-40	2017	2040	2017	2040
North America	1.0%	0.8%	0.7%	487	571	81%	87%
United States	0.9%	0.7%	0.6%	327	376	82%	87%
Central and South America	1.2%	0.8%	0.6%	516	599	81%	86%
Brazil	1.0%	0.6%	0.4%	209	232	86%	91%
Europe	0.3%	0.1%	0.1%	690	700	75%	81%
European Union	0.3%	0.1%	0.0%	512	513	75%	82%
Africa	2.6%	2.4%	2.3%	1 256	2 100	42%	54%
South Africa	1.4%	1.1%	0.9%	57	69	66%	76%
Middle East	2.3%	1.6%	1.4%	237	323	71%	78%
Eurasia	0.4%	0.4%	0.2%	232	243	65%	70%
Russia	-0.1%	-0.1%	-0.3%	144	136	74%	80%
Asia Pacific	1.1%	0.7%	0.5%	4 098	4 636	47%	60%
China	0.5%	0.3%	0.0%	1 392	1 401	58%	77%
India	1.4%	1.0%	0.8%	1 339	1 605	34%	46%
Japan	-0.0%	-0.3%	-0.4%	126	114	92%	94%
Southeast Asia	1.3%	1.0%	0.7%	646	766	48%	61%
World	**1.2%**	**1.0%**	**0.9%**	**7 516**	**9 172**	**55%**	**64%**

Note: See Annex C for composition of regional groupings.

Sources: UN Population Division databases; IEA databases and analysis.

- Population is a major determinant of many of the trends in our *Outlook*. We use the medium variant of the United Nations projections as the basis for population growth in all scenarios, but this is naturally subject to a degree of uncertainty.
- The rate of growth in population is assumed to slow over time, but the global population nonetheless exceeds 9 billion by 2040 (Table B.1).
- Around half the increase over our projection period comes from Africa and a further third from the Asia Pacific region.
- India adds over 250 million people to its population, overtaking China (where the population is projected to grow by around 10 million) to become the world's most populous country.
- The share of the world's population living in towns and cities has been rising steadily, a trend that is projected to continue over the period to 2040. In aggregate, this means that *all* of the 1.7 billion increase in global population over the period is added to cities and towns.

Economic growth

Table B.2 ▷ Real gross domestic product (GDP) **growth assumptions by region**

	Compound average annual growth rate			
	2000-17	**2017-25**	**2025-40**	**2017-40**
North America	1.9%	2.1%	2.1%	2.1%
United States	1.8%	2.0%	2.0%	2.0%
Central and South America	2.7%	2.6%	3.0%	2.9%
Brazil	2.3%	2.3%	3.0%	2.8%
Europe	1.8%	2.1%	1.6%	1.8%
European Union	1.5%	1.8%	1.4%	1.6%
Africa	4.4%	4.1%	4.4%	4.3%
South Africa	2.8%	1.9%	2.8%	2.5%
Middle East	4.1%	3.3%	3.5%	3.4%
Eurasia	4.0%	2.2%	2.5%	2.4%
Russia	3.4%	1.6%	2.1%	1.9%
Asia Pacific	6.0%	5.4%	4.0%	4.5%
China	9.1%	5.8%	3.7%	4.4%
India	7.2%	7.8%	5.7%	6.5%
Japan	0.8%	0.7%	0.7%	0.7%
Southeast Asia	5.2%	5.3%	4.0%	4.5%
World	**3.6%**	**3.7%**	**3.3%**	**3.4%**

Note: Calculated based on GDP expressed in year-2017 dollars in purchasing power parity (PPP) terms.

Sources: IMF (2018); World Bank databases; IEA databases and analysis.

- Over the projection period, the compound average annual rate of 3.4% growth in global economic activity to 2040 is similar to that of *WEO-2017* (Table B.2). However, there have been some quite substantial revisions to the near-term economic outlook for various countries, based on updated assessments from the International Monetary Fund.
- In general, near-term growth in advanced economies has been revised up, not least because of strong performances in Europe, Japan and United States in 2017.
- Near-term economic performance in several emerging markets and developing economies, including in Southeast Asia and Brazil, is higher than in *WEO-2017*; this is offset by sharp downward revisions for some other countries, notably Venezuela, Pakistan and South Africa.
- The way that economic growth translates into energy demand growth varies substantially depending on each country's economic structure and stage of development, as well as pricing and efficiency policies.

Fossil fuel resources

Table B.3 ▷ Remaining technically recoverable fossil fuel resources, end-2017

Oil (billion barrels)	Proven reserves	Resources	Conventional crude oil	Tight oil	NGLs	EHOB	Kerogen oil
North America	228	2 315	246	128	138	804	1 000
Central and South America	321	845	238	60	50	494	3
Europe	14	117	61	19	29	3	6
Africa	127	454	311	54	86	2	-
Middle East	808	1 145	921	29	151	14	30
Eurasia	144	961	246	85	60	552	18
Asia Pacific	52	290	131	72	68	3	16
World	**1 694**	**6 127**	**2 155**	**446**	**582**	**1 872**	**1 073**

Natural gas (trillion cubic metres)	Proven reserves	Resources	Conventional gas	Tight gas	Shale gas	Coalbed methane
North America	12	134	50	11	66	7
Central and South America	9	84	28	15	41	-
Europe	6	47	19	5	18	5
Africa	18	101	51	10	40	0
Middle East	81	122	103	9	11	-
Eurasia	76	171	134	10	10	17
Asia Pacific	20	139	44	21	53	21
World	**221**	**798**	**429**	**81**	**239**	**50**

Coal (billion tonnes)	Proven reserves	Resources	Coking coal	Steam coal	Lignite
North America	259	8 389	1 032	5 838	1 519
Central and South America	14	61	3	32	25
Europe	135	977	188	387	402
Africa	13	297	35	261	0
Middle East	1	41	19	23	-
Eurasia	189	4 301	731	2 190	1 380
Asia Pacific	423	8 941	1 505	6 022	1 414
World	**1 034**	**23 007**	**3 513**	**14 754**	**4 740**

Notes: NGLs = natural gas liquids; EHOB = extra-heavy oil and bitumen. The breakdown of coal resources by type is an IEA estimate. Coal world resources exclude Antarctica.

Sources: BGR (2017); BP (2018); Cedigaz (2018); OGJ (2017); US DOE/EIA (2018a, 2018b); US DOE/EIA/ARI (2013, 2015); USGS (2012a, 2012b); IEA databases and analysis.

- The *WEO* supply modelling relies on estimates of the remaining technically recoverable resource, rather than the (often more widely quoted) numbers for proven reserves.
- Resource estimates are inevitably subject to a considerable degree of uncertainty; this is particularly true for unconventional resources (e.g. tight oil, shale gas) that are very large, but still relatively poorly known – even in North America (Table B.3).
- Numbers for proven reserves are important in some cases as an indication of what companies have decided to line up for development, but they do not provide a complete picture either of the resource base or of long-term production potential.
- The remaining technical recoverable resources of fossil fuels are comfortably sufficient to meet the projections of global demand growth to 2040 in all three scenarios.
- In the case of oil and gas, however, their gradual depletion (at a pace that varies by scenario) forces operators to develop more difficult and complex reservoirs. This tends to push up production costs over time, although this effect is offset by the assumed continuous adoption of new, more efficient production technologies and practices.
- Our estimates of the remaining technically recoverable resources of most sources of oil have not increased significantly from last year, with the exception of the numbers for tight oil resources in the United States; these have been raised in the *WEO-2018* to just over 115 billion barrels (from 105 billion barrels last year), in line with the latest numbers from the US Energy Information Administration (US EIA, 2018a and 2018b).
- The main uncertainty for tight oil relates to the resource potential of some of the most prolific US plays, notably in the Permian Basin.
- Our estimate for remaining technically recoverable shale gas resources in the United States has been raised to 34 trillion cubic metres (tcm), from 29 tcm in last year's *Outlook*, again in line with higher estimates from the US Energy Information Administration (US EIA, 2018a and 2018b).
- We distinguish in the analysis between conventional and unconventional resource types, but the distinction between the two, in practice, is an inexact and somewhat artificial one (and what is considered unconventional today may be considered conventional tomorrow).
- Remaining technically recoverable coal resources are huge and more widely distributed than those of oil and gas. This means that, although environmental concerns are widespread, the availability of coal supply is typically not an issue.
- World coal resources are made up of different types of coal: around 80% is steam and coking coal and the remainder is lignite.

Fossil fuel prices

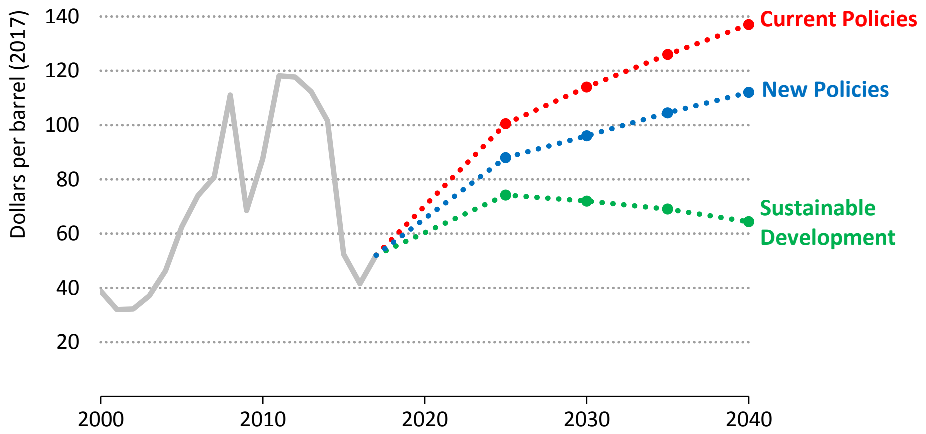
Table B.4 ▷ Fossil fuel prices by scenario

				New Policies				Current Policies		Sustainable Development	
Real terms ($2017)	**2000**	**2010**	**2017**	**2025**	**2030**	**2035**	**2040**	**2025**	**2040**	**2025**	**2040**
IEA crude oil ($/barrel)	39	88	52	88	96	105	112	101	137	74	64
Natural gas ($/MBtu)											
United States	6.0	4.9	3.0	3.3	3.8	4.3	4.9	3.4	5.3	3.3	3.6
European Union	3.9	8.4	5.8	7.8	8.2	8.6	9.0	7.9	9.4	7.5	7.7
China	3.6	7.5	6.5	9.2	9.4	9.5	9.8	9.3	10.2	8.3	8.5
Japan	6.6	12.3	8.1	9.8	10.0	10.0	10.1	9.9	10.5	9.0	8.8
Steam coal ($/tonne)											
United States	38	64	60	63	63	64	64	64	69	58	56
European Union	47	103	85	80	83	84	85	84	98	69	66
Japan	45	120	95	85	88	89	90	89	105	74	70
Coastal China	35	130	102	91	93	94	94	95	106	81	79

Notes: MBtu = million British thermal units. The IEA crude oil price is a weighted average import price among IEA member countries. Natural gas prices are weighted averages expressed on a gross calorific-value basis. The US natural gas price reflects the wholesale price prevailing on the domestic market. The European Union and China gas prices reflect a balance of pipeline and liquefied natural gas (LNG) imports, while the Japan gas price is solely LNG imports; the LNG prices used are those at the customs border, prior to regasification. Steam coal prices are weighted averages adjusted to 6 000 kilocalories per kilogramme. The US steam coal price reflects mine-mouth prices (primarily in the Powder River Basin, Illinois Basin, Northern Appalachia and Central Appalachia markets) plus transport and handling cost. Coastal China steam coal price reflects a balance of imports and domestic sales, while the EU and Japanese steam coal price is solely for imports.

- The equilibrium **oil** prices are similar to those in last year's *Outlook*, but as ever these prices come with a number of caveats. The trajectories do not attempt to anticipate the fluctuations that characterise commodity markets in practice, in particular the risk of a shortfall in supply in the early 2020s (discussed in Chapter 3); it remains difficult, in our view, to plot a smooth pathway for oil markets to 2025.
- The upward drift in oil prices in the New Policies Scenario (which is even more pronounced in the Current Policies Scenario) reflects the large requirement for new resource development (Table B.4). Most of this is needed to compensate for declines in output from existing fields.
- We assume, in all scenarios, that major resource-holders maintain a strategy of market management. This means that the marginal project required to meet demand is more expensive than would be implied only by the global supply-cost curve.
- In the Sustainable Development Scenario, market dynamics and price trends are quite different, limiting the call on higher cost oil to balance the market and meaning that the oil market balances at a much lower price (Figure B.1).

Figure B.1 ▷ Average IEA crude oil price by scenario



The oil price trajectory varies widely between scenarios, reflecting their different supply, demand and policy elements

- The main change, compared with last year's edition, relates to the equilibrium prices for **natural gas**. The *WEO-2018* incorporates a higher US shale gas resource base that brings down prices in the United States and in all importing regions.
- Our projections assume movement towards a more integrated global gas market, in which internationally traded gas moves in response to price signals determined by the supply-demand balance in each region.
- In this market, US production flexibility and a growing North American LNG export industry actively seeking arbitrage opportunities play a critical role in our global price trajectories. As a result, the differences between regional prices in the latter part of the projection period reflect only the costs of transporting gas between them.
- In the case of **coal**, several regional coal prices exist which are usually closely correlated. Differences between regional coal prices reflect the transport cost between locations, infrastructure bottlenecks and coal quality differences.
- Coal prices have risen since 2016 due to consolidation on the supply side, including capacity cuts administered in China, and relatively strong import demand. In the New Policies Scenario, coal prices decrease slightly from current levels until the mid-2020s as markets rebalance.
- Long-term fundamentals dictate a modest coal price increase from the mid-2020s in the New Policies Scenario, reflecting upward cost pressure caused by the need to tap more remote coal deposits, worsening geological conditions and higher costs for consumables like fuel, explosives and tyres.

CO_2 prices

Table B.5 ▷ CO_2 prices in selected regions by scenario ($2017 per tonne)

Region	Sector	2025	2040
Current Policies Scenario			
Canada	Power, industry, aviation, others*	35	39
Chile	Power	5	5
China	Power	15	31
European Union	Power, industry, aviation	22	38
Korea	Power, industry	22	39
New Policies Scenario			
Canada	Power, industry, aviation, others*	35	39
Chile	Power	8	20
China	Power, industry, aviation	17	36
European Union	Power, industry, aviation	25	43
Korea	Power, industry	25	44
South Africa	Power, industry	11	24
Sustainable Development Scenario			
Advanced economies	Power, industry, aviation**	63	140
Selected developing economies	Power, industry, aviation**	43	125

* In Canada's benchmark/backstop policies, a carbon price is applied to fuel consumed in additional sectors. ** Coverage of aviation is limited to the same regions as in the New Policies Scenario.

- Compared with the *WEO-2017*, longer term carbon prices in the European Union and Korea (which are assumed to be linked due to future market coupling) have been revised downwards in the Current Policies and New Policies scenarios, largely because of lower natural gas prices.
- China's emissions trading scheme for the power sector is included in the Current Policies Scenario. In the New Policies Scenario, coverage expands to include energy-intensive industrial sectors and aviation, in line with announced plans.
- In the Sustainable Development Scenario, a higher and broader CO_2 price is assumed, rising to $140/tonne in advanced economies and $125/tonne in Brazil, China, Russia and South Africa by 2040. The carbon price applies to power generation, industry and, in some countries, aviation.
- The commitment to carbon pricing in Canada's Pan-Canadian Framework on Clean Growth and Climate Change is modelled in the Current Policies and New Policies scenarios as a national scheme, although in practice there are multiple approaches in place for different jurisdictions within the country.

Power generation technology costs

Table B.6 ▷ Technology costs by selected region in the New Policies Scenario

		Capital costs ($/kW)		Capacity factor (%)		Fuel and O&M ($/MWh)		LCOE ($/MWh)		VALCOE ($/MWh)	
		2017	2040	2017	2040	2017	2040	2017	2040	2017	2040
United States	Nuclear	5 000	4 500	90	90	30	30	105	100	105	100
	Coal	2 100	2 100	60	60	30	35	75	75	75	75
	Gas CCGT	1 000	1 000	50	50	30	40	50	65	45	60
	Solar PV	1 560	860	20	23	10	5	105	50	105	55
	Wind onshore	1 620	1 480	42	44	10	10	60	50	70	60
	Wind offshore	4 720	2 960	45	49	40	25	180	105	190	115
European Union	Nuclear	6 600	4 500	75	75	35	35	150	110	150	110
	Coal	2 000	2 000	40	40	45	45	120	145	105	120
	Gas CCGT	1 000	1 000	40	40	55	75	90	120	80	95
	Solar PV	1 300	760	12	13	20	15	160	85	165	105
	Wind onshore	1 820	1 700	28	30	20	15	100	90	105	105
	Wind offshore	4 260	2 820	50	55	35	25	150	90	160	105
China	Nuclear	2 320	2 500	75	75	25	25	60	65	60	65
	Coal	800	800	70	70	35	30	50	70	50	65
	Gas CCGT	560	560	50	50	70	90	85	115	80	105
	Solar PV	1 120	640	17	19	10	10	90	45	90	65
	Wind onshore	1 200	1 180	25	27	15	15	70	65	70	70
	Wind offshore	4 120	2 740	46	50	35	25	145	90	150	95
India	Nuclear	2 800	2 800	80	80	30	30	70	70	70	70
	Coal	1 200	1 200	60	60	35	35	60	55	60	50
	Gas CCGT	700	700	50	50	80	90	95	105	90	80
	Solar PV	1 120	620	19	22	10	10	80	40	80	65
	Wind onshore	1 080	1 040	25	30	10	10	60	50	65	55
	Wind offshore	3 320	2 220	40	44	40	25	155	95	160	100

Notes: O&M = operation and maintenance; LCOE = levelised cost of electricity; VALCOE = value-adjusted LCOE; kW = kilowatt; MWh = megawatt-hour; CCGT = combined-cycle gas turbine. LCOE and VALCOE figures are rounded. Lower figures for VALCOE indicate improved competitiveness. Coal refers to supercritical, except China that refers to ultra-supercritical.

Sources: IEA analysis; IRENA Renewable Cost Database; Bolinger and Seel (2018).

- Technology costs vary substantially by region and evolve over time.
- Major contributors to the LCOE include: overnight capital costs; capacity factor that describes the average output over the year relative to the maximum rated capacity (typical values provided); the cost of fuel inputs; plus operation and maintenance.
- For all technologies, a standard weighted average cost of capital was assumed (7% in developing economies and 8% in advanced economies, in real terms).
- The value-adjusted LCOE (or "VALCOE") incorporates information about both costs and the value provided to the system. Based on the LCOE, estimates of energy, capacity and flexibility value are incorporated to provide a new metric of competitiveness for power generation technologies (see section 8.3.4 of Chapter 8). This metric provides a more robust approach to compare dispatchable technologies and variable renewables.
- Additional power generation cost information is provided online at iea.org/weo/.

Policies

The policy actions assumed to be taken by governments are a key variable in this *Outlook* and the main reason for the differences in outcomes across the scenarios. An overview of the policies and measures that are considered in the various scenarios is included in the Tables B.7 – B.11.

The policies are cumulative: measures listed under the Sustainable Development Scenario (SDS) supplement those in the New Policies Scenario (NPS), which in turn supplement policies in the Current Policies Scenario (CPS). The tables begin with broad cross-cutting policy frameworks, followed by more detailed policies by sector: power, transport, industry and buildings. The "new policies" that are considered in the NPS are derived from an exhaustive examination of announcements and plans in countries around the world.

Table B.7 ▷ Cross-cutting policy assumptions by scenario for selected regions

	Scenario	Assumptions
All regions	CPS	• Fossil fuel subsidies phased out in countries that already have relevant policies in place.
	NPS	• Fossil fuel subsidies phased out in the next ten years in all net-importing countries, and in net-exporting countries where specific policies have been announced.
	SDS	• Universal access to electricity and clean cooking facilities by 2030. • Staggered introduction of CO_2 prices (see Table B.5). • Fossil fuel subsidies phased out by 2025 in net-importing countries and by 2035 in net-exporting countries. • Maximum sulfur content of oil products capped at 1% for heavy fuel oil, 0.1% for gasoil and 10 ppm for gasoline and diesel. • Regions that experience a change in water scarcity from 2016 to 2030 rely less on once-through freshwater cooling for new coal-fired, nuclear and concentrating solar power power plants.
United States	CPS	• Extension and increase of "45Q" tax credits for carbon capture, utilisation and storage: rising to \$35/t CO_2 in 2026 for enhanced-oil or gas recovery, and to \$50/t CO_2 sequestered in saline geological formations. • State-level renewable portfolio standards. • Regional Greenhouse Gas Initiative: mandatory cap-and-trade scheme covering fossil fuel power plants in nine northeast states, and economy-wide cap-and-trade scheme in California with binding commitments.
European Union	CPS	• 2020 Climate and Energy Package: o Reduce GHG emissions 20% below 1990 levels. o Increase share of renewables to at least 20%. o Partial implementation of 20% energy savings. • Emissions Trading System (ETS) reducing GHG emissions 21% below 2005 level in 2020.
	NPS	• NDC targets and 2030 Climate and Energy Framework: o Reduce GHG emissions at least 40% below 1990 levels. o Increase share of renewables to at least 32%. o Partial implementation of goal to save 32.5% of energy use compared with business-as-usual scenarios. • ETS reducing GHG emissions 43% below the 2005 level in 2030. • National Emission Ceilings Directive to reduce emissions of SO_2 by 79%, NO_X by 63%, $PM_{2.5}$ by 49%, NMVOC by 40% and NH_3 by 19% below 2005 levels by 2030. • Increase share of renewables in heating and cooling by 1% per year to 2030.

Table B.7 ▷ Cross-cutting policy assumptions by scenario for selected regions (continued)

	Scenario	Assumptions
Japan	NPS	• NDC targets: economy-wide target of reducing GHG emissions by 26% below fiscal year 2013 levels by fiscal year 2030; sector-specific targets. • The 5th Strategic Energy Plan under the Basic Act on Energy Policy.
China	CPS	• Action Plan for Prevention and Control of Air Pollution. • ETS for the power sector.
	NPS	• NDC GHG targets: achieve peak CO_2 emissions around 2030, with best efforts to peak early; lower CO_2 emissions per unit of GDP 60-65% below 2005 levels by 2030. • NDC energy target: increase the share of non-fossil fuels in primary energy consumption to 20% by 2030. • 13th Five-Year Plan targets for 2020: o Services sector value to be increased to 56%. o Non-fossil fuels to reach 15% of TPED. o Energy intensity per unit of GDP limited to 15% below 2015 levels. o Carbon emissions per unit of GDP limited to 18% below 2015 levels. o SO_2 and NO_x emissions reduced by 15%. • "Made in China 2025" transition from heavy industry to higher value-added manufacturing. • Expand the role of natural gas. • ETS expansion to domestic aviation and selected industry sectors. • Energy price reform, including more frequent adjustments in oil product prices and reduction in natural gas price for non-residential consumers. • Three-year action plan for cleaner air, announced in July 2018.
India	CPS	• National Mission on Enhanced Energy Efficiency. • National Clean Energy Fund to promote clean energy technologies based on a levy of INR 400 ($6) per tonne of coal. • "Make in India" campaign to increase the share of manufacturing in the national economy.
	NPS	• NDC GHG target: reduce emissions intensity of GDP 33-35% below 2005 levels by 2030. • NDC energy target: achieve about 40% cumulative installed capacity from non-fossil fuel sources by 2030 with the help of technology transfer and low-cost international finance. • Efforts to expedite environmental clearances and land acquisition for energy projects. • Opening of coal, gas and oil sectors to private and foreign investors.
Brazil	NPS	• NDC GHG economy-wide targets: reduce GHG emissions 37% below 2005 levels by 2025. • NDC energy goals for 2030: o Increase share of sustainable biofuels to around 18% of TPED. o Increase renewables to 45% of TPED. o Increase non-hydro renewables to 28-30% of TPED and 23% of power supply. • Partial implementation of National Energy Efficiency Plan.

Notes: NDC = Nationally Determined Contributions; GHG = greenhouse gases; LPG = liquefied petroleum gas; SO_2 = sulfur dioxide; NO_x = nitrogen oxides; $PM_{2.5}$ = fine particulate matter; NMVOC = non-methane volatile organic compounds; NH_3 = ammonia; TPED = total primary energy demand; ETS = emissions trading system. Pricing of CO_2 emissions is by emissions trading systems or taxes.

Table B.8 ▷ Power sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All regions	SDS	• Increased low-carbon generation from renewables and nuclear. • Expanded support for the deployment of CCUS. • Efficiency and emissions standards preventing the refurbishment of old inefficient plants. • Stringent pollution emissions limits for industrial facilities above 50 MW_{th} input using solid fuels, set at 200 mg/m^3 for SO_2 and NO_X and 30 mg/m^3 for $PM_{2.5}$.
United States	CPS	• Extension of Investment Tax Credit and Production Tax Credit. • State renewable portfolio standards and support for renewables. • Mercury and Air Toxics Standards. • New Source Performance Standards. • Clean Air Interstate Rule regulating SO_2 and NO_X. • Lifetimes of some nuclear plants extended beyond 60 years.
	NPS	• Extension and strengthening of support for renewables, nuclear and CCUS. • Affordable Clean Energy Rule.
Canada	CPS	• Emissions performance standard of 420 g CO_2 per kWh for new coal-fired electricity generation units, and units that have reached the end of their useful life. • New Brunswick and Alberta phase out unabated coal-fired power by 2030. • Introduction of country-wide carbon pricing in 2019.
	NPS	• Complete phase out of traditional coal-fired power in line with the Pan-Canadian Framework on Clean Growth and Climate Change. • Emissions performance standard for natural gas-fired electricity generation.
Mexico	CPS	• Clean energy share of 25% in total electricity generation by 2018, 30% by 2021 and 35% by 2024 (including efficient cogeneration).
	NPS	• Enhanced efforts to strengthen the national grid and reduce transmission and distribution losses.
European Union	CPS	• ETS in accordance with 2020 Climate and Energy Package. • No new coal power plants post-2020 in 26 of 28 member states. • Early retirement of all nuclear plants in Germany by end-2022. • Removal of some barriers to CHP plants. • Support for renewables in accordance with overall target. • Industrial Emissions Directive.
	NPS	• ETS in accordance with 2030 Climate and Energy Framework. • Coal phase out in a subset of member states, notably in Italy, Finland, France, Netherlands and United Kingdom. • Extended and strengthened support to renewables-based power generation technologies in accordance with overall target. • Further removal of barriers to CHP through partial implementation of the Energy Efficiency Directive. • Power market reforms to enable recovery of investments for adequacy. • New standards for Large Combustion Plants from the review of the Best Available Techniques Reference Document.

Table B.8 ▷ Power sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
Japan	CPS	• Air Pollution Control Law. • Retail power market liberalisation. • Support for renewables-based power generation.
	NPS	• Achievement of the power mix target by 2030 (renewables: 22-24%; nuclear power: 20-22%; gas: 27%; coal: 26%; oil: 3%). • Lifetime of some nuclear plants beyond typical lifetime of 40 years. • Non-fossil fuels to supply 44% of power generation by 2030, corresponding to carbon intensity of 370 g CO_2/kWh. • Implementation of the feed-in tariff amendment law. • Efficiency standards for new thermal power plants (coal: 42%; gas: 50.5%; oil: 39%).
China	CPS	• Air pollutant emissions standard for thermal power plants with limits on $PM_{2.5}$: 30 mg/m³; SO_2: 100-200 mg/m³ for new plants and 200-400 mg/m³ for existing plants; NO_X: 100-200 mg/m³. • ETS for the power sector.
	NPS	• 13th Five-Year Plan targets for 2020: o 58 GW nuclear, 380 GW hydro, at least 210 GW wind and at least 110 GW solar. o Retrofit of 133 GW of CHP and 86 GW of condensing coal plants in order to increase flexibility. o Coal limited to 1 100 GW, by delaying 150 GW of new builds and retiring 20 GW of existing plants.
India	CPS	• Renewable Purchase Obligation and other fiscal measures to promote renewables. • Increased use of supercritical coal technology. • Restructured Accelerated Power Development and Reform Programme to finance the modernisation of transmission and distribution networks. • Pollution control rules limiting emissions from coal power plants.
	NPS	• Environmental (Protection) Amendment Rules. • Universal electricity access achieved by 2023. • Strengthened measures such as competitive bidding to increase the use of renewables towards the national target of 175 GW of non-hydro renewables capacity by 2022 (100 GW solar, 75 GW non-solar). • Expanded efforts to strengthen the national grid, upgrade the transmission and distribution network, and reduce aggregate technical and commercial losses to 15%. • Increased efforts to establish the financial viability of all power market participants, especially network and distribution companies.
Brazil	CPS	• Technology-specific power auctions for all fuel types. • Guidance on fuel mix from the Ten-Year Plan for Energy Expansion.
Middle East	CPS	• Partial implementation of nuclear programmes, including in Saudi Arabia and United Arab Emirates. • Partial implementation of renewable targets and programmes. o Vision 2030 in Saudi Arabia. o Dubai Integrated Energy Strategy 2030. • Renewable Portfolio Standards in Iran.
	NPS	• Accelerated progress towards nuclear and renewables targets.

Notes: CCUS = carbon capture, utilisation and storage; CHP = combined heat and power; SO_2 = sulfur dioxide; NO_X = nitrogen oxides; $PM_{2.5}$ = fine particulate matter; g CO_2/kWh = grammes of carbon dioxide per kilowatt-hour; GW = gigawatts; PV = photovoltaic; ETS = emissions trading system.

Table B.9 ▷ Transport sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All regions	NPS	• Road transport: fuel sulfur standards of 10-15 ppm. • Aviation: International Civil Aviation Organization goal to improve fuel efficiency by 2% per year until 2020; aiming for carbon-neutral growth from 2020 onwards. • International shipping: global cap of 0.5% on sulfur content in fuel in 2020, tightened NO_X emissions standards in control areas by 2025 and Energy Efficiency Design Index, in line with International Maritime Organization (IMO) regulation.
	SDS	• Strong support for electric mobility and enhanced support to alternative fuels. • Retail fuel prices kept at a level similar to the NPS. • PLDVs: on-road stock emissions intensity limited to 55 g CO_2/km in advanced economies and 75 g CO_2/km elsewhere by 2040. • Two/three-wheelers: phase out two-stroke engines. • Light-duty gasoline vehicles: three-way catalysts and tight evaporative controls required. • Light-duty diesel vehicles: limit emissions to 0.1 g/km NO_X and 0.01 g/km PM. • Light commercial vehicles: full technology spill-over from PLDVs. • Medium- and heavy-freight vehicles: 30% more efficient by 2040 than in the NPS. • Heavy-duty diesel vehicles: limit emissions to 3.5 g/km NO_X and 0.03 g/km PM. • Aviation: fuel intensity reduced by 2.6% per year; scale-up of biofuels to reduce CO_2 emissions by 50% below 2005 levels in 2050. • International shipping: annual GHG emissions trajectory consistent with at least 50% below 2008 levels in 2050, in line with IMO GHG emissions reduction strategy.
United States	CPS	• Renewables Fuel Standard 2. • LDVs: Phase 2 of CAFE standards until 2020 and Safer Affordable Fuel Efficient rule for model years 2021-2026. • LDVs: Tier 3 Motor Vehicle Emission and Fuel Standards, equivalent to Euro 6. • Medium and heavy-duty trucks: low range of Phase 2 of EPA/NHTSA GHG emissions and fuel efficiency standards. • HDVs: Tier 3 Motor Vehicle Emission and Fuel Standards, equivalent to Euro VI.
	NPS	• Moderate increase of ethanol and biodiesel use after 2022. • Electric cars: stock target of 4 million by 2025 across eight states. • Road freight: support for natural gas.
European Union	CPS	• Subsidy supporting biofuels blending, 7% cap on conventional biofuels blending rate. • LDVs: Euro 6 emissions and fuel sulfur standards. • HDVs: Euro VI emissions and fuel sulfur standards. • Domestic aviation: ETS.
	NPS	• Announcements to phase out gasoline and diesel car sales including Denmark, Ireland, France, Netherlands, Norway, Slovenia and United Kingdom. • Increase renewables-based fuels to 10% of transport energy demand by 2020. • Renewable energy share in the transport sector of 14% by 2030; as well as a cap on food-based biofuels. • Fuel Quality Directive, reducing GHG intensity of road transport fuels by 6% in 2020. • PLDVs: emissions target of 95 g CO_2/km by 2021. • Commercial LDVs: emissions target of 147 g CO_2/km by 2020. • Post-2020 CO_2 targets for PLDVs and commercial LDVs with an intermediate target of 15% below 2021 levels by 2025, and 30% below by 2030. Parallel incentive system for advanced powertrains (i.e. electric vehicles) allows the relaxation of this measure. • CO_2 standards applied to subset of HDVs; 15% and 30% lower emissions assuming 2019 as a base year. • Electric vehicles (EVs): enhanced support to alternative fuels and vehicle powertrains, including sales and stock share targets for EVs. • Domestic aviation: ETS in accordance with 2030 Climate and Energy Framework.

Table B.9 ▷ Transport sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
Japan	CPS	• Financial incentives for plug-in hybrid, electric and fuel cell vehicles. • PLDVs: fuel-economy target at 20.3 kilometres per litre (km/L) by 2020. • Post New Long-term Emissions Standards for LDVs and HDVs equivalent to Euro 6 and VI.
	NPS	• Revitalisation strategy: target sales share of next generation vehicles of 50-70% by 2030. • EVs: stock target of 1 million by 2020, including purchase incentives and infrastructure. • Basic Strategy for Hydrogen: fleet of 80 000 fuel cell cars and 1 200 buses by 2030.
China	CPS	• Ethanol and biodiesel blending mandates of 10% and 7% respectively in some provinces. • Promotion of fuel-efficient/ hybrid cars and EVs; consolidation of vehicle charging standards. • PLDVs: cap on sales in some cities to reduce air pollution and traffic. • LDVs: China 6 emissions standards and Euro 6 equivalent fuel sulfur standards. • HDVs: China V (diesel) emissions standards and Euro VI equivalent fuel sulfur standards.
	NPS	• Subsidies for alternative-fuel vehicles, mainly electric scooters and public buses. • EVs: stock target of 5 million electric cars by 2020, including purchase and use incentives. • New Energy Vehicle mandate: credit target of 12% of the car market by 2020. • PLDVs: fuel-economy target at 5 litres per 100 km by 2020, and ambitions for 4 litres per 100 km by 2025. • HDVs: Stage III of National Standard targeting a 15% reduction in fuel consumption compared to 2015 from 2021 onwards. • Promotion of public transport in large and medium cities.
India	CPS	• Increasing blending mandate for ethanol and support for alternative-fuel vehicles. • LDVs: Bharat IV emissions standards and Euro 4 equivalent fuel sulfur standards. • HDVs: Bharat IV emissions standards and Euro IV equivalent fuel sulfur standards.
	NPS	• Declared intent to move to 30% electric share in vehicle sales by 2030. • Extended support for alternative-fuel two/three-wheelers, cars and public buses. • National Biofuel Policy with indicative blending share targets for bioethanol and biodiesel. • LDVs: Bharat VI emissions standards by 2020; fuel-economy standards at 130 g CO_2/km in 2017 and 113 g CO_2/km in 2022. • HDVs: Bharat VI emissions standards by 2020; fuel-economy targets for 2018 and 2021. • Dedicated rail corridors to encourage shift away from road freight.
Brazil	CPS	• Ethanol blending mandates in road transport of minimum 27%. • Biodiesel blending mandate of 9% in 2018 and 10% in 2019. • LDVs: PROCONVE L6 emissions standards, equivalent to Euro 5 but without limit on PM; Euro 2 (gasoline) and Euro 4 (diesel) equivalent fuel sulfur standards. • HDVs: PROCONVE P7 emissions standards, equivalent to Euro V; Euro II (gasoline) and Euro IV (diesel) equivalent fuel sulfur standards.
	NPS	• RenovaBio: further increase of ethanol and biodiesel blending mandates to cut carbon emissions from fuels sector by 10 % through 2028. • LDVs: Rota 2030 initiative targeting fuel efficiency improvement of 11% by 2022 compared to 2017 levels. • Local renewables-based fuel targets for urban transport. • National urban mobility plan. • Long-term plan for freight transport.

Notes: ppm = parts per million; NO_X = nitrogen oxides; g/km = grammes per kilometre; PM = particulate matter; CAFE = Corporate Average Fuel Economy; PLDVs = passenger light-duty vehicles; LDVs = light-duty vehicles; HDVs = heavy-duty vehicles; EVs = electric vehicles; FCVs: fuel cell vehicles; GHG = greenhouse gases; g CO_2/km = grammes of carbon dioxide per kilometre; ETS = emissions trading system; EPA = Environmental Protection Agency; NHTSA = National Highway Traffic Safety Administration.

Table B.10 ▷ Industry sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All regions	SDS	• Stringent emissions limits for industrial facilities above 50 MW_{th} input using solid fuels, set at 200 mg/m^3 for NO_X and SO_2 and 30 mg/m^3 for $PM_{2.5}$. • Emission limits for facilities below 50 MW_{th} based on size, fuel and combustion process. • Industrial processing plants to be fitted with the best available technologies in order to obtain operating permits. Existing plants to be retrofitted within ten years. • Enhanced minimum energy performance standards by 2025, in particular for electric motors; incentives for the introduction of variable speed drives in variable load systems, and implementation of system-wide measures. • International agreements on steel and cement industry energy intensity targets. • Mandatory energy management systems or energy audits. • Policies to support increased recycling of aluminium, steel, paper and plastics. • Policies to support the introduction of CCUS in industry. • Wider hosting of international projects to offset CO_2 emissions.
United States	CPS	• Better Buildings, Better Plants Program and Energy Star Program for Industry. • Boiler Maximum Achievable Control Technology to impose stricter emissions limits on industrial and commercial boilers, and process heaters. • Superior Energy Performance certification that supports the introduction of energy management systems. • Industrial Assessment Centers providing no-cost energy assessments to SMEs. • Permit program for GHGs and other air pollutants for large industrial installations. • Business Energy Investment Tax Credit and funding for efficient technologies.
	NPS	• Further assistance for SME manufacturers to adopt "smart manufacturing technologies" through technical assistance and grant programs.
European Union	CPS	• ETS in accordance with 2020 Climate and Energy Package. • White certificate scheme in Italy and energy saving obligation scheme in Denmark. • Voluntary energy efficiency agreements in Belgium, Denmark, Finland, Hungary, Ireland, Luxembourg, Netherlands, Portugal, Sweden and United Kingdom. • EcoDesign Directive standards for motors, pumps, fans, compressors and insulation. • Implementation of Medium Combustion Plant Directive. • Industrial Emissions Directive.
	NPS	• ETS in accordance with 2030 Climate and Energy Framework. • Implementation of Energy Efficiency Directive and extension to 2030: o Mandatory and regular energy audits for large enterprises. o Incentives for the use of energy management systems. o Encouragement for SMEs to undergo energy audits. o Technical assistance and targeted information for SMEs.
Japan	CPS	• Energy efficiency benchmarking. • Tax credits for investments in energy efficiency. • Financial incentives for SMEs to invest in energy conserving equipment and facilities. • Free energy audits for SMEs. • Mandatory energy management for large business operators. • Top Runner Programme of minimum energy standards for machinery and equipment.
	NPS	• Maintenance and strengthening of top-end low-carbon efficiency standards: o Higher efficiency CHP systems. o Promotion of state-of-the-art technology, faster replacement of ageing equipment. o Continuation of voluntary ETS.

Table B.10 ▷ Industry sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
China	CPS	• Accelerated elimination of outdated production capacity. • Partial implementation of Industrial Energy Performance Standards. • Mandatory adoption of coke dry-quenching and top-pressure turbines in new iron and steel plants. Support of non-blast furnace in iron production. • Mechanism to incentivise energy-efficient "leaders", i.e. manufacturers and brands that exceed specific benchmarks set by the China Energy Label. • Pilot of China's ETS for some provinces and industrial sectors.
	NPS	• Accelerated retrofit of older coal-fired industrial boilers. • Expansion of ETS to select industry sectors. • "Made in China 2025" targets for industrial energy intensity. • Continuation of industrial energy intensity reduction contributing to the 13th Five-Year Plan target (2016-20). • Full implementation of Industrial Energy Performance Standards. • Enhanced use of energy service companies and energy performance contracting. • Clean Winter Heating Plan promoting the use of natural gas.
India	CPS	• Energy Conservation Act: o Mandatory energy audits. o Appointment of an energy manager in seven energy-intensive industries. • National Mission on Enhanced Energy Efficiency (NMEEE): o Cycle II and III of Perform, Achieve and Trade (PAT) scheme, which benchmarks facilities' performance against best practice and enables trading of energy savings certificates. o Income and corporate tax incentives for energy service companies, including the Energy Efficiency Financing Platform. o Framework for Energy-Efficient Economic Development offering a risk guarantee for performance contracts and a venture capital fund for energy efficiency. • Energy efficiency intervention in selected SME clusters including capacity building.
	NPS	• Further implementation of the NMEEE's recommendations including: o Tightening of the PAT mechanism under Cycle III. o Further strengthening of fiscal instruments to promote energy efficiency. • Strengthen existing policies to realise the energy efficiency potential in SMEs.
Brazil	CPS	• PROCEL (National Programme for Energy Conservation). • PROESCO (Support for Energy Efficiency Projects). • Partial implementation of the National Energy Efficiency Plan, with fiscal and tax incentives for industrial upgrading, investment in training efficiency and encouragement to reuse industrial waste. • Incentives to increase biomass use in industry.
	NPS	• Extension of PROESCO.

Notes: CCUS = carbon capture, utilisation and storage; MW_{th} = megawatts thermal; mg/m^3 = milligrams per cubic metre; ETS = emissions trading system; SO_2 = sulfur dioxide; NO_X = nitrogen oxides; PM = particulate matter; CHP = combined heat and power; SMEs = small and medium enterprises.

Table B.11 ▷ Buildings sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All regions	SDS	• SDG 7.1: universal access to affordable, reliable and modern energy achieved by 2030. • Phase out least efficient appliances, light bulbs and heating or cooling equipment by 2030 at the latest. • Emissions limits for biomass boilers set at 40-60 mg/m^3 for PM and 200 mg/m^3 for NO_X. • Introduction of mandatory energy efficiency labelling requirements for all appliances. • Mandatory energy conservation building codes, including net-zero emissions requirement for all new buildings, by 2030 at the latest. • Increased support for energy efficiency measures, direct use of solar thermal and geothermal, and heat pumps. • Digitalization of buildings electricity demand to increase demand-side response potential, through greater flexibility and controllability of end use devices.
United States	CPS	• Association of Home Appliance Manufacturers – American Council for an Energy-Efficient Economy Multi-Product Standards Agreement. • Energy Star: new appliance efficiency standards. • Steady upgrades of building codes; incentives for utilities to improve building efficiency. • Weatherisation programmes: funding for refurbishments of residential buildings. • Federal and state rebates for renewables-based heat, including Residential Renewable Energy Tax Credit for solar water heaters, heat pumps and biomass stoves.
	NPS	• Partial implementation of the Energy Efficiency Improvement Act of 2015. • Mandatory energy efficiency requirements in building codes in some states, including California's 2019 Building Energy Efficiency Standards. • Tightening of efficiency standards for appliances.
European Union	CPS	• Energy Performance of Buildings Directive 2010. • EcoDesign and Energy Labelling Directive including requirements for boilers to have 75-77% efficiency depending on size and to limit pollutant emissions (PM: 40-60 mg/m^3; NO_X: 200 mg/m^3 for biomass boilers and 350 mg/m^3 for fossil fuel boilers; CO: 500-700 mg/m^3). • Individual member state financial incentives for renewables-based heat in buildings.
	NPS	• Partial implementation of the Energy Efficiency Directive. • 2016 update of Energy Performance of Buildings Directive mandating new buildings to be "nearly zero-energy" from 2020, and increased retrofit rates. • Mandatory labelling for sale or rental of all buildings and some appliances. • Further product groups in EcoDesign Directive. • Enhanced renewables-based heat support in member states.
Japan	CPS	• Building Efficiency Act for new buildings, renovations and extensions. • Top Runner Programme efficiency standards for home appliances. • Large operators to reduce energy consumption 1% per year and complete annual reports. • Energy efficiency standards for new buildings and houses larger than 300 m^2. • Capital Grant Scheme for renewable energy technologies.
	NPS	• Extension of the Top Runner Programme. • Voluntary equipment labelling programmes. • Building Energy Efficiency Act regulations for new large-scale non-residential buildings and incentives for all new buildings. • Net zero-energy buildings by 2030 for all new construction.

Table B.11 ▷ Buildings sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
China	CPS	• Civil Construction Energy Conservation Design Standards. • Appliance standards and labelling programme.
	NPS	• Promotion of green buildings: o New urban residential buildings to increase energy efficiency by 20% from 2015 levels to 2020. o 50% of new urban buildings to meet energy conservation requirements. • Retrofit of 500 million m^2 of residential buildings and 100 million m^2 of public buildings. • Promotion of electricity to replace decentralised coal and oil boilers. • Urban gasification of 57% by 2020. • Solar water heaters to cover 800 million m^2 by 2020. • Mandatory energy efficiency labels for appliances and equipment. • Clean Winter Heating Plan: switch from coal to gas and electricity for northern China including the "26+2" main cities in the Beijing-Tianjin-Hebei region and surroundings.
India	CPS	• Universal electricity access achieved by 2023. • Rural electrification under Deen Dayal Upadhyaya Gram Jyoti Yojana scheme. • Promotion of clean cooking access with LPG, including free connections to poor rural households through Pradhan Mantri Ujjwala Yojana. • Measures under the National Solar Mission. • Energy Conservation Building Code 2007 with voluntary standards for commercial buildings. • "Green Rating for Integrated Habitat Assessment" rating system for green buildings. • Promotion and distribution of LEDs through the Efficient Lighting Programme.
	NPS	• Standards and Labelling Programme, mandatory for air conditioners, lights, televisions and refrigerators, voluntary for seven other products and LEDs. • Phase out incandescent light bulbs by 2020. • Voluntary Star Ratings for the services sector. • Measures under the National Mission on Enhanced Energy Efficiency. • Energy Conservation in Building Codes made mandatory in eight states that regulate building envelope, lighting and hot water. • Efforts to plan and rationalise urbanisation in line with the "100 smart cities" concept. • Enhanced efforts to increase electricity access for households.
Brazil	CPS	• Labelling programme for household goods and public buildings equipment.
	NPS	• Partial implementation of National Energy Efficiency Plan. • Mandatory certification of public lighting; ban on inefficient incandescent bulbs.

Notes: mg/m^3 = milligrams per cubic metre; SO_2 = sulfur dioxide; NO_X = nitrogen oxides; PM = particulate matter; LED = light-emitting diodes; LPG = liquefied petroleum gas.

Definitions

This annex provides general information on terminology used throughout *WEO-2018* including: units and general conversion factors; definitions of fuels, processes and sectors; regional and country groupings; and abbreviations and acronyms.

Units

Area	Ha	hectare
	km^2	square kilometre
Coal	Mtce	million tonnes of coal equivalent (equals 0.7 Mtoe)
	Mtpa	million tonnes per annum
	gce	grammes of coal equivalent
Emissions	ppm	parts per million (by volume)
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	g CO_2/km	grammes of carbon dioxide per kilometre
	g CO_2/kWh	grammes of carbon dioxide per kilowatt-hour
Energy	boe	barrel of oil equivalent
	toe	tonne of oil equivalent
	ktoe	thousand tonnes of oil equivalent
	Mtoe	million tonnes of oil equivalent
	MBtu	million British thermal units
	kcal	kilocalorie (1 calorie x 10^3)
	Gcal	gigacalorie (1 calorie x 10^9)
	MJ	megajoule (1 joule x 10^6)
	GJ	gigajoule (1 joule x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	PJ	petajoule (1 joule x 10^{15})
	EJ	exajoule (1 joule x 10^{18})
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	scf	standard cubic foot

Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)
Monetary	$ million	1 US dollar x 10^6
	$ billion	1 US dollar x 10^9
	$ trillion	1 US dollar x 10^{12}
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	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})
Water	bcm	billion cubic metres
	m^3	cubic metre

General conversion factors for energy

Convert to:	**TJ**	**Gcal**	**Mtoe**	**MBtu**	**GWh**
From:	multiply by:				
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11 630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3 412	1

Note: There is no generally accepted definition of boe; typically the conversion factors used vary from 7.15 to 7.40 boe per toe.

Currency conversions

Exchange rates *(2017 annual average)*	**1 US Dollar equals:**
British Pound	0.78
Chinese Yuan Renminbi	6.76
Euro	0.89
Indian Rupee	65.12
Indonesian Rupiah	13 380.87
Japanese Yen	112.17
Russian Ruble	58.34
South African Rand	13.33

Source: OECD National Accounts database, September 2018.

Definitions

Advanced biofuels: Sustainable fuels produced from non-food crop feedstocks, which are capable of delivering significant lifecycle greenhouse gas emissions savings compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts. This definition differs from the one used for "advanced biofuels" in the US legislation, which is based on a minimum 50% lifecycle greenhouse gas reduction and which, therefore, includes sugar cane ethanol.

Agriculture: Includes all energy used on farms, in forestry and for fishing.

Back-up generation capacity: Households and businesses connected to the main power grid may also have some form of "back-up" power generation capacity that can, in the event of disruption, provide electricity. Back-up generators are typically fuelled with diesel or gasoline and capacity can be as little as a few kilowatts. Such capacity is distinct from mini-grid and off-grid systems that are not connected to the main power grid.

Biodiesel: Diesel-equivalent, processed fuel made from the transesterification (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

Bioenergy: Energy content in solid, liquid and gaseous products derived from biomass feedstocks and biogas. It includes solid biomass, biofuels and biogas.

Biofuels: Liquid fuels derived from biomass or waste feedstocks and include ethanol and biodiesel. They can be classified as conventional or advanced biofuels according to the technologies used to produce them and their respective maturity. Unless otherwise stated, biofuels are expressed in energy-equivalent volumes of gasoline or diesel.

Biogas: A mixture of methane and carbon dioxide produced by bacterial degradation of organic matter and used as a fuel.

Buildings: The buildings sector includes energy used in residential, commercial and institutional buildings, and non-specified other. Building energy use includes space heating and cooling, water heating, lighting, appliances and cooking equipment.

Bunkers: Includes both international marine bunkers and international aviation bunkers.

Capacity credit: Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.

Clean cooking facilities: Cooking facilities that are considered safer, more efficient and more environmentally sustainable than the traditional facilities that make use of solid biomass (such as a three-stone fire). This refers primarily to improved solid biomass cookstoves, biogas systems, liquefied petroleum gas, electric, ethanol and solar stoves.

Coal: Includes both primary coal (including lignite, coking and steam coal) and derived fuels (including patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas-works gas, coke-oven gas, blast-furnace gas and oxygen steel furnace gas). Peat is also included.

Coalbed methane (CBM): Category of unconventional natural gas, which refers to methane found in coal seams.

Coal-to-gas (CTG): Process in which mined coal is first turned into syngas (a mixture of hydrogen and carbon monoxide) and then into "synthetic" methane.

Coal-to-liquids (CTL): Transformation of coal into liquid hydrocarbons. It can be achieved through either coal gasification into syngas (a mixture of hydrogen and carbon monoxide), combined using the Fischer-Tropsch or methanol-to-gasoline synthesis process to produce liquid fuels, or through the less developed direct-coal liquefaction technologies in which coal is directly reacted with hydrogen.

Coking coal: Type of coal that can be used for steel making (as a chemical reductant and source of heat), where it produces coke capable of supporting a blast furnace charge. Coal of this quality is also commonly known as metallurgical coal.

Conventional biofuels: Fuels produced from food crop feedstocks. These biofuels are commonly referred to as first-generation and include sugar cane ethanol, starch-based ethanol, fatty acid methyl esther (FAME) and straight vegetable oil (SVO).

Decommissioning (nuclear): The process of dismantling and decontaminating a nuclear power plant at the end of its operational lifetime and restoring the site for other uses.

Decomposition analysis: Statistical approach that decomposes an aggregate indicator to quantify the relative contribution of a set of pre-defined factors leading to a change in the aggregate indicator. The *World Energy Outlook* uses an additive index decomposition of the type Logarithmic Mean Divisia Index (LMDI) I.

Demand-side integration (DSI): Consists of two types of measures: actions that influence load shape such as energy efficiency and electrification; and actions that manage load such as demand-side response.

Demand-side response (DSR): Describes actions which can influence the load profile such as shifting the load curve in time without affecting the total electricity demand, or load shedding such as interrupting demand for short duration or adjusting the intensity of demand for a certain amount of time.

Dispatchable: Dispatchable generation refers to technologies whose power output can be readily controlled – increased to maximum rated capacity or decreased to zero – in order to match supply with demand.

Electricity generation: Defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own-use. This is also referred to as gross generation.

Energy services: see useful energy.

Ethanol: Refers to bio-ethanol only. Ethanol is produced from fermenting any biomass high in carbohydrates. Today, ethanol is made from starches and sugars, but second-generation technologies will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

Gas (also referred to as natural gas): comprises gases occurring in deposits, whether liquefied or gaseous, consisting mainly of methane. It includes both "non-associated" gas originating from fields producing hydrocarbons only in gaseous form, and "associated" gas produced in association with crude oil as well as methane recovered from coal mines (colliery gas). Natural gas liquids (NGLs), manufactured gas (produced from municipal or industrial waste, or sewage) and quantities vented or flared are not included. Gas data in cubic metres are expressed on a "gross" calorific value basis and are measured at 15 °C and at 760 mm Hg ("Standard Conditions"). Gas data expressed in tonnes of oil equivalent, mainly for comparison reasons with other fuels, are on a "net" calorific basis. The difference between the "net" and the "gross" calorific value is the latent heat of vaporisation of the water vapour produced during combustion of the fuel (for gas the net calorific value is 10% lower than the gross calorific value).

Gas-to-liquids (GTL): Process featuring reaction of methane with oxygen or steam to produce syngas (a mixture of hydrogen and carbon monoxide) followed by synthesis of liquid products (such as diesel and naphtha) from the syngas using Fischer-Tropsch catalytic synthesis. The process is similar to those used in coal-to-liquids.

High-level waste (HLW): The highly radioactive and long-lived waste materials generated during the course of the nuclear fuel cycle, including spent nuclear fuel (if it is declared as waste) and some waste streams from reprocessing.

Heat (end-use): Can be obtained from the combustion of fossil or renewable fuels, direct geothermal or solar heat systems, exothermic chemical processes and electricity (through resistance heating or heat pumps which can extract heat from ambient air and liquids). This category refers to a wide range of end-uses, including space and water heating, and cooking in buildings, desalination and process applications in industry. It does not include cooling applications.

Heat (supply): Obtained from the combustion of fuels, nuclear reactors, geothermal resources and the capture of sunlight. It may be used for heating or cooling, or converted into mechanical energy for transport or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation.

Hydropower: The energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) plants.

Industry: Includes fuel used within the manufacturing and construction industries. Key industry branches include iron and steel, chemical and petrochemical, cement, and pulp and paper. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under other energy sector. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption by off-road vehicles is reported under industry.

International aviation bunkers: Includes the deliveries of aviation fuels to aircraft for international aviation. Fuels used by airlines for their road vehicles are excluded. The domestic/international split is determined on the basis of departure and landing locations and not by the nationality of the airline. For many countries this incorrectly excludes fuels used by domestically owned carriers for their international departures.

International marine bunkers: Covers those quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship. Consumption by fishing vessels and by military forces is also excluded and included in residential, services and agriculture.

Investment: All investment data and projections reflect "overnight investment", i.e. the capital spent is generally assigned to the year production (or trade) is started, rather than the year when it actually incurs. Investments for oil, gas and coal include production, transformation and transportation; those for the power sector include refurbishments, uprates, new builds and replacements for all fuels and technologies for on-grid, mini-grid and off-grid generation, as well as investment in transmission and distribution. Investment data are presented in real terms in year-2017 US dollars.

Lignite: Type of coal that is used in the power sector mostly in regions near lignite mines due to its low energy content and typically high moisture levels, which generally makes long-distance transport uneconomic. Data on lignite in the *WEO* includes peat, a solid formed from the partial decomposition of dead vegetation under conditions of high humidity and limited air access.

Lignocellulosic feedstock: Crops cultivated to produce biofuels from their cellulosic or hemicellulosic components, which include switchgrass, poplar and miscanthus.

Liquid fuels: The classification of liquid fuels used in our analysis is presented in Figure C.1. Natural gas liquids accompanying tight oil or shale gas production are accounted together with other NGLs under conventional oil.

Lower heating value: Heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapour and the heat is not recovered.

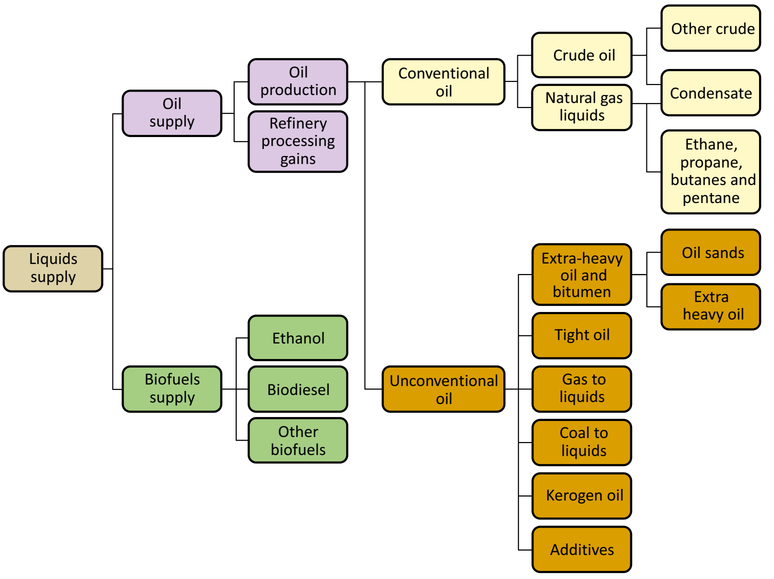
Middle distillates: Include jet fuel, diesel and heating oil.

Mini-grids: Small grid systems linking a number of households or other consumers.

Modern energy access: Includes household access to a minimum level of electricity; household access to safer and more sustainable cooking and heating fuels and stoves; access that enables productive economic activity; and access for public services.

Modern renewables: Includes all uses of renewable energy with the exception of traditional use of solid biomass.

Figure C.1 ▷ Liquid fuels classification



Modern use of solid biomass: Refers to the use of solid biomass in improved cookstoves and modern technologies using processed biomass such as pellets.

Natural gas liquids (NGLs): Liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. These are the portions of natural gas which are recovered as liquids in separators, field facilities or gas processing plants. NGLs include but are not limited to ethane (when it is removed from the natural gas stream), propane, butane, pentane, natural gasoline and condensates.

Non-energy use: Fuels used for chemical feedstocks and non-energy products. Examples of non-energy products include lubricants, paraffin waxes, asphalt, bitumen, coal tars and oils as timber preservatives.

Nuclear: Refers to the primary energy equivalent of the electricity produced by a nuclear plant, assuming an average conversion efficiency of 33%.

Off-grid systems: Stand-alone systems for individual households or groups of consumers.

Oil: Oil production includes both conventional and unconventional oil (Figure C1). Petroleum products include refinery gas, ethane, liquid petroleum gas, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin, waxes and petroleum coke.

Other energy sector: Covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses by gas works, petroleum refineries, blast furnaces, coke ovens, coal and gas transformation and liquefaction. It also includes energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category.

Power sector: Includes fuel use in electricity plants, heat plants and combined heat and power (CHP) plants. Both main activity producer plants and small plants that produce fuel for their own use (auto-producers) are included.

Pre-salt oil and gas: These resources are referred to as such because they predate the formation of a thick salt layer, which overlays the hydrocarbons and traps them in place.

Productive uses: Energy used towards an economic purpose: agriculture, industry, services, and non-energy use. Some energy demand from the transport sector (e.g. freight) could also be considered as productive, but is treated separately.

Refining processing gains: Processing gains are volume increases that occur during crude oil refining.

Renewables: Includes bioenergy, geothermal, hydropower, solar photovoltaic (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Residential: Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices and cooking equipment.

Resistance heating: Refers to direct electricity transformation into heat through the joule effect.

Self-sufficiency: Corresponds to indigenous production divided by total primary energy demand.

Services: Energy used in commercial (e.g. hotels, offices, catering, shops) and institutional buildings (e.g. schools, hospitals, offices). Services energy use includes space heating and cooling, water heating, lighting, equipment, appliances and cooking equipment.

Shale gas: Natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. Shale gas is generally produced using hydraulic fracturing.

Solid biomass: Includes charcoal, fuelwood, dung, agricultural residues, wood waste and other solid wastes.

Steam coal: Type of coal that is mainly used for heat production or steam-raising in power plants and, to a lesser extent, in industry. Typically, steam coal is not of sufficient quality for steel making. Coal of this quality is also commonly known as thermal coal.

Tight oil: Oil produced from shales or other very low permeability formations, using hydraulic fracturing. This is also sometimes referred to as light tight oil. Tight oil includes tight crude oil and condensate production except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids).

Total final consumption (TFC): Is the sum of consumption by the various end-use sectors. TFC is broken down into energy demand in the following sectors: industry (including manufacturing and mining), transport, buildings (including residential and services) and other (including agriculture and non-energy use). It excludes international marine and aviation bunkers, except at world level where it is included in the transport sector.

Total final energy consumption (TFEC): Is a variable defined primarily for tracking progress towards target 7.2 of the Sustainable Development Goals. It incorporates total final consumption (TFC) by end-use sectors but excludes non-energy use. It excludes international marine and aviation bunkers, except at world level. Typically this is used in the context of calculating the renewable energy share in total final energy consumption (Indicator 7.2.1 of the Sustainable Development Goals), where TFEC is the denominator.

Total primary energy demand (TPED): Represents domestic demand only and is broken down into power generation, other energy sector and total final consumption.

Traditional use of solid biomass: Refers to the use of solid biomass with basic technologies, such as a three-stone fire, often with no or poorly operating chimneys.

Transport: Fuels and electricity used in the transport of goods or persons within the national territory irrespective of the economic sector within which the activity occurs. This includes fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at the domestic level.

Useful energy: Refers to the energy that is available to end-users to satisfy their needs. This is also referred to as energy services demand. As result of transformation losses at the point of use, the amount of useful energy is lower than the corresponding final energy demand for most technologies. Equipment using electricity often has higher conversion efficiency than equipment using other fuels, meaning that for a unit of energy consumed electricity can provide more energy services.

Variable renewable energy (VRE): Refers to technologies whose maximum output at any time depends on the availability of fluctuating renewable energy resources. Reported totals for VRE include wind power and solar PV, but the term can also refer to run-of-river hydro, concentrating solar power (where no thermal storage is included) and marine (tidal and wave).

Waste storage and disposal: Activities related to the management of radioactive nuclear waste. Storage refers to temporary facilities at the nuclear power plant site or a centralised site. Disposal refers to permanent facilities for the long-term isolation of high-level waste, such as deep geologic repositories.

Water consumption: The volume withdrawn that is not returned to the source (i.e. it is evaporated or transported to another location) and by definition is no longer available for other uses.

Water sector: Includes all processes whose main purpose is to treat/process or move water to or from the end-use: groundwater and surface water extraction, long-distance water transport, water treatment, desalination, water distribution, wastewater collection, wastewater treatment and water re-use.

Water withdrawal: The volume of water removed from a source; by definition withdrawals are always greater than or equal to consumption.

Regional and country groupings

Advanced economies: OECD regional grouping and Bulgaria, Croatia, Cyprus,[1,2] Latvia, Lithuania, Malta and Romania.

Africa: North Africa and sub-Saharan Africa regional groupings.

Asia Pacific: Southeast Asia regional grouping and Australia, Bangladesh, China, Chinese Taipei, India, Japan, Korea, Democratic People's Republic of Korea, Mongolia, Nepal, New Zealand, Pakistan, Sri Lanka and other countries and territories.[3]

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Central and South America: Argentina, Bolivia, Bolivarian Republic of Venezuela, Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, and other countries and territories.[4]

China: People's Republic of China, including Hong Kong.

Developing Asia: Asia Pacific regional grouping excluding Australia, Japan, Korea, and New Zealand.

Developing economies: All other countries not included in the "advanced economies" regional grouping.

Eurasia: Caspian regional grouping and Russian Federation.

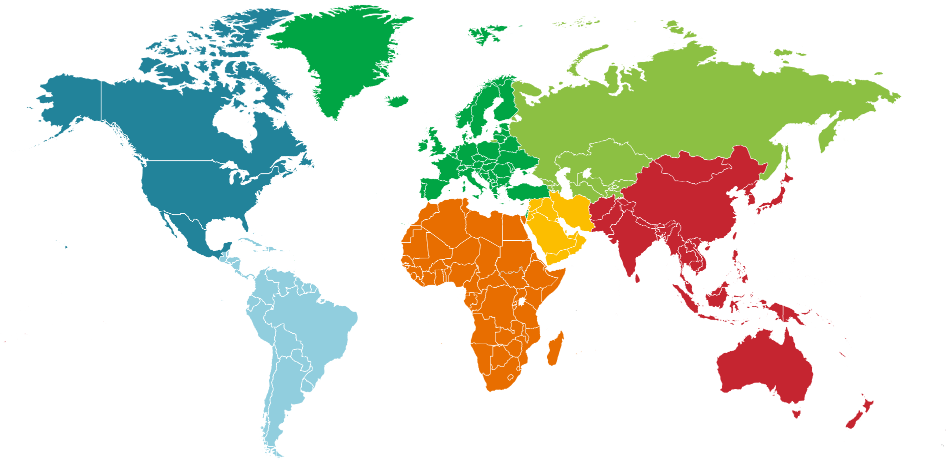
1. Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

2. Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

3. Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste and Tonga and Vanuatu.

4. Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guiana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Saba, Saint Eustatius, Saint Kitts and Nevis, Saint Lucia, Saint Vincent and the Grenadines, Saint Maarten, Turks and Caicos Islands.

Figure C.2 ▷ *World Energy Outlook* main country groupings



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

Europe: European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, Gibraltar, Iceland, Israel[5], Kosovo, Montenegro, Norway, Serbia, Switzerland, the Former Yugoslav Republic of Macedonia, Republic of Moldova, Turkey and Ukraine.

European electricity market regions: *Central Western Europe* (Austria, Belgium, France, Germany, Luxembourg, Netherlands, Switzerland); *United Kingdom and Ireland*; *Northern Europe* (Denmark, Estonia, Finland, Latvia, Lithuania, Norway, Sweden); *Italy*, *Iberian Peninsula* (Portugal, Spain); *Central and South Eastern Europe* (Bulgaria, Croatia, Cyprus[1,2], Czech Republic, Greece, Hungary, Malta, Poland, Romania, Slovak Republic and Slovenia).

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus[1,2], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain, Sweden and United Kingdom.

IEA (International Energy Agency): OECD regional grouping excluding Chile, Iceland, Israel, Latvia, Lithuania and Slovenia.

Latin America: Central and South America regional grouping and Mexico.

Middle East: Bahrain, Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen.

Non-OECD: All other countries not included in the OECD regional grouping.

5. The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Non-OPEC: All other countries not included in the OPEC regional grouping.

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

North America: Canada, Mexico and United States.

OECD (Organisation for Economic Co-operation and Development): Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States. Latvia and Lithuania became members of the OECD in July 2016 and July 2018, and their membership is not yet reflected in *WEO* projections for the OECD.

OPEC (Organization of Petroleum Exporting Countries): Algeria, Angola, Republic of the Congo, Ecuador, Equatorial Guinea, Gabon, Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Republic of the Congo, Côte d'Ivoire, Democratic Republic of the Congo, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritius, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Zambia, Zimbabwe and other countries and territories.[6]

Abbreviations and Acronyms

APEC	Asia-Pacific Economic Cooperation
ASEAN	Association of Southeast Asian Nations
BEV	battery electric vehicles
CAAGR	compound average annual growth rate
CAFE	corporate average fuel-economy standards (United States)
CBM	coalbed methane
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CEM	Clean Energy Ministerial
CFL	compact fluorescent lamp

6. Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Réunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara.

CH_4	methane
CHP	combined heat and power; the term co-generation is sometimes used
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-eq	carbon-dioxide equivalent
COP	Conference of Parties (UNFCCC)
CPS	Current Policies Scenario
CSP	concentrating solar power
CTG	coal-to-gas
CTL	coal-to-liquids
DER	distributed energy resources
DSI	demand-side integration
DSR	demand-side response
EHOB	extra-heavy oil and bitumen
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (United States)
EU	European Union
EU ETS	European Union Emissions Trading System
EV	electric vehicle
FAO	Food and Agriculture Organization of the United Nations
FDI	foreign direct investment
FiES	Future is Electric Scenario
FiT	feed-in tariff
FOB	free on board
GDP	gross domestic product
GHG	greenhouse gases
GTL	gas-to-liquids
HDI	human development index
HFO	heavy fuel oil
IAEA	International Atomic Energy Agency
ICE	internal combustion engine
ICT	information and communication technologies
IEA	International Energy Agency
IGCC	integrated gasification combined-cycle

IIASA	International Institute for Applied Systems Analysis
IMF	International Monetary Fund
IMO	International Maritime Organization
IOC	international oil company
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity
LCV	light-commercial vehicle
LED	light-emitting diode
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LULUCF	land use, land-use change and forestry
MER	market exchange rate
MEPS	minimum energy performance standards
NDCs	Nationally Determined Contributions
NEA	Nuclear Energy Agency (an agency within the OECD)
NGLs	natural gas liquids
NGV	natural gas vehicle
NPS	New Policies Scenario
NPV	net present value
NOC	national oil company
NO_X	nitrogen oxides
NPS	New Policies Scenario
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
PHEV	plug-in hybrid electric vehicles
PLDV	passenger light-duty vehicle
PM	particulate matter
PPA	power purchase agreement
PPP	purchasing power parity
PSH	pumped storage hydropower
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
RRR	remaining recoverable resource
SDS	Sustainable Development Scenario
SME	small and medium enterprises

SMR	steam methane reformation
SO_2	sulfur dioxide
SWH	solar water or solar water heaters
T&D	transmission and distribution
TES	thermal energy storage
TFC	total final consumption
TFEC	total final energy consumption
TPED	total primary energy demand
UAE	United Arab Emirates
UN	United Nations
UNDP	United Nations Development Program
UNEP	United Nations Environment Program
UNFCCC	United Nations Framework Convention on Climate Change
URR	ultimately recoverable resources
US	United States
USGS	United States Geological Survey
VALCOE	value-adjusted levelised cost of electricity
VRE	variable renewable energy
WACC	weighted average cost of capital
WEO	World Energy Outlook
WEM	World Energy Model
WHO	World Health Organization

References

Part A: Global Energy Trends

Chapter 1: Overview and key findings

Arnell et al. (2018), "Direct Risks of Climate Change", *Development Indicators of Climate Risk,* London, United Kingdom and Beijing, China.

IEA (International Energy Agency) (2018a), *World Energy Investment 2018*, OECD/IEA, Paris.

– (2018b), *Outlook for Producer Economies, World Energy Outlook Special Report*, OECD/ IEA, Paris.

– (2018c), *Status of Power System Transformation 2018*, OECD/IEA, Paris.

– (2017), *Energy Access Outlook 2017: From Poverty to Prosperity, World Energy Outlook Special Report,* OECD/IEA, Paris.

– (2015), *Energy and Climate Change: World Energy Outlook Special Report*, OECD/IEA, Paris.

– (2003), *World Energy Investment Outlook*, OECD/IEA, Paris.

Chapter 2: Energy and the Sustainable Development Goals

Bijl et al. (2016), "Long-term Water Demand for Electricity, Industry and Households", *Environmental Science & Policy,* Vol. 55 (1), pp.75-86.

ENERGIA, World Bank and UN Women (2018), *Global Progress on SDG 7 - Energy and Women, Policy Brief #12 in "Accelerating SDG 7 Achievement: Policy Briefs in Support of the First SDG 7 Review at the UN High-Level Political Forum 2018",* United Nations, New York.

Fuso Nerini et al. (2017), "The Cost of Cooking a Meal: the Case of Nyeri County, Kenya", *Environmental Research Letters*, Vol. 12/6, http://iopscience.iop.org/article/10.1088/ 1748-9326/aa6fd0/meta.

HEI (Health Effects Institute) (2018), *State of Global Air 2018*, Health Effects Institute, Boston, MA., United States.

IEA (International Energy Agency) (2018a), *Energy Efficiency 2018,* OECD/IEA, Paris.

– (2018b), *Perspectives for the Energy Transtion: the Role of Energy Efficiency*, German Federal Ministry for Economic Affairs and Energy, Berlin.

– (2018c), *Tracking Clean Energy Progress: Informing Energy Sector Transformations*, IEA, www.iea.org/tcep/.

– (2018d), *Global Energy and CO_2 Status Report*, IEA, www.iea.org/geco/.

– (2018e), *World Energy Investment 2018,* OECD/IEA, Paris.

– (2018f), *Offshore Energy Outlook, World Energy Outlook Series,* OECD/IEA, Paris.

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

– (2018h), *Outlook for Producer Economies, World Energy Outlook Special Report*, OECD/IEA, Paris.

– (2017a), *Energy Access Outlook 2017: From Poverty to Prosperity, World Energy Outlook Special Report,* OECD/IEA, Paris.

– (2017b), *World Energy Outlook-2017*, OECD/IEA, Paris.

– (2017c), *Real-world Policy Packages for Sustainable Energy Transitions*, OECD/IEA, Paris.

– (2016a), *Energy and Air Pollution: World Energy Outlook Special Report,* OECD/IEA, Paris.

– (2016b), *World Energy Outlook-2016*, OECD/IEA, Paris.

– (2016c), *Water-Energy Nexus: World Energy Outlook Special Report,* OECD/IEA, Paris.

– (2015), *Energy and Climate Change: World Energy Outlook Special Report,* OECD/IEA, Paris.

IPCC (Intergovernmental Panel on Climate Change) (2018), *IPCC Special Report on the Impacts of Global Warming of 1.5 °C Above Pre-Industrial Levels*, IPCC.

– (2014), *Fifth Assessment Report,* IPCC, Cambridge University Press, Cambridge, United Kingdom and New York.

IRP (International Resource Panel) (2016), *Options for Decoupling Economic Growth from Water Use and Water Pollution*, United Nations Environment Program, Paris.

IWA (International Water Association) (2018), *Wastewater Report 2017: The Reuse Opportunity*, IWA, London.

Kusumawardhani et al. (2017), *Gender and Fossil Fuel Subsidy Reform: An Audit of Data on Energy Subsidies, Energy Use and Gender In Indonesia,* International Institute for Sustainable Development, Winnipeg, Canada.

Lewis, J. (2014), *The Impact of Technological Change within the Home,* University of Toronto, Canada.

Luck, M., M. Landis and F. Gassert (2015), *Aqueduct Water Stress Projections: Decadal Projections of Water Supply and Demand Using CMIP5 GCMs*, World Resources Institute, Washington, DC.

Millar et al. (2017), "Emission Budgets and Pathways Consistent with Limiting Warming to 1.5 ^{o}C", *Nature Geoscience*, Vol. 10, pp. 741-747.

Noble, N. (2012), *Solar Photovoltaic Water Pumping,* Practical Action, London.

OECD (Organisation for Economic Development and Co-operation) (2018), *Taxing Energy Use 2018,* OECD, Paris.

Orozco Corona, M. and S. Gammage, (2017), *Cash Transfer Programmes, Poverty Reduction and Women's Economic Empowerment: Experience from Mexico,* International Labour Organization, Geneva.

Power for All (2018), *Power for All Fact Sheet: Decentralized Renewables: Supporting Sanitation and Access to Clean Water*, Power for All, www.powerforall.org/application/files/7615/2364/4966/Decentralized-Renewables-Supporting_Sanitation_and_Access_to_Clean_Water-final-draft.pdf, accessed 13 June 2018.

Power for All (2017), *Solar mini-grids deliver clean water to rural India*, Medium, https://medium.com/energy-access-india/solar-mini-grids-bring-clean-water-to-rural-india-36ea8bb16c4b, accessed 13 June 2018.

REN21 (2017), *Renewables 2017 – Global Status Report*, REN21 Secretariat, Paris.

Rural Water Supply Network (2009), Hand pump Data, University of Portsmouth, United Kingdom, www.rural-water-supply.net/en/resources/details/203.

Singh, D., S. Pachauri and H. Zerriffi (2017), "Environmental Payoffs of LPG Cooking in India", *Environmental Research Letters*, 12 (11).

Slaymaker, T. and R. Bain (17 May 2017), "Access to Drinking Water Around the World", The Guardian, London.

Tsani et al. (2013), "Female Labour Force Participation and Economic Growth in the South Mediterranean Countries", *Economics Letters*, 120(2), 323-328.

UN (United Nations) (2018), *Accelerating SDG 7 Achievement: Policy Briefs in Support of the First SDG 7 Review at the UN High-Level Political Forum 2018*, United Nations Department of Economic and Social Affairs, New York.

UN Water (2017), *World Water Development Report 2017: Wastewater, the untapped resource*, www.unwater.org/publications/world-water-development-report-2017/.

– (n.d), "Water, Sanitation and Hygiene", www.unwater.org/water-facts/water-sanitation-and-hygiene/.

UNDESA (United Nations Department of Economic and Social Affairs) (2018), *2018 Revision of World Urbanization Prospects*, www.un.org/development/desa/en/news/population/2018-revision-of-world-urbanization-prospects.html.

– (n.d), Sustainable Development Goal 6, https://sustainabledevelopment.un.org/sdg6, accessed 8 October, 2018.

UNGA (United Nations General Assembly) (2017), "2018 Revision of Resolution adopted by the General Assembly on 25 September 2015", www.un.org/ga/search/view_doc.asp?symbol=A/RES/70/1&referer=/english/&Lang=E.

UNHLPF (United Nations High-Level Political Forum) (2018), *Policy Brief 14: the Interlinkages Between Energy And Sustainable Cities*, https://sustainabledevelopment.un.org/content/documents/17557PB_14_version2.pdf.

UNICEF (United Nations Children's Fund) (2018), *Fact Sheet: Decentralized Renewables: Supporting Sanitation and Access to Clean Water*, Power for All.

– (2016a), *Collecting water is often a colossal waste of time for women and girls*, www.unicef.org/media/media_92690.html, accessed 13 June 2018.

– (2016b), *Scaling Up Solar Powered Water Supply Systems: A Review of Experiences,* UNICEF, New York.

US EPA (United States Environmental Protection Agency) (2008), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006,* US EPA, Washington, DC.

Wada, Y., et al. (2016), "Modeling Global Water Use for the 21st Century: the Water Futures and Solutions Initiative and Its Approaches", *Geoscientific Model Development*, Vol. 9, pp.175-222.

WEF (World Economic Forum), (2016), *The New Plastics Economy: Rethinking the Future of Plastics,* WEF, Geneva.

WHO (World Health Organization) (2016), *WHO Global Urban Ambient Air Pollution Database* (Update 2016), www.who.int/phe/health_topics/outdoorair/databases/cities/en/.

WHO/UNICEF JMP, *WASH Data*, https://washdata.org/data, accessed 8 October, 2018.

Winther, T. (2006), *Social Impact Evaluation Study of the Rural Electrification Project in Zanzibar, Phase IV (2003-2006),* Centre for Development and the Environment, Oslo.

Winther, T., K. Ulsrud, and A. Saini, (2018), "Solar Powered Electricity Access: Implications for Women's Empowerment in Rural Kenya", *Energy Research & Social Science*, Vol. 44, pp. 61-74.

World Bank (2018), "*Mind the gap: how bringing together cities and private investors can close the funding gap for urban resilience",* http://blogs.worldbank.org/sustainablecities/mind-gap-how-bringing-together-cities-and-private-investors-can-close-funding-gap-urban-resilience.

Chapter 3: Outlook for oil

IEA (International Energy Agency) (2018a), *The Future of Petrochemicals*, OECD/IEA, Paris.

– (2018b), *World Energy Investment 2018*, OECD/IEA, Paris.

– (2018c), *Outlook for Producer Economies, World Energy Outlook Special Report*, OECD/IEA, Paris.

– (2018d), *Market Report Series: Oil 2018*, OECD/IEA, Paris.

Chapter 4: Outlook for natural gas

Boersma, T., Losz, A., and A. Ummat (2017), *The Future of Natural Gas in India: A Country at a Crossroads*, Center on Global Energy Policy, Columbia University, New York.

European Network of Transmission System Operators for Gas (ENTSOG) (2017), *Ten Year Network Development Plan*, ENTSOG, Brussels.

IEA (International Energy Agency) (2018a), *Global Energy and CO_2 Status Report*, OECD/IEA, Paris.

– (2018b), *World Energy Investment 2018*, OECD/IEA, Paris.

– (2018c), *Market Report Series: Gas 2018*, OECD/IEA, Paris.

Chapter 5: Outlook for coal

CIL (Coal India Limited) (2018a*), Provisional Production and Offtake Performance of CIL and Subsidiary Companies*, www.coalindia.in/DesktopModules/DocumentList/documents/Provisional_Production_and_Offtake_Performance_of_CIL_and_Subsidiaries_Companies_for_the_ month_of_Mar_18_and_for_Apr_17_Mar_18_01042018.pdf, accessed 10 July 2018.

– (2018b), *Unlocking Transparency by Third-Party Assessment of Mined Coal*, http://uttam.coalindia.in/, accessed 15 July 2018.

– (2016), *Price Notification No - 01 of 2016*, www.coalindia.in/DesktopModules/DocumentList/documents/Revised_Prices_in_respect_of_non-coking_coal_effective_from_30.05.2016_30052016.pdf, accessed 15 July 2018.

CRU (2018), *Thermal Coal Cost Model 2017* (commercial database), accessed 15 July 2018.

Gonzales-Salazar, M., T. Kirsten and L. Prchlik (2018), "Review of the Operational Flexibility and Emissions of Gas- and Coal-Fired Power Plants in a Future with Growing Renewables", *Renewable and Sustainable Energy Reviews*, Vol. 82.

IEA (International Energy Agency) (2018), *Status of Power System Transformation 2018: Advanced Power Plant Flexibility*, OECD/IEA, Paris.

IEA CCC (IEA Clean Coal Centre) (2014), *Increasing the Flexibility of Coal-Fired Power Plants*, IEA Clean Coal Centre, London.

IHS Energy (2018), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Indian Railways (2017), *Annual Statistical Statements 2016-17*, Indian Railways - Statistics and Economics: www.indianrailways.gov.in/railwayboard/uploads/directorate/stat_econ/IRSP_2016-17/Facts_Figure/Indian%20Railway%20Annual%20Statistical%20Statements%20Final.pdf, accessed 10 July 2018.

NREL (National Renewable Energy Laboratory) (2013), *Cost-Benefit Analysis of Flexibility Retrofits for Coal and Gas-Fueled Power Plants*, NREL, Golden, CO., United States.

PIB (Press Information Bureau) (2015), "CIL Gearing Up for 1 Billion Tonne Coal Production Mark", 15 February 2015, Government of India Press Information Bureau: http://pib.nic.in/newsite/PrintRelease.aspx?relid=115635, accessed 19 July 2018.

Chapter 6: Energy efficiency and renewable energy

Empresa de Pesquisa Energética (2017), *RenovaBio: Biocombustiveis 2030*, Ministério de Minas e Energia, Rio de Janeiro.

European Environment Agency (2018), *No Improvements on Average CO_2 Emissions from New Cars in 2017*, www.eea.europa.eu/highlights/no-improvements-on-average-co2, accessed 23 April 2018.

IEA (International Energy Agency) (2018a), *Energy Efficiency 2018*, OECD/IEA, Paris.

– (2018b), *World Energy Investment 2018*, OECD/IEA, Paris.

– (2018c), *Renewables 2018*, Market Report Series, OECD/IEA, Paris.

– (2017a), *Energy Access Outlook 2017: From Poverty to Prosperity, World Energy Outlook Special Report*, OECD/IEA, Paris.

– (2017b), *Digitalization and Energy 2017*, OECD/IEA, Paris.

– (2013), *Technology Roadmap: Energy Efficiency Building Envelopes*, OECD/IEA, Paris.

REN21 (2018), *Renewables 2018 – Global Status Report*, REN21 Secretariat, Paris.

Part B: Special focus on Electricity

Chapter 7: Electricity today

Bolinger, M. and J. Seel (2018). *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition*, Lawrence Berkeley National Laboratory, Berkeley, CA., United States.

Cleantech Group (2018), *Blockchain in Energy & Industry Raises $1 Billion – and Heads into Challenging Times*, https://www.cleantech.com/blockchain-in-energy-industry-raises-1-billion-and-heads-into-challenging-times/, accessed 25 July 2018.

IEA (International Energy Agency) (2018a), *The Future of Cooling*, OECD/IEA, Paris.

– (2018b), *Renewables 2018, Market Report Series*, OECD/IEA, Paris.

– (2018c), *World Energy Investment 2018*, OECD/IEA, Paris.

– (2018d), *Offshore Energy Outlook: World Energy Outlook Series*, OECD/IEA, Paris.

– (2018e), *CO_2 Emissions from Fuel Combustion*, OECD/IEA, Paris.

– (2018f), *World Energy Balances*, OECD/IEA, Paris.

– (2017), *Getting Wind and Sun onto the Grid – A Manual for Policy Makers*, OECD/IEA, Paris.

– (2003), *World Energy Investment Outlook 2003 Insights*, OECD/IEA, Paris.

– (2002), *Lessons from Liberalised Electricity Markets*, OECD/IEA, Paris.

IRENA (International Renewable Energy Agency) (2018), *Renewable Power Generation Costs in 2017*, IRENA, Abu Dhabi.

NRG (NRG Expert Energy Intelligence) (2018), *Electricity Transmission and Distribution Database – 2017*, NRG, London.

REN21 (2018), *Renewables 2018 – Global Status Report*, REN21 Secretariat, Paris.

S&P Global Platts (2018), *World Electric Power Plants Database*, March 2018, S&P Global Platts, London.

WindEurope (2018), *Offshore Wind in Europe: Key trends and statistics 2017*, WindEurope, Brussels.

Chapter 8: Outlook for electricity demand and supply

BNEF (Bloomberg New Energy Finance) (2018), *Energy Storage System Costs Survey 2018.* Bloomberg Finance L.P., London.

Cisco (2018), *Cisco Global Cloud Index: Forecast and Methodology, 2016–2021*, https://www.cisco.com/c/en/us/solutions/collateral/service-provider/global-cloud-index-gci/white-paper-c11-738085.pdf.

Hirth, L. (2018), "What Caused the Drop in European Electricity Prices? A Factor Decomposition Analysis", *Energy Journal*, 39(1), https://www.faee.fr/files/file/aee/IAEE%20TOC/EJ39-1%20TOC.pdf.

IEA (International Energy Agency) (2018a), *The Future of Cooling*, OECD/IEA, Paris.

– (2018b), *Offshore Energy Outlook: World Energy Outlook Series*, OECD/IEA, Paris.

– (2018c), *Renewables 2018, Market Report Series*, OECD/IEA, Paris.

– (2017), *World Energy Outlook-2017*, OECD/IEA, Paris.

– (2016), *World Energy Outlook-2016*, OECD/IEA, Paris.

– (2015), *World Energy Outlook-2015*, OECD/IEA, Paris.

Lazard (2017), Levelized Cost of Storage Analysis – version 3.0, https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf.

Masanet et al. (2018), *Global Data Center Energy Use: Distribution, Composition, and Near-Term Outlook*, Northwestern University Working Paper, Evanston, IL., United States.

REN21 (2018), *Renewables 2018 Global Status Report*, REN21 Secretariat, Paris.

Shehabi et al. (2016), *United States Data Center Energy Usage Report*, Berkeley, CA., United States, https://doi.org/LBNL-1005775.

Würzburg et al. (2013), "Renewable Generation and Electricity Prices: Taking Stock and New Evidence for Germany and Austria" *Energy Economics*, Vol. 40, pp. 159-171, DOI: 10.1016/j.eneco.2013.09.011.

Chapter 9: Alternative electricity futures

Bendiksen, C. and S. Gibbons (2018), *The Bitcoin Mining Network -Trends, Marginal Creation Cost, Electricity Consumption & Sources*, https://s3-eu-west-2.amazonaws.com/assets.coinshares.co.uk/wp-content/uploads/2018/06/06140515/MiningWhitepaperFinal.pdf, accessed 20 July 2018.

Bevand, M. (2018), *Electricity Consumption of Bitcoin: A Market-Based and Technical Analysis*, http://blog.zorinaq.com/bitcoin-electricity-consumption/#summary, accessed 29 June 2018.

Bloomberg (2018), "New York to Crypto Miners: Looking for Cheap Power? Let's Talk" www.bloomberg.com/amp/news/articles/2018-07-12/new-york-to-crypto-miners-looking-for-cheap-power-let-s-talk, accessed 20 July 2018.

BNEF (Bloomberg New Energy Finance) (2018), *Bitcoin in Energy Crisis as China Cracks Down*, https://about.bnef.com/blog/bitcoin-can-drop-50-and-china-miners-will-still-make-money/.

Brolin et al. (2017), *Industry's Electrification and Role in the Future Electricity System: A Strategic Innovation Agenda*, produced in collaboration by Research Institutes of Sweden and Chalmers University of Technology, www.diva-portal.org/smash/get/diva2:1073841/FULLTEXT01.pdf, accessed 18 June 2018.

Brown, A., J. Gonder and B. Repac (2014), "Road Vehicle Automation", *Road Vehicle Automation*, https://doi.org/10.1007/978-3-319-05990-7.

De Vries, A. (2018a), *Bitcoin's Growing Energy Problem*, https://doi.org/10.1016/j.joule.2018.04.016.

– (2018b), "Bitcoin Energy Consumption Index", *Digiconomist*, https://digiconomist.net/bitcoin-energy-consumption, accessed 25 July 2018.

EPRI (Electric Power Research Institute) (2018), *Electromagnetic Processing of Materials (EPM) – Europe Industrial Electrification Potential Assessment*, Report prepared for the Europejski Instytut Miedzi Sp. z o.o. (European Copper Institute) by EPRI, www.leonardo-energy.org/resources/1407.

Eurelectric (2018), *Decarbonization Pathways (electrification part)*, Eurelectric, Brussels, https://cdn.eurelectric.org/media/3172/decarbonisation-pathways-electrificatino-part-study-results-h-AD171CCC.pdf.

Fulton, L., J. Mason and D. Meroux (2017), *Three Revolutions in Urban Transportation*, University of California, Davis, and The Institute for Transportation and Development Policy, New York, https://steps.ucdavis.edu/wp-content/uploads/2017/05/ITDP-3R-Report-v6.pdf.

Greenblatt, J. and S. Saxena (2015), "Autonomous Taxis Could Greatly Reduce Greenhouse-gas Emissions of US Light-duty Vehicles", *Nature Climate Change*, Vol. 5(9), pp. 860–863, https://doi.org/10.1038/nclimate2685.

Hileman, G. and M. Rauchs (2017), "2017 Global Crypto-currency Benchmarking Study", *SSRN Electronic Journal*, https://doi.org/10.2139/ssrn.2965436.

IEA (International Energy Agency) (2018a), *The Future of Cooling*, OECD/IEA, Paris.

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

– (2017a), *Digitalization and Energy,* OECD/IEA, Paris.

– (2017b), *Energy Access Outlook: from Poverty to Prosperity: World Energy Outlook Special Report*, OECD/IEA, Paris.

– (2017c), *World Energy Outlook-2017*, OECD/IEA, Paris.

– (2016), *Water-Energy Nexus: World Energy Outlook Special Report*, OECD/IEA, Paris.

– (2014), *Africa Energy Outlook: World Energy Outlook Special Report*, OECD/IEA, Paris.

Jadun et al. (2017), *Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050*, National Renewable Energy Laboratory, NREL/TP-6A20-70485, Golden, CO., United States, www.nrel.gov/docs/fy18osti/70485.pdf.

Luo et al. (2018), *Parched Power: Water Demands, Risks, and Opportunities for India's Power Sector*, World Resources Institute, Washington, DC.

McKinsey & Company (2018), "Decarbonization of Industrial Sectors: the Next Frontier", *Mckinsey Insights*, www.mckinseyenergyinsights.com/insights/decarbonization-of-industrial-sectors-the-next-frontier/, accessed 25 June 2018.

Morgan Stanley (2018), *Bitcoin ASIC Production Substantiates Electricity Use, Points to Coming Jump,* www.cell.com/joule/pdf/S2542-4351(18)30177-6.pdf.

Slowik, P. (2018), *The Future of Transportation: Autonomous and Internal Combustion?*, ICCT, www.theicct.org/blog/staff/future-transportation-autonomous-internal-combustion, accessed 25 June 2018.

Stephens et al. (2016), *Estimated Bounds and Important Factors for Fuel Use and Consumer Costs of Connected and Automated Vehicles*, National Renewable Energy Laboratory, Golden, CO., United States, www.nrel.gov/docs/fy17osti/67216.pdf.

Wadud, Z., D. MacKenzie and P. Leiby (2016), "Help or hindrance? The travel, energy and carbon impacts of highly automated vehicles", *Transportation Research* Part A: Policy and Practice, Vol. 86, pp. 1–18, https://doi.org/10.1016/j.tra.2015.12.001.

Chapter 10: Global implications of an electrifying future

Bernard et al. (2018), *Determination of Real-World Emissions from Passenger Vehicles Using Remote Sensing Data*, TRUE - The Real Urban Emissions Initiative, London.

IEA (International Energy Agency) (2018), *Outlook for Producer Economies, World Energy Outlook Special Report*, OECD/IEA, Paris.

– (2017), *World Energy Outlook-2017*, OECD/IEA, Paris.

– (2016), *Energy and Air Pollution: World Energy Outlook Special Report,* OECD/IEA, Paris.

MIT (Massachusetts Institute of Technology) (2016), *Utility of the Future*, MIT Press, Boston, MA., United States.

Part C: WEO Insight

Chapter 11: Innovation and the environmental performance of oil and gas supply

Azzolina et al. (2015), "CO_2 Storage Associated with CO_2 Enhanced Oil Recovery: A Statistical Analysis of Historical Operations", *International Journal of Greenhouse Gas Control*, Vol. 37, pp. 384–397.

CIEP (Clingendael International Energy Programme) (2018), *Refinery 2050: Refining the Clean Molecule*, CIEP, The Hague.

Cooney et al. (2017), "Updating the US Lifecycle GHG Petroleum Baseline to 2014 with Projections to 2014 Using Open-Source Engineering-Based Models", *Environmental Science & Technology*, 977-987.

DOE/NETL (Department of Energy/ National Energy Technology Laboratory) (2013), *Gate-to-Gate Lifecycle Inventory and Model of CO_2-Enhanced Oil Recovery*, DOE/NETL, Pittsburgh, PA., United States.

Gordon et al. (2017), "The Oil-Climate Index: Assessing GHG Emission Impacts Across the Oil Value Chain", *Encyclopedia of Sustainable Technologies*, Elsevier.

IEA (International Energy Agency) (2015), *Storing CO_2 through Enhanced Oil Recovery*, Insights Series, OECD/IEA, Paris.

Keith et al. (2018), "A Process for Capturing CO_2 from the Atmosphere", *Joule,* Vol. 2(8), pp. 1573-1594.

Masnadi et al. (2018), "Global Carbon Intensity of Crude Oil Produciton", *Science,* Vol. 361 (6405), pp. 851-853.

Masnadi, M. and A. Brandt (2017), "Climate Impacts of Oil Extraction Increase Significantly with Oilfield Age", *Nature Climate Change*, 551-556.

Motazedi, K., J. Abella and J. Bergerson (2017), "Techno–economic Evaluation of Technologies to Mitigate Greenhouse Gas Emissions at North American Refineries", *Environmental Science & Technology*, Vol. 51 (3), pp.1918-1928.

Ocko et al. (2017), "Unmask Temporal Trade-Offs in Climate Policy Debates", *Science,* Vol. 356 (6337), pp. 492-493.

S&T Squared Consultants (2012), *GHGenius natural gas pathway update*, Natural Resources Canada, Ottawa.

Yeh et al. (2010), "Land-use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands", *Environmental Science and Technology*, 8766-8772.

Annex B

BGR (German Federal Institute for Geosciences and Natural Resources) (2017), *Energiestudie 2017, Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen,* (Energy Study 2017, Reserves, Resources and Availability of Energy Resources), BGR, Hannover, Germany.

Bolinger, M. and J. Seel (2018). *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition*, Lawrence Berkeley National Laboratory, Berkeley, CA., United States.

BP (2018), *BP Statistical Review of World Energy 2018*, BP, London.

Cedigaz (2018), Cedigaz Databases, Cedigaz, Rueil-Malmaison, France, www.cedigaz.org.

IMF (International Monetary Fund) (2018), *World Economic Outlook*, IMF, Washington, DC.

OGJ (Oil and Gas Journal) (2017), "Worldwide Oil, Natural Gas Reserves Inch Higher in 2017", *OGJ* 115 (12), Pennwell Corporation, Oklahoma City, OK., United States.

US DOE/EIA (US Department of Energy/Energy Information Adminstration) (2018a), *U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2016,* US DOE/EIA, Washington, DC.

– (2018b) *Assumptions to the Annual Energy Outlook 2018*, US DOE/EIA, Washington, DC.

US DOE/EIA/ARI (US Department of Energy)/(Energy Information Administration)/(Advanced Resources International) (2013 and last updated September 2015), *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, US DOE/EIA, Washington, DC.

USGS (United States Geological Survey) (2012a), "Assessment of Potential Additions to Conventional Oil and Gas Resources of the World (Outside the United States) from Reserve Growth", *Fact Sheet 2012–3052*, USGS, Boulder, CO., United States.

– (2012b), "An Estimate of Undiscovered Conventional Oil and Gas Resources of the World", *Fact Sheet 2012–3042*, USGS, Boulder, CO., United States.

IEA/OECD possible corrigenda on: www.oecd.org/about/publishing/corrigenda.htm

IEA Publications
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/about/contact
Layout in France by DESK, November 2018
(612018191E1) ISBN: 9789264306776
Cover design: IEA, photo credits: ShutterStock

World Energy Outlook 2018

What do today's energy policies, policy ambitions and technology trends tell us about the future? Is the world getting closer or is it moving away from meeting energy-related sustainable development goals?

Drawing on the latest data on energy markets and technology trends, this year's *World Energy Outlook* – the gold standard of long-term energy analysis – provides detailed analyses of these fundamental issues to 2040, covering all fuels, technologies and regions.

Electricity is the special focus of the 2018 edition. The share of electricity in global energy use is growing while the rise of low-carbon technologies is prompting a major transformation in the way electricity is generated. What might tomorrow's power sector look like? How can it ensure reliable supply while reducing emissions?

WEO-2018 also asks what can be done to reduce the environmental footprint of the world's oil and gas supply.

iea.org/weo/

€ 120 (61 2018 19 1E1)
ISSN: 2072-5302
ISBN: 978-92-64-30677-6

9 789264 306776