Asia-Pacific
Economic Cooperation

APEC ENERGY OVERVIEW 2018

APERC
Asia Pacific Energy Research Centre





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The views and opinions expressed in this publication belong solely to the authors. For consistency and veracity of the policies and other information contain here, the EGEDA focal points and EWG members of the respective economies were consulted.

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FOREWORD

The APEC Energy Overview is an annual publication outlining the energy situation in each of the 21 APEC economies.

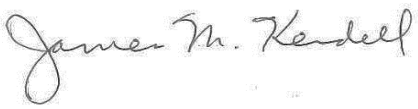
Based on the latest data compiled by the Expert Group on Energy Data and Analysis (EGEDA), this publication provides updated information on APEC's energy supply and demand trends. It also contains information on notable energy developments in the region, as well as APEC's progress towards its twin targets of reducing energy intensity by at least 45% by 2035 (from 2005 levels) and doubling the share of renewables in its energy mix from 2010 to 2030.

It is encouraging to note that various efforts and measures have been put in place by economies to contribute towards the APEC targets. These include increased investment in energy efficiency, increased deployment of renewable resources, promotion of good energy management practices and the conduct of several energy-efficiency awareness raising campaigns.

We hope that this report will help stakeholders deepen their understanding of energy issues in APEC, promote the use of EGEDA data and provide useful insights to policy makers in the region.



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EXECUTIVE SUMMARY

In 2016, the APEC economy continued to outperform the rest of the world with a 3.5% increase in GDP from 2015 to reach 61.2 billion USD (PPP, constant 2011 USD). Economic growth in China (6.7%), South-East Asia (4.7%) and Oceania (2.9%) continued to contribute to APEC growth from 2015 to 2016. Total primary energy supply (TPES) in APEC in 2016 was 7 892 Mtoe. The slight increase from 2015 TPES levels was due in part to the significant increases in renewable energy (5.4%) and nuclear (3.6%) in 2016. By region, Russia can also be contributed to the increase in APEC TPES, bouncing back significantly from its contraction in the previous year with a 3.1% surge in 2016. The US and for the first time China, recorded negative growth in 2016 at 1.0% and 0.6%, respectively. Total final energy consumption expanded 1.3 percentage points to reach 4 737 Mtoe (1.5%) in 2016. If non-energy is included, total final consumption was up 1.7% to 5 313 Mtoe in 2016.

The APEC Overview has become the platform to monitor APEC goals— energy intensity reduction by 45% by 2035 (against the 2005 level) and doubling the renewable energy share by 2030 with 2010 as base year. As agreed during the 49th EGEEC (Experts Group on Energy Efficiency) meeting and subsequently at 53rd EWG (Experts Working Group) Meeting, APERC is now monitoring energy intensity improvement in final energy consumption excluding non-energy. Also in coordination with EGEDA, rough estimates of the possible growth rate of the share of modern renewables in final energy consumption are presented.

According to the most recent data, GDP and final energy consumption remain decoupled so that final energy intensity in APEC has been improving. In 2016, the final energy intensity has reduced 2% to 77 tonnes of oil equivalent (toe) per million USD (2011 Price and 2011 PPP) as compared with the 2015 final energy intensity level of 79 toe/million USD (2011 Price and 2011 PPP). Between 2005 and 2016, final energy intensity (ex. non-energy) has improved significantly by 19.8%. If the current trend continues, final energy consumption intensity (ex. non-energy) reduction would meet the APEC goal: 45% in 2035.

APERC in cooperation with EGEDA, developed the definition of modern renewables and biomass that is part of monitoring the renewable doubling goal. Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. Traditional biomass will not be part of the renewables goal. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on) including biogas and wood pellets are considered modern renewables (although data on wood pellets are limited) and their share in total final energy consumption will be monitored for the renewables doubling goal.

Year-on-year consumption of modern renewables increased 6.7% in 2016 (369 Mtoe), 4.8 percentage points more than 2015 levels. Its share to the total final energy consumption in 2016 was 7.8%, a 5.1% increase from the 2015 levels. Relatedly, the use of modern renewables grew rapidly during 2010-2016 brought about by rapid decline in costs and favourable government policies such as feed-in tariffs, auctions and RPS, with 5.7% CAGR between the years. While they continue to increase, modern renewables, through extrapolation would only reach 11.6% by 2030, which would be still short of the doubling goal. With this, additional efforts in the region are necessary especially in addressing the barriers to renewable development.

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ACRONYMS

AAGR	average annual growth rate
ACCC	Australian Competition and Consumer Commission
ACE	Affordable Clean Energy
ADB	Asian Development Bank
AEDP	Alternative Energy Development Plan
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEP	Atomenergoprom
AER	Australian Energy Regulator
AESO	Alberta Electricity System Operator
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
APG	ASEAN Power Grid
ARENA	Australian Renewable Energy Agency
ASEA	Agency of Security, Energy and Environment
ASEAN	Association of Southeast Asian Nations
ASEP	Access to Sustainable Energy Programme
ASTRID	Advanced Sodium Technological Reactor for Industrial Demonstration
BATAN	Badan Tenaga Nuklir Nasional
BAU	business-as-usual
BCA	Building and Construction Authority
BDPKS	Badan Pemeriksa Keuangan Republik Indonesia
BEC	Building Energy Code
BGC	Brunei Gas Carriers Sdn Bhd
BKPM	Badan Koordinasi Penanaman Modal
BLM	Bureau of Land Management
BNERI	Brunei National Energy Research Institute
BOE	Bureau of Energy
BOEM	Bureau of Ocean Energy Management
BOT	Build-Operate-Transfer
BP	British Petroleum
BPMC	Berakas Power Management Company Sdn Bhd
BRESL	Barrier Removal to the Cost-Effective Development and Implementation of Energy Efficiency Standards and Labelling
BSP	Brunei Shell Petroleum Company Sdn Bhd
BSR	Binh Son Refining and Petrochemical Company
BUMD	Badan Usaha Milik Daerah
CAGR	compound annual growth rate
CAIT	Climate Analysis Indicators Tool

CARB	California Air Resources Board
CCGT	Combined-Cycle Gas Turbine
CCHEN	Comisión Chilena de Energia Nuclear
CCIR	Carbon Competitiveness Incentive Regulation
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CEFC	Clean Energy Finance Corporation
CEN	Coordinador Eléctrico Nacional
CEPA	Closer Economic Partnership Arrangement
CERA	Cambridge Energy Research Associates
CFE	Committee on the Future Economy
CFL	Compact Fluorescent Lamp
CHP	combined heat and power
CIF	cost, insurance and freight
CIT	corporate income tax
CLP	Climate Leadership Plan
CLP	CLP Power Hong Kong Limited
CNE	Comisión Nacional de Energía
CNESA	China Energy Storage Alliance
CNG	compressed natural gas
CNPC	China National Petroleum Corporation
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
COAG	Council of Australian Governments
COGOA	Canada Oil and Gas Operations Act
COP	Conference of the Parties
COS	Cost of Service
COW	Contracts of Work
CPC	Chinese Petroleum Corporation
CPP	Clean Power Plan
CPRA	Canada Petroleum Resources Act
CSAPR	Cross State Air Pollution Rule
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	concentrated solar power
CSP	Competitive Selection Process
DASAP	Demand Aggregation and Supply Auctioning Policy
DCS	District Cooling Systems
DEEP	Debottlenecking Project Financing for Small-scale Renewable Energy
DES	Department of Electrical Services
DfE	Design for Efficiency
DGEE	Directorate for Energy Efficiency
DGNREEC	Directorate General of New Renewable Energy and Energy Conservation
DMF	Department of Mineral Fuels
DOE	Department of Energy
DOI	Department of the Interior

DOT	Department of Transportation
DPE	Department of Petroleum and Energy
DPR	Dewan Perwakilan Rakyat
DR	demand response
DSM	Demand-Side Management
DSP	Development Strategic Plan
E&P	Exploration and Production
EAC	Energy Audit Code
EAS	East Asia Summit
EC	Energy Commission
ECA	Energy Conservation Act
ECCC	Environment and Climate Change Canada
EDB	Economic Development Board
EDGE	Enhancing Development and Growth through Energy
EDI	Exploration Development Incentive
EDPMO	Energy Department, Prime Minister's Office
EE	energy efficiency
EEAP	Energy Efficiency Action Plan
EEC	energy efficiency and conservation
EECA	Energy Efficiency and Conservation Authority
EEDP	Energy Efficiency Development Plan
EENP	Energy Efficiency National Partnership
EERS	Energy Efficiency Resource Standards
EGAT	Electricity Generating Authority of Thailand
EGEDA	Expert Group Energy Data Analysis
EI	energy intensity
EIPO	Energy Innovation Programme Office
EIRP	Energy Innovation Research Programme
EISA	Energy Independence and Security Act
EMA	Energy Market Authority
EMS	energy management systems
ENAP	Empresa Nacional de Petroleo
ENERCOM	Energy Regulatory Commission
EOR	enhanced oil recovery
EP	Exploration and Production
EPA	Environmental Protection Agency
EPC	Engineering Performance Contacting
EPIRA	Electric Power Industry Reform Act
EPNS	Energy Projects of National Significance
EPPO	Energy Policy and Planning Office
ERAV	Electricity Regulatory Authority of Viet
ERC	Energy Regulatory Commission
ERF	Emissions Reduction Fund
ERIA	Economic Research Institute for ASEAN and East Asia

ERP	Electronic Road Pricing
ESB	Energy Security Board
ESCO	Energy Service Company
ESPO	Eastern Siberia Pacific Ocean
ESS	energy storage system
ESSD	Energy Sector Strategic Directions
ETS	emission trading systems
ETS	emissions trading scheme
EV	electric vehicle
EVN	Vietnam Electricity
EVTF	EV Taskforce
EWP	Energy White Paper
FED	final energy demand
FERC	Federal Energy Regulatory Commission
FID	Final Investment Decision
FiT	feed-in-tariff
FOB	free-on-board
FOREM	Federal Wholesale Electricity Market
FPT	freehold production tax
FPV	floating photovoltaic
FRT	first registration tax
FTP	first tranche petroleum
GBI	Green Building Index
GDP	Gross Domestic Product
GFA	Gross Floor Area
GGA	Global Geothermal Alliance
GGP	Government Green Procurement
GHG	greenhouse gas
GIS	Geographic Information System
GNC	Gas Network Code
GNWT	Government of Northwest Territories
GOC	Government of Canada
GOM	Government of Manitoba
GOO	Government of Ontario
GOQ	Government of Québec
GPSA	Gas Purchase and Supply Agreement
GR	Government Regulations
GSO	Grid System Operator
GSO	General Statistics Office of Viet Nam
GTFS	Green Technology Financing Scheme
GTMP	Green Technology Master Plan
GWA	Geothermal Working Areas
HDB	Housing & Development Board
HDV	heavy-duty vehicles
HEPS	High Energy Performance Standards
HFC	hydrofluorocarbons
HKE	Hong Kong Electric Company Limited
HQ	Hydro-Québec
IBR	Incentive-Based Regulation
ICCC	Independent Consumer and Competition Commission
IEA	International Energy Agency
IIP	Index of Industrial Products

IMCSD	Inter-Ministerial Committee on Sustainable Development
IMO	Independent Market Operator
INDC	Intended Nationally Determined Contribution
IPCC	Intergovernmental Panel on Climate Change
IPL	International Power Line
IPM	Intermittency Pricing Mechanism
IPP	Independent Power Producers
IRENA	International Renewable Energy Agency
ISP	Integrated System Plan
ITC	Input Tax Credits
ITC	Investment tax credit
IUPTL	Izin Usaha Penyediaan Tenaga Listrik
IWMF	Integrated Waste Management Facility
JBIC	Japan Bank for International Cooperation
JICA	Japan International Cooperation Agency
JODI	Joint Organizations Oil Data Transparency
JOGMEC	Japan Oil, Gas and Metals National Corporation
JPDA	Joint Petroleum Development Area
KCH	Kumul Consolidated Holdings
KEEI	Korea Energy Economics Institute
KEN	Kebijakan Energi Nasional
KEPCO	Korea Electric Power Corporation
KMC	Kinder Morgan Canada
KNOC	Korea National Oil Corporation
KOGAS	Korea Gas Corporation
KPPA	Konebada Petroleum Park Authority
LCOE	Levelized Cost of Electricity
LDV	Light- and Heavy-Duty Vehicles
LED	Light Emitting Diode
LEED	Leadership in Energy and Environmental Design
LGSE	Ley General de Servicios Eléctricos
LNG	liquefied natural gas
LoA	letter of approval
LPG	liquefied petroleum gas
LRET	Large-scale Renewable Energy Target
LSS	Large-Scale Solar
LTA	Land Transport Authority
LTBR	the long-term Government of Canada bond rate
LTEP	long-term energy planning
LULUCF	Land Use, Land-Use Change, and Forestry
MATS	Mercury and Air Toxics Standard
MBIE	Ministry of Business, Innovation and Employment
MCC	China Metallurgical Construction Corporation
MEA	Ministry of Economic Affairs

MEE	Ministry of Ecology and Environment
MEELS	Mandatory Energy Efficiency Labelling Scheme
MELS	Mandatory Energy Labelling Scheme
MEM	Ministry of Energy and Mines
MEMI	Ministry of Energy, Manpower and Industry
MEMR	Ministry of Energy and Mineral Resources
MEPS	Minimum Energy Performance Standards
METI	Ministry of Economy, Trade and Industry
MIR	Minimum Inventory Requirement
MKE	Ministry of Knowledge Economy
MOA	Memorandum of Agreement
MOCA	Ministerial for Climate Action
MOE	Ministry of the Environment
MOEA	Ministry of Economic Affairs
MOIT	Ministry of Industry and Trade
MOTIE	Ministry of Trade, Industry and Energy
MOU	memorandum of understanding
MRA	Mineral Resources Authority
MRRT	Minerals Resource Rent Tax
MSW	Municipal Solid Waste
MTDP	Medium-Term Development Plan
MVA	mega-volt-ampere
NAMA	Nationally Appropriate Mitigation Actions
NCCP	National Climate Change Policy
NCRE	Non-Conventional Renewable Energy
NDC	Nationally Determined Contribution
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NEA	Nuclear Energy Agency
NEA	National Energy Authority of Papua New Guinea
NEA	National Electrification Administration
NEA	National Environment Agency
NEB	National Energy Board
NEG	National Energy Guarantee
NEM	National Electricity Market
NEM	Net Energy Metering
NEMS	National Electricity Market of Singapore
NEP	National Energy Policy
NEPIO	Nuclear Energy Programme Implementing Organisation
NEPP	National Energy Productivity Plan
NEROP	National Electrification Rollout Plan
NESA	National Energy Security Assessments

NEV	Neighbourhood Electric Vehicle
NGL	natural gas liquids
NGTP	National Green Technology Policy
NGV	natural gas vehicle
NGVPPT	Natural Gas Vehicle Programme for Public Transportation
NHTSA	National Highway Transportation Safety Administration
NPC	National Power Corporation
NRA	Nuclear Regulation Authority
NRC	National Research Council
NRC	Nuclear Regulatory Commission
NRE	New and Renewable Energy
NREP	National Renewable Energy Programme
NREPAP	New and Renewable Energy Policy and Action Plan
NRF	National Research Foundation
NSCC	National Strategy on Climate Change
NTI	National Technology Initiative
NTNDP	National Transmission Network Development Plan
NUS	National University of Singapore
NWT	Northwest Territories
NZEECS	New Zealand energy Efficiency and Conservation Strategy
NZP&M	New Zealand Petroleum & Minerals
OECD	Organisation for Economic Cooperation and Development
OEM	Open Electricity Market
ORRC	Organic Resources Recovery Centre
PCECP	Philippine Conventional Energy Contracting Program
PDNGR	Philippine Downstream Natural Gas Regulation
PDP	Power Development Plan
PEP	Philippines Energy Plan
PESLP	Philippine Energy Standards and Labelling Programme
PGU	Peninsular Gas Utilisation
PHMSA	Pipeline Safety and Hazardous Materials Administration
PI	Participating Interest
PIDPT	Pengerang Independent Deepwater Petroleum Terminal
PIPC	Pengerang Integrated Petroleum Complex
PKUK	Pemegang Kuasa Usaha Ketenagalistrikan
PLN	Perusahaan Listrik Negara
PMB	Pulau Muara Besar
PMR	Partnership of Market Readiness
PNAA	The National Environmental Action Plan
PNG	Papua New Guinea

PNG	piped natural gas
PNOC	Philippine National Oil Company
POM	Port Moresby System
PPL	PNG Power Limited
PPP	Purchasing Power Parity
PPP	Public-Private Partnership
PPPC	Public–Private Partnership Center
PPS	Power Producers and Suppliers
PRLCE	Peer Review on Low Carbon Energy
PRRT	Petroleum Resource Rent Tax
PSALM	Power Sector Assets and Liabilities Management
PSC	Production Sharing Contract
PTC	Production Tax Credit
PTT	Public Company Limited
PTTEP	PTT Exploration and Production Plc
PUB	Public Utilities Board
PUP	Perjanjian Usaha Pertambangan
PV	photovoltaic
PVEP	PetroVietnam Exploration Production Corporation
PVN	PetroVietnam
QTP	Qualified Third Party
R&D	research and development
RAPG	Renewable and Alternative Power Generation
RAPID	PETRONAS Refinery and Petrochemical Integrated Development
RD&D	research, development and demonstration
RE	renewable energy
REC	renewable energy certificates
REDD	Reducing Emissions from Deforestation and forest Degradation
RET	Renewable Energy Target
RFP	Request-for-Proposal
RGGI	Regional Greenhouse Gas Initiative
RGT	Regasification Terminal
RMA	Resource Management Act
RPS	renewable portfolio standards
RRR	Reserve Replacement Ratio
RTS	Rapid Transit System
RUEN	Rencana Umum Energi Nasional
SB	Single Buyer
SCA	Scheme of Control Agreements
SCOD	Scheduled Commercial Operation Date
SEB	Sarawak Energy Berhad
SEC	Superintendencia de Electricidad y Combustibles
SEDA	Sustainable Energy Development Authority
SEN	National Electricity System
SERC	State Electricity Regulatory Commission
SERIS	Solar Energy Research Institute of Singapore
SESB	Sabah Electricity Sendirian Berhad

SIRIM	Standard and Industrial Research Institute of Malaysia
SIT	Special Industrial Tariff
SLNG	Singapore LNG Corporation
SME	Small and Medium Enterprise
SNI	Standar Nasional Indonesia
SOE	State-Owned Enterprises
SOE	State-Owned Energy Enterprises
SPARK	Sungai Liang Industrial Park
SPP	Small Power Producers
SPR	Strategic Petroleum Reserve
SRES	Scale Renewable Energy Scheme
SSLI	Smart Street Lighting Initiative
STF	Sludge Treatment Facility
TAC	Technical Assistance Contracts
TAGP	Trans-ASEAN Gas Pipeline
TFC	total final consumption
TFEC	total final energy consumption
TIEB	Thailand Integrated Energy Blueprint
TMX	Trans Mountain Pipeline
TNB	Tenaga Nasional Berhad
TPA	Third-Party Access
TPAS	Tiwai Point Aluminium Smelter
TPC	Taiwan Power Company
TPES	total primary energy supply
TREES	Thailand's Rating of Energy and Environmental Sustainability
UNFCCC	United Nations Framework Convention on Climate Change
URE	Unconventional, Renewable Energy
USACEP	US–Asia Pacific Comprehensive Energy Partnership
USGS	United States Geological Survey
USSR	Union of Soviet Socialist Republics
VAT	value-added tax
VNEEP	Viet Nam National Energy Efficiency Program
VPM	Venta de Primera Mano
VSPP	Very Small Power Producers
VVER	Water–water Energetic Reactors
VWEM	Vietnam Wholesale Electricity Market
WACS	Water-cooled air-Conditioning systems
WCI	Western Climate Initiative
WCSB	Western Canadian Sedimentary Basin
WESA	WtE Services Agreement
WESM	Wholesale Electricity Spot Market
WNA	World Nuclear Association
WtE	Waste-to-Energy
WTO	World Trade Organization
ZEV	zero-emission vehicle

CURRENCY CODES

Code	Currency	Economy
AUD	Australian dollar	Australia
BND	Brunei dollar	Brunei Darussalam
CAD	Canadian dollar	Canada
CLP	Chilean peso	Chile
CNY	yuan renminbi	China
TWD	New Taiwan dollar	Chinese Taipei
HKD	Hong Kong dollar	Hong Kong, China
IDR	rupiah	Indonesia
JPY	yen	Japan
KRW	won	Korea
MYR	Malaysian ringgit	Malaysia
MXN	Mexican peso	Mexico
NZD	New Zealand dollar	New Zealand
PGK	kina	Papua New Guinea
PEN	nuevo sol	Peru
PHP	Philippine peso	Philippines
RUB	Russian ruble	Russia
SGD	Singapore dollar	Singapore
THB	baht	Thailand
USD	US dollar	United States
VND	dong	Viet Nam

AUSTRALIA

INTRODUCTION

Australia is the sixth-largest economy in the world in terms of land area, covering approximately 7.7 million square kilometres (km²). It lies in the Southern Hemisphere between the Indian and Pacific Oceans and comprises six states and two territories. The population of approximately 24 million mostly lives in major cities or regional centres along the eastern and south-eastern seaboards. The economy has maintained robust economic growth, with an average annual growth rate (AAGR) of 2.9% from 2000 to 2016 (EGEDA, 2018). In 2016, gross domestic product (GDP) reached USD 1 077 billion (2011 USD purchasing power parity [PPP]), a 2.8% increase from 2015 (EGEDA, 2018). Australia is the only developed economy in APEC to have recorded no annual recessions over the last 25 years (Austrade, 2018).

Australia has abundant, high-quality energy resources that are likely to last for many decades at the current rates of production. Energy production increased at an AAGR of 3.3% from 2000 to 2016 and 2.5% from 2015 to 2016 (reaching 390 493 kilotonne oil equivalent [ktoe]) supported by growth in coal and gas production (EGEDA, 2018). Australia produces energy for both domestic consumption and export; however, it is becoming increasingly export-oriented. Net energy exports grew by 4.1% and constituted 67% of domestic energy production in 2016 (EGEDA, 2018).

In 2016–17, coal constituted 71% of Australia's primary energy production in energy content terms, followed by gas (23%), oil (3.8%) and renewables (2.1%) (Environment, 2018). Coal was even more dominant in the energy export mix, constituting 76% of the total, followed by gas (20%) and oil (4.1%). The Australian energy industry constituted 6.3% (AUD 115 billion) of the economy in 2017–18 (ABS, 2018) and, along with other bulk resource commodities, 55% of exports (OCE, 2019).

Australia is the world's largest metallurgical coal and second-largest thermal coal exporter (OCE, 2019). Australian metallurgical and thermal coals are high in energy content and relatively low in sulphur, ash and other contaminants. Metallurgical coal is Australia's second-largest commodity export, earning AUD 38 billion in 2017–18, followed by liquefied natural gas (LNG) (AUD 31 billion) and thermal coal (AUD 23 billion) (OCE, 2019). Given Australia's large energy resources and geographical proximity to burgeoning markets in the Asia-Pacific region, it is capable of meeting a significant proportion of the world's growing energy demand as well as its own domestic needs for years to come.

Table 1: Key data and economic profile, 2016

Key data [a]		Energy reserves [b]	
Area (million km²)	7.7	Oil (billion barrels)	5.4
Population (million)	24	Gas (petajoules)	279 685
GDP (2011 USD billion PPP)	1 077	Coal (million tonnes)	146 947
GDP (2011 USD PPP per capita)	44 493	Uranium (kilotonnes U308)	1 814

Sources: [a] EGEDA (2018); [b] GA (2018).

Notes: Oil reserves comprise all identified crude, condensate and LPG. Gas reserves comprise all identified resources. Coal reserves are defined as recoverable economically demonstrated resources of black and brown coal. Uranium reserves are considered to be reasonably assured resources at USD 130/kg U.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2016, Australia's total energy production was 390 493 ktoe and total primary energy supply (TPES, the energy that is used in the economy) was 129 752 ktoe (EGEDA, 2018). Coal narrowly remains the primary source of domestic energy supply in Australia at 34%, followed by oil (33%), gas (27%) and renewables and others (6.0%).

Coal's primary role is in the transformation sector, which constitutes 94% of use (Environment, 2018), almost entirely at coal-fired power stations and coke ovens. Significant black coal basins in New South Wales and Queensland

and Victoria's enormous brown coal resources have historically provided stable and affordable energy. However, coal's share of TPES has been decreasing over the past decade, from 45% in 2005, due to decreased use in the electricity generation sector (which has seen flat consumption and an increased share of gas and renewables) and closures at iron and steel works.

Gas has become increasingly important to the Australian economy as a source of export income and as a contributor to domestic energy needs. Almost all of Australia's conventional gas comes from three basins: the offshore Carnarvon Basin in Western Australia, the offshore Gippsland Basin in Victoria and the onshore Cooper–Eromanga Basin, which straddles the South Australian and Queensland borders (GA, 2018). Unconventional production, in the form of coal seam gas (CSG), mainly occurs in Queensland and has grown rapidly in recent years. Gas production in 2016–17 of 106 billion billion cubic metres was a 19% increase on the previous year as offshore Western Australia expanded to support the start of LNG exports from new projects around Dampier (OCE, 2019). Several other LNG projects will be completed in coming years as gas production continues to grow strongly until 2020.

Australia is a net importer of oil products but a net exporter of liquefied petroleum gas (LPG) (Environment, 2018). Primary energy supplies of crude and refined products are roughly equal. This is because approximately half of Australia's liquid fuel consumption comes from direct imports (mostly from other APEC economies) and the rest from domestic refineries. Supply of crude oil and LPG production declined by 11% in 2016–17 relative to 2015–16, largely due to maturing oilfields, but will be bolstered in coming years by increasing condensate production associated with offshore gas fields being developed for LNG (Environment, 2018).

Renewable primary energy supply has grown by 3.7% a year since 2010 (to reach 8 287 ktoe in 2016) due to significant investments by the electricity sector in utility-scale wind and solar, residential-scale solar photovoltaic (PV) and hot water (EGEDA, 2018). This growth has been somewhat offset by the decreasing use of biomass in the residential sector and lower-than-average hydro generation in recent years due to drought.

In 2016, 256 319 gigawatt-hours (GWh) of electricity was generated, mostly from coal-powered thermal sources (EGEDA, 2018). Given its abundance, coal is likely to remain the most commonly used fuel for electricity generation. However, its share has declined over the past decade, a trend that will continue as a large number of committed and existing wind and solar energy projects will constitute an increasing proportion of total electricity generation. In 2016, renewable energy accounted for 15% of the electricity generation mix, from 13% in 2015, mainly due to increased solar PV generation (EGEDA, 2018).

FINAL ENERGY CONSUMPTION

Australia's total final consumption rose slightly to 81 256 ktoe in 2016, following three flat years (EGEDA, 2018). The transport sector is the largest end-use sector, constituting 41% of Australia's total final consumption, followed by industry (28%) and others (26%), which includes the commercial, residential and agriculture sectors and non-energy (5.6%) (EGEDA, 2018). By fuel type, oil constituted 51% of final energy consumption in 2016, followed by electricity (24%), gas (16%), renewables (5.9%) and coal (3.2%) (EGEDA, 2018). Oil, electricity and gas consumption have all been growing in recent years, while coal is in structural decline as an end-use fuel type. Direct-use renewable energy consumption has been relatively stagnant since 2010, as an increasing uptake of solar hot water offsets falling biomass use in the residential sector (Environment, 2018).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	390 493	Industry sector	22 822	Total power generation	256 319
Net imports and others	–259 690	Transport sector	32 921	Thermal	219 083
Total primary energy supply	129 752	Other sectors	20 944	Hydro	15 074
Coal	43 754	Non-energy	4 569	Nuclear	0
Oil	43 071	Final energy consumption*	81 256	Others	22 162
Gas	34 546	Coal	2 468		

Renewables	8 287	Oil	39 005		
Others	94	Gas	12 399		
		Renewables	4 508		
		Electricity and others	18 307		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel types do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to comprise renewables.*

ENERGY INTENSITY ANALYSIS

Australia has been contributing to APEC's aspirational goal of a 45% energy intensity reduction by 2035 from the 2005 level. However, in 2016, primary energy intensity increased by 0.84% despite final energy intensity declining by 2.8% (EGEDA, 2018). Australia's energy intensity improvements have historically been mainly due to structural shifts in the economy, away from energy-intensive industries and towards commercial sectors (such as financial services, education and tourism), and efficiency improvements driven by advances in technology (particularly in the transport and building sectors) (OCE, 2015). The increase in primary energy intensity in 2016 is likely due to rapid growth in LNG production, which is highly energy-intensive and only captured in primary energy intensity (as it is a transformation process) and not final energy intensity.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%)
	2015	2016	2015 vs 2016
Total primary energy supply	119	120	0.84
Total final consumption	73	71	−2.8
Final energy consumption excl. non-energy	77	75	−2.2

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Modern renewable consumption increased by 2.4% from 2015 to 2016. This was mainly due to increased solar hot water in the residential sector and increased solar PV and wind energy in the electricity generation sector. The share of modern renewables also increased by 2.4%, as final energy consumption was almost unchanged (−0.026%). Traditional biomass, which shrunk by 1.3% in 2016, has been in structural decline in Australia for a number of years as gas and electricity replace wood-fired heating.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	76 707	76 687	−0.026%
Non-renewables (Fossils and others)	70 876	70 718	−0.22%
Traditional biomass*	1 198	1 183	−1.3%
Modern renewables*	5 831	5 969	2.4%
Share of modern renewables to final energy consumption (%)	7.6%	7.8%	2.4%

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on) including biogas and wood pellets are considered modern renewables, although data on wood pellets are limited*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Australia's system of government has three tiers: federal, state and territory, and local. Federal government and state/territory governments own Australian energy resources, rather than private individuals. None of the tiers of government engages in commercial exploration or development. The Australian Federal Government has title and power over energy resources located outside the first three nautical miles of the territorial sea ('offshore'). The state governments and the Northern Territory have jurisdiction over resources on their lands or inside the first three nautical miles of the territorial sea ('onshore').

Each state and territory government has primary responsibility for assessing and approving oil and gas exploration within their jurisdiction. Similarly, each state/territory assesses safety requirements and environmental regulations for the coal industry in its respective jurisdiction. The Australian Government, in the form of the Australian Department of the Environment and Energy, has a role in regulating activities likely to significantly impact nationally protected environmental matters in accordance with the Environment Protection and Biodiversity Conservation Act 1999. In addition, the National Offshore Petroleum Safety and Environmental Management Authority regulates environmental management and structural and well integrity for offshore petroleum activities in Commonwealth waters.

At the federal level, the Department of the Environment and Energy oversees energy matters. This includes energy security, international engagement, energy efficiency programmes and energy markets. The Department of Industry, Innovation and Science oversees resources issues (including some related to onshore gas). All six states and both territories have energy- or mining-related departments (or divisions) responsible for similar matters at the state or territory level.

The COAG (Council of Australian Governments) Energy Council, a ministerial forum comprising the Commonwealth, state, territory and New Zealand governments, handles much of the responsibility for advancing national energy market reform. Such action includes developing and implementing an integrated and coherent energy and mineral resources policy. The COAG Energy Council is responsible for the regulations of the former Standing Council on Energy Reform (SCER), the Ministerial Council on Energy (MCE) and the former Ministerial Council on Mineral and Petroleum Resources (COAG, 2019a). The Australian Minister for Energy and Emissions Reduction chairs the Energy Council.

The Energy Council's work covers the following broad themes:

- Overarching responsibility of and policy leadership for Australian gas and electricity markets;
- The promotion of energy efficiency and energy productivity in Australia;
- Australian electricity, gas and petroleum product energy security;
- Cooperation between Commonwealth, state and territory governments; and
- Facilitation of the economic and competitive development of Australia's mineral and energy resources.

ENERGY SECURITY

Australia's energy security policy does not equate to energy independence or self-sufficiency in a particular energy source. Instead, energy security is enhanced by diverse commercially driven fuel options and supply and delivery sources, including the importation of liquid fuels from multiple sources. The Australian Government broadly defines energy security as the *adequate*, *reliable* and *competitive* supply of energy to support the functioning of the economy and social development. *Adequate* is defined as the provision of sufficient energy to support economic and social activity; *reliable* is defined as the provision of energy with minimal disruptions to supply; and *competitive* is defined as the provision of energy at an affordable price.

The Australian Government assesses Australia's energy security through National Energy Security Assessments (NESAs) that consider the effectiveness and anticipated resilience of Australia's electricity, natural gas and liquid fuel markets and changes in energy security drivers. In 2009, the Australian Government released the inaugural NESA, which found that Australia's energy sector was adequately meeting the economy's economic and social needs. The second assessment in 2011 found that Australia's energy security situation continued to be robust. Furthermore, Australia's overall energy security should remain adequate and reliable because of the level of new investment going forward and the price of energy (Environment, 2019a).

Australia has been non-compliant with the International Energy Agency's (IEA's) treaty obligation to have oil stocks equivalent to 90 days of the previous calendar year's average daily net imports since 2012 (Environment, 2019b). Falling domestic crude oil production, along with rising product demand and imports are responsible for this non-compliance. As a result, the economy's net imports have increased under the IEA statistical methodology, while demand cover stock levels have remained relatively stable. The Australian Government does not have public stockholdings or place minimum stockholding obligations on the industry. In 2016, the government proposed, however, a phased plan to return to compliance. Phase 1 of this plan includes purchasing tickets equivalent to up to 400 kilotonnes in the 2018–19 and 2019–20 financial years and the commencement of a mandatory industry reporting scheme for petroleum statistics in January 2018. The Australian Government is currently developing Phase 2 of the compliance plan that targets a long-term and least-cost approach to returning to full compliance by 2026.

A liquid fuel security assessment, which assesses the human and environmental threats to adequate, reliable and affordable energy delivery, is also currently being undertaken by the federal government. On 4 April 2019, the Department of the Environment and Energy released the *Liquid Fuel Security Review Interim Report* for public consultation. The Liquid Fuel Security Review will be finalised in the second half of 2019. The outcomes of this assessment will input into the development of Phase 2 of the IEA compliance plan. The assessment will also contribute to a broader NESA due to be released in late-2019, which will consider electricity and natural gas. This NESA, the first since 2011, will be vital in helping shape Australia's energy security policy for the next decade.

UPSTREAM ENERGY DEVELOPMENT

The following basic principles guide the Australian Government's approach to developing the economy's energy resources:

- The efficient commercial development of energy resources should be promoted to provide the highest value return for the community;
- Energy resource development should be safe, sustainable and consistent with all relevant environmental and health and safety standards and obligations;
- The development of Australia's energy resources should contribute to its ongoing domestic energy security;
- The development of Australia's energy resources should enhance its international competitiveness; and
- The energy resource development framework should appropriately and effectively interface with other relevant markets or regulatory frameworks to support efficient investment in upstream development and downstream supply capacity.

The Australian Government does not undertake or finance energy resource exploration or development. In the offshore petroleum sector, the Australian Government relies on an annual acreage release of vacant offshore areas to create opportunities for investment. The release, distributed worldwide, is a comprehensive package that includes geological details of the acreage, bidding requirements and investment considerations for each release area on offer. The onshore petroleum sector is managed by the relevant state/territory jurisdiction.

ENERGY MARKETS

MARKET REFORMS

The COAG Energy Council, under the Energy Market Reform programme, currently has eight priority areas (COAG, 2019b):

- Consumer empowerment;
- Energy market transformation;

- Australian gas markets;
- Energy and carbon policy;
- Institutional performance improvement;
- Security and reliability, of the National Electricity Market;
- Energy market governance; and
- Energy security board

These priority areas have been guided by the *Independent Review into the Future Security of the National Electricity Market*, released in mid-2017. The events that led to the review and its conclusions are discussed in the 'Notable Energy Developments' section.

ELECTRICITY AND GAS MARKETS

The National Electricity Market (NEM) was established in 1998 to enable the inter-jurisdictional flow of electricity among the Australian Capital Territory, New South Wales, Queensland, South Australia and Victoria (Tasmania joined the NEM in 2005). Western Australia and the Northern Territory are not connected to the NEM because of their distance from the market. The NEM comprises a wholesale sector and a competitive retail sector. All dispatched electricity is traded through a central pool, where output from generators is aggregated and scheduled at five-minute intervals to meet demand.

The Australian gas market comprises three distinct regional markets defined by pipeline transmission infrastructure—the eastern gas market (including the Australian Capital Territory, New South Wales, Queensland, South Australia, Tasmania and Victoria), the northern gas market (Northern Territory) and the western gas market (Western Australia). The Northern Gas Pipeline, completed in December 2018, has linked the eastern and northern gas markets for the first time, but has a capacity of only 90 terajoules per day and is unlikely to seriously affect dynamics in either market.

All three of Australia's gas markets are, to varying degrees, grappling with structural change associated with the development of huge amounts of new LNG supply capacity. This is most keenly felt in the eastern gas market where the growth of unconventional gas production has underpinned new LNG plants that link that market to global gas markets for the first time (the western and northern markets have been linked for some time). This has prompted several government reviews; including two by the Australian Competition and Consumer Commission (ACCC, 2016 and 2018) and the Australian Energy Market Commission (AEMC, 2016); on the supply, demand and competitiveness of the east coast gas market.

The impact of these reviews in driving new policy and the adverse effects of gas price and supply issues on energy markets are discussed in the 'Notable Energy Developments' section.

A key component of ongoing energy market reforms was the establishment of the Australian Energy Market Operator (AEMO) on 1 July 2009. AEMO represents the amalgamation of six electricity and gas market bodies: the National Electricity Market Management Company (NEMMCO), Victorian Energy Networks Corporation (VENCorp), Electricity Supply Industry Planning Council, Retail Energy Market Company (REMCO), Gas Market Company and Gas Retail Market Operator (AEMO, 2019a).

AEMO's functions include operating the NEM and the retail and wholesale gas markets in eastern and southern Australia; overseeing the system security of the NEM grid and the Victorian gas transmission network; undertaking economy-wide transmission planning; and establishing a short-term trading market for gas from 2010. In 2015, AEMO also took responsibility as the wholesale and retail market operator in Western Australia and the gas market bulletin board. Power system operation functions in Western Australia were handed over to AEMO in 2016.

AEMO is also responsible for improving the operation of Australia's energy markets. It has historically prepared and published a 20-year National Transmission Network Development Plan, which provides information to market participants and potential investors. In addition, it publishes the Electricity Statement of Opportunities and the Gas Statement of Opportunities, both of which forecast long-term supply and demand in the eastern market. It also maintains Australia's gas market bulletin board; more recently, having taken charge of Western Australia's gas and electricity markets, it releases similar publications for that market (AEMO, 2019a).

AEMO oversees Australia's energy market governance in cooperation with the Australian Energy Market Commission (AEMC), which is the rule-making body, and the Australian Energy Regulator (AER), which is the regulating body. The COAG Energy Council, discussed previously, is responsible for energy policy and the legislative frameworks under which AEMO, AEMC and AER operate.

FISCAL REGIME AND INVESTMENT

FEDERAL CORPORATE INCOME TAX

The corporate taxation treatment of companies operating in the energy sector is generally the same as those in all other industries. Corporations that earn income in Australia are subject to corporate income tax imposed at a rate of 30%. Project ring fencing does not apply, and the profits and losses of one project can be used to offset those of another project subject to common ownership criteria.

Certain expenditures incurred by energy companies, such as exploration expenditure and royalty payments, are immediately deductible for corporate income tax purposes. Other indirect taxes, such as the payroll tax, fringe benefits tax, fuel excise and land tax may apply.

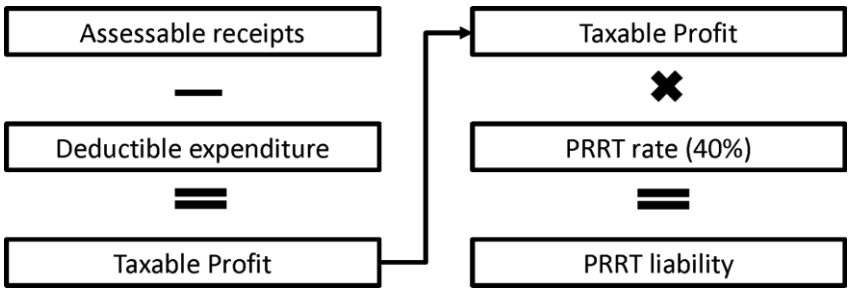
FEDERAL PETROLEUM RESOURCE RENT TAX

The Petroleum Resource Rent Tax (PRRT) is a federal profits-based tax payable on the upstream profits of a petroleum project. The PRRT has been in operation in Australia since 1 July 1986. Previously applied solely to operations in offshore Australia, it was extended to apply to all onshore and offshore projects operating in Australia from 1 July 2012 (ATO, 2019a). However, the PRRT legislation has recently been amended, and from 1 July 2019, onshore projects have been removed from the scope of the PRRT.

Unlike royalty and excise regimes, the PRRT applies to the profits derived from a petroleum project and not the volume or value of the petroleum produced. Deductions are provided for all allowable expenditures (together with indexation of carry-forward losses) to ensure that only the economic rent generated from a petroleum project is captured by the PRRT. Further, when other layers of resource taxes are applicable, such as state and territory royalties and federal crude oil excise, such expenditures are creditable against the liabilities of PRRT projects. This ensures that petroleum projects are not subject to double taxation (ATO, 2019a).

The PRRT applies at a rate of 40% to taxable profit derived in a financial year from a petroleum project. Taxable profit is calculated by deducting eligible project expenses from the assessable revenues derived from the project. Because the PRRT is a project-based tax, losses are not generally allowed to be offset against other project income. The exception is exploration expenditure, which is transferable to other petroleum projects subject to conditions. PRRT payments are deductible for income tax purposes. PRRT liability is calculated as shown in Figure 1 below (ATO, 2019a).

Figure 1: Calculating the PRRT liability



Source: ATO (2018a).

The government recently completed a review of the design and operation of the PRRT. Released in April 2017, the review highlighted possible improvements to the PRRT but did not recommend changes to the crude oil excise or royalty schemes (Treasury, 2017).

ROYALTIES

Royalties are generally levied by the states as an alternative mechanism of charging for resource extraction. Royalty rates vary across states and commodities. They are either specific, *ad valorem*, profit-based or a hybrid (flat *ad valorem* with a

profit component). With regard to petroleum, the state and Northern Territory governments collect royalties for onshore production. The rate is generally from 10% to 12.5% of the net wellhead value of production depending on whether it is from a primary or secondary production licence or a combination of these (Industry, 2019).

With regard to offshore production (excluding petroleum), 60% of the royalties are directed to the state or territory governments and the remaining 40% to the Australian Government.

FEDERAL CRUDE OIL EXCISE

Excise arrangements apply to eligible crude oil and condensate production from the North West Shelf project area and onshore areas (including coastal waters). Excise is levied on the price of all sales made in a producing region at rates based on the timing of the discovery and/or the date of development. The first 30 000 barrels of cumulative production from each field are exempt from crude oil excise (ATO, 2019b).

EXPLORATION DEVELOPMENT INCENTIVE

Effective from 1 July 2014, the Australian Government introduced the Exploration Development Incentive (EDI) to encourage investments in small exploration companies that undertake 'greenfield' mineral exploration in Australia. The scheme is available to junior mineral exploration companies that incur eligible 'greenfield' exploration expenditures in Australia (ATO, 2019c).

When a mining company does not have sufficient income to utilise exploration deductions, the EDI provides a mechanism for Australian resident shareholders to deduct the expense of mining exploration against their taxable income. The EDI does not apply to exploration for quarry materials, petroleum exploration (including exploration for natural gas from coal seams and shale oil) or geothermal energy resources.

RESEARCH AND DEVELOPMENT TAX INCENTIVE

The research and development tax offset has been in effect since 1 July 2011. The two core components of the package are as follows (ATO, 2019d):

- A 45% refundable tax offset for companies with a turnover of less than AUD 20 million per year; and
- A 40% non-refundable tax offset for aggregate turnover equal to or greater than AUD 20 million per year.

MINERALS RESOURCE RENT TAX

The Minerals Resource Rent Tax (MRRT) regime applied to iron ore and coal mining in Australia between 1 July 2012 and 30 September 2014. Following the repeal of the tax, no Australian entities have faced further MRRT-related liabilities since 1 October 2014 (ATO, 2019e).

JOINT PETROLEUM DEVELOPMENT AREA

Petroleum produced within the Joint Petroleum Development Area (JPDA), located in the Timor Sea between Australia and Timor-Leste, is subject to fiscal terms outlined in a production sharing contract (PSC). PSCs are agreements between the parties to a petroleum extraction facility and the Australian and Timor-Leste governments regarding the percentage of production each party will receive after the participating parties have recovered a specified amount of costs and expenses. Government revenues from petroleum extracted within the JPDA are divided, with 90% going to Timor-Leste and 10% to Australia (ANPM, 2019).

ENERGY EFFICIENCY

In December 2015, the COAG Energy Council released the National Energy Productivity Plan (NEPP). By better coordinating energy efficiency, energy market reform and climate policy, the NEPP brings together new and existing measures from across the COAG Energy Council's work programme as well as from the Commonwealth and industry. The NEPP provides a framework and an economy-wide work plan designed to coordinate efforts and accelerate initiatives to deliver a 40% improvement in Australia's energy productivity from 2015 to 2030. Current research has suggested that Australia can meet this target by implementing financially attractive end-use energy efficiency initiatives. In particular, there are cost-effective opportunities to improve energy productivity in the transport, manufacturing and building sectors (COAG, 2017).

Energy productivity is a measure of the amount of economic output derived from each unit of energy consumed. Over the past decade, Australia's energy productivity has improved; however, it still lags behind many other developed

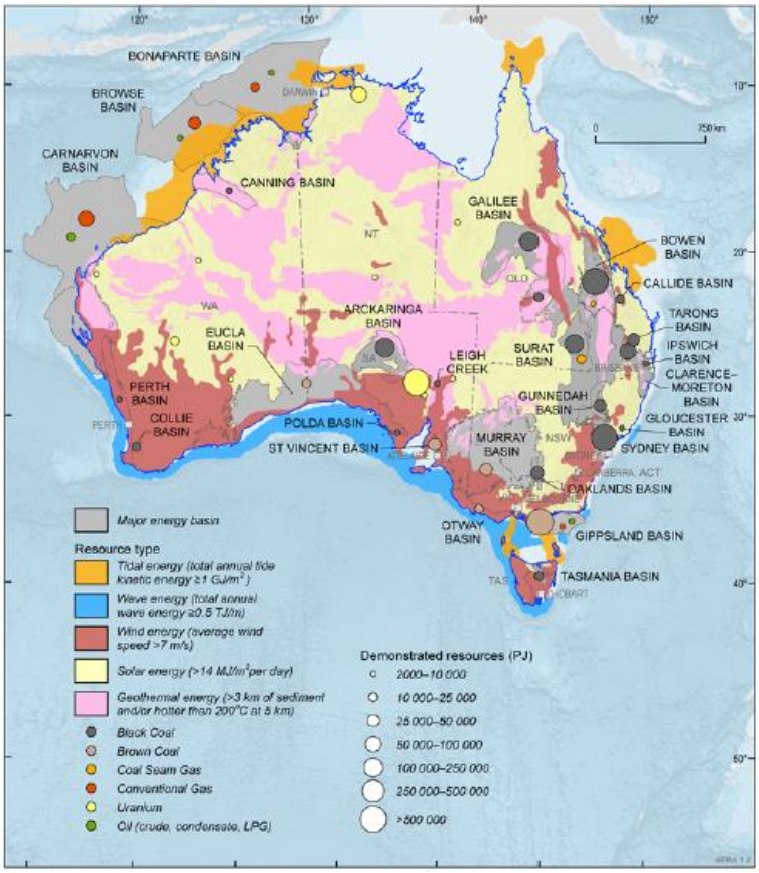
economies such as Japan, Germany and the United Kingdom. The NEPP takes action to address this gap. In the past, improving Australia's energy productivity has been challenging because of separation between supply-side energy market reform and demand-side energy efficiency actions. The NEPP aims to bring supply-side and demand-side policies closer to fully realise the benefits to both the customer and the broader energy system. Policies such as the commercial building disclosure programme, the emissions reduction fund, the Victorian residential efficiency scorecard, Commonwealth Scientific and Industrial Research Organisation's (CSIRO's) national energy analytics research program and ARENA's and CEFC's (see next section for more detail on these organisations) funding of energy efficiency projects are all assisting in achieving this goal.

RENEWABLE ENERGY

Australia has abundant and diverse clean energy resources with significant potential for future development, as shown in Figure 2. Australia's best wind and wave resources are mostly located towards the 'roaring forties' (the strong westerly winds found in the Southern Hemisphere between the latitudes of 40 and 50 degrees) along the Southern and Western coastlines, while outstanding solar resources exist across inland Australia. Large tidal and geothermal resources exist in Northern and Central Australia, respectively.

From 2016 to 2017, large-scale solar PV electricity generation increased by 30% and small-scale solar PV increased by 18% due to strong growth in capacity which partially offset much lower hydro generation (–23%, due to lower water inflows) (Environment, 2018). Wind generation grew strongly between 2008 and 2015 but has plateaued in recent years as new renewable capacity has favoured PV.

Figure 2: Map showing the distribution of Australia's energy resources



Source: GA (2018).

Australia's Renewable Energy Target (RET) has been in operation since 2001 and aims to increase the share of electricity generation from renewable sources to 23.5% by 2020 (Environment, 2019c). Previously known as the

Mandatory Renewable Energy Target (and aiming to source only 2% of electricity generation from renewable resources), the RET has undergone several amendments since 2001, including being split into two parts: the small-scale renewable energy scheme (SRES) and the large-scale renewable energy target (LRET) in 2011. The LRET mandates 33 000 GWh of total electricity generation in 2020. The uncapped SRES provides a subsidy to small-scale technologies, such as residential solar panels and solar hot water systems.

The Australian Renewable Energy Agency (ARENA) is an independent agency established by the Australian Government on 1 July 2012. It has AUD 2 billion to fund renewable energy projects (for example, solar, bioenergy, marine, geothermal and enabling technologies such as storage) until 2022. It also supports research and development, commercialisation and early deployment activities, energy efficiency and low-emission technology and activities that capture and share knowledge. The two primary objectives of ARENA are to improve the competitiveness of renewable energy technologies and increase the supply of renewable energy in Australia. The Australian Centre for Renewable Energy and Australian Solar Institute were incorporated into ARENA.

In the 2017–18 financial year, ARENA committed AUD 967 million in support of 211 projects, studies, fellowships and scholarships (ARENA, 2018). ARENA's independent decision-making board comprises up to seven members appointed by the Minister for Energy. The board also has a CEO appointed by the minister on the recommendation of the board. For more information, see: www.arena.gov.au.

The Clean Energy Finance Corporation (CEFC) is a statutory authority established and financed by the Australian Government in 2012 to help mobilise investment in renewable energy, low-emission and energy efficiency projects and technologies in Australia. The CEFC is mandated to act with commercial rigour and seek benchmark rates of return.

Between its establishment and June 2018, the CEFC has invested AUD 6.6 billion in projects worth AUD 19 billion (CEFC, 2018). Like ARENA, the CEFC is controlled by an independent board that appoints a CEO who is responsible for day-to-day operations.

There is no Australia-wide feed-in tariff scheme to support small-scale renewable technologies. Most state and territory governments have previously implemented jurisdictional feed-in tariff arrangements for small-scale renewable technologies; however, most of these schemes have now been amended or closed.

Growth in renewable energy in Australia over the past decade has been mostly driven by residential solar PV and utility-scale wind farms. This dynamic is changing slightly as utility-scale solar has built momentum in the last few years with the Nyngan (102 MW), Broken Hill (53 MW) and Royalla Solar PV Farms (20 MW) in New South Wales and the Australian Capital Territory. Other large solar projects such as Aurora and Bungala in Port Augusta (150 MW and 220 MW, respectively), Manildra and Parkes in New South Wales (50 MW and 55 MW, respectively), Clare, Darling Downs and Whitsunday in Queensland (150 MW, 110 MW and 67.5 MW, respectively) and Bannerton and Yatpool in Victoria (88 MW and 81 MW, respectively) are all committed or under construction (AEMO, 2019b).

A significant number of wind generation projects such as Stockyard Hill (530 MW), Coopers Gap (453 MW), Sapphire (270 MW), Silverton (199 MW), Mt Emerald (181 MW), Mt Gellibrand (132 MW) and Lincoln Gap (126 MW) are also committed or under construction (AEMO, 2019b). The government has also undertaken a feasibility study on an expansion of the Snowy Hydro scheme (dubbed Snowy Hydro 2.0) to expand the project by 2 gigawatt (GW) of capacity as well as provide an additional 350 000 megawatt-hours (MWh) of storage at a cost of AUD 3.8 to 4.5 billion (Snowy Hydro, 2018). Snowy Hydro is undertaking a planning and environmental process and is expected to make a final investment decision in 2019.

ENERGY TECHNOLOGY AND RESEARCH AND DEVELOPMENT

In the Australian science system, the bulk of basic research occurs in the university sector. Funding delivery comes from organisations such as the Australian Research Council, which has established a range of competitive grant schemes. Furthermore, the CSIRO's Energy Flagship Program provides a focus for energy research and development in Australia, and ARENA supports research and development into renewable energy through funding and knowledge sharing.

NUCLEAR

Australia does not have any commercial nuclear reactors, but research is undertaken by the Australian Nuclear Science and Technology Organisation.

CLIMATE CHANGE

The Australian Government has two main commitments to reducing greenhouse gas emissions. The first one is a 5% reduction of the 2000 levels by 2020. The second is Australia's Nationally Determined Contribution (NDC), submitted to the United Nations Framework Convention on Climate Change (UNFCCC) in 2015, which targets a 26–28% reduction of the 2005 levels by 2030 (Environment, 2019d). The Emissions Reduction Fund (ERF) is the government's tent-pole programme to meet this target. Legislation for the ERF was passed by Parliament on 31 October 2014.

The fund has three main components: crediting emission reductions, purchasing emission reductions and safeguarding emission reductions. The Clean Energy Regulator (CER) administers the fund that operates as a reverse auction, where the government purchases emission reductions on eligible carbon reduction projects. The total amount of money in the fund is AUD 2.55 billion. The most recent auction concluded in December 2018, where 36 abatement contracts were awarded to deliver 3.3 million tonnes (Mt) of abatement at an average price per tonne of $13.82 for a total of AUD 45 million (Environment, 2019e). Eight auction rounds have awarded 477 carbon abatement contracts for 193 Mt of abatement since the implementation of the fund in 2014. The average price across all eight auctions is now AUD 12 per tonne.

Other programmes, policies and tools supporting action on climate change include the 20 million trees and carbon neutral programmes, taxation measures and energy efficiency initiatives. Further detail regarding these and other programmes is available at http://environment.gov.au/climate-change/government. The repeal of the carbon tax by Parliament became effective on 1 July 2014 (Environment, 2019f).

NOTABLE ENERGY DEVELOPMENTS

THE FINKEL REVIEW AND NATIONAL ENERGY GUARANTEE

On 16 September 2016, South Australia experienced a rare 'system black' event—the total shutdown of power supply to the grid. An extreme weather event damaged 23 pylons on electricity transmission towers in the state, which led to a cascading series of events—automatic shutdowns at interconnectors and wind farms, chief amongst them—that left the grid without power for several days. The economic and political consequences of these events were widespread and catalysed debate about the role of renewables in the NEM, prices, system operation and stability, and costs and investment.

One of the government's first responses was to establish The Independent Review into the Future Security of the Electricity Market, chaired by Australia's chief scientist, Dr Alan Finkel (Environment, 2019g). The key issue tackled by the review surrounds the energy 'trilemma': the need to deliver energy securely, affordably and sustainably. Historically, Australia has satisfied two of these criteria: affordability and security of supply (mainly via cheap baseload coal-fired generation). Over the past decade, the sustainability of the grid has improved via investment in wind and solar capacity; however, this has occurred at the same time as dramatically rising prices. South Australia's system black event showed that security, the final pillar of the trilemma, was also under pressure.

The review makes numerous recommendations addressing each of these three challenges. Chiefly amongst which was the need to agree on an emission reduction trajectory and develop a clean energy target to achieve that goal. The review emphasises the importance of agreement across political lines to create certainty for the market to make the investments required to build sufficient new capacity. Other recommendations affect frequency response and inertia (required to maintain system stability); generator closures; improved system planning and integration; and better data, forecasting and analysis. According to COAG, as of December 2018, most recommendations are currently under review or on track, with a small number deemed to be under consideration or on hold (COAG, 2018).

One of the first recommendations implemented by government was the establishment of an Energy Security Board (ESB). The ESB developed the national energy guarantee (NEG) with the aim of reducing carbon emissions while maintaining system reliability (Environment, 2019g). The NEG comprised two parts. The first was a reliability guarantee, which would be set to ensure that retailers and some large users deliver a sufficient amount of dispatchable generation. The second was an emission guarantee that would be set to ensure that Australia achieves its international emission commitments. In September 2018, the government removed the emissions component and abandoned the NEG as a package, but retained the reliability component as part of ongoing energy market reform (AER, 2018).

SYSTEM PLANNING

AEMO has traditionally been responsible for an annual system planning publication called the National Transmission Network Development Plan (NTNDP). The Finkel Review recommended that AEMO should undertake an integrated grid plan to facilitate the development and connection of renewable energy zones. AEMO responded by rolling the 2017 NTNDP into this new publication, called an Integrated System Plan (ISP). The first ISP, released in mid-2018, has a greater focus on the role of distributed renewable generation in the grid, including particular consideration of renewable energy zones and transmission development options (AEMO, 2019c).

GAS MARKETS

Australia's east coast gas market has been undergoing transformative change in recent years as new LNG plants come online, drastically increasing gas production and consumption and linking the domestic and international markets for the first time. Gas prices have increased dramatically, and long-term contracts have become much harder for buyers to secure. This has occurred due to several reasons, chief amongst which is the lower-than-expected production at Queensland CSG fields. Higher gas consumption from the electricity sector (because of coal plant closures), higher production costs and restrictions on fracking in some states and territories have also contributed to price rises (Environment, 2019h).

The government introduced the Australian Domestic Gas Security Mechanism in July 2017 as a temporary measure to deal with gas shortfalls. The mechanism allows the Minister for Resources and Northern Australia, on the recommendation of the AEMO, the ACCC, industry and other stakeholders, to restrict LNG exports by producers that are drawing more gas from the domestic market than they are replacing (Environment, 2019i). The government has also allocated AUD 90 million in the 2017–18 budget and AUD 2.5 million in the 2018–19 budget towards numerous other measures aimed at alleviating tightness in the gas market. These include resource assessments and supply-side reforms, in addition to improvements to transport and data transparency (Environment, 2019i).

COAG's Gas Market Reform Group, established in August 2016, led the design, development and implementation of a new commercial arbitration framework for pipelines, capacity trading reforms, market transparency reforms and wholesale market reforms aimed at promoting the National Gas Objective[1] (COAG, 2019a).

NEW ENERGY PROJECTS

The huge wave of investment in Australia's LNG sector is nearing its conclusion. Of the seven new LNG projects to commence construction in the last five years, only two are still under construction. Ichthys, a two-train 8.4-Mtpa project in Darwin, and Prelude, a 3.6-Mtpa floating LNG project off the coast of Western Australia, have both reached commissioning and will ramp up towards full production in 2019 (OCE, 2019).

Numerous smaller coal, gas and oil projects, including the Byerwen coal project, Gorgon Stage 2 gas and Greater Enfield oil, are also under construction and will be completed in 2019. Other new energy projects at the feasibility stage, including a number of enormous thermal coal mines in Queensland (such as Wandoan, Carmichael and Galilee Coal), face uncertain prospects as companies wait to see how market conditions unfold (OCE, 2019).

[1] The national gas objective is to promote efficient investment in and efficient operation and use of natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

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BRUNEI DARUSSALAM

INTRODUCTION

Brunei Darussalam is a small sultanate bordering the South China Sea and the state of Sarawak, Malaysia. The economy has a land area of 5 765 square kilometres (km²). It is divided into four administrative districts, namely, Brunei–Muara, Belait, Tutong and Temburong. Its capital city is Bandar Seri Begawan, located in the Brunei–Muara District. In 2016, the population was 417 256 and the gross domestic product (GDP) growth declined by 2.5% to USD 30 billion (2011 USD purchasing power parity [PPP]) from 2015. Owing to the abundance of oil and natural gas, Brunei Darussalam continues to prosper. Accordingly, it is one of the wealthiest economies in the APEC region. Strategically located within a region with vast hydrocarbon wealth, Brunei Darussalam has been able to finance its development programmes since the discovery of oil in 1929. Crude oil, liquefied natural gas (LNG) and methanol have also dominated the economy's foreign trade, constituting approximately 90.5% of the total exports in 2016, whereas imports are dominated by machinery, transport equipment, manufactured goods and food (DEPD, 2018).

The dependency on crude oil and natural gas exports for revenue remains high, which constitutes more than 50% of the economy's GDP. This has generated a high per capita GDP of USD 71 789 (2011 USD PPP per capita) in 2016, which has enabled the government to continue providing the citizens a high standard of living, no income tax and free health and education, among other services. The government has proposed efforts to diversify the economic structure and has introduced several reforms focusing on new foreign direct investments (FDI) (DEPD, 2018).

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[b]	
Area (km²)	5 765	Oil (billion barrels)	1.1
Population (thousands)	423	Gas (billion cubic metres)	300
GDP (2011 USD billion PPP)	30	Coal (million tonnes)	–
GDP (2011 USD PPP per capita)	71 789	Uranium (kilotonnes U)	–

Sources: [a] EGEDA (2018); [b] BP (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Brunei Darussalam is rich in crude oil and natural gas. In 2016, approximately 80% of the economy's primary energy was met by natural gas, while oil's share remained at 16%. The total primary energy supply was 4 310 kilotonnes of oil equivalent (ktoe) in 2016, which represents an increase of 3.2% from 4 177 ktoe in 2015.

Due to the small size of Brunei Darussalam's population, domestic energy needs are modest; thus, the bulk of natural gas and crude oil produced in Brunei Darussalam is exported. Only a small percentage of natural gas is allocated for domestic power generation and to the downstream petrochemical sector. Similarly, approximately 4% of the crude oil produced is refined to produce petroleum products to meet domestic demand, and the rest is exported.

In 2016, Japan was the largest buyer of LNG exports from Brunei Darussalam, at approximately 67%, followed by other economies in the APEC region such as Korea (22%); Malaysia (5%) and Chinese Taipei (5%); a small percentage was exported to China (1%). Crude oil is exported as term cargoes, and the main destinations are APEC economies at 76%, while the rest is destined for other Asian economies. Thailand was the primary export destination, at 21% of the total crude oil exports (DEPD, 2018).

Brunei Darussalam's total installed electricity generation capacity from public utilities and auto producers reached 1 006 megawatts (MW) in 2018. In the same year, total electricity generated was 4 270 gigawatt-hours (GWh). Almost all of the electricity was generated by natural gas (EGEDA, 2018).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	17 588	Industry sector	116	Total power generation	256 319
Net imports and others	–13 278	Transport sector	434	Thermal	219 083
Total primary energy supply	4 310	Other sectors	303	Hydro	15 074
Coal	–	Non-energy	564	Nuclear	–
Oil	685	Final energy consumption*	854	Others	22 162
Gas	3 625	Coal	–		
Renewables	–	Oil	556		
Others	–	Gas	17		
		Renewables	–		
		Electricity and others	280		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

Brunei Darussalam's final energy consumption (excluding non-energy) in 2016 declined by 6.1% to 854 ktoe from the previous year's level. The transport sector constituted a large share of the total energy consumption in 2016 (50.8%). Due to the lack of public transport, per capita vehicle ownership in Brunei Darussalam is one of the highest in the APEC region, which is equivalent to one vehicle being registered for every 2.8 Bruneians, according to the Ministry of Communication's Land Transport Master Plan (MOC, 2014). The low price of oil also triggered high consumption in this sector. The economy has the lowest pump prices in South-East Asia.

The other sectors (residential, commercial and agricultural sectors combined) followed with 35.4% of the economy's energy consumption. The remaining amount was for the industry sector (8.2%). In terms of the energy source, oil constituted 65% of the final consumption, followed by electricity and others (33%) and gas (2%). Natural gas constituted 99% of the fuel type used to generate electricity, while 0.95% was generated by diesel fuel and 0.05% from photovoltaic (PV) solar power systems (Energy Department, 2014).

ENERGY INTENSITY ANALYSIS

In line with APEC's overall target, Brunei Darussalam intends to reduce 45% of its energy intensity by 2035 from the 2005 level. In 2016, primary intensity increased by 5.8% to 142 tonnes of oil equivalent per million USD (toe/million USD) while final consumption intensity declined to 28 toe/million USD, representing a year-on-year decline of 3.7%. This was due to a fall in the consumption of natural gas for activities in the non-energy sector compared with that in the previous year. The final energy consumption intensity, however, rose significantly if measured in the absence of non-energy. This could imply that changes in intensity are attributed to the trend in the non-energy sector and that this sector plays a significant role in determining Brunei Darussalam's energy intensity.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	132	142	5.8
Total final consumption	29	28	–3.7
Final energy consumption excl. non-energy	43	47	6.4

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Brunei Darussalam heavily relies on fossil fuels to meet its energy demand. At present, approximately 99.95% of the economy's electricity is sourced from non-renewables and the remaining 0.05% comes from solar. The main obstacle to renewable development in Brunei Darussalam lies in the cost. The economy's electricity price is heavily subsidised due to vast hydrocarbon resources used for electricity generation in its thermal power plants.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption	909	854	–6.1
Non-renewables (Fossils and others)	909	854	–6.1
Traditional biomass*	0	0	0
Modern renewables*	0	0	0
Share of modern renewables to final energy consumption (%)	0	0	0

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Brunei Darussalam's energy policy is centred on its oil and gas industry. Following the oil production peak at 254 000 barrels per day (bbl/d) in 1979, the government imposed a strict conservation policy on production at 150 000 bbl/d in 1981. However, the policy was revised in November 1990 when the government removed the limit on production. This increased production wherein oil production level reached 219 000 bbl/d in 2006.

The Brunei Natural Gas Policy (Production and Utilisation) was introduced in 2000 to satisfy gas export obligations. The policy aimed to maintain gas production at a level that could sustain obligations, open new areas for exploration and development and encourage increased exploration by new and existing operators. Under the policy, priority is always given to domestic gas use, especially for electricity power generation.

Brunei Darussalam's energy sector plays a pivotal role in the realisation of Wawasan Brunei 2035 (Vision Brunei 2035), the long-term development plan for the economy. Wawasan Brunei 2035 has three main goals for the next two decades as follows:

- To support and enhance the accomplishments of its well-educated and highly skilled people, as measured by the highest international standards;
- To achieve quality of life that is among the top 10 economies of the world; and
- To build a dynamic and sustainable economy with an income per capita that is also among the top 10 economies of the world.

Achieving the goals of Wawasan Brunei 2035 will require a significant increase in the activity level of all the economic sectors in the economy, including the energy sector.

ENERGY SECTOR STRUCTURE

The Ministry of Energy, Manpower and Industry (MEMI), formerly known as the Energy Department, Prime Minister's Office (EDPMO), acts as a regulator for the oil and gas industry in Brunei Darussalam. It oversees all activities conducted by oil and gas companies in Brunei Darussalam. MEMI has set four strategic goals to accelerate and enhance the economic growth of the economy as follows:

- Strengthen and diversify our economy;
- Nurture conducive business environments;
- Ensure safe and secure work environments; and
- Develop an industry-ready local workforce.

The above strategic goals not only encompass goals to be achieved within the oil and gas sector but also relate to the development of the non-oil and gas sector.

PetroleumBRUNEI, Brunei Darussalam's national oil company, was ratified in January 2002 by the Brunei National Petroleum Company Order. It is a private limited company solely owned by the government. PetroleumBRUNEI is given designated areas for which the company has the right to negotiate, conclude and administer petroleum agreements.

ENERGY SECURITY

Brunei Darussalam recognises the need to enhance energy security and sustainability, improve energy efficiency and accelerate the deployment of renewable energy and a clean energy supply. Consequently, the economy works to strengthen the partnership arrangements among all its stakeholders.

Brunei Darussalam is an active member of the ASEAN. It likewise supports the implementation of strategies that relate to energy security as well as energy efficiency and conservation among the regions. The economy is actively working with ASEAN towards the achievement of the targets set under the ASEAN Plan of Action for Energy Cooperation 2016–2025 (the Action Plan). This includes flagship projects such as the ASEAN Power Grid (APG) and the Trans-ASEAN Gas Pipeline (TAGP) projects, among others.

UPSTREAM ENERGY

Brunei Darussalam is the fourth-largest oil producer in South-East Asia. Brunei Shell Petroleum Company Sdn Bhd (BSP) is the main oil producer in the economy, jointly owned by the government and the Royal Dutch Shell Company. BSP has seven offshore and two onshore oilfields. The offshore fields are Southwest Ampa, Fairley, Fairley Baram (shared with Malaysia), Magpie, Gannet, Iron Duke, Champion West and Champion. The Champion field holds approximately 40% of the economy's oil reserves. It is situated within 30 metres of water approximately 70 km northeast of Seria. Meanwhile, 13 km off Kuala Belait, the Southwest Ampa field holds more than half of the economy's total gas reserves. The other oil and gas companies that currently operate in the concession and production-sharing areas are Total E&P Deep Offshore Borneo B.V. (Total), Petronas Carigali Brunei Limited and Shell Deepwater Borneo Limited.

Brunei Darussalam has long-term plans to boost upstream production levels from 370 000 barrels of oil equivalent per day (BOE/d) in 2018 to 485 000 BOE/d by 2024 and 650 000 BOE/d by 2035. To achieve oil and gas reserve replacement ratio (RRR) >1 with the 2024 forecasted production as stated, additional reserves

required is about 182 million barrels oil equivalent by 2024 with 5 years rolling average RRR of 1.33 where additional reserves totalling 3.5 billion barrels will be targeted by 2035. Brunei Darussalam is committed to maintaining its oil and gas RRR at more than one to meet its upstream production target. Specifically, the economy will undertake several initiatives to stimulate production, such as rejuvenating existing fields, maximising economic recovery from mature and newly discovered fields including deep water area and reviewing potential solutions for the development of uneconomic, small and unconnected fields.

New offshore discoveries in the South China Sea are expected to prolong Brunei Darussalam's hydrocarbon production past the lifespan of its maturing fields. In a bid to develop these fields, the economy's oil and gas industry has opened tenders valued at more than USD 2.2 billion since early 2016. Calls for tender have been made for the provision of information technology, security and support services and construction and maintenance, along with the supply of advanced technology, training, seabed sampling and other exploratory analysis. A Malaysian service operator, Icon Offshore, has won a USD 27 million contract to provide offshore support vessels, while an Indonesian offshore services company, Wintermar Offshore Marine, has been awarded contracts with BSP valued at USD 5.5 million to serve coastal platforms.

The economy also aims to achieve around 100 000 BOE/d from upstream international venture investments by 2035. On 19 November 2013, PetroleumBRUNEI was awarded Block EP-1, the onshore Kyaukkyi-Mindon area located 250 km north of Yangon, Myanmar. This covers an area of 1 135 km^2. PetroleumBRUNEI will conduct all petroleum activities in Myanmar under the production sharing agreement. Other upstream projects for PetroleumBRUNEI abroad include an offshore block in Sarawak, Malaysia, and a shale gas project in Canada, thereby increasing international investments (PB, 2013).

DOWNSTREAM ENERGY

Brunei Darussalam aims to increase the revenue from domestic downstream industries to BND 5 billion in 2035. The highest contribution to the existing downstream industry in the economy comes from methanol produced from the economy's natural gas resources as feedstock. This industry aims to contribute approximately BND 300 million to the economy annually, which means increasing the economic output from downstream processing to satisfy the growing demand, especially from emerging markets. To accommodate these growing needs, the Brunei Economic Development Board (BEDB) initiated the development of specialised industrial parks, such as the Sungai Liang Industrial Park (SPARK) and Pulau Muara Besar (PMB), for petrochemicals and other downstream oil and gas activities.

The government will provide appropriate support and incentives to encourage more investors to venture into developing and diversifying additional downstream opportunities, such as gas-based petrochemicals and crude- and condensate-based petrochemicals. A priority initiative entitled 'Evaluate Feasibility of Downstream Derivatives' was likewise established as part of the downstream energy development to ensure the achievement of this target. Enabling such activity under this initiative could function as a possible extension of the petrochemical chain, which includes ethylene and propylene building blocks.

ENERGY MARKETS

The government regulates the energy market in Brunei Darussalam. In view of the maturing energy markets, especially in the oil and gas industry, the government recognises the importance of having a comprehensive policy and regulatory framework to support the strategic objectives established for the energy sector. MEMI has initially identified key regulatory policies and frameworks, which include, among others, monitoring the local content requirement in the bidding process for contracts from operators. A Local Business Development (LBD) framework has been enforced to ensure a fair and level-playing field in the market and maximise local spin offs from oil and gas activities.

ELECTRICITY MARKET

Brunei Darussalam's transmission system comprises three independent networks operated by two electrical utilities, the Department of Electrical Services (DES) and the Berakas Power Management Company Sdn Bhd (BPMC). The DES, under the umbrella of MEMI, was set up in 1921, and its functions are to manage and oversee the development of the electricity sector (DES, 2013). The BPMC, a private company, is owned by the Darussalam Asset (DA) that reports to a board of directors. Brunei Darussalam's electricity generation is

almost entirely natural gas-fired. The only exceptions are the diesel power station in the Temburong District and the 1.2-MW Tenaga Suria Brunei (TSB) PV demonstration plant. Approximately 99% of the economy's population is connected to the electrical grid.

ENERGY EFFICIENCY

Brunei Darussalam established the Energy Efficiency and Conservation (EEC) roadmap in 2011, which specifies comprehensive EEC action plans that will be implemented for the next 17 years until 2035. Through the rigorous implementation of EEC key initiatives, coupled with the deployment of renewable energy (RE) programmes, Brunei Darussalam will be able to reduce the nation's total electricity consumption by up to 17% by 2024 compared to electricity consumption in 2011. The reduction will primarily come from a reduction in electricity consumption via four major sectors, namely, commercial, residential, government and industrial. Some of the key action plans that have been and will be undertaken to support the key initiatives are as follows (UNFCCC, 2015):

- *Electricity Tariff Reform*

Electricity tariff reform for the residential sector was implemented on 1 January 2012 to help low-income citizens through the minimum charge of one cent per kWh for basic electricity consumption and, concurrently, to promote energy saving and avoid energy wastage. These measures were designed to be progressive in contrast to the nature of regressive tariffs to enhance the element of energy saving within the reform package. The government is also planning to initiate electricity tariff reforms in other sectors as deemed appropriate.

- *Standards and Labelling Order*

MEMI, in collaboration with the Brunei National Energy Research Institute (BNERI), has developed the Standard and Labelling Order which is currently in the final process of reviewing at the Attorney General Chambers (AGC). The objective of the order is to restrict or perhaps to halt the imports of non-efficient electrical appliances and products, such as air conditioners, as well as to educate and encourage people to opt for more energy-efficient electrical appliances and products. The Order will be implemented and enforced in 2020.

- *EEC Building Guidelines for the Non-Residential Sector*

The 2015 EEC Building Guidelines for Non-Residential Buildings was launched by the Ministry of Development in May 2015. All government and new buildings are obligated to adopt the guidelines in accordance with the Energy Efficiency Index (EEI) baseline in kilowatt-hours per square metre, which has been set in the guidelines. The guidelines are also to be made mandatory to commercial building as early as 2020.

- *Fuel Economy Regulation*

MEMI is currently working with the Ministry of Transportation and Infocommunication (MTIC) for the implementation of Fuel Economy Regulations (FER). To support this policy initiative, the introduction of hybrid cars, fuel-efficient vehicles (FEV) and Electric Vehicles (EVs) has already been widely undertaken. The first phase of FER will be implemented in 2025 and the drafting will start as early as 2023.

- *Financial Incentives*

MEMI and the Ministry of Finance are examining the introduction of appropriate financial incentives for energy-efficient appliances and vehicles in the form of tax exemptions, tax reductions or rebate schemes for energy-efficient appliances and products.

- *Energy Management Policy*

Brunei Darussalam is considering the adoption of an energy management policy compatible with ISO 50001. To support this policy, MEMI is currently in the process of establishing the Energy Manager for

building by focusing on government building. Each government ministers will establish their own Energy Manager via training that will be conducted by certified Energy Managers from MEMI and BNERI.

- *Awareness Raising Programme (ARP)*

The government will continue to increase awareness through energy clubs, energy exhibitions, road shows, seminars and workshops on energy savings and best practices in the EEC for Brunei Darussalam.

Further, the government endeavours to improve Brunei Darussalam's power generation efficiency to greater than 45% by 2020 by replacing simple-cycle power plants with a combined-cycle or cogeneration plant (CHP plant) and by establishing a structured maintenance programme.

BRUNEI DARUSSALAM ENERGY CONSUMPTION SURVEY FOR RESIDENTIAL SECTOR (2015)

This is the first comprehensive energy consumption survey in Brunei Darussalam. It provides insights into the consumption behaviour of the residential sector and recommends policy options and measures that have the greatest impact. This project was conducted and supported by the Economic Research Institute for ASEAN and East Asia (ERIA) in cooperation with MEMI and BNERI. The survey was completed in December 2015. From the survey, it was concluded that the pattern of end-use energy consumption is completely dominated by cooling systems, followed by refrigeration, lighting and water heating. Four major policies have been identified, namely, standards and labelling, incentive tariff reforms, residential building energy efficiency and greater campaign on awareness.

BRUNEI DARUSSALAM DOMESTIC GAS CONSUMPTION SURVEY (2016)

In late October 2016, the Public Works Department and MEMI initiated surveys on the consumption of domestic gas supplies at residences in the Belait District. The government commenced the study to look for more efficient ways of operating the direct gas supply line to reduce wastage. Approximately 10 000 households and businesses in Seria and Kuala Belait (towns in the Belait District) are directly supplied domestic gas through pipelines instead of gas cylinders, which are used by a majority of the population.

RENEWABLE ENERGY

Brunei Darussalam has set a long-term goal that requires 10% of the economy's total power generation mix to come from renewable energy sources by 2035. This represents one of the key performance indicators (KPI) under the second series of key strategic goals. Renewable energy development in Brunei Darussalam has four major priority initiatives as follows (MEMI, 2014):

- The introduction of renewable energy policies and regulatory frameworks;
- The growth of the market deployment of solar PV and the promotion of waste-to-energy technologies;
- The growth of awareness and the promotion of human capacity development; and
- Support for R&D and technology transfers.

Solar energy is by far the most promising renewable energy source, given the economy's exposure to equatorial sunshine. In July 2010, the government commissioned a 1.2-MW solar power plant—TSB. TSB is connected to the national power grid, which can power up approximately 200 homes with a designed installed capacity of 1.2 MW. The plant operated as a three-year demonstration project from July 2010 to October 2013 before it managed to generate approximately 5 514 MWh of electricity, thus saving approximately 48 302 million British thermal units (MMBtu) of natural gas and avoiding approximately 3 939 tonnes of carbon dioxide (CO_2) emissions.

Meanwhile, Brunei is currently looking at other potential alternative energy sources, which include waste to energy, wind power and micro-hydropower and are subjected to further R&D collaboration among MEMI, BNERI and other agencies (both the government and private sectors). Deployment of these alternative energy sources will depend on the maturity of their technologies, and they have been integrated into the national RE roadmap based on medium-term and long-term timelines.

NUCLEAR

Brunei Darussalam does not have a nuclear energy industry.

CLIMATE CHANGE

Brunei Darussalam's net GHG emissions represented a small fraction of approximately 0.016% of global emissions in 2010 (UNFCCC, 2016). Although the contribution to global GHG emissions is and will remain relatively small, Brunei Darussalam was committed to play a part in combatting the adverse effects of climate change by ratifying the Paris Agreement under the auspices of the UNFCCC on 21 September 2016. The agreement entered into force on 4 November 2016.

Under the purview of MEMI, the Brunei National Council on Climate Change (BNCCC) was revived in July 2018. The Executive Committee on Climate Change (ECCC) was also established along with the revival of BNCCC. The members comprise of representatives from key ministries and stakeholders as well as non-government agencies. Three working groups (Mitigation, Adaptation and Resilience, and Support Framework) were formed to discuss pertaining climate issues, besides ensuring performance and achievement of all targets, deadlines and implementation of climate activities are in accordance with policies of respective agencies under the working groups.

The secretariat to BNCCC, ECCC, and the three working groups is the Brunei Climate Change Secretariat (BCCS), a unit under MEMI. BCCS is currently formulating a long term GHG reduction target, with a national action plan to reach the proposed GHG reduction target.

Brunei Darussalam intends to reflect these increased climate ambitions in the next NDC in 2020.

NOTABLE ENERGY DEVELOPMENTS

ENERGY INFRASTRUCTURE PROJECTS

Brunei Darussalam seeks to maximise the potential of the economy's oil and gas resources and take advantage of its strategic location for trading. One of the key initiatives under Vision Brunei 2035 is to designate industrial 'cluster-specific' sites with supporting infrastructures and facilities. The first site, established in 2007, was the SPARK, specifically designed for downstream petrochemical processing activities. The first petrochemical plant constructed at the site, a methanol production plant, was successfully commissioned in April 2010 (BMC, 2010).

The construction of a government-owned Brunei Fertiliser Industries (BFI) is currently in progress at SPARK. It is expected to be operational in 2021, with a capacity of 1.4 million tonnes of urea per year and 0.8 million tonnes of ammonia. The economy will become one of South-East Asia's largest fertiliser plants if it runs at full production capacity. Approximately 500 billion cubic feet of natural gas will be supplied by BSP over the next 20 years for the production of fertiliser to be exported to the agriculture industry in the region.

A one-year demonstrative project by an association composed of four industry-leading companies from Japan (Advanced Hydrogen Energy Chain Association for Technology Development) will commence in January 2020, supplying 210 tonnes of hydrogen that can power approximately 40 000 fuel cell vehicles. The hydrogenation plant, located at SPARK, is scheduled for completion in September 2019. The plant will produce liquefied hydrogen from gas piped from Brunei LNG and will be shipped to a dehydrogenation plant in Kawasaki, Japan.

The second industrial site is being developed at PMB for oilfield support services, such as an integrated marine supply base (IMSB), fabrication yard and further downstream activities. The anchoring project will be a USD 3.4 billion oil refinery and aromatics cracker project to be developed by the Zheijiang Hengyi Group Co. Ltd. The project is expected to begin operation by end of 2019, with a production capacity of approximately 175 000 bbl/d. The project will produce paraxylene and benzene, in addition to refined products such as gasoline, jet fuel and diesel.

In the power sector, a memorandum of understanding was signed among the government, Brunei LNG and BSP to expand the Lumut Co-Generation Power Station to an installed capacity of 246 MW, an increase of 66 MW. This will meet the growing energy demand for the next 15 years and beyond based on the expected increase in the number of households and industrial activities. The new expanded plant which are currently operational, improved the overall plant efficiency to greater than 30% through the application of combined heat and power integration or cogeneration (MEMI, 2014). In addition, a new 240-MW coal power plant is expected to be operational by end of 2019 in PMB to provide power to Hengyi, where coal would be sourced from South-East Asia.

Meanwhile, Brunei Gas Carriers Sdn Bhd (BGC) welcomed its fifth A-class vessel in the third quarter of 2015. The vessel, named 'Amadi', follows the arrival of its sister ship 'Amani', BGC's largest ship with a capacity of 155 000 cubic metres. The replacement of B-class ships owned by Brunei Shell Tankers (BST), which have a smaller capacity for transporting LNG to A-class ships, is in accordance with a strategic programme by the LNG carrier to modernise and localise its service. BGC provides LNG transportation services from Brunei Darussalam to Japan, Korea, Malaysia and Chinese Taipei (BGC, 2015).

THE US–ASIA PACIFIC COMPREHENSIVE ENERGY PARTNERSHIP

At the seventh East Asia Summit (EAS) in 2012, US President Obama, in partnership with His Majesty the Sultan and Yang Di-Pertuan of Brunei Darussalam and President Susilo Bambang Yudhoyono of Indonesia, announced the formation of the US–Asia Pacific Comprehensive Energy Partnership (USACEP).

Under the auspices of USACEP, a new renewable and alternative power generation (RAPG) work stream was established as part of the energy cooperation initiative of the EAS. The main aim of the RAPG work stream is to encourage new renewable energy collaboration and cooperation in the EAS region. The RAPG projects will coexist and complement current renewable energy activities within ASEAN and dialogue with partners to elevate the role of renewable energy in the region. The project areas cover solar PV, wind and hydro. The work stream is currently co-chaired by Brunei Darussalam and the Republic of Korea.

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USEFUL LINKS

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Brunei Economic Development Board—www.bedb.com.bn

Brunei LNG Sdn Bhd—www.bruneilng.com/home.asp

Brunei Methanol Company Sdn Bhd - http://www.brunei-methanol.com/

Brunei Shell Petroleum Company Sdn Bhd—www.bsp.com.bn

Department of Electrical Services - http://www.des.gov.bn/Theme/Home.aspx

Ministry of Communications—http://www.mincom.gov.bn/Theme/Home.aspx

Ministry of Energy, Manpower and Industry—www.ei.gov.bn

PetroleumBRUNEI—www.pb.com.bn

CANADA

INTRODUCTION

Canada is the world's second-largest economy after Russia in terms of landmass. The Canada–US border is the world's longest international border and extends from the Pacific Ocean to the west, Atlantic Ocean to the east and Arctic Ocean to the north. There are 10 provinces and 3 territories in Canada, with a total population of 36 million in 2016 (EGEDA, 2018). In 2016, Canada's gross domestic product (GDP) grew by 1.4% to USD 1 568 billion (2011 USD purchasing power parity [PPP]) and GDP per capita grew by 0.2% to USD 43 238 (EGEDA, 2018).

Canada is the fourth-largest energy producer in the APEC region and the sixth-largest in the world after China, the US, Russia, Saudi Arabia and India (NRCan, 2018a). The energy sector directly contributed 7.3% to Canada's GDP in 2017 and indirectly contributed (through purchases of goods and services from non-energy industries) an additional 3.3% (NRCan, 2018a). In 2017, Canada exported CAD 113 billion worth of energy products and imported CAD 41 billion (NRCan, 2018a). Canada is one of the world's top five exporters of crude oil, natural gas, uranium and electricity (NRCan, 2018a).

The economy has extensive conventional and unconventional oil, natural gas and coal reserves as well as significant uranium deposits. It has the world's third-largest amount of proven oil reserves after Venezuela and Saudi Arabia. The reserves were estimated at 169 billion barrels, of which oil sands constituted 98% (163 billion barrels) as of December 2017 (BP, 2018; NRCan, 2018a). The bulk of reserves are in the province of Alberta. Alberta and Saskatchewan have the largest onshore reserves, while Newfoundland and Labrador has the largest offshore reserves (NEB, 2018a).

Canada has substantial proven gas reserves, which are estimated at 67 trillion cubic feet (Tcf) and equal to 1.0% of global reserves in 2017 (BP, 2018). The largest concentrations of gas reserves are in Alberta and British Columbia. Saskatchewan, Newfoundland and Labrador, New Brunswick, Nova Scotia, the Northwest Territories (NWT) and Yukon also have established reserves, although significantly smaller (NEB, 2018a).

Canada currently holds 6 582 million tonnes of proven resources of coal (EGEDA, 2018). More than 90% of Canada's coal deposits are located in the Western provinces, namely, Alberta, British Columbia and Saskatchewan, while the rest is located in the eastern province of Nova Scotia (CAC, 2016).

Canada has the third-largest uranium resources in the world after Australia and Kazakhstan. As of 2017, Canada's uranium resources were estimated at 410 kilotonnes (NEA, 2018), most of which are located in the Athabasca Basin of northern Saskatchewan). These resources are equal to 11% of the world's known resources that are recoverable at a price of US$130 per kilogram.

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c, d]	
Area (million km²)	10	Oil (billion barrels)	169
Population (million)	36	Gas (trillion cubic feet)	67
GDP (2011 USD billion PPP)	1 568	Coal (million tonnes)	6 582
GDP (2010 USD PPP per capita)	43 238	Uranium (kilotonnes U)	410

Sources: [a] EGEDA (2018); [b] StatCan (2016a); [c] BP (2018); [d] NEA, 2018.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Canada's domestic energy production reached 475 713 kilotonne oil equivalent (ktoe) in 2016. This represented an increase of 0.8% compared with that in 2015 (472 028 ktoe) (EGEDA, 2018). Fossil fuel dominated this production with a share of 84%. Oil, including natural gas liquids (NGL), constituted the largest share (224 019 ktoe, 47%), followed by gas (146 033 ktoe, 31%) and coal (30 025 ktoe, 6.3%). The share of nuclear energy production was 5.5% (26 354 ktoe), thereby leaving a share of approximately 10% for renewables. Renewables comprised hydro (33 284 ktoe, 7.0%); other renewables (bioenergy), including biomass, wood and waste (13 048 ktoe, 2.7%); and geothermal, solar, wind and ocean (2 645 ktoe, 0.56%) (EGEDA, 2018). Canada is a leading global producer of energy, as evident in its global production ranks for gas (fifth), crude oil (fourth), hydro (second) and uranium (second) as of 2015 (NRCan, 2018a).

Canada is a net exporter of oil, gas, coal, uranium and electricity. The economy's energy exports go mainly to the US. From 2000 to 2016, energy exports grew at 2.7% per year. Exports increased by 3.2% in 2016 (EGEDA, 2018). In 2015, Canada exported 284 306 ktoe of energy (excluding uranium exports), which comprised crude oil and NGL (168 564 ktoe), petroleum products (21 329 ktoe), gas (68 767 ktoe), coal and coal products (18 089 ktoe), electricity (6 316 ktoe) and renewables (1 241 ktoe) (EGEDA, 2018). In 2016, energy exports constituted 22% (CAD 113 billion) of domestic merchandise export revenue (NRCan, 2018a).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	475 713	Industry sector	41 938	Total power generation	667 191
Net imports and others	–196 232	Transport sector	61 111	Thermal	132 358
Total primary energy supply	280 097	Other sectors	64 575	Hydro	387 097
Coal	16 957	Non-energy	23 777	Nuclear	101 143
Oil	98 544	Final energy consumption*	167 624	Others	46 593
Gas	94 759	Coal	2 426		
Renewables	48 793	Oil	71 561		
Others	21 044	Gas	42 567		
		Renewables	9 503		
		Electricity and others	41 567		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

CRUDE OIL

Canada's oil production has increased over the past two decades. In 2016, it was the world's fourth-largest oil producer. In 2016, Canada produced 224 019 ktoe of crude oil, including NGL. This was a decrease of 0.1% from 2015 (EGEDA, 2018). This decrease was the result of several oil sands producers reducing production in response to wildfires in the Fort McMurray region (NEB, 2016a). Production from oil sands, which are mainly located in the Athabasca oilfields in Alberta, has consistently grown since it began in 1967, surpassing conventional production levels in 2010. A sustained period of high prices attracted significant investment into incremental capacity gains over the past decade, driving production to 2.8 million barrels per day (Mbbl/D) in 2017, an increase of 165% over 2005 levels (NEB, 2018a). Conventional oil production in 2017 was 1.5 Mbbl/D, a decrease of 5.6% from 2014 levels (NEB, 2018a).

Although Canada's crude oil and equivalent production is geographically dispersed, 94% of production in 2017 came from Western Canada, of which 69% was from the oil sands. The bulk of Canadian crude oil and equivalent production occurred in Alberta (81%), followed by Saskatchewan (11%), British Columbia (1.9%) and Manitoba (0.8%) (NEB, 2018a). Offshore production in the Atlantic Ocean constituted 5.1%, except for small-scale production in Ontario (<0.1%) and the Atlantic provinces (<0.1%). Pentanes plus and condensates constituted 7.6% of total crude oil and equivalent production (NEB, 2018a). In 2016, the economy's oil exports, including NGL, (168 564 ktoe) increased over those in 2015 by 4.1%. Exports of petroleum products (21 329 ktoe) decreased by 6.0% (EGEDA, 2018). The main export market was the US.

GAS

Canada holds large proven natural gas reserves. It is the world's fourth-largest producer and fifth-largest exporter of natural gas (NRCan, 2018a). In 2016, Canada's natural gas production reached 146 033 ktoe, an increase of 4.9% from 2015 (EGEDA, 2018). This increase in production continues a recent growth trend that began in 2013 when gas production began to ramp up again after a seven-year period of decline (IEA, 2017a). In terms of exports, the volume of its gas exports was 68 767 ktoe, an increase of 4.2% compared with that in 2015 (EGEDA, 2018). After several years of successive decline, gas export volumes to the United States appear to be stabilising around these levels.

Although conventional natural gas reserves are shrinking, technological advances in hydraulic fracturing have renewed the growth potential from the Western Canadian Sedimentary Basin (WCSB). In Canada, these developments have mostly fostered the development of tight gas resources, particularly the Montney formation and Alberta Deep Basin. This contrasts with the United States, where hydraulic fracturing predominately targets shale resources. Canada has vast shale resources, but they are either in their infant stages of development (the Duvernay), lack the NGLs needed to make drilling economic at today's prices (Horn River Basin) or are located in areas where hydraulic fracturing is under moratorium (the shale formations in Quebec and New Brunswick).

Western Canada constituted 99% of the economy's marketable gas production in 2017, with most coming from Alberta (67%), British Columbia (29%) and Saskatchewan (2.6%) (NEB, 2018a). Alberta and British Columbia, from the Montney, Deep Basin and Durvernay plays, drove production growth, more than offsetting declines from conventional plays and the rest of the economy. Eastern Canada's marketable gas production is in decline, with Nova Scotia (0.77%) expected to shut-in its off-shore production by 2020 and small amounts of onshore production in Ontario and New Brunswick making up less than 0.070% of Canadian gas production (NEB, 2018a). Solution gas—gas produced in association with oil production—continues to play a role, making up 11% of production in 2017. Oil producers offshore of Newfoundland and Labrador also produce associated gas but consume all of it on site via electricity generation or flaring.

COAL

Annual coal production has declined since 2014 (BP, 2018) driven by Ontario's phase-out of coal-fired electric generation and lower global metallurgical prices. In 2016, Canada produced 30 025 ktoe of coal, a decrease of 2.4% from its 2015 production (EGEDA, 2018). According to Statistics Canada, production declined by 1.3% further in 2017 and by another 10% decline in 2018 (StatCan, 2019). Almost all of Canada's coal production is taking place in Western Canada; however, Nova Scotia restarted production at its Donkin mine in 2017 to supply domestic power needs and for export to global thermal and metallurgical markets (Morien, 2018).

Canada ranks 13th in global coal production (NRCan, 2018a). Approximately 56% of its annual production of 61 million tonnes (Mt) is metallurgical (coking coal, which is used in steel manufacturing and is largely exported). The other 48% is thermal coal for use in electricity generation and some heating requirements in both domestic and export markets (CAC, 2017). Canada exported 60% (18 060 ktoe) of its coal production in 2016, a 0.53% decline from its 2015 exports (EGEDA, 2018). Coking coal constituted 92% of the exports (EGEDA, 2018). In 2017, Canada exported CAD 6.8 billion worth of coal, of which most went to Asia.

URANIUM

Canada is among the three leading producers of uranium, along with Kazakhstan and Australia. Despite a 7% decline in production, Canada maintained its position as the world's second-largest uranium producer in 2017, producing 13 kilotonnes of uranium metal (tU) (WNA, 2018). Current production is entirely from the

Athabasca Basin of northern Saskatchewan, where the two largest-producing uranium mines in the world, McArthur River (6 924 tU) and Cigar Lake (6 193 tU), produced 22% of the total world output in 2017 (WNA, 2018).

RENEWABLES

Canada is a world leader in the production and use of renewable energy. In 2016, the economy's total renewable production was 49 076 ktoe, slightly below 2015 levels, consisting of hydro (33 284 ktoe); bioenergy and waste (13 048 ktoe); and solar, geothermal, wind and ocean (2 950 ktoe) (EGEDA, 2018). Renewables constituted almost 10% of the total indigenous energy production in 2016 (EGEDA, 2018).

Hydro is the most important source of renewable energy in Canada, supplying 60% of Canada's electricity generation in 2017 from an installed hydraulic capacity of 80 714 MW (NEB, 2018a). Hydro is also the key fuel source for Canada's electricity exports, making up 72% of the generation in the six provinces that export electricity to the United States. The completion of several largescale projects across the country will bring an additional 2.3 GW of hydroelectric capacity online by 2023 to service both domestic demand growth and exports markets. These projects include Site C in British Columbia, Keeyask in Manitoba, Romaine-4 in Québec and the Lower Churchill Project in Newfoundland & Labrador (Site C, 2017), (Manitoba Hydro, 2019), (HQ, 2019), (Nalcor, 2019).

Canada has access to large and diversified biomass resources for energy production owing to its large landmass and active forests that are utilised by the agricultural, forest and paper industries. In 2016, bioenergy was the second-most important form of renewable energy, with biofuels and renewable waste representing 2.7% of Canada's total primary energy supply (EGEDA, 2018). It is estimated that 6.3% of gasoline demand in Canada is blended ethanol and 2.2% of diesel is blended biodiesel (CEEDC, 2018).

Wind is also an important renewable energy source whose provincial generating leaders are Ontario, Québec and Alberta (NEB, 2018a). While Prince Edward Island (PEI) only makes up 1.7% of Canada's wind generation, wind's share of its provincial generation leads Canada at over 99%. However, other provinces with wind potential are increasing the share of wind energy in their power mix. Canada has vast areas with significant potential for wind resources to make the expansion of wind-generated power economical, particularly in Alberta and Saskatchewan. Installed wind power capacity has rapidly expanded in recent years and is estimated to grow at a rapid pace given the low prices that have been demonstrated at recent capacity auctions (AESO, 2018a). Canada has close to 300 wind farms in operation, with a total installed capacity of 12 663 MW in 2017 (CanWEA, 2018), (NEB, 2018a).

Solar energy has also experienced continuous growth both in thermal and photovoltaic (PV) power. Cumulative PV power capacity grew to 2 842 MW in 2017 (NEB, 2018a). Ontario is the leading province in terms of solar capacity (99% of total installed capacity) (IEA, 2017b). Off-grid capacities were not reported in 2013 but were estimated at approximately 1% of the total installed capacity (IEA, 2017b). Alberta and NWT also expanded solar capacity in 2017 (NEB, 2018a).

Canada has access to a significant energy source in the form of ocean waves and tides because of its proximity to the Atlantic and Pacific oceans. The province of Nova Scotia has one of the world's few tidal power plants, with 20 MW of generation capacity, and has several prospective projects looking to install capacity in the Bay of Fundy, Nova Scotia in the upcoming years.

Geothermal power has not experienced the momentum of solar, wind and biomass. A number of heat and power generation projects are being considered in Alberta, British Columbia, Saskatchewan, the NWT and the Yukon where the highest temperature geothermal resources are located. Demonstration projects are underway in Western Canada, with commission planned in the 2020 timeframe.

FINAL ENERGY CONSUMPTION

Canada's final energy consumption in 2016 reached 167 624 ktoe, a decrease of 1.4% from that in 2015 (EGEDA, 2018). This makes Canada the fifth-largest energy consumer in APEC after China; the US; Russia; and Japan (EGEDA, 2018).

A combination of smaller sectors, including residential, commercial and public services, together with agriculture and non-specified others, constituted the largest share of total final consumption (64 575 ktoe,

34%), followed by the transport sector (61 111 ktoe, 32%) and the industrial sector (41 938 ktoe, 22%) (EGEDA, 2018). Non-energy (fuels used as raw materials and not consumed as fuel or transformed into another fuel), which is excluded from final energy consumption, was 23 777 ktoe in 2016 (EGEDA, 2018).

Fossil fuels constituted the largest share in final energy consumption (70%), comprising petroleum products (71 561 ktoe, 43%), gas (42 567 ktoe, 25%) and coal and coal products (2 426 ktoe, 1.4%) in 2016 (EGEDA, 2018). The remainder was the share of renewables (9 503 ktoe, 5.7%) and electricity and others (41 567 ktoe, 25%), of which the share of renewable electricity and others was 26 623 ktoe (64%) (EGEDA, 2018).

POWER GENERATION

Canada generated 667 191 gigawatt-hours (GWh) of electricity in 2016, a decrease of 0.11% from the previous year's level (EGEDA, 2018). Renewables constituted the largest share of this generation (65%), with hydro as the major contributor (58%) and solar and wind at 5.1%. The share of nuclear was 15%, which increased the combined share of non-emitting power generation to 80%. The share of oil, gas and natural gas-fuelled thermal generators was 20% (EGEDA, 2018). Coal constituted the largest share of the latter (9.3%), followed by gas (9.3%) and other fossil fuels such as diesel, light fuel oil, heavy fuel, wood and spent pulping liquor (1.3%) (EGEDA, 2018).

Canada has been increasing the share of renewables, including hydroelectricity, for electricity generation since 2000. Low natural gas prices, the rapidly decreasing cost of renewable energy and new regulations that limit the use of coal have all decreased the greenhouse gas (GHG) intensity of Canada's electricity sector. Canada is the APEC region's and the world's second-largest hydroelectricity producer after China (NRCan, 2018a). Canada's rich water resources enable many parts of the economy to rely on hydropower.

Several provinces have introduced policies and programs to promote renewable energy while discouraging the continued use of coal-fired power plants. In 2016, the federal government announced its plan to accelerate the phase-out of coal-fired electricity generation in Canada by 2030. Flexibility in achieving this goal will be allowed through the negotiation of equivalency agreements with the provinces (GOC, 2017a). For example, an agreement-in-principle was reached with the federal government that will allow Nova Scotia to burn some coal after the deadline during periods of high demand in exchange for deeper sectoral reductions elsewhere in the economy (PNS, 2016).

Coal generation was phased out by Ontario in 2013 (NEB, 2015) and large increases in solar and wind capacity have been fostered through competitive bidding processes; while many contracts were cancelled, Ontario's renewable capacity is still set to grow for the next few years (NEB, 2018a). As part of the 2017 Long-Term Energy Plan, Ontario intends for nuclear to continue to be a major source for the province's electricity supply (Ontario, 2017). To this end, the province plans to continue with the refurbishment of 10 nuclear reactors, albeit on an altered, more cost-effective schedule. These refurbishments will add approximately 25–30 years to the operational life of each unit.

In November 2015, Alberta also announced a new policy to accelerate the 2012 federal plan to phase out coal-fired power generation. Alberta's plan will result in the retirement of six coal-fired electricity plants or their conversion to natural gas by 2030 (Alberta Energy, 2015). However, in 2018, the combination of low natural gas prices, higher carbon prices and an output based emission-pricing system that uses a natural gas-based benchmark increased the operating cost of coal-fired generation and incentivized several utilities to co-fire natural gas at existing coal units in an effort to reduce their carbon compliance costs[1]. This reduced coal-fired generation by 22% in 2018 while increasing gas-fired generation by 26% (AESO, 2019). On the renewable side, Alberta has had several successful bidding processes to increase wind capacity over the next several years (AESO, 2018a).

The electricity networks of Canada and the US are highly integrated, and the US is a net importer of electricity from its northern neighbour. In 2016, Canada exported 6 316 ktoe of electricity to the US while importing 800 ktoe (EGEDA, 2018). The bulk of the electricity trade with the US occurs among the provinces of Québec, Ontario, Manitoba and British Columbia with their neighbouring American states (NEB, 2018b).

[1] This fact is derived by analysing the financial statements and investor presentations of the utilities who operate the remaining coal fleet in Alberta. Coal-unit operators who embraced natural gas co-firing in 2018 include Capital Power and ATCO (Capital Power, 2019), (ATCO, 2019).

New capacity additions and low domestic electricity demand resulted in Canadian net exports, reaching 62 terawatt-hours (TWh) in 2017, a slight drop from their all-time peak of 64 TWh in 2016 (NEB, 2018b). In 2015, the National Energy Board (NEB) received the first application for a new international power line (IPL) since 2005, the ITC Lake Erie Connector from Ontario to Pennsylvania (NEB, 2016b). According to public sources, four additional IPLs are under consideration, with three located in Québec and one in Manitoba, the Manitoba-Minnesota Transmission Line (NEB, 2016b). Both the ITC Lake Erie and Manitoba-Minnesota Transmission Line have been approved by the federal government and certificates issued by the NEB. In 2018, it was announced that Hydro Québec had been successful in its bid to deliver 1 900 MW of hydropower to the New England electric grid via the proposed Northern Pass Transmission Line (HQ, 2018).

ENERGY INTENSITY ANALYSIS

A number of factors contribute to the energy intensiveness of Canada's economy. These factors include its vast geography, cold climate and an industrial structure with a high rate of energy-intensive industries. The economy's abundant fossil energy reserves and renewable capacity (particularly hydro) at relatively low costs also play a role.

Nevertheless, Canada has been successful in gradually reducing its energy intensity over the past few decades. Primary energy intensity and final energy consumption intensity fell by 1.6% and 2.1% from 2015, respectively (EGEDA, 2018). This was mainly because of a significant decrease in the energy intensity of the residential sector and freight transport, which registered the largest sub-sectoral reductions in both their energy use and energy intensity compared with 2015 levels (OEE, 2018). Increasing energy efficiency and reducing energy intensity have been policy goals of the Canadian Government as a means to mitigate climate change and conserve energy.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%)
	2015	2016	2015 vs 2016
Total primary energy supply	182	179	–1.6
Total final consumption	110	107	–2.7
Final energy consumption excl. non-energy	125	122	–2.1

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

The share of modern renewables in the final energy consumption remained flat in 2016 at 19.8% because non-renewables declined higher year-over-year than modern renewables. Use of traditional biomass also remained flat, while modern biomass declined by 0.9% from 2015 to 2016 (EGEDA, 2018).

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	169 912	167 624	–1.4
Non-renewables (Fossils and others)	136 500	134 500	–1.5
Traditional biomass*	3 002	3 002	0
Modern renewables*	33 412	33 124	–0.9
Share of modern renewables to final energy consumption (%)	19.7	19.8	-0.7

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on) including biogas and wood pellets are considered modern renewables, although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Canada's federal, provincial and territorial governments all have a role in shaping the economy's energy policy. The fundamental principles include respect for jurisdictional power granted under the Constitution Act of 1867 and targeted intervention in the market process to achieve specific policy objectives (for example, pipeline regulation) through regulation and other means (GOC, 1867).

The Canadian provinces are the owners of ground resources and mineral rights within provincial boundaries, excluding the resources located in aboriginal lands and frontier lands (that is, national parks and international waters) in accordance with sections 91 and 92 of the Canadian Constitution (GOC, 1985a). The provincial governments have the primary responsibility for shaping policies in their jurisdictions; consequently, energy policy varies from jurisdiction to jurisdiction. Unlike the provinces, the three territories do not own the ground resources but share partial management responsibility. In addition to frontier lands, the federal government is responsible for regulating uranium mining and nuclear energy, interprovincial/international trade and commerce, trans-boundary environmental impacts and interprovincial work (for example, pipelines) as well as developing policies in the national interest (economic development, health and safety and energy security) (GOC, 1985b; NEB, 2018c).

Energy policy at the federal level involves a number of government agencies that are responsible for development and implementation. Natural Resources Canada (NRCan) is the federal department mandated to 'ensure that Canada's resource sector remains a source of jobs, prosperity, and opportunity within the context of a world that increasingly values sustainable practices and low carbon process'(PMO, 2015). The NEB is an independent federal regulator responsible for pipelines and transmission lines that cross international borders or provincial boundaries, energy development, and trade issues in the Canadian public interest. The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) is the independent joint agency of the governments of Canada and Nova Scotia and regulates petroleum activities in the Nova Scotia Offshore Area (CNSOPB, 2018). The Canadian Nuclear Safety Commission (CNSC) regulates the use of nuclear energy and materials to protect health, safety, security and the environment and implements Canada's international commitments on the peaceful use of nuclear energy. Other important government organisations include Environment and Climate Change Canada, Fisheries and Oceans Canada, Indigenous and Northern Affairs Canada and Global Affairs Canada.

ELECTRICITY MARKETS

Federal and non-federal actors have distinct roles in the Canadian electricity market. The federal government is responsible for electricity exports, international and designated interprovincial power lines and nuclear policy, including regulation and safety. These issues are especially important because the Canadian market is interconnected at many points with the US. The provinces and territories have jurisdiction over the generation, transmission and distribution of electricity within their boundaries, which also encompasses restructuring initiatives and electricity prices.

The electricity industry in most provinces is highly integrated. A small number of dominant utility providers deliver the bulk of generation, transmission and distribution services. While some private utility ownership exists, provincial governments own many utility providers through Crown corporations. Exceptions exist in the provinces of Alberta, which has moved to full wholesale and retail competition, and Ontario, which has established a hybrid system with competitive and regulated elements.

In November 2016, Alberta announced the addition of a capacity market to co-exist with the current energy-only market. The Alberta Electric System Operator (AESO) had recommended the implementation of a capacity market to provide greater revenue certainty for generators, thereby encouraging investment in new

generation capacity while maintaining the competitive market structure used to set wholesale prices (AESO, 2018b). The AESO will be responsible for designing and implementing the capacity market. This process began with stakeholder engagement and market design in 2017, and the first round of procurement will occur in 2019 with contracts awarded by 2020–21 (AESO, 2018b).

Electricity prices vary across the provinces in terms of their levels and the mechanisms by which they are set. Provinces with an abundant supply of hydroelectricity generally have the lowest prices. In most provinces, the regulator sets the prices according to a formula that determines the cost of service (COS) plus a reasonable rate of return. There are two exceptions: in Alberta, retail electricity prices are derived from a competitive wholesale market; in Ontario, retail prices are derived from a combination of market spot prices and a dynamic price component (global adjustment) set to cover the costs of guaranteed rates to generators (IESO, 2019). Transmission and distribution rates across provinces generally follow the COS operating model described above and are passed on to customers based on fixed and variable components.

ENERGY MARKET

OIL AND NATURAL GAS

Canada's wellhead oil and natural gas prices are fully deregulated since the conclusion of the Western Accord and the Agreement on Natural Gas Markets and Prices fully deregulated Canada's wellhead oil and natural gas prices in 1985. The agreement opened up the oil and gas markets to greater competition by permitting more exports, allowing users to buy directly from producers and unbundling production and marketing from transportation services (NEB, 1996). Oil and gas pipeline networks continue to be regulated as natural monopolies.

The fiscal regime applied to the Canadian oil and gas industry comprises a combination of corporate income taxes and royalty payments. As of 2016, the following general corporate income tax rates applied to the key oil and gas regions.

Table 4: Corporate income tax rates, 2017

CIT rates	British Columbia	Alberta	Saskatchewan	Newfoundland and Labrador	Nova Scotia
Federal	15%	15%	15%	15%	15%
Provincial	12%	12%	12%	15%	16%
Total	27%	27%	27%	30%	31%

Sources: BDO (2018).

Canada does not allow corporations to file consolidated tax returns; each corporation must compute and pay taxes on a separate legal entity basis. Non-capital losses (business losses) can be carried back 3 years and carried forward 20 years. Capital gains are subject to tax at one-half the capital gain (taxable capital gain) at regular income tax rates. Capital losses are exclusively deductible against capital gains and can be carried back three years and forward indefinitely or until the company is acquired. Non-capital losses can be deducted against taxable capital gains (EY, 2018).

Royalty regimes (or rent-based taxes) are set by the owner of the resource, typically the applicable province, but a small percentage has petroleum rights owned by surface owners (freehold land) or First Nations. The resource owner leases the land to potential developers in exchange for a fee (land sale) and royalty agreement. Parcels of crown land are auctioned off to the highest bidder for a fixed period, often with clauses tied to maintaining an active interest in the parcel (that is, drilling or production). Royalty regimes vary both by province and by commodity and are typically paid based on a combination of well productivity and wellhead price (EY, 2018). Royalties paid are deductible for tax purposes.

Table 5 describes the basic structure of royalty regimes across Canada, as published in a report by Chen & Mintz (2012) and updated to reflect recent changes to existing structures in the report by Crisan & Mintz (2016), both of which were published through the University of Calgary, School of Public Policy.

Table 5: Summary of regional royalty regimes, 2017

Province	Royalty	Rent-based tax
British Columbia	For conventional oil and gas, the royalty is based on gross revenue. The royalty rate differs first by product category, such as density of oil or type of gas (that is, conservation vs. non-conservation gas) and by well age (except for heavy oil and conservation gas). Formulation of the royalty rate for a given product category differs between oil, gas and natural gas by-products. For oil, the royalty rate is sensitive mainly to productivity; for gas, it is sensitive only to price; natural gas by-products have set royalty rates. For certain high-cost gas projects, there is a pre-payout of 2% royalty on gross revenue (refer to next column).	For certain high-cost gas projects, a newly introduced net profit royalty program with four tiers of royalty rates applies: a pre-payout of 2% royalty on gross revenue and three post-payout tiers associated with a royalty that is the greater than 5% of gross revenue and a higher rate of net revenue (that is, 15%, 20% or 35%, depending on the tier order). To reach each of the three tiers of net royalty, a progressive return allowance applies.
Alberta	For conventional oil and gas, the royalty rate on sales will remain price-sensitive but unrelated to volume until a threshold is reached (royalty rates decline when production drops below 194 cubic metres per month or approximately 40 barrels per day). A cost recovery allowance, sensitive to well depth but otherwise based on industry experience, will be provided instead of various drilling incentives. Royalty rates are consolidated for various product types produced from a well, as well as a 5% minimum royalty on sales until the cost allowance is used up. Further, the government has also announced two new programs—the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program—that will provide an allowance for eligible costs with a corresponding royalty rate of 5%. Once the cost allowance is depleted, the new royalty rates will apply.	For oil sands only, in addition to a pre-payout gross royalty, there is a net royalty of 25–40% after payout depending on the price level of the oil. The regime remained unchanged after a review in 2015.
Saskatchewan	The crown royalty and the freehold production tax (FPT) on oil and gas are determined using formulas containing parameters that are adjusted monthly by the government. Both royalty and FPT are sensitive to price and well productivity and differ by product in terms of their vintage and characteristics (for example, type of product, well and location). The FPT is lower than the crown royalty by a production tax factor (PTF), which varies by the type of product and ranges from 6.9–12.5%.	None.
Newfoundland and Labrador *(Updated)*	The province introduced a new, generic offshore-oil royalty regime in November 2015 based on the recovery factor approach (revenue over accumulated cost index). The system includes a basic royalty rate ranging from 1.0–7.5% applied to gross revenue as the project starts producing oil, increasing as the project recovers more of its costs.	Simplified the net royalty system by removing the two-tiered approval. After payout is reached, the net royalty payable is equal to the net royalty rate multiplied by net revenue. The net royalty ranges from 10–50%, depending on the recovery factor.

Province	Royalty	Rent-based tax
Nova Scotia	The revenue-based or gross royalty is two-tiered: 2% before payout and 5% after payout. It is deductible for calculating the base for the net-revenue royalty. Note that regardless of the revenue and profit level reached, the 2% gross royalty applies for a minimum of 24 months, and the 5% gross royalty applies for a minimum of 36 months. This implies that there is no net royalty or rent tax payable for the first five years after the commencement of production.	The two-tier net royalty rate is 20% and 30%, depending on the net-revenue tier reached. Even after the net royalties become payable, only the greater rate of the 5% of gross revenue and 20% or 35% of the net revenue is payable. To reach each of the two tiers of the net royalty scheme, a progressive return allowance applies; 20% above LTBR for Tier 1 and 45% above LTBR for Tier 2.

Sources: Chen & Mintz (2012); Crisan & Mintz (2016); McInnes Cooper (2018)

Canada has three expenditure pools that are particularly relevant to the oil and gas sector.

- Oil and gas rights expenditures are accumulated in a pool called the Canadian Oil and Gas Property Expense (COGPE), which are deductible at up to 10% on a declining balance basis.
- Drilling and completion expenditures are accumulated in a pool called the Canadian Development Expense (CDE), which are deductible at up to 30% per year on a declining balance basis.
- Exploration expenditures are accumulated in a pool called the Canadian Exploration Expense (CEE), immediately deductible in the year incurred.

An LNG tax was conceptualised and enacted in British Columbia and went into effect on 1 January 2017. However, the current provincial government announced that it would repeal the LNG tax if a positive final investment decision (FID) was made to build a large-scale LNG export project; as LNG Canada reached FID in October 2018, it is expected that the LNG tax will be repealed (LNG Canada, 2018).

Indirectly, the energy sector is subject to general, provincial and harmonised sales taxes as well as climate-related policies such as carbon taxes or cap-and-trade systems. However, businesses paying GST/HST are eligible to receive input tax credits (ITCs) to the extent that purchases are for consumption, use or supply in commercial activities. Climate policies will be discussed in more detail in the 'Climate Change' section.

COAL

Canada is rich in coal resources. The largest known reserves are located in the Western provinces, which are also Canada's principal producers. Nova Scotia restarted production at its Donkin mine in 2017. Together with provincial-level law and regulations, 35 federal acts and regulations relate to the mining industry (CAC, 2016).

Among the many existing guidelines, Canada finalised a regulation to effectively phase-out conventional coal generation by 2029 (GOC, 2018a). These regulations effectively built upon a performance standard on new coal-fired electricity established in 2012. This should further reduce coal consumption in Canada but not necessarily coal production due to the prevalence of metallurgical production. It regulation contains a caveat to encourage new technology for the reduction of GHG emissions whereby units that incorporate carbon capture and storage (CCS) technology are exempted from the performance standard. Furthermore, an equivalency agreement between the federal government and Nova Scotia allows the latter to burn coal past the 2029 deadline.

ENERGY EFFICIENCY

The federal and provincial governments have joint responsibility for energy efficiency, but their roles and responsibilities vary and target different aspects. Each province has ministries responsible for administering energy and environmental policies and programs, including energy efficiency programs. Examples of energy efficiency programs include energy-efficient building codes, equipment standards and consumer rebates. The foundation of all provincial policies rests upon the federal Energy Efficiency Act 1992, which was amended in 2009 to expand its scope and effectiveness (GOC, 1992). This act provides for the creation and enforcement

of regulations on the energy efficiency of products and supports the replacement of the least efficient products with high-efficiency, cost-effective ones.

NRCan through its Office of Energy Efficiency (OEE) administers the Energy Efficiency Act 1992 and related efficiency issues at the federal level. The aim is to improve the utilisation of energy through energy efficiency (NRCan, 2019).

The Government of Canada is investing more than CAD 300 million to foster greater electrification and use of lower-carbon fuels in the transportation sector. These investments support the development of a coast-to-coast network of fast-chargers for EVs, a network of EV chargers where Canadian's live, work, and play, natural gas refuelling stations along key freight corridors, and hydrogen stations in metropolitan areas. These investments are also supporting the demonstration of next-generation charging technologies, and the development of enabling codes and standards.

Additionally, the Federal Buildings Initiative (FBI) is an NRCan initiative now called NRCan's Greening Government Services. Implemented in 1991, it aims at assisting federal departments and agencies to reduce the energy consumption and GHG emissions of their facilities (NRCan, 2018b). This voluntary program provides knowledge, training, and expertise that helps custodial departments through the process of undertaking energy efficiency enhancing retrofit projects in their buildings and assists them to plan for an energy performance contract that allows major retrofits to be self-financing. The suite of services has been recently updated to help federal organizations achieve the goal of reducing buildings and transport fleet emissions 40% below 2005 levels by 2030 (NRCan, 2018b).

CLEAN ENERGY RESEARCH AND DEVELOPMENT

The federal government is taking a comprehensive approach to clean energy research, development, and demonstration (RD&D). Budget 2017 funded seven program streams, which focused in whole or in part on clean technology innovation. Actions on clean energy innovation support the Pan-Canadian Framework on Clean Growth and Climate Change, which includes Clean Technology, Innovation, and Jobs as one of four pillars. In 2017, Canada launched Generation Energy with the goal of helping identify actions to reduce emissions and support a competitive energy industry. Through public consultation, the initiative identified four low-carbon pathways for Canada: wasting less energy, using clean power, supporting renewable fuels, and producing cleaner oil and gas (NRCan, 2018c).

As the federal lead on clean energy innovation, Natural Resources Canada (NRCan) funds and performs clean energy research, development, and demonstration. Public research and development of clean energy technologies are led by the CanmetENERGY and CanmetMATERIALS federal laboratories. These laboratories are located across Canada and undertake RD&D that reflects Canada's geographic and industrial strengths.

NRCan also funds industry-led RD&D to advance emerging technologies across the energy sector. Programs such as the Energy Innovation Program and the Green Infrastructure programs support innovations in clean electricity, low carbon transportation, energy-efficient buildings, and industry. NRCan's Clean Growth Program will support clean technology RD&D in natural resource operations. These innovation programs target innovations that can reduce environmental impacts while enhancing competitiveness and creating jobs. Other federal organisations, including the Natural Sciences and Engineering Research Council (NSERC) and Sustainable Development Technology Canada (SDTC) also contribute to advancing clean energy innovation in Canada.

NRCan collaborates with the National Research Council (NRC) and the Canadian Commission on Building and Fire Codes to establish national energy codes—energy-efficient design and construction frameworks—for new buildings. NRC published a revised building code in 2017 that improves the overall energy performance of new buildings. The code is a stride towards achieving the Pan-Canadian Framework's goal of achieving Net Zero Energy Ready buildings by 2030.

The federal government is also implementing crosscutting measures to enhance Canada's clean energy innovation ecosystem. These include the Clean Growth Hub, an interdepartmental effort to streamline client services, improve program coordination, and track outcomes. Further, NRCan is implementing the Clean Technology stream of the Impact Canada Initiative to pilot new, outcome-focused programs, such as prize-

based challenges. This program will leverage experimentation and rigorous evaluation to pilot innovative approaches and scale 'what works'.

Federal investments are complemented by greater alignment with partners at the provincial, territorial, and international levels. For example, through the Clean Growth Program, the Government of Canada is forming 'Trusted Partnerships' with provincial and territorial funding bodies to pool resources, share risks, and streamline delivery. Through international initiatives such as Mission Innovation and the Powering Past Coal Alliance, Canada is collaborating with global partners to accelerate clean energy innovation.

NUCLEAR POWER

Nuclear energy is an important component of Canada's energy mix. In 2016, nuclear energy accounted for 15% of its electricity generation (EGEDA, 2018). Canadian nuclear power generation is concentrated in the provinces of Ontario (18 reactors) and New Brunswick (one reactor). In 2012, Gentilly 2, Québec's only nuclear plant, was permanently shut down and put in a safe storage state following the decision of the provincial energy utility provider, Hydro Québec, to discontinue refurbishment because of the high cost (CNA, 2014). Hydro Québec is now proceeding with a 50-year decommissioning plan.

Unlike other energy sources, nuclear energy falls within federal jurisdiction. The federal government is responsible for all regulation of nuclear materials and activities along with supporting R&D. Concerned with the impact of nuclear activities on health, safety, security and the environment, the federal government has put in place a comprehensive nuclear legislation framework. The latter comprises the Nuclear Safety and Control Act 1997, Nuclear Energy Act 1985, Nuclear Fuel Waste Act 2002 and Nuclear Liability Act 1985[2] (NRCan, 2017a). They provide the framework for developing nuclear energy in Canada.

However, the decision to invest in nuclear power plants for electricity generation rests with the provinces (in concert with relevant provincial energy utilities) (NRCan, 2017a). Although there are currently no plans to build new nuclear power plants, nuclear energy remains an option for certain provinces in light of Canada's commitment to phase out coal-fired power plants and through the development of new technologies, such as small modular reactors. As mentioned previously, Ontario plans to refurbish 10 nuclear reactors in Ontario before 2035: four at the Darlington Nuclear Generating Station and six at the Bruce Nuclear Generating Station (GOO, 2017). Refurbishment at Darlington began in 2016 with one reactor, and commitments on subsequent reactors will consider the cost and timing of preceding refurbishments, with appropriate off-ramps in place. Refurbishment at Bruce is scheduled to start in 2020.

CLIMATE CHANGE

Climate change is a complex issue making Canada's approach multifaceted and layered at the provincial, federal and international levels. Canada's international commitments support and drive action at the federal and provincial levels. Canada is a signatory to the United Nations Framework Convention on Climate Change (UNFCCC) and has committed to fulfilling the GHG reduction target stemming from the Twenty-First Conference of the Parties (COP21) in December 2015 (the Paris Agreement).

Section 91 of the Constitution Act, 1867 gives the federal government the authority to make laws on a broad range of issues. Section 92 sets out the issues for which the provinces may make laws. The environment is not explicitly listed in either section. As a result, there is often overlap and uncertainty in terms of which the level of government is responsible for various aspects of the environment. Based on a number of Supreme Court of Canada decisions, protection of the environment is recognised as a matter of shared jurisdiction between the Parliament and provincial legislatures.

Since 2015, Canada has seen significant changes to its climate policy, most notably with the Pan-Canadian Framework on Clean Growth and Climate Change (the Pan-Canadian Framework), which was collaboratively developed by federal, provincial and territorial governments and with input from Canadians, including businesses, non-governmental organisations and Indigenous Peoples.

[2] The Nuclear Liability and Compensation Act (NLCA), which entered into force on 1 January 2017, repealed and replaced the previous Nuclear Liability Act of 1985. The NLCA provides stronger legislation in order to deal more effectively with liability for a nuclear accident within Canada and allows Canada to join the International Atomic Energy Agency (IAEA) Convention on Supplementary Compensation for Nuclear Damage. The NLCA increases the operator's liability limit from CAD 75 million under the previous Nuclear Liability Act to CAD 1 billion, an amount to be phased in from CAD 650 million in 2017 to CAD 1 billion in 2020.

PAN-CANADIAN FRAMEWORK ON CLEAN GROWTH AND CLIMATE CHANGE

The Pan-Canadian Framework was adopted by First Ministers on 9 December 2016. It is a comprehensive plan to reduce emissions across all sectors of the economy, accelerate clean economic growth and build resilience to the impacts of climate change (GOC, 2016). The actions outlined in the Pan-Canadian Framework will contribute to Canada's goal of reducing emissions to at least 30% below the 2005 levels by 2030.

The Pan-Canadian Framework builds on the leadership of provinces and territories and the diverse array of policies and measures already in place across Canada to reduce GHG emissions in all sectors of the economy. Pricing carbon pollution is central to Canada's climate plan. The Government of Canada has outlined a benchmark for pricing carbon pollution that will build on existing provincial systems and expand carbon pricing across Canada in 2019. Provinces and territories may choose to implement a price-based system or a cap-and-trade system. Jurisdictions with a price-based system should have a minimum price of CAD 10 per tonne in 2018, rising to CAD 50 per tonne by 2022. Provinces with cap-and-trade systems must have (i) a 2030 emission-reduction target greater than or equal to Canada's 30% reduction target and (ii) declining (more stringent) annual caps to at least 2022 that correspond, at a minimum, to the projected emission reductions resulting from the carbon price that year in price-based systems. Revenue generated by carbon pricing will remain in the jurisdiction of origin. The federal government introduced legislation and regulations to implement a carbon pollution pricing system—the backstop—for those provinces that do not have carbon pricing systems that align with the benchmark in 2018 (GOC, 2018b). The backstop includes an output-based pollution pricing system plan to mitigate the competitiveness impacts for trade-exposed, carbon-intensive industrial emitters while still providing them with the incentive to reduce emissions (GOC, 2018c).

The Pan-Canadian Framework includes a commitment for a review of the overall approach to pricing carbon by early 2022 to confirm the path forward. An interim report will be completed in 2020. As an early deliverable, the review will assess approaches and best practices to address the competitiveness of emissions-intensive, trade-exposed sectors (GOC, 2016).

In addition to carbon pricing, complementary mitigation measures are included in the framework. Expanding the use of clean electricity and low-carbon fuels, as well as increasing energy efficiency, are foundational actions that will reduce emissions across the economy.

To increase the use of low-carbon fuels, the federal government, working with provincial and territorial governments, industry and other stakeholders, will develop a clean fuel standard that sets emissions intensity requirements for liquid, gaseous and solid fossil fuels. A regulatory design paper released by ECCC in late 2018 expects an 11% carbon intensity improvement in the liquid stream from the standard by 2030. Consideration for the gaseous and solid streams is ongoing. ECCC is targeting 2022 for the enforcement of the liquid fuel stream standards and 2023 for the gaseous and solid stream standards (ECCC, 2018a).

Using a mix of regulations and investments, Canada will also continue to drive down emissions from electricity. This will include new regulations to accelerate the phase-out of traditional coal units by 2030, performance standards for natural gas-fired electricity, and an output-based pollution pricing system for electricity generation that varies by the carbon-intensity of fuel type (GOC, 2018c). These actions will be complemented by investments to reduce diesel use in rural and remote communities, supporting emerging renewable energy sources and modernise Canada's electricity systems, including in smart grid and energy storage technologies, and build new and enhanced transmission lines to connect new sources of clean power with places that need it (GOC, 2016).

In addition to transitioning to lower-carbon fuels and clean electricity in the built environment, transportation and industrial sectors, Canada will take action to reduce energy use by improving energy efficiency, fuel switching and supporting innovative alternatives. In the built environment sector, this will include developing 'net-zero energy ready' building codes to be adopted by 2030 for new buildings; retrofitting existing buildings based on new retrofit codes and providing businesses and consumers with information on energy performance; and improving the energy efficiency of appliances and equipment.

Actions in the transportation sector include continuing to set increasingly stringent standards for light- and heavy-duty vehicles (LDVs and HDVs), in addition to taking action to improve efficiency and support fuel switching in the rail, aviation, marine and off-road sectors. In 2018, Canada released new HDV standards

covering the 2021-2027 model period (ECCC, 2018b) and began the process of reviewing its LDV standards (ECCC, 2018c). In addition to developing a Clean Fuel Standard, Canada is running two competitions to encourage the adoption of alternative jet fuel in the aviation sector (Impact Canada, 2018). Canada will also be developing a zero-emission vehicle (ZEV) strategy; investing in infrastructure to support lower carbon and zero-emission vehicles; and investing in public transit and other infrastructure to support shifts from higher- to lower-emitting modes of transportation (GOC, 2016).

To reduce emissions from industrial sectors, Canada is looking at improving energy efficiency, targeted regulations and strategic investments in clean energy technology. Canada developed regulations to achieve a reduction in methane emissions from the oil and gas sector, including offshore activities, by 40–45% below 2012 levels by 2025 (ECCC, 2018d). Federal, provincial, and territorial governments will work together to help industries improve their energy efficiency and invest in new technologies to reduce emissions; for example, the Canada and Quebec governments are partnering with private investors to commercialise the world's first carbon-free aluminium smelting process in Quebec (PMO, 2018). Canada has also committed to finalising regulations to phase down the use of hydrofluorocarbons (HFCs) in line with the Kigali Amendment to the Montreal Protocol (ECCC, 2018e).

Other actions in the Pan-Canadian Framework involve protecting and enhancing carbon sinks, including those in forests, wetlands and agricultural lands; identifying opportunities to generate renewable fuel from waste; and demonstrating leadership by reducing emissions from government operations and scaling up the procurement of clean energy and technologies. The framework also includes support for clean technology and innovation that promote clean growth, including early-stage technology development; establishing international partnerships; and encouraging 'mission-oriented' research to help generate innovative new ideas and create economic opportunities. Other complementary actions include support for RD&D or clean technology in Canada's natural resource sectors, and a Smart Cities Challenge (GOC, 2016).

The Pan-Canadian Framework also recognises the importance of building climate resilience and sets out measures to help Canadians understand, plan for and take action to adapt to the unavoidable impacts of climate change. With the understanding that Indigenous Peoples and coastal and northern regions are particularly vulnerable to climate impacts, action is also being taken to help these communities (GOC, 2016).

In addition, the Pan-Canadian Framework highlights specific provincial and territorial actions to reduce GHG emissions, implement carbon pricing and accelerate clean growth as well as identifies areas to explore further federal–provincial-territorial collaboration.

PROVINCIAL

Each province develops and implements policies, regulations and initiatives in an effort to mitigate climate change by reducing GHG emissions and supporting the transition to clean growth. The below examples of regulations and programs focused on reducing direct GHG emissions include those highlighted in the Pan-Canadian Framework as well as new initiatives post-adoption of the framework.

- British Columbia: The province introduced a carbon tax in 2008, which is applied to the purchase or use of fossil fuels. The province increased the price to its current rate of CAD 35 per tonne of CO_2 equivalent (tCO_2)in 2018 and plans to increase it CAD 5 per tCO_2 annually until it reaches CAD 50 per tonne in 2021 (Government of B.C., 2018a). In 2018, British Columbia released the first phase of its CleanBC climate plan, which includes measures to meet 75% of its 2030 GHG reduction goal and plans to release further measures to meet the rest of its reduction goal in 2019 (Government of B.C., 2018b). Key elements of the strategy include: phasing in a ZEV standard with the goal of new vehicles sales being 100% ZEVs in 20 years; increasing the 2030 carbon intensity improvement requirement of the Low Carbon Fuel Standard to 20%; increasing building efficiency with improved building codes and the encouragement of heat pump adoption; mandating a 15% renewable standard for natural gas use; and electrifying natural gas producers and large industrial operations with clean electricity.
- Alberta: In November 2015, Alberta announced the results of its Climate Leadership Plan (CLP) panel recommendations, which included a CAD 20 per tCO_2 economy-wide carbon price beginning in 2017, which increases to CAD 30 per tCO_2 in 2018 (GOA, 2018a). Alberta has made future increases to the carbon price contingent of the construction of the Trans Mountain Pipeline project (Government of

Alberta, 2018a). The CLP also included provisions to address secondary impacts of the policy, including rebates for low-income earners, output-based allocations for trade-exposed energy-intensive industries and transitional support for coal communities (PA, 2015). The output-based allocation system, called the Carbon Competitiveness Incentive Regulation (CCIR), replaced the Specified Gas Emitters Regulation on large facilities in 2018 to mitigate the competitiveness concerns of trade-exposed, carbon-intensive industries while maintaining the incentive to reduce emissions. Unlike the federal system, the output-based pricing schedule for electricity generators in the CCIR does not vary by fuel type, which provides a higher incentive for reducing electricity emissions (Government of Alberta, 2018b). The province also announced a cap on GHG emissions from oil sands production (excluding those related to primary production, net new upgrading facilities and cogeneration) of 100 Mt per year, a commitment to phase out coal-generated electricity by 2030 and a target to competitively procure 5 GW of renewable energy capacity by 2030. The province procured over 1300 MW of wind capacity at a weighted price of $38 per MWh in three rounds of bidding over the past two years (AESO, 2018a).

- Saskatchewan: The provincial power utility, SaskPower, has made the world's largest per capita investment in CCS technology at its electricity generating facility at Boundary Dam. Since October 2014, the plant has captured over 1.9 Mt of carbon dioxide (CO_2) (SaskPower, 2018a). Saskatchewan uranium fuels nuclear power plants in Ontario, New Brunswick and other plants internationally, displacing between 230 and 550 Mt of the world's GHG emissions each year. In 2015, Saskatchewan announced a goal to double the percentage of renewable capacity to 50% by 2030. The province also plans to procure 60 MW of solar capacity in 2018 and has a target of 30% wind capacity by 2030 (SaskPower, 2018b). Saskatchewan will apply sector-specific output-based performance standards to industrial facilities emitting in excess of 25 Mt of CO_2-e per year (CEC, 2017) and released the expected emission intensity reductions resulting from the standards in 2018 (Government of Saskatchewan, 2018). Because Saskatchewan has not released plans to price carbon pollution, the federal government imposed its backstop price schedule on the province in 2018 (ECCC, 2018f). However, Saskatchewan is challenging if the imposition is constitutional.

- Manitoba: In October 2017, Manitoba announced its provincial Climate and Green Plan with a carbon price of CAD 25 per tonne in 2018 with output-based allowances for large industrial emitters (GOM, 2017). However, in October 2018, the province announced that it would no longer be implementing its own carbon pricing system; as such, the federal backstop price schedule will apply to Manitoba starting in 2019.

- Ontario: Ontario joined the Western Climate Initiative (WCI) cap-and-trade market operating in Quebec and California on January 1, 2018, but passed legislation to withdraw from the WCI on July 3, 2018 (GOO, 2018a). Ontario also cancelled its electric and hydrogen vehicle and charging incentive programs (MTO, 2018) in the same month, and released an updated climate plan in November 2018. Notable measures in the climate plan include an industry-performance standard for large emitters and the intention to increase the ethanol content of gasoline to 15% by 2025 (GOO, 2018b). However, without a plan in place to price carbon pollution, the federal backstop price schedule will apply to Ontario starting in 2019.

- Quebec: Quebec has an economy-wide cap-and-trade system linked with California through the WCI. In 2015, Quebec adopted two emission reduction objectives: 1) to reduce emissions 20% below 1990 levels by 2020; and, 2) to reduce emissions 37.5% below the 1990 levels by 2030 (GOQ, 2018a). Through the implementation of its 2018-2023 Master Plan, Quebec is targeting energy efficiency increases of 1% a year and petroleum demand reductions of at least 5% below 2013 levels (GOQ, 2018b). Quebec is the first province to introduce a ZEV standard. The standard, which came into effect in 2018, utilises a credit system to encourage automakers to increase both the number of low carbon vehicles and the number of low carbon vehicle models (GOQ, 2018c).

- New Brunswick: The province has GHG emission reduction targets that reflect a total output of 11 Mt by 2030 and 5.0 Mt by 2050. New Brunswick also plans to phase out coal-fired generation (PNB, 2016). New Brunswick proposed a carbon pricing system but the federal government determined that it was not stringent enough to meet its benchmark requirements and as such, imposed its backstop

pricing system onto the province. Large industrial emitters now face the federal government's standards as of 2018 (PNB, 2017).

- Nova Scotia: The Greenhouse Gas Emissions Regulations 2009 places a cap on electricity sector emissions from all facilities, with targets that have been set until 2030. In November 2016, Nova Scotia and the Government of Canada agreed to negotiate a new equivalency agreement regarding federal coal-fired electricity regulations. Nova Scotia committed to establishing a cap-and-trade program at the beginning of 2019 for large industrial facilities, the electricity sector, petroleum product suppliers and natural gas distributors to comply with the pan-Canadian approach to pricing carbon pollution (PNS, 2018). The federal government approved of the stringency of Nova Scotia's system in 2018.
- PEI: The PEI government released its Climate Change Action Plan in 2018 (PEI, 2018a). While PEI agreed to adopt the federal benchmark for pricing emissions from large emitters, it adopted a slightly different approach to carbon pricing that includes some exemptions for various industries, fuels and end-uses (PEI, 2018b).
- Newfoundland and Labrador: Newfoundland and Labrador released its carbon-pricing plan in October 2018. The plan includes a broad-based carbon price, with some exemptions, including the use of heating fuels, aviation fuels, marine transport fuels, diesel fuel by electric generators and fuel by offshore petroleum exploration activities, and a mechanism to ensure that overall gasoline taxation compares to other Atlantic provinces (GNL, 2018). The plan also includes a modified output-based performance standard to address competitive concerns with trade-exposed, carbon-intensive industries, including a separate standard to govern offshore petroleum resource production. In 2016, the province created a new fund for clean technology, funded through a form of carbon pricing on large industry (PNFLD, 2016). The Management of Greenhouse Gas Act was passed in June 2016 and aims at reducing GHG emissions from large-emitters.
- The Territories: NWT reached an agreement to adopt the federal benchmark with exemptions for aviation fuels, heating fuels, and diesel-fired generation, and a rebate for 75% of carbon compliance costs related to the combustion of non-motive diesel and heating oil by large industrial emitters (GNWT, 2018). The federal government approved the pricing plan along with its implementation date of July 1. 2019. Yukon and Nunavut have both been imposed an altered version of the federal backstop, which includes the federal output-based pricing system for large emitters, exempts the combustion of aviation fuels and provides relief for diesel-fired generation in remote communities. The implementation date for the two territories is also July 1, 2019.

INTERNATIONAL

Canada has been active on the international climate change stage. Prior to the Paris Agreement., Canada signed the Copenhagen Accord (2009) and committed to reducing GHG emissions to 17% below the 2005 levels by 2020 (EC, 2013). Since the end of the Doha round of negotiations under the UNFCCC in December 2012, Canada has continued its engagement in the negotiations to support the establishment of a fair and comprehensive global climate change regime, leading up to the signing of the Paris Agreement in 2016, where it pledged to reduce its 2030 emissions to 30% below 2005 levels.

In 2015, Canada announced it would contribute CAD 2.65 billion over the next five years to help developing countries tackle climate change and in 2017 announced a partnership with the World Bank Group to support climate action in developing countries and small island developing states (World Bank, 2018). In addition, Canada helped secure an agreement amongst the 197 signatories to the Kigali agreement, an amendment to the Montreal Protocol, to reduce the use of factory-made HFC gases and at COP23, Canada co-founded the Powering Past Coal Alliance with the United Kingdom.

From 3 September to 9 September 2017, Canada hosted the 46th session of the Intergovernmental Panel on Climate Change (IPCC) in Montréal. Hundreds of scientists and representatives from 195 countries gathered to advance the science of climate change and decide the scope of the sixth IPCC assessment report. The IPCC reports provide the most up-to-date international scientific knowledge on climate change and play an important part in supporting the implementation of the Paris Agreement and the Pan-Canadian Framework on Clean Growth and Climate Change (IPCC, 2017).

Canada has been a member of IPCC since its inception in 1988. Canada makes significant scientific contributions to the IPCC, with Canadian scientists holding leadership positions on the IPCC's scientific advisory body and Task Force on National Greenhouse Gas Inventories and serving as authors for IPCC reports.

The Ministerial for Climate Action (MOCA) was launched in 2017 by Canada, China and the European Union as a forum for over 30 ministers from major economies, and key players on climate change, to discuss the ambitious implementation and help build common ground on on-going multilateral negotiations. The first MOCA took place in September 2017 in Montreal, Canada.

NOTABLE ENERGY DEVELOPMENTS

REGULATORY DEVELOPMENTS

On February 8th, 2018, the Government of Canada introduced an integrated bill, Bill C-69, an Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts. The proposed changes aimed to: instil public trust in the project review process, improve investor confidence in Canadian projects, advance Canada's reconciliation with Indigenous peoples, encourage public participation in the project review process, alter the scope of the review process to assess what matters to Canadians, streamline the review process with the aim of minimising the number of reviews per project – with a goal of one review per project – and, replace the National Energy Board (NEB) with a new agency, the Canadian Energy Regulator to harmonize the aforementioned changes.

The new proposed rules must still be passed by Parliament. Until the new rules come into effect, existing laws and interim principles for project reviews will continue to apply to projects under review. The government will seek input from Canadians on regulations and policy changes required to accompany the legislation. Once the new rules come into effect, the government will not be revisiting project decisions made under previous legislation.

On May 12, 2017, the Government of Canada introduced Bill C-48, an Act to enact the Oil Tanker Moratorium Act (GOC, 2017b). The act aims to prohibit the shipment of crude oil along B.C.'s north coast if the oil component of the shipment exceeds 12 500 metric tonnes, which would effectively prohibit shipments from most oil tankers. In the long-term, this Act will likely discourage the development of an oil export pipeline on B.C.'s north coast, as the tonnage limit would prohibit seaborne crude oil shipments via the more economic very large and ultra-large crude carriers (EIA, 2014). This result is consistent with the government's rejection of the Northern Gateway Pipeline, which proclaimed that the presence of an oil pipeline and increases in tanker traffic are not in the best interests of local communities or indigenous peoples who depend on the health of the rainforest and sea in the area (PMO, 2016).

OIL INFRASTRUCTURE DEVELOPMENTS

Oil exports through pipelines are a major means for accessing markets for the landlocked portion of Canada's oil industry, which is mainly located in the WCSB. While some domestic refinery demand exists in Western Canada, most production travels via pipeline to the major refining hubs in the US Midwest and US Gulf Coast. With expectations of significant growth in heavy oil production from the oil sands going forward, Canada has been looking to increase its WCSB export capacity to both the US Gulf Coast, the world's largest heavy oil refining market, and to its coasts to access an expanding overseas market.

While pipeline capacity out of the WCSB grew over two Mbbl/D from 2010 to 2016 to about four Mbbl/D, it has since stalled at 2016 levels. Meanwhile, production from the oil sands and new light oil prospects have been steadily growing. As a result, in 2018, crude available for export from the WCSB exceeded pipeline capacity for the first time; this exceedance reached about 202 Mbbl/d in the fall of 2018 (NEB, 2018d). This surplus supply led to several market anomalies in 2018. Inventories in Alberta began to build and eventually reached their highest levels ever recorded, ranging from 15 to 30% above the five-year average. Canadian benchmark price discounts increased to abnormal levels (NEB, 2018d). These constraints and record discounts led to record levels of Canadian crude-by-rail (CBR) exports, as producers turned to more expensive transport methods to move surpass crude oil production to market.

The benchmark prices suggested that many producers were selling some oil at levels below their cash costs to produce it. This precarious market condition prompted government intervention in December 2018, as the Albertan government mandated an 8.7% crude oil production decrease, and announced that it would procure railcars, with the aim of clearing the inventory build and lower the price discount facing Albertan producers. Price discounts have since returned to their historically normal levels and the government will reassess the production cut throughout 2019. Despite the recent streak of no pipeline capacity growth, Canadian governments and industry have been working together to find options to increase pipeline capacity for several years. The federal government granted approval to two pipeline projects in 2016, the expansion of Kinder Morgan Canada (KMC)'s Trans Mountain Pipeline (TMX), flowing from Edmonton, Alberta to Vancouver, British Columbia, and the expansion of Enbridge's Line 3 Pipeline from Edmonton, Alberta to Superior, Wisconsin. During the same announcement, Enbridge's Northern Gateway pipeline project was rejected. Prime Minister Trudeau cited Alberta's recent Climate Leadership Plan as vital to the approval of both pipeline expansions (CP, 2016).

Shortly after its approval, mounting opposition to the TMX project, in the form of protests and legal challenges from the B.C. provincial government, several B.C. municipal governments, and first nations along the pipeline route, created significant political uncertainty surroundings its construction, and KMC threatened to withdraw the TMX application if the government could not eliminate this political uncertainty. This resulted in the federal government reaching an agreement to purchase the entire pipeline from KMC, which would keep the expansion application open despite the presence of political uncertainty. However, on August 30, 2018, the same day that KMC shareholders approved of the asset sale, the federal court of appeal quashed the approval of the Trans Mountain Pipeline. The federal government is in the process of addressing the shortcomings of its original approval. A timeline for a potential approval is not clear at this time. TransCanada's Keystone XL Pipeline project has been in political limbo for about a decade. In 2017, it received the presidential permit required from the US Trump Administration. The pipeline also cleared a regulatory hurdle in Nebraska in November 2017. However, in November 2018, a Montana federal judge ruled that a supplemental environmental review must occur before construction or operation of the project could continue. It is not clear how long this review will delay the project. Furthermore, in early 2019, permitting delays in Minnesota have delayed the expansion of Enbridge Line 3 until at least the latter half of 2020. However, further capacity expansions depend on the ongoing review processes facing the TMX and Keystone pipelines and the prospects of long-term oil production growth from Canada is likely dependent on the success of these pipeline developments.

NATURAL GAS INFRASTRUCTURE DEVELOPMENTS

In recent years, Canadian natural gas supply growth is occurring in new areas of the WCSB, and this is creating bottlenecks, as infrastructure development has been unable to keep pace with resource development. This, combined with the declining demand from traditional markets, has put Canadian natural gas prices at a heavy discount to Henry Hub prices (NEB, 2018e). Several producers are curtailing spending plans and production guidances in response to sustained low prices, which will limit the short-term growth prospects for Canadian natural gas production. The prospects of long-term production growth are dependent on the successful reconfiguration of WCSB upstream infrastructure and the diversification of Canada's exports markets.

LNG export facilities are the sole means of growing Canada's natural gas export market, as American production growth from shale and tight gas plays has partially displaced Canadian gas from its traditional eastern Canadian and eastern American markets. After years of declining prospects for LNG export development, 2018 saw two positive FIDs for LNG export facilities off the west coast of B.C.: Woodfibre LNG and LNG Canada. While both expect to be exporting LNG by the early 2020s, there is potential for project delays. Coastal Gaslink, the connector pipeline for the LNG Canada project, faces significant opposition and there is currently a review to determine if the jurisdiction of the project requires it to apply for federal approval (NEB, 2019).

Arctic and offshore Energy Exploration by the oil and gas industry and the Geological Survey of Canada have long indicated a strong potential for petroleum discoveries in Canada's northern region, particularly in the Arctic section. However, the costs of developing the fields and transporting oil and gas to markets have been quite high. In particular, the low oil prices in the previous decades and transportation bottlenecks have made discoveries uneconomical to develop (NRCan, 2007).

Except for most onshore lands in the NWT, which the Government of NWT assumed responsibility for in 2014, Canada's oil and gas industry in the north, including offshore drilling in the Arctic, is regulated by the NEB, as set out in the Canada Oil and Gas Operations Act (COGOA), Canada Petroleum Resources Act (CPRA) and National Energy Board Act. However, Canada's Atlantic offshore oil and gas industry is regulated by the CNSOPB and the Canada-Newfoundland and Labrador Offshore Petroleum Board. It is important to note that a 1972 federal moratorium restricts offshore field development off the Pacific coast of Canada, where there are an estimated 9.8 billion barrels of recoverable resources (NRCan, 2016d).

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USEFUL LINKS

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Canada Gazette—www.gazette.gc.ca

Canada-Nova Scotia Offshore Petroleum Board—http://www.cnsopb.ns.ca/

Canadian Nuclear Laboratories—www.cnl.ca

Canadian Nuclear Safety Association—http://nuclearsafety.gc.ca

Canada Newfoundland and Labrador Offshore Petroleum Board http://www.cnlopb.ca/

Environment and Climate Change Canada—www.ec.gc.ca

National Energy Board—www.neb.gc.ca

Natural Resources Canada—www.nrcan-rncan.gc.ca

Statistics Canada—www.statcan.ca

Transport Canada—www.tc.gc.ca

CHILE

INTRODUCTION

Chile is bordered by Peru to the north, Bolivia to the north-east and Argentina to the east. One of the three Latin American members of the Asia-Pacific Economic Cooperation (APEC), a member since November 2014, Chile has a land area of 756 102 square kilometres (km^2). Its Pacific coastline is 6 435 km long, and its land area has an average width of 175 km. The north is almost entirely desert, and mining drives energy demand in the region, most of which is met with imported fossil fuels despite high solar and wind energy potential. In central and southern Chile, which are colder and wetter, abundant hydro and biomass resources are the main energy sources.

Administratively, Chile has 16 regions headed by president-appointed regional governors. In 2017, the population reached just over 18 million, with 40% residing in the Santiago Metropolitan Region (INE 2017). Chile's economic growth is based on solid macroeconomic fundamentals, such as fiscal responsibility, an independent central bank with an explicit inflation target and a floating exchange rate system. Chile has increased its GDP per capita by 60% from USD 8 992 in 1990 to USD 22 614 in 2016 (2011 USD purchasing power parity [PPP]). It is one of the fastest-growing economies in South America, with an average annual growth rate of 2.9% between 2000 and 2016. In 2016, Chile's GDP reached USD 405 billion (2011 USD PPP), which represents an increase of 1.3% from the 2015 levels.

Despite Chile's geographical diversity and abundant renewable resources (solar, wind, hydro and geothermal), it has very limited fossil fuel resources and is a net importer of oil, gas and coal. In 2016, Chile imported all of the oil it used from Brazil (61%) and Ecuador (35%). Natural gas came from Trinidad and Tobago (72%) and USA (21%), and coal was mostly from Colombia (59.5%), the US (28.1%) and Australia (9.1%) (CNE a 2018). Chile's overall net installed electricity capacity was 23 gigawatts (GW) in September 2018, with thermal power plants representing 53% of the total capacity and hydropower (29%), solar photovoltaic (PV) (10%), onshore wind (6.1%), biomass (1.4%) and geothermal (0.11%) accounting for the remainder (CNE, 2018b).

Fossil fuel reserves are limited, so nearly the entire fossil fuel supply is imported (around 69% of total primary energy supply [TPES] in 2016). Chile has vast untapped potential for solar power (PV and concentrated solar power [CSP]) as well as for onshore wind, geothermal and hydro energy. Solar PV potential is estimated at 829 GW, CSP at 510 GW, onshore wind power at 37 GW, geothermal energy at 2 GW and hydropower at 6 GW (Ministerio de Energia, 2018). These estimates are based on geo-referencing data and assessments of technical, territorial and environmental constraints.

Table 1: Key data and economic profile, 2016

Key data[a]		Energy reserves[b]	
Area (km^2)	756 092	Oil (million barrels)	11.8
Population (million)	18	Gas (million cubic metres)	8.1
GDP (2011 USD billion PPP)	405	Coal (million tonnes)	171
GDP (2011 USD PPP per capita)	22 614	Uranium (kilotonnes U)	3.7

Sources: [a] EGEDA (2017); [b] CCHEN (2013).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

According to the Expert Group on Energy Data Analysis 2018 (EGEDA 2018), Chile's TPES increased by 6.4% from 2015 to 2016 to reach 37 795 kilotonnes of oil equivalent (ktoe). Approximately 42.6% of this energy volume was supplied in the form of crude oil and its by-products, 19% as coal, 11% as natural gas and the remaining 27% as renewable energy, including biomass, solar, wind and hydropower. Given its limited natural endowment in hydrocarbons, Chile is a net importer of primary energy, especially fossil fuels. Its net primary energy imports represent 69% of the TPES, having increased by nearly 2.7% from 2010 to 26 142 ktoe in 2016.

Final energy consumption (excluding non-energy) increased in 2016, reaching 25 925 ktoe, 4.6% higher than the 2015 level. Fossil fuel consumption increased by 5.1% from 2015 to 2016; in fact, 56% (14 490 ktoe) of the final energy consumption (excluding non-energy) is represented by oil, followed by 5.5% by gas (1 436 ktoe) and 0.8% by coal (218 ktoe). The remaining final energy consumption comes from renewable energy (14.5%) and electricity and others (23%). According to the National Oil Company (Empresa Nacional de Petroleo [ENAP]) studies, endorsed by the United States Geological Survey (USGS), the existence of a non-conventional gas potential in Magallanes was confirmed, which could amount to 8.3 trillion cubic feet (tcf). This value doubles the volume of gas extracted from the Magallanes Basin during the 70 years of operation of ENAP, which reached 4.2 tcf. This ensures the future supply of thermal consumption in the region and generates significant industrial and economic activity (ENAP, 2016).

FINAL ENERGY CONSUMPTION

In 2016, Chile's final energy consumption was 25 925 ktoe, representing an increase of 4.6% from the previous year's level.

By sector, the total final consumption in the industrial sector accounted for 40%, transport accounted for 33% and others (including the residential, commercial and public sectors) accounted for 24%. The remaining 2% represented non-energy use, including agriculture and other.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	12 537	Industry sector	10 612	Total power generation	79 308
Net imports and others	26 142	Transport sector	8 835	Thermal	44 989
Total primary energy supply	37 795	Other sectors	6 478	Hydro	23 274
Coal	7 088	Non-energy	563	Nuclear	-
Oil	16 115	Final energy consumption*	25 925	Others	11 045
Gas	4 348	Coal	218		
Renewables	10 244	Oil	14 490		
Others	0	Gas	1 436		
		Renewables	3 748		
		Electricity and others	6 033		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

By energy source, around 55% of Chile's final energy consumption was met by oil consumption, which was primarily consumed by the transport and industrial sectors, followed by electricity and other sources (23%), natural gas (5.5%) and coal (0.8%). Oil consumption increased by 5.5% from 2015, and electricity and others consumption increased by 4.7% (EGEDA, 2018).

ENERGY INTENSITY ANALYSIS

Energy intensity has been declining since 2000, indicating a more efficient use of energy sources. Chile's energy intensity in terms of primary energy supply in 2016 was 93 tonnes of oil equivalent per million USD (toe/million USD), increasing by 5.1% from 89 toe/million USD in 2015. The energy intensity for total final consumption increased by 3.3%, from 62 toe/million USD in 2015 to 64 toe/million USD in 2016.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	89	93	5.1
Total final consumption	62	64	3.3
Final energy consumption excl. non-energy	63	65	4.5

Source: EGEDA (2018)

RENEWABLE ENERGY SHARE ANALYSIS

In 2016, the share of modern renewable energy to final energy consumption was 18%, a decrease of 1 percentage point from the previous year's level.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	24 795	25 925	4.56%
Non-renewables (Fossils and others)	20 293	21 334	5.13%
Traditional biomass*	18 587	19 566	5.27%
Modern renewables*	1 706	1 768	3.63%
Share of modern renewables to final energy consumption (%)	18.2%	17.7%	-2.47%

Source: EGEDA (2018)

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies, which often have adverse effects on human health. This definition is applicable to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.*

ENERGY POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Since the 1980s, Chile has embarked upon developing an economy based on international trade and the rules of the free market. It has reaped various benefits as the economy has significantly grown. From the 1980s to 2014, Chile has more than doubled its income per capita and has been one of the fastest-growing economies in Latin America. In addition, it provides a business environment conducive to foreign investments, given its streamlined administrative processes and simplified tax payments.

Being an open-market economy, Chile is highly integrated with other world markets. Its participation in free trade agreements has increased its options for sustainable development, as evidenced by increased trade opportunities, reduced dependency on mineral exports and the creation of trade products with higher value added.

In line with these principles, Chile's energy policy is based on the development of a free market economy and oriented towards enhancing its economic efficiency and energy security by reducing its vulnerability to supply disruptions and its high dependence on imports.

The Chilean Parliament approved the creation of a Ministry of Energy in November 2009, and the new Ministry of Energy started operations in February 2010. This ministry centralises the functions of developing, proposing and evaluating public policies in this area, including the definition of objectives, regulatory framework and strategies to be applied as well as the development of public policy instruments.

Chile's Ministry of Energy presented the National Energy Policy 2050 in December 2015 to guide long-term energy policy development. The four pillars of Chile's energy policy that will help make its energy sector 'reliable, inclusive, competitive and sustainable' by 2050 are as follows: a) quality and security of supply; b) energy as a driving force for development; c) environmentally friendly energy; and d) energy efficiency and energy education (Ministerio de Energia, 2015).

In December 2017, Chile announced an electro-mobility strategy that outlines actions to be taken in the short and medium term to meet the government's goal of having 40% of the private vehicle and 100% of the public transport fleet powered by electricity in 2040. The new strategy's objectives are to establish regulations and requirements to standardise components and promote the efficient development and increased penetration of electric vehicles (EVs), to support research and development and to enhance human capital and knowledge transfer (Ministerio de Energia, 2017).

In May 2018, the Ministry of Energy presented an Energy Roadmap to serve as a guideline for government action in promoting socially responsible energy policies for the next four years (2018-2022). It contains short-term commitments based on the following pillars (Ministerio de Energia, 2018):

- Energy modernisation;
- Energy for social development;
- Energy development;
- Energy with low emissions;
- Efficient transport;
- Energy efficiency; and
- Energy education and training.

During the joint presentation of the Energy Roadmap, the president requested that the Ministry of Energy place special emphasis on 10 'mega-commitments' and President Piñera included the 11th commitment related to energy integration with neighbouring economies (Gobierno de Chile, 2018):

- Create the economy's first map of energy vulnerability, identifying families without electricity and other energy services, with a view to narrowing the existing gaps.
- Modernise the energy institutional framework to increase governmental efficiency and provide the public with a better service, specifically the Superintendency for Electricity and Fuels (Superintendencia de Electricidad y Combustibles, SEC) and the Chilean Nuclear Energy Commission (Comisión Chilena de Energía Nuclear, CCHEN).
- Reduce the processing time associated with obtaining environmental permits for projects that join the +Energy Plan by 25% with respect to the time taken over the last four years.

- Achieve a fourfold increase in the current capacity of renewable small-scale distributed generation (less than 300 kW) by 2022.
- Achieve a tenfold increase in the number of electric vehicles circulating in Chile.
- Modernise the regulation of electricity distribution through a participatory process, so it allows new circumstances of the energy sector to be identified and facilitates more efficient and competitive implementation.
- Regulate solid biofuels, such as firewood and its derivatives, empowering the Ministry of Energy to establish technical specifications and the regulations for the commercialisation of firewood in urban areas.
- Establish a regulatory framework for energy efficiency that provides the necessary incentives to promote the efficient use of energy in the sectors with the highest consumption (industry and mining, transport and construction) and create a true energy culture in Chile.
- Launch the process of decarbonisation of the energy mix by preparing a schedule for the withdrawal or reconversion of coal-fired power plants, and introducing specific measures for electro-mobility.
- Train 6 000 operators, technicians and professionals, developing skills and competencies for energy management and sustainable energy use in the electricity, fuels and renewable energy sectors, certifying at least 3 000 people.

Nuclear energy is not a short-term option under the Energy PEnergy Policy or the current Energy RoadmapEnergy Roadmap 2018-2022, but further research has been proposed to be considered in the next policy review. A complete revision and update of the Energy Policy will start in 2019, and the final document will be ready by 2020.

Modification to the law N° 20.365 of tax exemption for thermal solar systems (Law N° 20.897, 2016). This amendment renewed the tax benefit for the installation of solar water heater, which had been in operation from 2010 to 2014, for a new period from 2015 to 2020.

Law of Residential Tariff Equity (N° 20928, 2016) introduces mechanisms for equity in electricity tariffs and seeks to reduce the differences in the electricity bills of final customers in different areas of the economy, with a clear objective of territorial equity. The distribution component of residential rates is modified, so that the average difference between the type bill and the highest type bill does not exceed 10%. Only residential customers with consumptions greater than 200kWh/month contribute to this measure. In the same line, this initiative also contemplates the recognition of power generation in communes (territorial administrative unit) that are intensive in electricity generation, which currently have higher tariffs, in relation to where there is no energy production

A modification to the Law N° 20.571 was enacted in November 2018 to promote residential/distributed generation by extending the maximum limit for private installations from 100 kW to 300 kW. This law promotes distributed generation for service and small industrial users and also for residential customers, who decide to invest in clean generation sources for their homes or, businesses (Ministerio de Energia, 2018).

MARKET DESIGN

PETROLEUM-BASED FUELS REGULATORY FRAMEWORK

The Gas Services Law (D.F.L N° 323 of 1931), amended by Law 20.999 of 2017, establishes that companies that own concessionary gas distribution networks are free to set their gas prices, subject to an annual maximum profitability check controlled by the National Energy Commission (Comisión Nacional de Energía or CNE). The three-year average profitability in a concession zone (concession zones are, as a general rule, the

same as Chile's administrative regions) for a company cannot exceed the three-year average of the cost of capital rate (these rates are company-and-zone-specific, and their minimum floor is 6%) plus an additional margin of three percentage points. In case that the profitability in a concession zone for a distribution company exceeds its ceiling, a rate-setting process will be initiated and carried out by the CNE, and this process will lead to a decree emitted by the Ministry of Energy with the regulated gas rates for a particular distribution zone for that company, which will be recalculated every four years (a distribution company can exit a regulated gas rates regime for a zone by asking the national competition tribunal to review their case. In case the Tribunal finds the competition pressure exerted by other energy sources is enough to avoid price abuse by the distribution company in that zone, it will order the Ministry of Energy to end the regulated rate regime for that specific concession zone for that company). For the Magallanes and Chilean Antarctica Region, the law establishes a permanent regulated gas rates regime (in this case, the regime cannot be exited and no annual profitability check is executed for this region), with gas rates also recalculated by the CNE every four years. On the other hand, the Gas Services Law regulates a change in gas company supplier, easing the transfer of personal property that is on the client's property. For these purposes, the CNE will issue a four-year valuation report on the movable facilities intended to provide residential gas service.

Likewise, the CNE determines the parity and reference prices of fuels weekly for the purposes of the application of the Fuel Price Stabilisation Mechanism created by Law 20 765 as well as the Oil Prices Stabilisation Fund of Law 19 030 and its respective amendments. Parity prices are determined weekly for gasoline fuels of 93 and 97 octane, diesel oil and liquefied gas (Law 20 765) and domestic kerosene (Law 19 030).

Moreover, the reference prices are expected values that reflect the price of the respective fuels without considering short-term volatility. These reference prices are determined for the case of Law 20 765 based on the past and future average values of crude oil representative of a relevant market and an average of past values of refining differentials, transportation costs, insurance, customs duties and other expenses and costs of admission, as appropriate and in the case of Law 19 030, as the weighted sum of three components: i) historical weighted component of parity prices for the last four semesters; ii) projection component of the short-term parity price (one year); and iii) long-term parity price projection component (10 years) (CNE, 2018a).

ELECTRICITY REGULATORY FRAMEWORK

The General Law of Electric Services (LGSE–Ley General de Servicios Eléctricos) mainly sets the legal base for the electricity sector. The law was originally enacted in the early 1980s, where all basic principles of the present energy regulation were defined. The law privatized the electricity industry; introduced competition into the generation sector; and separated the industry's generation, transmission and distribution segments. Privatisation of the state-owned utilities began in 1986 and was completed by 1998. These principles have remained valid until now despite minor changes. Chile was the first economy in the world to deregulate its power industry, with the incorporation of free market principles (CNE, 2018a).

The LGSE has been amended several times with different modifications.

- Short Law I, Law 19 940 (Ley Corta I) – March 2004: It introduces modifications to the LGSE with the main objective of regulating the decision making and the development of the expansion of the transmission of electricity. It also establishes incentives for non-conventional sources and small generation units.
- Short Law II, Law 20 018 (Ley Corta II) – May 2005: It introduces modifications to the LGSE with the main objective of stimulating the development of investments in the generation segment through supply bids made by distribution companies.
- Law NCRE (Ley ERNC): It introduces modifications to the LGSE, establishing short- and long-term policy targets for the share of renewable energy in the total electricity generation. The short-term target, initially adopted in 2008 by Law 20 257, stated that between 2010 and 2014, 5% of the energy should come from non-conventional renewable energy (NCRE), increasing by 0.5% annually from 2015 to reach 10% by 2024. In 2013, the share was increased by Law 20 698 to 20% by 2025. The law defines the following energy sources as NCRE: biomass, hydropower with capacity less than 20 MW, geothermal, solar, wind, marine energy and other means of generation determined by the CNE.

- Transmission Law, Law 20 936–July 2016: It introduces a major reform to the LGSE. The law enhances the role of the state in energy planning and the expansion of the transmission system—the state now assumes certain functions that were previously in the hands of the private sector. The law introduces several new regulatory changes for Chile's electricity sector. It created the National Electric Coordinator (Coordinador Eléctrico Nacional, CEN), a unified independent system operator. It supports grid expansion and cross-border connections as well as a long-term energy planning (LTEP) process for a time span of at least 30 years. Transmission expansion planning processes carried out by the CNE use one or more results from the LTEP, considering a 20-year outlook. In the remuneration of the transmission system, tolls are completely borne by the consumers and defined by the mechanisms to determinate the cost of capital rate, which could fluctuate between 7% and 10% after taxes.

WHOLESALE ELECTRICITY MARKET

The wholesale electricity market in the Chilean system has two components:

- Spot market: generators buy and sell electricity.
- Financial contract market: large consumers and distributors buy electricity from the generators.

The spot market (or market for short-term transactions) consists of the purchase/sale of electricity at a marginal cost and is operated by the CEN. Only generators may sell or buy electricity on the spot market. Power plants are dispatched in a merit order using regulated estimates of their marginal costs (audited variable costs). This is mainly to avoid the negative impacts of high levels of market concentration. The marginal costs of the system are calculated on an hourly basis for each node of the system.

The financial contract market has two components: one for large customers and another for distributors. Generators can sell their electricity to large consumers at prices freely agreed between the parties. In contrast, electricity sales to distribution companies with regulated customers are organised through tenders for long-term supply.

Wholesale competition in Chile occurs in the 'contract market', in which generators sell electricity freely to large (non-regulated) customers, and through tenders to distributors that supply small (regulated) customers. Around half of the electricity demand in Chile is supplied under these tenders.

Customers connected to the grid through a local distribution company, with power connection between 0.5 and 5 MW, can choose between being a regulated or a non-regulated customer for a period of four years.

- Regulated customers: Regulated price considers the distribution fee and node price based on the price of energy of the respective tenders, capacity charge, transmission charge and distribution charge. Both the transmission charge and the distribution charge are volumetric ($/KWh))
- Non-regulated customers: These customers are free to directly negotiate with the power generation companies but will have to stay in the free market for at least four years and inform the distributor at least a year in advance.

DISTRIBUTION

This sector is organised through concessions, and there are 32 distribution companies. The distribution sector induces the existence of natural monopolies based on geography. These companies are subject to the fixing of their energy charges, which are obtained from an analysis carried out by the CNE every four years. Distribution energy charges are calculated by comparison with a model company so that distributors receive a return for all of their efficient costs: capital, operation, maintenance and administration. Similar to energy prices, distribution charges are also subject to an equalisation mechanism to ensure similar distribution charges across Chile.

The government is working on a proposal for a new distribution law that would ensure the modernisation of the distribution sector, which will include energy storage as an alternative. The objective is to encourage the development of a more efficient and intelligent distribution grid, to introduce new technologies and new companies and to expand business opportunities in the sector. Moreover, in April 17th 2019 the government sent to the deputies a short modification of distribution law. This includes:

- Determination of a new rate of cost of capital of the distribution companies, coming from a study, which will have a floor of 6% and will be applied after taxes;
- New procedure to carry out tariff studies. Just one studies and will be to the panel expert;
- Improvement of the "common areas".

TENDERS FOR LONG-TERM ELECTRICITY SUPPLY

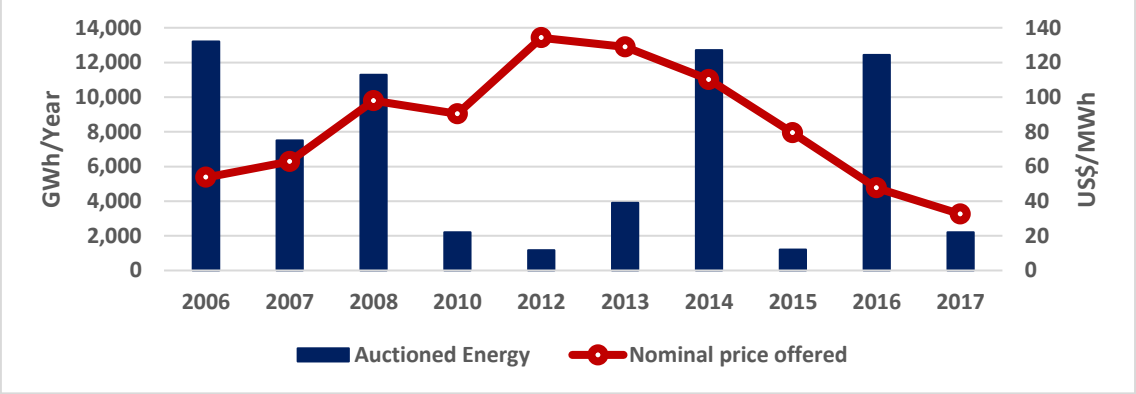
The New Electricity Act on Energy Auctions (Law 20 805, 2015) establishes the process of open energy auctions, encouraging the entrance of new players and electricity generation technologies. This improves competitiveness and promotes better price mechanisms in favour of end users in the electricity market for regulated users (CNE, 2018a).

Following are the main features of these tenders:

- The energy tenders provide the opportunity to acquire 15-year power purchase agreement (PPAs) and materialise new generation investments;
- The coming long-term tenders will lead to supply starting five years after the supply contract, giving enough time for the construction of new projects;
- The maximum limit for regulated customers from 2 MW to 5 MW will be increased, allowing some free customers to access prices determined by the supply bids and, at the same time, improve their negotiation conditions with generators.
- Different generation projects and efficient technologies will be able to participate due to the several supply blocks offered and
- Prices may be revised if taxes or laws change.

The auction winners in 2017 will start delivering energy to the grid from 2022 to 2041. In 2017, the average price per MW/h was USD 32.5, the lowest since 2006. The average price since 2012 has decreased from 134.2 USD/MWh to 32.5 USD/MWh.

Figure 1: Energy Auctions 2006–2017.



Source: Empresas Electricas (2018)

ENERGY MARKETS

Despite Chile's geographical diversity and abundant renewable resources (solar, wind, hydro and geothermal), it has very limited fossil fuel resources and is a net importer of oil, gas and coal. In 2016, Chile imported all of the oil it used from Brazil (62%) and Ecuador (38%). Natural gas came from Trinidad and Tobago (79%) and Norway (21%), and coal was mostly from Colombia (42%), the US (33%) and Australia (21%) (CNE a 2018).

Chile has vast untapped potential for solar power (PV and CSP) as well as for onshore wind, geothermal and hydro energy. Solar PV potential is estimated at 829 GW, CSP at 510 GW, onshore wind power at 37 GW, geothermal energy at 2 GW and hydropower at 6 GW (Ministerio de Energia 2018). These estimates are based on geo-referencing data and assessments of technical, territorial and environmental constraints.

Chile's fuel mix has historically been dominated by oil, most of which is consumed in the industry and transport sectors. Industry oil use has risen in the past decade in response to the severe energy crisis that occurred when natural gas imports from Argentina suddenly dropped in 2004 (Chavez-Rodriguez, et al. 2017). Transport is the largest oil consumer, however, and has the second-highest overall energy consumption after industry. As economic growth has improved living standards, the number of private vehicles has increased.

Hydropower has long been a key component of Chile's electricity generation mix, but when the supply of gas from Argentina was curtailed in 2008, it rose significantly. Chile's energy transformation over the past 20 years has involved power generators switching from natural gas to diesel, then to coal and most recently to renewable energy. At the beginning of 2010, only 3% of power generation capacity used unconventional renewable energy (URE) sources: 183 MW in onshore wind farms and small amounts of solar PV, small hydro, biomass and biogas plants. By 2017, URE sources made up 18%, with 4 110 MW of installed capacity (33% for onshore wind farms, 47% for solar PV, 11% for small hydro and the rest in biomass, geothermal and biogas plants) (CNE b 2018). New policies, such as a 20% target for renewables by 2025, combined with declining capital costs and outstanding renewable resources have helped transform the market.

ELECTRICITY SECTOR

One of the main economic foundations of the LGSE and its regulation is the promotion of competition in the electricity sector in all activities wherever possible.

The analysis of the technical and economic characteristics of the generation, transmission and distribution segments shows that a high degree of competition can be achieved in the generation segment due to its scarce economies of scale. This is followed by the transmission segment, where the characteristic of natural monopoly with important economies of scale is recognised but in which competition can be achieved through tenders of transmission works. Finally, there is a distribution segment with clear natural monopoly characteristics that the LGSE regulates exhaustively without leaving activities of this segment with competition rules, except when superimposed concessions that can eventually lead to limited competition are allowed.

The regulatory framework for Chile's electricity supply industry is based on the principle of competitive markets for generation and supply. Private companies wholly serve the electricity market, while the government remains a regulator, policy-maker and technical support to identify the requirements to meet the projected demand growth. The Ministry of Energy is the main governmental institution in charge of the energy sector in Chile. The ministry supports its actions through the National Energy Commission (Comisión Nacional de Energía or CNE) and the Superintendence of Electricity and Fuels (Superintendencia de Electricidad y Combustibles or SEC). The CNE is a technical organisation that acts as a regulator of the Chilean Energy Market, analyses prices, tariffs and technical norms that may affect energy production, generation, transport and distribution, and provides advice to the government through the Ministry of Energy in any field related to the energy sector for its development. SEC monitors the compliance of legal regulatory requirements and technical standards.

In Chile, marginal cost pricing was adopted as a way to emulate competition so that the marginal costs resulting from dispatch operate at minimum cost, which is done regardless of the ownership of the facilities and the contracts' purchase/sale of electricity, and allows the delivery of appropriate signals to producers and consumers. This means that consumers, on one hand, receive electricity at the lowest possible price with the quality and safety of service established in the current legal regulations, and on the other hand, that the generators can obtain profit according to the risks they face.

In this way, the electricity market was organised with a dispatch of the generating units at minimum cost, totally independent of the ownership of the facilities and the electricity purchase and sale contracts; with a spot market price in which only generators participate and with a contract market in which all of the demand should

be covered and in which generation companies, distribution companies and unregulated customers or 'free customers' participate.

Generation companies are defined as companies that own generation plants and whose energy is transmitted and distributed to final consumers. Generation companies have the obligation to sell whole production to spot market, and additionally can negotiate a contract with consumers or participate in open energy auctions. The transmission system in Chile has open access, giving transmission companies the right to impose the payment of tolls over the available transmission capacity. Finally, the distribution companies operate under a 'distribution public concession regime' with service obligations and regulated tariffs for the regulated customers. Chilean regulation defines regulated customers as those with a connected capacity of below 500 kW. Those who have a connected capacity of over 5 000 kW can negotiate the energy price directly with generation companies. Those who fall in between (500 to 5000 kW) can choose either regulated or unregulated tariffs for periods of no less than four years.

Chile has three main separated electricity systems:

1. National Electricity System (SEN).
    - Serves the northern and central part of Chile. The desert mining regions in the northern part covers an area equivalent to 25% of Chile's continental territory, in which about 6% of the population of Chile lives. The central part of the economy reaches about 92% of the population, with more than 70% of customers under a regulated tariff;
    - Total installed capacity of 22 964MW, 53% thermal (21% coal, 19% natural gas and 13% diesel), 29% hydro, 9% PV, 7% onshore wind, 2% biomass and one geothermal plant of 48 MW (CNE c 2018).

The Aysén and Magallanes systems serve small areas in the extreme southern part of the economy.

2. Aysén
    - Total installed capacity of 63 MW; 58% diesel, 36% hydro and 6% onshore wind (CNE c 2018);

3. Magallanes
    - Total installed capacity of 104 MW; 82% natural gas, 15% oil and 3% onshore wind (CNE c 2018).

OIL

Oil is the most dominant fuel in Chile, accounting for 43% of TPES and 56% of total final consumption (excluding non-energy) in 2016 (EGEDA, 2018). In 2016, domestic production accounted for less than 2% of the supply (234 million cubic metres) and the rest was imported. The current mandatory minimum oil inventory is the equivalent of 25 days of average sales (or average imports).

Considering the low domestic production, nearly all of Chile's crude oil supply (16 115 ktoe) in 2016 came from imports, which also included by-products such as diesel, gasoline and liquefied petroleum gas (LPG) (EGEDA, 2018). In fact, Chile heavily relies on imports to satisfy its oil demand; 62% of the imported crude oil comes from Brazil, followed by 38% from the Ecuador.

From 2007 to 2008, oil consumption faced an abrupt increase, driven by the need to compensate the curtailment of natural gas imported from Argentina. Nevertheless, the share of oil was about 53% in 2007 and decreased to 43% in 2016 due to the increase in renewable energy and coal.

The transport sector is the largest oil consumer, accounting for 59% in 2016 (IEA (International Energy Agency) 2018). Road transport consumes 90% of the total oil products, followed by air transportation at 5%.

Industry is the second-largest oil consumer, accounting for 26% in 2016, and its consumption has increased by 87% over the past decade. Mining is the largest oil-consuming industrial sector.

NATURAL GAS

Natural gas is the fourth dominant fuel used in Chile, accounting for 11% of TPES and 5.6% of total final consumption (excluding non-energy) in 2016. Domestic gas production accounts for 23% of the primary energy supply.

Considering the low domestic production, nearly all of Chile's natural gas supply (4 348 ktoe) in 2016 came from imports (EGEDA, 2018). In fact, Chile heavily relies on imports to satisfy its gas demand, where 73% of the imported natural gas comes from Trinidad and Tobago, followed by the US at 17% and the rest from other economies.

In 1997, Chile imported exclusively from Argentina. By 2004, gas supply hit a peak of 7 011 ktoe and fell to a low of 2 108 ktoe in 2008. The gas networks of Chile and Argentina are connected by seven pipelines, which runs from Mendoza in western Argentina to Santiago in central Chile. The so-called 'gas crisis' began with a restriction in the supply of natural gas from Argentina.". In this context, based on governmental priorities, a group of private and public investors worked together to build LNG terminals to avoid dependence on only one supplier. Quintero LNG was built in the Valparaiso region and Mejillones LNG was built in the Antofagasta region. Mejillones LNG has a storage capacity of 175 000 m^3 (one tank) with a regasification capacity of 5.5 million m^3/d, and Quintero LNG has a storage capacity of 334 000 m^3 (two tanks) with a regasification capacity of 15 million m^3/d (Ministerio de Energia 2018 c).

Industry is the largest gas consumer, accounting for 48% in 2016 (IEA (International Energy Agency) 2018), followed by the service and residential sectors, which consume 16%.

Between May and August 2016 and 2017, Chile supplied natural gas to Argentina, with a total flow of 360 million cubic metres (mcm). Between May and June, 86 mcm were supplied through the Norandino gas pipeline and another 274 million m^3 between June and August through the GasAndes gas pipeline (Ministerio de Energia, 2018c). In October 2018, Argentina restarted pipeline exports as a significant step towards regional energy integration.

COAL

Coal is the third dominant fuel in Chile, accounting for 43% of the TPES and 0.8% of total final consumption (excluding non-energy) in 2016. Domestic coal production accounts for 29% of the primary energy supply.

Considering the low domestic production, nearly all of Chile's coal supply of 7 088 ktoe in 2016 came from imports (EGEDA, 2018). In fact, Chile heavily relies on imports to satisfy its coal demand; 42% of the imported coal comes from Colombia, followed by the US (33) and Australia (21%).

By 2004, the coal supply was 2 704 ktoe, increasing to a peak of 4 403 ktoe in 2008. After the curtailment of gas, the use of coal increased in the power generation sector. This helped to maintain the security of electricity supply and reduced the use of expensive diesel fuel. In the last 10 years, the coal supply has increased by 98% (3 771 ktoe).

The industry sector is the largest coal consumer, accounting for 98% in 2016. In 2016, domestic production accounted for 14% of the total supply (IEA (International Energy Agency) 2018).

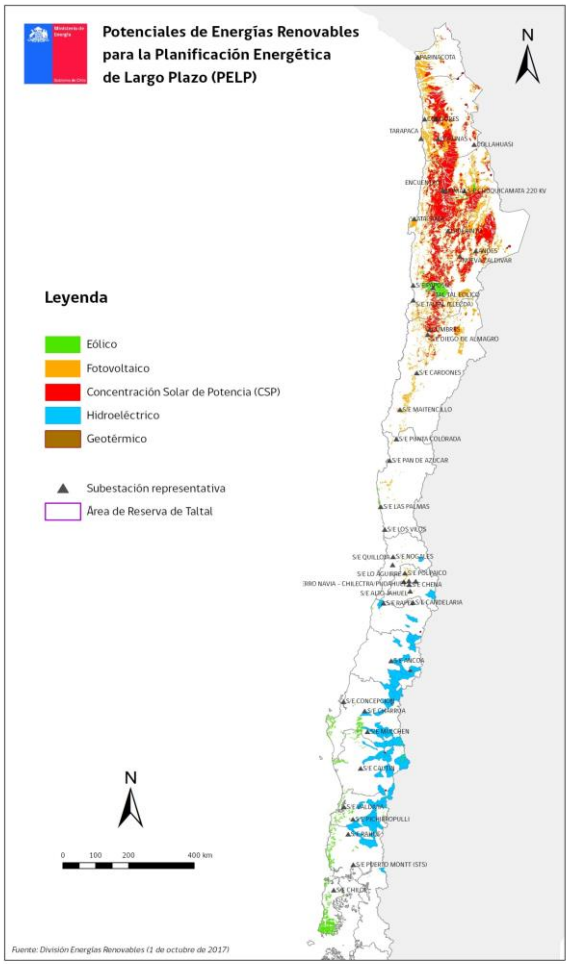
RENEWABLES

Chile has abundant renewable resources, being the second dominant fuel contributing economy to the TPES, with a total of 10 244 ktoe (27%) in 2016 and accounting for 14% of total final consumption (excluding non-energy) (EGEDA, 2018). Chile's primary supply of non-fossil energy in 2016 mainly consisted of biomass, solar, wind and hydropower. From 2000 to 2016, the renewable energy supply in the TPES grew by 38% (3 931 ktoe).

In December 2017, the Ministry of Energy published the LTEP process, which detailed the vast untapped potential for solar (PV and concentrated solar power), onshore wind, geothermal and hydro. PV potential was estimated at 829 GW, concentrated solar power (CSP) at 510 GW, onshore wind power at 37 GW, geothermal at 2 GW and hydropower at 6 GW. Note that the study defines these potential areas with electricity generation potential based on renewable energy resources, which are based on the georeferencing and characterisation of usable resources for renewable energy in consideration of some technical, territorial

and environmental constraints through the combined use of geospatial information (Ministerio de Energia, 2018d). Figure 2 below shows the vast untapped potential for solar (PV and CSP), onshore wind, geothermal and hydro.

Figure 2: Potential renewable resources in Chile



Source: Ministerio de Energia (2018d)

At the end of November 2018, Chile had an installed capacity of 4 704 MW of NCRE, with solar and wind representing 9% and 7%, respectively, and a total of NCRE 1 192 MW is under construction. The installed capacity of NCRE represents 20% of the total installed capacity and 15% of the total system generation (CNE, 2018b).

Table 6: NCRE units in operation and under construction

Energy Source	Operation (MW)	Construction (MW)
Biomass	501	
CSP		110
Geothermal	48	
Hydro (<= 20 MW)	494	75
Solar PV	2 137	265
Wind	1 524	742
Total	**4 704**	**1 192**

Source: CNE (2018b)

NUCLEAR ENERGY

In 1965, Chile created the CCHEN to address problems related to the production, acquisition, transfer, transport and peaceful uses of atomic energy. CCHEN regulates, authorizes and supervises the national nuclear and radioactive facilities catalogued as first category as well as the operators working on them. CCHEN also helps protects people and the environment carrying out monitoring, surveillance, calibration, managing radioactive waste and providing training in the radiological area. CCHEN operates the research reactor RECH-1 located in the Santiago metropolitan region, which have been used for research, radioisotopes production and other civil purposes.

Its main duties are as follows:

- To provide technical and legal advice to the government on nuclear issues related to energy and radiation;
- To conduct research and development in peaceful uses of nuclear energy;
- To regulate, control and supervise nuclear facilities and
- To undertake technology transfer and its applications.

Given the energy requirements of the Chilean economy, the use of nuclear energy has been subject to concerted debate. In 2007, the Nuclear Energy Working Group was formed to study the feasibility of the implementation and use of nuclear energy in Chile. This study concluded that according to international experience and despite the risks of earthquakes faced by Chile and potential waste management problems, nuclear energy is a viable option (MINREL, 2007).

In January 2015, the Government of Chile created the Nuclear Power Energy Committee, which prepared the report 'Nuclear Power Generation in Chile: Towards a Rational Decision' (CCHEN, 2015). This report agrees with a previous report from 2010 in that the economy must continue working to close the gaps inhibiting the proper implementation of nuclear energy. Furthermore, the report states that the possibility of using nuclear energy should not be discarded without a 'rational and comprehensive analysis and considering all relevant aspects of this technology and the feasibility of its use in Chile'. Finally, the report concludes that social approval is crucial to start any project involving nuclear energy development in Chile.

Clearly, from the perspective of the Chilean Government, despite the exclusion of nuclear energy from the final Energy Road 2018-2022, its possible use in the future has not been ruled out. In fact, the need for additional studies related to technology, location, waste management and public approval have been recognised. Energy 2050 notes that nuclear energy is not a short-term option for Chile at present and its uptake depends on further research regarding security and economic rationality, as well as community acceptance.

For this reason, CCHEN has been appointed to conduct a process for developing the required information in ways that a nuclear power option could be considered in the next review of energy policy, which will take place in 2020. For accomplishing this task, the Strategic Development and Nuclear Power Office was created in CCHEN on March 2016 and resources were allocated for performing studies on the main relevant topics.

ENERGY EFFICIENCY

Energy efficiency (EE) is among Chile's priorities as it works towards achieving its key goal of enhancing its energy security. These efforts also encompass the stabilisation of demand growth through EE measures.

In terms of EE, the Ministry of Energy is responsible for the development of policies and guidelines, including the promotion and enhancement of economy-wide efficient energy use as a means of contributing to the achievement of this goal. Furthermore, in pursuing these objectives, the Ministry of Energy entrusts the Chilean Energy Sustainability Agency, which is responsible for implementing many of these policies by promoting, disseminating and implementing dedicated programmes, opening new markets and exploring opportunities in the field of energy efficiency and developing EE markets to recognise and reward leading EE companies. The current goal is to foster the efficient use of energy as an energy resource. The government has established a 20% savings goal by 2025 after considering the expected growth in energy consumption for the economy.

The Energy Policy defines long-term goals by 2035 and 2050 in EE. These goals are organised in the following 11 alignments:

- Forming a robust market of consultants and enterprises of energy services;
- Applying progressively energy management tools validated by competent entities;
- Using local available resources and exploiting the potential energy in the productive process;
- Efficiently incorporating EE standards in design, construction and conditioning;
- Promoting smart control systems and owning energy production in ways to apply to buildings with efficient solutions;
- Strengthening the efficient edification market and moving towards more productive and efficient local markets;
- Improving EE of vehicles;
- Promoting more efficient transportation alternatives;
- Ensuring the availability of massive and clear information regarding rights and duties of consumers, including alternative energies and methods;
- Designing, implementing and tracking of an energy education strategy jointly with the different initiatives developed by the Ministry of Energy and related institutions;
- Developing professional and technical human capital for the production.

The agenda states short-term concrete activities to encourage EE, which considers measures to extend the development of EE projects, including the continuity of the Action Plan on Energy Efficiency 2020, published in 2012 (Ministerio de Energia, 2012). These measures are applicable to industry and mining, transport, buildings, end-use devices and heating.

Table 8: Chile's action plan on energy efficiency, 2020

Industry and mining	- Promote energy management systems - Promote energy cogeneration - Encourage efficient technologies - Technical assistance in industry and mining projects
Transport	- Improve EE standards for light- and heavy-duty vehicles - Use new transport technologies in heavy-duty vehicles - Promote public transportation - Promote electric vehicles - Technical assistance in transport projects
Buildings	- Encourage efficient technologies - Improve thermal insulation in buildings without EE standards - Promote energy management in buildings - Training to relevant actors in the construction chain - Promote building labelling - Promote EE in street lighting
End-use devices	- Extend appliance labelling - Establish minimum energy performance standard (MEPS) - Promote minimum lighting efficiency standards throw specific programmes focused in low income households
Heating	- Encourage new technologies in the use of firewood - Improve firewood quality - Improve the knowledge in the regarding the correct use of firewood and its process

Source: Ministerio de Energia (2012)

The government is implementing the Action Plan for Energy Efficiency 2020. Since 2012, the Superintendent of Electricity and Fuels certifies security, emission levels and EE standards on firewood home appliances, which have been part of the institutional framework for EE policies owing to the importance of firewood in residential consumption in Chile (Ministerio de Energia, 2012). In addition, the Chilean Government approved the Minimum Energy Efficiency Standards Act, which applied to refrigerators and

lamps in 2014, in early 2017 to three-phase induction electric motors up to 10 horse-powers, as well as a minimum standard for air, conditioning systems and in late 2015, the government banned the commercialisation of incandescent bulbs. New regulations on vehicle labelling, water heating and appliances have also been approved. Chile has one of the most-comprehensive energy programmes in the world by the IEA.

The agenda also considers the implementation of programmes focused on EE with subsidies for housing thermal insulation, the promotion of energy efficiency in public buildings (especially hospitals until 2017, currently extended to all public buildings), the replacement of public lighting with more efficient technologies and massive campaigns to teach the proper use of energy to the population.

The Chilean government has been working in an EE law, which currently is under discussion in the Congress.

The Energy Efficiency Bill was recently approved in general by the Senate (April 24, 2019) and continues its discussion in Congress (Bulletin 12058-08). The Law includes measures to be adopted in all productive sectors, in addition to contributing to create an energy culture throughout the population. The Energy Efficiency Bill proposes changes to the current regulations in six dimensions: 1) institutionalise energy efficiency within the framework of the Council of Ministers for Sustainability; 2) promote the management of energy in large consumers; 3) deliver information to home buyers, regarding the energy requirements in the use of the houses; 4) promote energy management in the public sector; 5) ensure the conditions that facilitate the installation and operation of charging stations for electric vehicles; and 6) promote the renewal of the vehicle fleet with more efficient vehicles, with emphasis on those of electric propulsion.

CLIMATE CHANGE

Chile became a signatory to the United Nations Framework Convention on Climate Change (UNFCCC) in 1992 and ratified the Kyoto Protocol in 2002. In December 2008, Chile published the National Action Plan on Climate Change 2008–12, which assigns institutional responsibilities for adapting, mitigating and strengthening Chile's response to climate change (MMA, 2008). According to the results of vulnerability studies conducted by the Ministry of the Environment (MMA in Spanish), the effects of climate change can be summarised as follows:

- There has been a decrease of up to 75% in precipitation in some regions, a temperature increase of up to 1.5% and a decrease to 77% of the flow rate in some regions.
- There is a marked reduction in the recorded population of a vast majority of species.
- Regions that are predominately small in area and have low levels of technological access show the greatest vulnerability to climate change.

While Chile's contribution to global carbon emissions is very low, at around 0.2% of the total CO_2 emitted globally in 2013 (WRI, 2017), its territory is highly vulnerable to the effects of climate change. Glacial melting, shifts in rainfall patterns, expanding deserts and greater frequency of El Niño weather patterns will have an impact on the economy's water supply, food production, tourism industry and migration, as well as on its socioeconomic development and energy security. In this regard, Chile's action plan identified hydroelectric resources, food production, urban and coastal infrastructure and energy supply as the four most vulnerable areas to climate change, where adaptation would be required.

To the date, nine sectoral Climate Change Adaptation Plans have been approved, the last one in February 2018 corresponding to the Energy Sector[1].

At the 21st Conference of the Parties (COP) to the UNFCCC in 2015, hereafter referred to as the 'COP21 Paris Agreement', Chile submitted a Nationally Determined Contribution (NDC) reflecting policy action to support the agreement. The NDC includes a target for carbon intensity, expressed in GHG emissions per unit of GDP, and another for tonnes of carbon dioxide equivalent (tCO_2) from LULUCF activities. Chile contributes only 0.24% of global emissions (Banco Central, 2018), but 78% of its CO_2 emissions came from

[1] This plan is currently being revised and edited.

the energy sector in 2016 (MMA, 2019. Informe del Inventario Nacional de Gases de Efecto Invernadero de Chile serie 1990-2016. Santiago, Chile). To reduce emissions under the COP21 Paris Agreement, Chile's NDC commits to (Gobierno de Chile, 2015) the following:

- Unconditionally reduce the intensity of emissions per unit of GDP to 30% below the 2007 level by 2030, not including LULUCF activities.
- Conditional on international funding, reduce CO_2 emissions per unit of GDP to 35% to 45% below the 2007 level by 2030, not including LULUCF activities.
- Make specific LULUCF contributions of:
    - Sustainably developing and recovering 100 000 hectares (ha) of forest land, mainly native, for GHG sequestrations and reductions equivalent to around 600 000 tCO_2 annually by 2030.
    - Reforesting 100 000 ha, mostly with native species, to sequester the equivalent of 900 000 tCO2 to 1 200 000 tCO_2 annually by 2030. This commitment is conditional on the extension of Decree Law 701 and approval of a new Forestry Promotion Law.

To reach the targets outlined in the INDC and to ensure the sustainability of Chile's energy future, the government prepared its second *National Action Plan for Climate Change 2017-22* (MMA, 2017). This plan contains the following action lines and objectives.

Table 9: National Action Plan for Climate Change 2017–22.

PLAN	OBJECTIVES
Adaptation	Strengthening the economy's capacity to adapt to climate change, improving the knowledge of its impacts and the vulnerability of the economy and generating actions to minimise negative effects and take advantage of positive effects, promoting economic and social development and ensuring environmental sustainability.
Mitigation	Creating the enabling conditions for the implementation, compliance and follow-up of Chile's GHG emission reduction commitments to the UNFCCC, and to contribute consistently to the economy's sustainable development and low growth in carbon emissions.
Implementation means	Creating the enabling conditions to implement the climate change mitigation and adaptation actions at a national and subnational level in the transversal elements related to institutional and legal areas,, technology transfers, capacity-building and technical assistance, financing and international negotiation.
Climate change at the regional and municipal levels	Developing the necessary institutional and operative elements and capacity building to advance the management of climate change in the territory, through regional and municipal governments, and incorporating all social actors.

Source: MMA (2017)

In 2016, GHG emissions were 111.68 $MtCO_2$-e, increasing by around 115% from 1990 levels and 7.1% since 2013. The main GHG emitted was CO_2 (79%), followed by CH_4 (12.5%). The energy sector is the main emitter (78%), primarily due to the utilisation of coal in power plants and diesel in the transport sector (MMA 2017).

The National Energy Policy 2050, includes goals to adopt the necessary mitigation and adaptation actions to achieve a sustainable and clean energy sector and to help to achieve the emission reduction targets set in Chile's Nationally Determined Contribution. Regarding climate change, this policy is explicit in terms of setting medium- and long-term goals. For instance, it states that this policy will contribute to the COP 21 commitment of reducing the intensity of GHG emissions in Chile by 30% in 2030 compared with the 2007 levels and commits the implementation of a GHG Emissions Mitigation Plan for the energy sector and of a

plan to adapt the energy sector to the impacts of climate change. For 2050, it states that 'GHG emissions of the energy sector are consistent with international thresholds and national NDCs'.

The Energy Sector Mitigation Action Plan (committed under the Energy Policy 2050), by the Ministry of Energy in collaboration with to other Ministries such as Transport, Economy, Mining, Housing, Environment, among others, and with the support of the Partnership of Market Readiness (PMR) Policy Analysis Work Programme, was approved in October 2017 by the Sustainability Ministries Council and its main goal is to address the energy sector's share of responsibility in achieving the economy's first NDC by proposing packages of measures on relevant sectors such as electricity production, transport, industry and mining, as well as commercial, public and residential.

Carbon market mechanisms are important here, since they can provide important incentives for clean technology investments, and therefore, for a transition to decarbonise the economy. Through the PMR initiative, in collaboration with the World Bank, economic and market-based instruments will be evaluated, such as emission trading systems (ETS or Cap & Trade), which aim to reduce CO_2 and other GHG emissions in the energy sector.

Embedded in the Energy Policy are the relevant related goals on renewables and energy efficiency, which will have a great impact on reducing GHG emissions and achieving the economy's commitments.

Additionally, in 2017, the Chilean Government applied a carbon tax of USD 5 per tonne of CO_2 emitted, thus affecting thermal plants with an installed capacity equal to or greater than 50 MW.

NOTABLE ENERGY DEVELOPMENTS

Despite Chile's geographical diversity and abundant renewable resources (solar, wind, hydro and geothermal), it has very limited fossil fuel resources and is a net importer of oil, gas and coal. Chile's transformation sector is much smaller than that of FED. On the other hand, electricity generation is dominated by coal (38%) and it is the third dominant fuel used in Chile. As outlined in the Energy Roadmap 2018-2022, the initiation of an energy sector decarbonisation process through preparation of a timeline for the withdrawal or conversion of coal-fired power plants will help to reduce CO_2 emissions in the electricity sector and collaborate with the NDC commitment.

A modification to the residential generation law was enacted in October 2018 to promote residential/distributed generation by extending the maximum limit for private installations from 100 kW to 300 kW. This law mainly focuses on residential customers, who often decide to invest in clean generation sources for their homes (Ministerio de Energia 2018), and will help to moderate demand growth for fossil fuels in the residential sector.

In October 2018, Argentina restarted pipeline exports as a significant step towards regional energy integration.

In September 2017, Enel and ENAP started operating South America's first and only geothermal power plant, the 48-MW Cerro Pabellón Project, sits at an elevation of 4 500 meters above sea level in Chile's harsh and remote Atacama Desert. It will be able to produce around 340 GWh per year, equivalent to the annual consumption needs of more than 165,000 Chilean households, while avoiding the emission into the atmosphere of more than 166,000 tons of CO2 per year (ENAP (Empresa Nacional del Petroleo) 2017).

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USEFUL LINKS

Chilean Commission of Energy (CNE)—www.cne.cl

Chilean Energy Efficiency Agency (AChEE)—www.acee.cl

National Electric Coordinator—https://www.coordinador.cl/

Government of Chile—www.gobiernodechile.cl

Ministry of Economy, Development and Reconstruction—www.economia.cl

Ministry of Energy—www.minenergia.cl

Ministry of Environment—www.mma.gob.cl

Nuclear Energy Chilean Commission (CCHEN)—www.cchen.cl

National Energy Commission (CNE)—www.cne.cl

National Institute of Statistics (INE)—www.ine.cl

National Oil Company (ENAP)—www.enap.cl

Superintendence of Electricity and Fuel (SEC)—www.sec.cl

CHINA

INTRODUCTION

China is one of the world's most important emerging economies. It is located in Northeast Asia and is bordered by the East China Sea, the Yellow Sea and the South China Sea. Its population of 1.4 billion is approximately one-fifth of the world's population. China has a land area of approximately 9.6 million square kilometers (km^2) with diverse landscapes, which comprise mountains, plateaus, plains, deserts and river basins. Its total maritime area is 4.7 million km^2, and the length of its coastline is 32 400 km (NBS, 2018).

After reforming and opening up its economy in 1978, China entered a new period of high-speed growth. Its entry into the World Trade Organization (WTO) in 2001 further contributed to its prosperity in the first decade of the 21st century. In 2004, China overtook Japan as the Asian's leading exporter. In 2009, China surpassed Germany to become the world's leading exporter. By 2017, China's merchandise exports constituted 13% of the world's merchandise exports (WTO, 2018). In 2016, China's GDP was USD 19 854 billion (2011 prices and 2011 purchasing power parity [PPP]), with the primary, secondary and tertiary industries constituting 7.9%, 41% and 52%, respectively (EGEDA, 2018; NBS, 2018).

With its huge population and booming economy, China plays an increasingly important role in the world's energy markets. According to British Petroleum (BP), China's energy consumption grew by 3.1% in 2017. This was still significantly slower than the 10-year average growth rate of 4.4% (BP, 2018). However, China remained the world's largest energy consumer and constituted 23% of the global energy consumption and 34% of the net global energy growth in 2017 (BP, 2018). Its per capita primary energy consumption, at 2.1 tonnes of oil equivalent (toe) in 2016, was far lower than that of most developed economies and below APEC's average of 2.8 toe (EGEDA, 2018)

China is relatively rich in energy resources, particularly coal. According to BP statistics published in June 2018, China had total proven coal reserves of approximately 138 819 million tonnes (Mt), total proven oil reserves of 26 billion barrels and proven natural gas reserves of 5.5 trillion cubic meters (tcm) (BP, 2017). In addition, China has 400 gigawatts (GW) of economic hydropower potential, more than any other economy. Coal and oil resources have been utilised more extensively than natural gas and hydro for power generation and industrial development.

The reserves per capita of coal, oil and gas are well below the world average levels. The limitations of its energy reserves per capita force China to conserve its resources. From 2000 to 2016, the compound annual growth rate (CAGR) of final energy consumption was 7.5% and the CAGR of GDP was 9.5% (EGEDA, 2018).

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c]	
Area (million km^2)	9.6	Oil (billion barrels)	26
Population (million)	1 379	Gas (trillion cubic metres)	5.5
GDP (2011 USD billion PPP)	19 854	Coal (million tonnes)	138 819
GDP (2011 USD PPP per capita)	14 401	Uranium (kilotonnes U)	370.9[d]

Sources: [a] EGEDA (2018); [b] NBS (2017); [c] BP (2018); [d] Recoverable resources, WNA (2018).
Note: Data for coal reserves is as of the end of 2017.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

China's primary energy supply has sharply expanded since 2001. This expansion was mainly driven by rapid economic growth, especially in energy consumption by heavy industry. In 2016, the total primary energy supply decreased by 0.60% compared with that in 2015, reaching 2 880 million tonnes of oil equivalent (Mtoe), including net imports and others. The decrease came from the replacement of coal with gas and rapid development of renewable energy, and the indigenous production decreased by 5.5% compared with that in 2015. Coal was the dominant source, constituting 66%, followed by oil (19%), gas (6.5%), renewables (6.1%) and others (2.8%) (EGEDA, 2018).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	2 291 753	Industry sector	1 034 764	Total power generation	6 142 486
Net imports and others	552 204	Transport sector	271 831	Thermal	4 437 068
Total primary energy supply	2 880 216	Other sectors	429 864	Hydro	1 193 374
Coal	1 890 248	Non-energy	177 877	Nuclear	213 287
Oil	547 956	Final energy consumption*	1 736 459	Others	298 757
Gas	186 862	Coal	648 596		
Renewables	175 744	Oil	402 205		
Others	79 407	Gas	117 849		
		Renewables	38 986		
		Electricity and others	528 823		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

China has been the world's second-largest economy in terms of electric power generation capacity since 1996. Its electric power industry experienced a serious overcapacity problem in the late 1990s, largely due to lower consumption after the closure of inefficient state-owned industrial units that were major consumers of electricity. Subsequently, however, a power supply shortage developed because of rapid economic expansion after 2001. During 2000–15, electricity generation output rapidly increased from 1 356 terawatt-hours (TWh) to 5 815 TWh, of which thermal power generation constituted 74% of the total power generation. In 2017, installed generation capacity reached 1 777 GW (NBS, 2018).

The power supply structure has diversified, with wind power and nuclear energy generation increasing rapidly. In 2017, the total power generation in China was 6 495 TWh. Thermal power constituted 72% (4 663 TWh of the total generation); hydropower constituted 18% (1 190 TWh); nuclear energy constituted 3.8% (248 TWh); wind power constituted 4.5% (295 TWh); and photovoltaic (PV) constituted 1.5% (97 TWh) (NBS, 2018.

FINAL ENERGY CONSUMPTION

Total final consumption in China reached 1 914 Mtoe in 2016, 2.9% higher than that in 2015. The industrial sector was the largest consumer, constituting 54% of the total final energy consumption, followed by other sectors (including residential, commercial and agricultural) at 23% and the transport sector at 14%. The remaining 9% was contributed by non-energy use (EGEDA, 2018). By energy source, coal constituted 37%

of the final energy consumption (excluding non-energy), followed by electricity and others (30%), oil (23%), gas (6.8%) and renewables (2.2%).

In the Thirteenth Five-Year Plan for energy development, China set its annual energy consumption growth target at an average of 2.5% during 2016–20, 1.1 percentage points lower than the 3.6% during 2011–15. As a result, the total energy consumption will be contained within 5.0 billion tonnes of coal equivalent by 2020.

ENERGY INTENSITY ANALYSIS

China has reduced its energy intensity in the last two decades. Compared with the 1990 levels, the intensities of primary energy supply and total final consumption in 2016 reduced by 62% and 69%, respectively. These are the biggest reductions among the APEC economies. However, energy intensity is still very high, and there is a lot of room for improvement (EGEDA, 2018).

In 2015, China eliminated more than 5.27 GW of outdated thermal power plants, 49.7 million tonnes (Mt) of outdated cement production capacity and 101.7 Mt of outdated coal mining production capacity (MIIT, 2017). With these efforts, the intensity of total final consumption decreased by 3.8% from 2015 to 2016. The government also introduced policies on energy structural optimisation and overall energy efficiency improvement in the industrial sector, contributing to a lower energy intensity from the industrial sector. However, because of the booming economy and transportation needs, vehicle purchases remain high, which has resulted in increased energy intensity in the transportation sector.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	156	145	–6.8
Total final consumption	91	87	–3.8
Final energy consumption excl. non-energy	100	96	–3.5

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

As a result of China's policy support to promote clean energy and a more diversified energy structure, China's final energy consumption of modern renewables increased by 6.8% from 2015 to 2016, the largest increase among APEC economies. China's traditional biomass consumption increased by 12.9% due to economic development and an increasing per capita energy consumption. To mitigate such increase, China has been working on shutting down backward thermal power capacity and heavily polluted fossil fuel consumption terminals, such as outdated steel and cement production lines. China's non-renewable energy consumption only increased by 2.32%. This was mainly due to declining coal consumption despite the rapid increase in the consumption of oil and natural gas between 2015 and 2016.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	1 691 989	1 736 459	2.6
Non-renewables (fossil fuels and others)	1 575 839	1 612 389	2.3
Traditional biomass*	19 032	21 494	13
Modern renewables*	116 150	124 071	6.8
Share of modern renewables to final energy consumption (%)	6.9	7.1	4.1

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered to be modern renewables, although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

China's energy consumption is growing rapidly in line with robust economic development and accelerated industrialisation. Energy has become an important strategic issue for China's economic growth, social stability and security. China aims to be a low-carbon economy. The structural transformation of energy is the key to economic restructuring, which is also an important indicator of social progress. Achieving the goal of a low-carbon and orderly energy structure is the basis of China's energy strategy.

During the Twelfth Five-Year Plan for National Economic and Social Development (2011–15), China secured an annual GDP growth rate of 7.8% and an annual energy consumption rate of 3.6%. Further, the installation scale of hydropower, nuclear power, wind power and solar power has increased by factors of 1.4, 2.6, 4.0 and 168 fold, respectively. The Thirteenth Five-Year Plan for National Economic and Social Development (2016–20) was approved by the National People's Congress in March 2016 (NDRC, 2017a). It has four major energy-related objectives:

- Enhance energy supply capability;
- Make a breakthrough with key technology;
- Greatly increase the share of non-fossil fuel consumption; and
- Make a breakthrough in the clean use of fossil fuels.

The Thirteenth Five-Year Plan for Energy is a specification of the Master Plan for the energy sector, with more detailed targets that will provide a better guide for policymaking, government spending and project planning in the sector. The State Council approved it in December 2016, and the National Energy Administration (NEA) unveiled it in January 2017 (NDRC, 2017b). Clean and low-carbon energy will account for most of the newly added energy supplies during 2016–20. By 2020, China expects an annual energy consumption of less than 5 billion tonnes of coal equivalent (tce) from 4.3 billion tce in 2015. This will ensure that the average annual growth rate remains below 3.0% over the next five years.

ORGANISATION

The National Energy Committee is a high-level body that coordinates overall energy policies. The committee, chaired by the premier, is in charge of formulating China's energy strategy and deliberating on major issues in energy security. In March 2013, the State Electricity Regulatory Commission (SERC) merged into the NEA under the administration of the National Development and Reform Commission (NDRC). The NEA is currently composed of 12 departments and has an authorised staffing complement of 248 civil servants. It is responsible for developing and implementing energy industry planning as well as industrial policies and standards. In addition, it is in charge of administering the energy sector, which includes coal, oil, natural gas and other forms of power such as nuclear energy and new and renewable sources of energy. The NEA has also assumed responsibility for the Office of the National Energy Committee. The NEA has 6 regional regulatory bureaus and 12 provincial-level regulatory offices overall. Formerly under the SERC, this administration takes the responsibilities of regulating local and state-owned energy enterprises. Some departments within the NDRC also contribute to energy conservation and climate change issues.

In 2009, China established the National Energy Conservation Centre under the NDRC to provide technical support to the government for the implementation of energy efficiency and conservation management initiatives. Its main duties include energy efficiency and conservation policy research; the assessment of fixed asset investment projects; information dissemination; the promotion of technologies,

products and new mechanisms; label management; and international cooperation in the field of energy conservation.

In 2018, to push forward reforms to streamline administration and improve services, China launched a massive cabinet reshuffle. After merging, restructuring and dissolving, 26 ministries and commissions remained, reducing the number of ministerial-level entities by eight and vice-ministerial-level entities by seven. Responsibility for addressing climate change and emission reduction was switched from the NDRC to the newly established Ministry of Ecology and Environment (MEE).

LAW

The laws relating to energy in China include the Coal Law (issued in 1996 and revised in 2013), Mining Law (issued in 1986 and revised in 1996 and 2009), Electricity Law (issued in 1995 and revised in 2015 and 2018), Renewable Energy Law (issued in 2005 and revised in 2009), Energy Conservation Law (issued in 1997 and revised in 2007) and Environmental Protection Law (issued in 1989 and revised in 2014). The Energy Law is a comprehensive legal basis for the energy sector and is currently under consideration. The Standing Committee of the National People's Congress endorsed the amended version of the Renewable Energy Law on 26 December 2009, which originally took effect on 1 April 2010. It more clearly defines the responsibilities of the power grid and power generation enterprises. It also emphasises the completely secure purchase of power from renewable energy sources and the establishment of a development fund for renewable energy. The amendment provides that power grid companies receive all of the revenue generated from the surcharge on retail power tariffs. In addition, it sets a minimum target for the amount of renewable electricity, which grid companies must buy from renewable energy projects (Xin Qiu and Honglin Li, 2012).

The Oil and Natural Gas Pipeline Protection Law endorsed on 25 June 2010 went into effect on 1 October 2010. This requires that oil and pipeline companies take safety measures while constructing pipelines. These measures include ensuring the quality of construction materials, conducting regular patrols of pipelines and promptly eliminating any hazards.

The State Council approved the Regulation on Electricity on 15 February 2005. It became effective on 1 May 2005. This regulation clarifies the content and responsibilities of electricity regulation.

The State Council approved the Regulation on the Administration of Urban Gas on 19 November 2010. It went into effect on 1 March 2011. This regulation clarifies the responsibilities and duties of gas operators, unifies gas market management into a regular channel and sets the basis for local government activities.

ENERGY SECURITY

China has been endeavouring to guarantee itself and its industries long-term access to sufficient energy and raw materials. Currently, China's energy portfolio mainly comprises domestic coal, oil and gas from domestic and foreign sources and small quantities of uranium. China has also created a strategic petroleum reserve to secure emergency supplies of oil for temporary prices and supply disruptions. Chinese policy focuses on diversification to reduce oil imports, which almost exclusively rely on producers in the Middle East.

On 13 June 2014, Chinese President Xi Jinping presided over the sixth meeting of the Leading Group for Central Financial Work, stressing that energy security is a global and strategic issue related to economic and social development. To enhance China's energy security, Xi Jinping proposed the promotion of a revolution in energy production and consumption. This revolution is a long-term strategy and contains the following five major requirements:

- The promotion of an energy consumption revolution, which curbs irrational energy consumption. This involves the firm control of total energy consumption; the effective implementation of an energy-saving priority principle; energy saving throughout the whole process of economic and social development and the adjustment of the industrial structure; significant emphasis on urban energy saving; the establishment of the concept of thrifty consumption; and the acceleration of the formation of an energy-saving society.
- The promotion of an energy revolution and the establishment of a multi-supply system. This system is based on domestic supply, with the goals of ensuring safety; vigorously promoting the efficient

use of clean coal; focusing on the development of non-coal energy; forming a multifaceted coal, oil, gas, nuclear, new energy and renewable energy supply system; and strengthening the energy transmission and distribution network and storage facilities.

- The promotion of an energy technology revolution and industrial upgrading. This is based on the economy's conditions and follows the new trend of the international energy technology revolution. The goals are guided by the principles of green, low-carbon energy; promotion of technological, industrial and business model innovation; vigorous promotion of high-tech fields; and cultivation of technology and related industries to upgrade the status of energy as domestic industry's new growth point.
- The promotion of an energy system revolution, which is achieved through fast-track energy development. The goals are not to stagnate or retreat but to develop the revolution, thereby reducing energy commodity attributes, constructing a market structure and system that have effective competition, ensuring that the formation of the market structure and system is mainly determined by the market mechanism of energy price, transforming government energy regulation and establishing and improving the energy law system.
- All-round strengthening of international cooperation to achieve energy security in accordance with the foregoing requirements. On the precondition that energy production is mainly domestic, the guideline sets forth to strengthen international cooperation in all aspects of the energy production and consumption revolution and make effective use of international resources.

In the Thirteenth Five-Year Plan for Energy Development, energy security is set as a clear target. The plan targets to keep China's energy self-sufficiency rate above 80% by the end of 2020, which was 84% in 2015. Since China's crude oil supply and natural gas supply heavily depend on imports through pipelines or marine transportation, the government expects to control China's dependence rate on foreign oil and natural gas through energy structure adjustment and efficiency improvement. APERC projects that China's oil and natural gas import will continuously increase in the next couple of decades due to the rapid increase in domestic consumption and population growth. To achieve such goals during the Thirteenth Five-Year Plan, energy supply-side reform and advanced fossil fuel geological exploration are considered as effective solutions. On the other hand, domestic shale gas, coal-bed methane, combustible ice utilisation and production developments are also potential possibilities to decrease China's energy dependence rate on foreign resources.

ENERGY MARKET

Energy market reform is a key driving force behind the acceleration of China's move towards a market-based economy. Therefore, the Chinese Government has promoted such reform in the past few years. The Chinese Government has announced that the entire range of projects included in the National Energy Plan is open to private investment, except where prohibited by laws and regulations. In 2010, the State Council issued a report titled *Several Opinions of the State Council on Encouraging and Guiding the Healthy Development of Private Investment*. This report encourages private capital to participate in the exploration and development of energy resources, oil and gas pipeline network construction, power plant construction, coal processing, energy conversion, the refining industry and a comprehensive, new renewable energy industry.

COAL MARKET

Owing to the abundant domestic reserves and low cost, coal has always been the primary energy fuel in China. However, due to seriously deteriorating air quality in recent years, China has been stepping up its efforts to reduce coal consumption to cope with air pollution issues and climate change.

In October 2013, several organisations, including government think tanks, research institutes and industry associations, jointly launched the China Coal Consumption Cap Project. This project aims to develop a comprehensive roadmap and policy package to cap coal consumption.

In November 2014, China's State Council launched the Energy Development Strategy Action Plan (2014–20). This sets the target for capping coal consumption at no more than 4.2 billion tce, with the share of coal in primary energy consumption kept below 62%.

In November 2015, the China Coal Cap Project issued a report entitled the China Coal Consumption Cap Plan and Research Report: Recommendations for the Thirteenth Five-Year Plan. This report presents recommendations for controlling and reducing China's coal use to below 3.8 billion tonnes and 3.4 billion tonnes by 2020 and 2030, respectively. In addition, the report recommends that the economy's total energy consumption should be at or lower than 4.7 billion tonnes of standard coal equivalent by 2020 and that the share of coal within primary energy consumption during this period should be reduced to less than 57%.

China also began its 'supply-side reform' in recent years to cut unnecessary and outdated production capacity. One of this reform's target is to avoid overcapacity of supply in the coal mining industry. From 2015 to 2017, China shut down many small and inefficient coal mines and merged several private mines into state-owned enterprises (SOEs) to improve efficiency and control overall production.

Furthermore, in December 2015, the Chinese State Council pledged to upgrade coal-fired power plants to cut pollutant discharge by 60% before 2020, thereby saving approximately 100 Mt of raw coal and reducing carbon dioxide (CO_2) emissions by 180 Mt annually. In addition, China aims to cut the total coal consumption to below 65% of the total primary energy consumption by 2017 as part of an energy supply structural transformation (SCC, 2015). According to a statement by the NDRC, the NDRC targeted a capacity cut of 250 Mt for 2016, a reduction that was met 'ahead of schedule' in late November.

In October 2016, the NEA issued the Thirteenth Five-Year Plan for Energy Development, in which China set the target for capping energy consumption at no more than 5 billion tonnes of coal equivalent and coal consumption at no more than 4.1 billion tonnes, with the share of coal in primary energy consumption reduced to below 58% and the share of coal used for generating electric power in coal consumption increased to 55% by 2020.

OIL MARKET

China surpassed the United States as the world's largest oil importer in April 2015. According to Chinese customs data, crude oil purchases from overseas reached a new record of 7.4 million barrels per day (Mbbl/D) in April. This is approximately 7.7% of the world's oil consumption per day and exceeds United States' imports of 7.2 Mbbl/D. Larger shipments from Iran, Oman and UAE (Abu Dhabi) partly contributed to the soaring increase in oil imports in China.

Although China faces slowing economic growth, oil consumption is still rapidly increasing. Hence, its state-owned oil traders, such as Unipec and China Oil, have been gaining increased visibility in the global crude oil market.

However, with China's high dependence on overseas oil imports of more than 60%, it must establish strategic oil reserves to secure its energy supply. As of the middle of December 2015, China's strategic crude oil reserves had reached 26 Mt or approximately 191 million barrels. This occurred at a time of low oil prices. Consequently, China has taken advantage of the lower prices to stockpile crude oil.

According to the Statistics Bureau, the reserves are stored in seven above-ground facilities in Zhoushan, Zhenhai, Dalian, Huangdao, Dushanzi, Lanzhou and Tianjin and one underground facility in Huangdao, with a total capacity of 29 million cubic metres (mcm) (or approximately 180 million barrels) (FT, 2015; Reuters, 2015).

China stopped the United States oil imports in October and November 2018 influenced by the tit-for-tat tariffs imposed on both sides of China–US trade war. China resumed some imports in December, but purchased only 1 million barrels, a minute portion of the more than 300 million barrels of total imports after the two countries entered into a truce of three months, agreeing to impose no new tariffs on each other that would take effect from 1 January 2019.(Reuters, 2018)

NATURAL GAS MARKET

Natural gas has not been a major component of China's primary energy supply. However, its share in the economy's energy mix has been increasing rapidly. In the first half of 2015, the consumption of natural gas was 91 billion cubic metres (bcm). This represented a rise of 2.1% from the same period in 2014 and was 5.5% of the energy mix. Production in the same period increased by 3.8% year-on-year to 66 bcm.

Securing a stable gas supply is one of China's energy strategies. Thus, China has been encouraging the transportation of gas from areas with significant resources (such as Western China, Russia and Central Asia) to East China, where gas consumption is high and an energy shortage is apparent.

China's first west–east gas pipeline was built by the China National Petroleum Corporation (CNPC) and completed in October 2004. At 4 200 km, this is China's longest natural gas pipeline, with one trunk line and three branch lines. The pipeline has an annual capacity of 600 billion cubic feet per year (Bcf/y).

In August 2007, the CNPC announced proposals for a second west–east gas pipeline with a capacity of 1.1 trillion cubic feet per year (Tcf/y) and a length of more than 5 480 km, including the trunk line and eight main branch lines. This natural gas pipeline now transports gas from Central Asia and Western China's Xinjiang Province to the south-eastern provinces. The western section of the line runs parallel to the first west-east gas pipeline to Zhongwei in North-Central China. The eastern section transports natural gas from Zhongwei to southern Guangdong Province and Shanghai in the east.

To meet rising gas demand in China, the CNPC began constructing the third west–east gas pipeline with a capacity of 1.1 Tcf/y. The western section of the pipeline was launched in 2014. The eastern section was in operation by the end of 2015. This pipeline runs parallel to the second pipeline for most of its length and ends in the south-eastern province of Fujian (EIA, 2015; Primeline, 2015).

In addition, the NDRC announced a reduction in the wholesale price of natural gas for non-residential users in November 2015. This lowers the gas price by an average of USD 0.1 (or approximately 28%) per cubic metre. This reduction was prompted by the decrease in gas procurement costs following the fall in oil and gas prices. It is also intended to make natural gas an alternative to coal for electricity generation. The NDRC predicts total operational cost savings of CNY 43 billion for industrial users, power generation companies, concentrated heating suppliers, taxi drivers, commercial entities, service providers and others in the downstream market.

The 'shifting from coal to gas' policy significantly impacts China's natural gas market. Between 2015 and 2017, NDRC and the Ministry of Environmental Protection jointly issued a series of policies to promote residential users and commercial enterprises to replace their coal-fired boilers and facilities with natural gas-fired facilities to solve the serious air pollution during winter in the northern area of China. This caused a large spike in demand for natural gas, and the LNG prices tripled from October 2017 to December 2017, leading to a large-scale natural gas shortage across the whole economy.

To meet the rapidly rising demand for natural gas, China increased its LNG imports since the 2000s and became the second-largest LNG importing economy after Japan in 2017. In the recent decade, China invested more money in LNG facilities, such as regasification stations, large-scale LNG marine carriers and LNG terminals to expand its LNG import ability. These facilities are mainly concentrated along the eastern coastal areas.

In addition, the NDRC has also announced that the gas pricing mechanism will be reformed by introducing 'benchmark city station gate prices' for non-residential gas. These will replace the rigid 'ceiling city station gate prices'. The benchmark prices could either increase by up to 20% or decrease to the level decided by suppliers and purchasers. On 1 Sept 2017, NDRC further lowered the city benchmark city station gate prices of non-residential natural gas by 100 RMB/1,000 cubic metres (NDRC, 2017c).

In 2018, China drew lessons from the severe gas shortages and record-high gas prices during the 2017–18 winter as well as took measures to avoid a repeat during the 2018–2019 winter, including by increasing domestic natural gas production, boosting gas pipeline infrastructure and connectivity, improving gas storage capacity and making pre-arrangements for peak demand. China has also set targets for all gas supply companies to ensure that they have sufficient gas storages by 2020. The implementation of coal-to-gas switching policy is more measured and moderate, taking expectations of gas demand into consideration. The NDRC has also pledged to strengthen monitoring to ensure stable gas prices and supply throughout the winter heating season (Guangming Online, 2018).

ELECTRICITY MARKET

The main objectives for electricity market development in the Thirteenth Five-Year Plan are to accelerate structural reformation and innovation, transform to green energy and relax the regulations regarding electricity supplies. To reach these objectives, there are five major strategies (CNSTOCK, 2015).

- The innovation of the electricity market structure. In 2015, the Chinese Government finalised the 'Deepening Reform of the Power Sector', a policy document co-signed by the Central Committee of the Communist Party and the State Council to accelerate the innovation of the electricity market structure. Further, an investment regime must be established by opening public bidding in a specific orderly manner, thereby developing innovation for the electricity market and its business model.
- Coherent development. The development of the electricity market and economics in upstream and downstream industries must be coordinated in a way that emphasises electricity consumption rather than supply. The planning of the electricity market, regional strategy, transmission lines and energy fuel allocation for peak hours must be strengthened.
- Continuation of green development. The objectives are to continue increasing the share of non-fossil fuels in power generation, optimise the energy mix for power generation with hydropower and nuclear energy as the prioritised choices in the energy mix, promote green transformation in the power generation structure and develop a low-carbon approach to secure a stable and economic supply of electricity in the long-term.
- Continuation of the open market. Domestic and international resources and markets must be combined to implement a 'One Belt, One Road' strategy, especially to export nuclear energy, hydropower and thermal power to overseas markets.
- Allocation concerning development. Trading in the electricity market must begin by establishing an electricity market trade platform, enhancing the service level of the electricity industry and accelerating the upgradation of the power distribution network.

Furthermore, on 30 November 2015, China announced reforms of its electricity sector to improve competition in the marketplace. These reforms will end the monopoly of electricity distribution by SOEs. The government will expand pilot programmes related to the cost of building transmission lines, thereby allowing electricity consumers to directly negotiate with electricity generators (OilPrice, 2015). In November 2015, the NEA issued a draft document called 'Basic Rules for Electricity Market Operations', which calls for expansion of longer-term markets based on contracting between generators on one side and large end users or retail companies on the other.

In summary, electricity market reform has mainly taken the form of expanded direct trading. This is partly in reaction to pressure from large users for lower electricity prices. Given their interest in finding a use for excess capacity, coal-fired generators have also been supportive of the emphasis on direct trading. Policymakers have proceeded cautiously so far, limiting the access of relatively inefficient end users, in line with China's longstanding policies on differential pricing.

In recent years, China has made some achievements in electricity market reform. Power trading centers have been set up. Power transmission and distribution price reform has realised a full coverage of provincial-level power grids. Power generation and consumption schedules have been orderly deregulated. Market-oriented power trading mechanism has improved gradually. Power distribution and retail businesses have been liberated accelerately. Electricity retailers have also ballooned.

In August 2017, NDRC and NEA jointly issued the Notice on Pilot Work of Electricity Spot Market Construction, designating eight regions, including Guangdong, Inner Mongolia, Zhejiang, Shanxi, Shandong, Fujian, Sichuan and Gansu, as the first pilot areas to start electricity spot market after launching electricity markets for monthly and quarterly prices. Southern China Power Gird first entered a simulated trial operation (NDRC, 2017d).

In December 2018, the State Grid Corporation launched its first trial operation of the spot electricity market in Gansu and Shanxi. This marks a great step forward in the pilot construction of the first batch of spot electricity market in China and a new stage in the reform of the national electricity market. China will

further promote the reform of electricity and continue to move to a full wholesale and retail competition market.

ENERGY EFFICIENCY

In June 2015, the Chinese Government announced its intention to develop an energy revolution that focuses on reducing energy consumption, increasing energy supply and improving energy efficiency. With regard to the energy efficiency improvement policy, there are two major strategies (USCBC, 2017).

- Eliminate inefficient facilities. In May 2014, the NEA issued a notice called the '2014 Elimination of Outdated Production Capacity for the Power Industry'. Shortly after this notice was issued, provincial-level NDRCs launched implementation plans. Meanwhile, the central government has made plans to develop large-scale power plants and combine heat and power stations to replace small power stations. At the State Council executive meeting in June 2014, Prime Minister Li Keqiang stated that new coal power plants would be prohibited in the Beijing, Tianjin and Hebei regions. Instead, large-scale coal power plants in Central and Western China will play a more significant role in power production and transmission.
- Establish a market-oriented energy pricing mechanism. Energy inefficiency in China is mainly caused by governmental control of energy pricing and the monopoly of SOEs. To encourage competition and weaken the power of SOEs, the Chinese Government will invite more private companies into the sector through a bidding process for power transmission, distribution and sales as part of the policy reform.

On 23 April 2015, the State Council introduced 80 pilot projects to attract private investments to infrastructure projects. These projects include hydropower, wind power, PV power, oil and gas pipelines, energy storage facilities, the modern coal chemical industry and the petrochemical industry. The State Council indicated that these projects would be put out to public tender to attract private capital through joint ventures, sole proprietorship or franchise arrangements. With regard to the next step, the government will release more projects from other sectors. These will include oil and gas exploration and water conservancy.

Carbon-trading schemes are also being used by the central government to promote market-based energy-pricing structures. Since October 2011, China has launched pilot carbon markets in two provinces (Hubei and Guangdong) and five cities (Beijing, Tianjin, Shanghai, Chongqing and Shenzhen). Under the Draft National Regulation, the Chinese carbon market will be a two-tier system where the applicable central government department will be responsible for regulating and supervising the Chinese carbon market at the economy level. The central government will determine greenhouse gas (GHG) categories, the scope of industries and the criteria of the companies or entities that the Chinese carbon market will cover. It will also approve, supervise and regulate the carbon exchanges. The local governments will have primary responsibility for implementation and monitoring in their jurisdictions. On 19 December 2017, China formally launched the national carbon market, and the first phase of this market only covers power stations. In the second phase, it will start the quota simulation trial of trading market in power sector. In the third phase, it will launch spot trading in power sector, and after stable operation, it will expand to other seven sectors such as petrochemical, chemical, building materials etc. (NDRC, 2017e).

RENEWABLE ENERGY

China's renewable energy sector is growing faster than its fossil fuels and nuclear energy sector. In 2015, China became the world's largest producer of PV power at 43 GW installed capacity. China also led the world in the production and use of wind power and smart grid technologies, generating almost as much water, wind and solar energy as all of France's and Germany's power plants combined.

China will spend CNY 2.5 trillion (USD 361 billion) on renewable power development by 2020, according to the latest strategy for the Thirteenth Five-Year Plan (2016–20). China's goal of generating 20% of its energy from non-fossil fuel sources by 2030 will require the installation of an additional 800–1 000 GW of renewable energy, an amount which is equal to the current size of the entire US electricity grid.

To better utilise renewable resources and reduce waste, the NDRC and NEA jointly issued the Clean Energy Consumption Action Plan (2018–2020) on 30 October 2018. As part of the new quota system,

minimum targets for renewable power consumption will be set for each region in China. The goal for 2020 is to solve the problem of renewable energy integration to power grid, where average utilisation rates for wind power, PV power and hydro power should reach about 95% while the curtailment is controlled at a reasonable level at around 5%; nuclear power nationwide should be safely and securely integrated into the power grid (NDRC, 2018a)

WIND

Wind offers one of the greatest opportunities for renewable energy growth in China. During 2007–14, China's wind energy capacity increased nearly 25 times, growing from 6.0 GW to 148.6 GW, and it is expected to continue to grow. Since 2010, China has been the largest wind power producer in the world. In 2016, the electricity generation output of wind reached 241 TWh, making it the third-most popular energy source in the economy after coal (3 906 TWh) and hydro (1 150 TWh) (EGEDA, 2017).

In 2016, China added 19.3 GW of wind power generation capacity and generated 241 TWh of electricity, representing 4% of the total economy's electricity consumption. Both China's installed capacity and new capacity in 2017 are the largest in the world by a wide margin, with the next largest market, the United States, adding 8.2 GW in 2016 and having an installed capacity of 82.2 GW. By the end of 2016, China's large-scale wind power capacity had reached 142 540 MW, which is 25.8% more than the previous year's level. China is estimated to have 250 GW of wind capacity by 2020 as part of the government's pledge to produce 15% of all electricity from renewable resources by that time.

However, the wind power industry faces the challenge of wind power curtailment because of the limitations of wind farm grid connections and grid capacity. The abandonment of wind power has occurred in China since 2010 and reached a peak in 2012, with 21 billion kWh of wind power electricity. This constituted just 17% of wind power electricity generated in that year, leading to a direct economic loss of CNY 100 billion. In 2013, the situation improved because the wind power curtailment rate fell to 11% and decreased further to 8.5% in 2014. In 2016, the average utilisation of wind power in China was 1 742 hours, 14 hours more compared with that in 2015; the abandoned wind power represented 49.7 billion kWh, with the average wind abandoning rate being 17.1% (NEA, 2017).

SOLAR

The solar PV industry in China has long depended on subsidies and is expected to experience a crucial period of transformation in 2016–20. Under the economy's energy transformation policy, China's solar PV industry is changing towards intelligent manufacturing for stronger competitive advantages. This is because China is endeavouring to accelerate energy technology innovation to construct a clean, low-carbon and high-efficiency energy system.

In 2015, China's installed solar PV capacity surpassed Germany and had the largest capacity in the world at 43 GW (PV Magazine, 2016). Indeed, China has been the world's largest market for solar PV since 2013, when it had 17.5 GW.

In 2016, China added 34.4 GW of solar PV generation capacity, and China's accumulated installed capacity reached 77.4 GW, including 67.1 GW of centralised PV power plant capacity and 10.3 GW of distributed PV. The total generation in 2016 was 66.2 TWh, constituting 1% of the economy's power generation.

In December 2016, the NEA issued the Thirteenth Five-Year Plan for Solar Energy Development, setting a target for installed solar power generation capacity of 110 GW by 2020, including 105 GW of solar PV capacity. The basis of this target is that the economy will continue to expand solar PV generation during the 13th FYP period. In addition, NDRC solicits opinions on reducing the benchmark on-grid price of electricity generated by wind and solar PV power every couple of years. The opinions requested are those of local governments and power companies. The intention is that a lower price will help the industry to expand (Xinhua Finance Agency, 2015).

In 2017, China surpassed its 2020 solar PV target with installed capacity reaching 130 GW, accounting for 32.4% of the global total (CEC, 2018). To promote a healthy and sustainable development of the PV industry and speed up the withdrawal of subsidies, China released a Circular Regarding Matters Related to

Photovoltaic Power Generation on 31 May 2018. It stopped approving any new subsidised utility-scale PV power stations in 2018 and set a cap of 10 GW on the distributed PV projects connected to the grid before 31 May. It also reduced feed-in tariffs (FiT) for new distributed PV projects (NDRC, 2018b).

According to the NDRC, solar construction costs in China were decreased by 45% from 2012 to 2017. In January 2019, the NDRC and NEA jointly issued the Circular on Actively Promoting Subsidy Free Wind and Solar Power Projects. Under the new policy, China will set up several pilot wind and solar power projects without subsidies, optimise the investment environment, support the construction of pilot projects involved in cross-regional deliveries, encourage the pilot projects obtain reasonable compensation from Green Certificates trading and encourage the power grid to support the development of the pilot projects by guaranteeing the integration and the priority electricity purchase of pilot projects and lowering transmission fees. Now, some regions with good natural resources and firm demands have already achieved subsidy-free or grid price parity conditions (NDRC, 2018c).

HYDRO

Hydropower is a significant part of China's renewable energy mix. However, it cannot be scaled up indefinitely. China is the world leader in terms of hydropower capacity. The installed capacity at the end of 2016 was 332 GW, including 27 GW of pumped storage, making it the economy's single largest renewable power source by far. Although China has set a goal to increase capacity to 350 GW by 2020, the potential for new large-scale hydropower capacity is limited. Thus, the proportion of hydropower in China's renewable energy mix is likely to decrease in the near future (EGEDA, 2017).

The pumped storage hydroelectricity industry has significantly developed in recent decades due to rapid development in the modern renewable energy industry. The deployment location of pumped storage stations are also becoming more diverse, and new pumped storage stations are constructed near energy basements or supply centres rather than demand centres to smooth the output of solar farms and wind farms or store energy during the off-peak time. By May 2017, China's installed capacity and under constructed capacity reached 28 GW and 31 GW, respectively, which are both the largest in the world. According to Hydro Power Development Plan for 13th Five-Year Plan, China targets to have 40 GW of pumped storage capacity by the end of 2020.

NUCLEAR

Following Japan's Fukushima Daiichi crisis in early 2011, China reviewed its nuclear plant safety requirements. On 25 October 2012, the State Council approved new safety rules and a nuclear power development plan, which prioritises safety and quality in Chinese regulations and sets a target of 58 GW nuclear capacity by 2020 (WNA, 2018). The Chinese Government has said that it will approve a small number of plants along the coast in accordance with new stricter safety rules, and no plants were approved for inland areas during the Twelfth Five-Year Plan (2011–15) (NNSA, 2013). According to the Energy Development Strategy Action Plan 2014–20, all new nuclear plants must meet the strictest world safety standards (SCC, 2014).

Because China is striving to reduce air pollution from coal-fired power plants, it is aiming to construct more nuclear power plants. By the end of 2016, 38 nuclear power reactors were in operation with 19 under construction and more to be constructed. In 2016, the electricity generation output of nuclear was 213 TWh, which was approximately 3.6% of the total power generation. The installed capacity was 26 GW, which was approximately 1.8% of the total capacity. The year 2015 also saw the beginning of the greatest number of nuclear power projects in a single year in China since the 2011 crisis, with eight new units being approved for construction.

No new nuclear projects were approved for construction in 2016. However, some projects were in the process of evaluation and were considered to start construction in the near term. These included the CAP1400 demonstrative project in Rongcheng City, Shangdong Province and the second phase of AP1000 nuclear reactors in Lufeng City, Guangdong Province; Sanmen City, Zhejiang Province; and Xu Dapu, Liaoning Province.

China also significantly focuses on the next generation of nuclear power. In China's nuclear development plan, pressurised water reactors (PWRs) are to be the main type of nuclear reactor before 2030.

Fourth-generation reactors (high-temperature, molten-salt, gas-cooled fast, sodium-cooled fast and lead-cooled fast reactors) with improved operating safety features will be available for commercial construction in approximately 2030. Then, the fourth-generation reactors will gradually replace the current PWRs. By 2040, new technology is projected to play an important role in China's energy supply (World Nuclear, 2016).

In December 2012, the Shidaowan nuclear power plant in Shandong Province, as China's first demonstration-scale 4th generation nuclear power plant, restarted construction as the original plan was cancelled after the Fukushima Daiichi crisis in 2011. This high-temperature gas-cooled technology nuclear power plant was projected to be completed and begin generating electricity at the end of 2018.

By the end of 2018, China has approximately 45 nuclear power reactors in operation, 15 under construction and more about to start construction. Taishan 1, the world's first European/Evolutionary Pressurised Water Reactor (EPR), and Sanmen 1, the world's first AP1000, have been put into operation consecutively, which marked an important milestone in the Chinese nuclear development programme. China has a strong desire to let domestic nuclear technology go global and promote 'Belt and Road' initiative. Hualong One technology, China's independent Gen-III nuclear technology was first applied in Fuqing-5 nuclear reactor. Pakistan is the first market that uses Hualong One reactor in its Karachi nuclear power plant. It has already been used in the Bradwell project in the United Kingdom. Some other also expressed interest in the technology, including Argentina, Thailand, and Indonesia etc. Even though there is a trade war between China and the United States and it has already influenced the nuclear power development, it has no practical effects on China's own independent Gen-III nuclear technology, Hualong One technology (WNA, 2019).

CLIMATE CHANGE

In June 2015, China submitted a climate action plan called the Intended Nationally Determined Contribution (INDC) to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC). In the action plan, China reaffirmed the bilateral climate deal agreement with the United States in November 2014. It also pledged to reach a total emission peak by approximately 2030 and try its best to peak earlier. Further, China committed itself to increase the share of non-fossil fuels in its energy mix to 20% by 2030.

China also announced two goals in addition to the November deal with the United States. These are to reduce carbon intensity by 60% to 65% based on the 2005 level and restore approximately 4.5 bcm of forested land beyond the 2005 level. This is an important change because the economy is increasingly decoupling its economic growth from greater growth in carbon emissions.

The cooperation between China and the United States on addressing climate change has injected momentum into UNFCCC negotiations. In 2013, the United States and China also came to a joint bilateral agreement to work through the existing Montréal Protocol and UNFCCC mechanisms to reduce the use of HFCs, which are potent GHGs emitted through a variety of industrial processes.

In November 2016, China's Greenhouse Gas (GHG) Control Work Plan and Power Sector Development Thirteenth Five-Year Plan were issued, while its Ecological and Environmental Protection Thirteenth Five-Year Plan was released later. Covering a comprehensive set of policies, these documents lay out benchmark goals for 2020 that will put China on track to overachieve its 2030 Paris goals, strengthen enforcement of environmental laws and standards and continue its transition to low-carbon energy.

In July 2018, China released a Three-year Action Plan to Win the Battle for a Blue Sky (2018–2020). The old Air Pollution Action Plan released in September 2013 expired at the end of 2017, which set the PM 2.5 (atmospheric particulate matter that has a diameter of less than 2.5 micrometers) reduction targets of 25%, 20% and 15% in the Beijing-Tianjin-Hebei Area, Yangtze River Delta and Pearl River Delta, respectively, between 2013 and 2017, had made great improvements to air quality. The new plan has given the timetable and roadmap for improving air quality in a larger area. By 2020, total emissions of sulphur dioxide and nitrogen oxides should decrease by more than 15% from 2015 levels, while PM 2.5 density should fall at least 18 percent from the 2015 levels. The rate of days with good air quality should reach 80 percent annually, and the percentage of heavily polluted days should drop by 25 % or more from the 2015 levels in cities at prefecture level and above. To achieve the goals, the new action plan puts forward six measures, including adjusting and optimising industrial structure to promote its green development;

accelerating the restructure of energy mix to build a clean, low-carbon and efficient energy system; actively restructuring the transport structure to develop a green transportation system; optimising land-use systems to enhance pollution management; implementing special actions to reduce pollutant emissions and strengthening regional joint control to deal with heavily polluted weather effectively (SCC, 2018).

By the end of 2017, China had cut carbon dioxide emissions per unit of GDP by 46% from the 2005 level, meeting its 2020 carbon emission target, which is reducing carbon emissions by 40-45% by 2020 from the 2005 level, three years ahead of schedule with the help of the economy's carbon trading system. China had raised the forest stock volume by 2.1 billion cubic meters from the 2005 level, meeting the goal of a 1.3-billion-cubic-meter increase by 2020(UNCC, 2018).

NOTABLE ENERGY DEVELOPMENTS

THE THIRTEENTH FIVE-YEAR ENERGY DEVELOPMENT PLAN (2016–20)

The year 2016 marks the beginning of China's thirteenth five-year development period. In December 2016, the NDRC and NEA finally unveiled the Thirteenth Five-Year Energy Development Plan (2016–20) (NDRC, 2017b). It includes a breakdown of the energy sector, with more detailed targets to better guide policymaking, government spending and project planning in the sector.

In the plan, China is determined to reduce coal's share in the economy's energy mix, lowering its 2020 percentage in primary energy consumption from 62% to 58%. China is also aiming towards more renewables: the installed capacity of wind energy and solar energy should reach 'more than 210 GW' and 'more than 110 GW' by 2020, respectively. By 2020, the proportion of non-fossil fuels should rise above 15% from 12% in 2015. Natural gas should constitute at least 10% of the energy consumption.

STRUCTURAL CHANGE AND A GREEN LEAP FORWARD

To reduce GHG emissions and address air quality impacts, China needs to move its energy structure from fossil fuel dominance to renewables and nuclear. A host of policies and regulations support China's ambitious push for renewables and encourage energy efficiency and domestic renewable energy deployment. China's five-year plans have pursued an aggressive renewable energy policy, pushing for an increase in renewable energy production to 15% of the total energy mix by 2020. In March 2015, China's State Council announced a plan to reform the power sector by improving the share of renewable energy in electricity generation, encouraging competition and developing greater efficiency.

Heavy government investment and subsidies could be the key drivers for success with these goals. According to the Statistics Bureau, China's solar and wind energy capacity increased by 80.6% and 14.9%, respectively, in 2016, while coal consumption dropped by 4.7%. China broke a new record in 2016, installing a record 34.5 GW of solar, including 4.2 GW of distributed PV power plants (a 200% increment compared with that in 2015) and 30.3 GW of centralised PV plants. Approximately 72% of these PV power plants were constructed outside the north-west area, which is rich in solar energy.

China has implemented supply-side reform in coal mining and coal-fired power generation since 2015 and has made significant progress in 2017. According to official data from the NDRC, China has eliminated over 150 Mt of unnecessary coal mining capacity and 50 GW of outdated coal-fired power generation capacity during 2017.

NEW ENERGY VEHICLES

A proposal in the Thirteenth Five-Year Plan states that the Chinese Government will implement a neighbourhood electric vehicle (NEV) popularisation programme. It will also upgrade the industrialisation level for electric car manufacturing to ensure the long-term development of China's NEV industry. The proposal expects that a market-oriented NEV industrial system will be developed by 2020. Further, an independent, controllable and complete NEV industrial chain will be built. This NEV industrial chain will produce three million NEV units each year.

The proposal has three aims:

- A greater than 80% share of the Chinese NEV market by domestically produced brands;

- The placement of two Chinese vehicle enterprises among the world's top 10 for NEV sales, with overseas sales constituting 10% of the total sales; and
- Automobile industry advances through NEV development, while foreign automobile makers remain inactive in promoting NEV.

At the end of 2016, Shanghai was the top city in the world for ownership of NEVs, according to the data provided by the automobile registration department of Shanghai.

NATIONAL CARBON EMISSION TRADING SYSTEM

On 19 December 2017, the Chinese Government launched the carbon emission trading system. This system covers approximately 1 700 coal-fired and gas-fired power generation enterprises, which emit over 26 000 tonnes of CO_2 per year and have emitted over 3 billion tonnes of CO_2 (39% of the total economy). Although the first phase of the system only covers the power generation industry, it is still the biggest carbon emission trading system in the world (1.5 times that of the European Union Emission Trading System [EU ETS]). Furthermore, the whole system needs approximately two years to optimise and test the trading system and establish the necessary policies and regulations. Currency trading will begin in 2019. The early launch of China's cap-and-trade system is a promising start, and this action has a great opportunity to become a very powerful policy that will cut carbon pollution cost-effectively and help China peak in its total CO_2 emissions before 2030.

INTERNATIONAL ENERGY COOPERATION UNDER 'THE BELT AND ROAD INITIATIVE'

Under the 'the Belt and Road Initiative', China has conducted a series of energy cooperation initiatives with other economies. In April 2017, the Sino-Myanmar oil and natural gas pipelines, which connect the south-west area of China with Myanmar, began operations. In April 2017, the southern Kazakhstan natural gas pipeline, which will deliver over 5 bcm per year to China, completed construction. On 1 January 2018, an extension of the East Siberia-Pacific Ocean oil pipeline between Russia and China started operations, doubling Russia-to-China export volumes from 15 Mt/a to 30 Mt/a (almost 220 million barrels/a).On April 28 2019, the Second Belt and Road Roundtable for Oil & Gas Cooperation was held at CNPC headquarters in Beijing, which triggered another wave of energy cooperation with the theme of building a community of shared interest with all parities based on large projects construction along the one belt and one road. Six agreements or MOUs on energy interconnection were signed at a side event hosted by the Global Energy Interconnection Development and Cooperation Organization. The agreements were signed between GEIDCO (Global Energy Interconnection Development and Cooperation Organization), UN agencies, governments, and international organizations in an effort to promote energy interconnectivity, which is key to global growth as part of the Belt and Road Initiative.

ENERGY STORAGE TECHNOLOGY

Since power supply and consumption are simultaneous while power load is fluctuant, energy storage plays a more and more significant role in balancing electricity supply and demand, keeping the stability of power grid, particularly with the rapid growth of intermittent energy sources such as wind and solar power. There are several ways of energy storage technologies such as mechanical energy storage, magnetic energy storage, electrochemical energy storage, chemical energy storage and heat energy storage. Energy storage now is widely applied to power grids as a flexible power source or power load from power generation, transmission and distribution to the end use to shift the peak load and regulate frequency and even provide ancillary services for power grid as well.

China has paid great attention to energy storage development. It calls for actively carrying out demonstration projects for energy storage and promoting coordinated and optimised operation of energy storages with renewable energy and power system in the 13th Five-Year Plan for Energy Development. The NDRC released the 13th Five-Year Plan for Energy Technology Innovation in 2016, calling for breakthrough in large capacity of energy storage technology to support renewables integration, electric vehicles and micro-grid development. In 2017, China released Guidance on Promoting the Development of Energy Storage Industry and Technology, giving the path of energy storage development at a national level in two stages for the next 10 years (NDRC, 2018d). The first stage is to realise the transition of energy storage from R&D demonstration to initial commercialisation mainly during the 13th Five-Year Plan Period. The

second stage is to realise the transformation from initial commercialisation to the large-scale development mainly during the 14th Five-Year Plan Period. In 2018, the NEA released the Implementation Plan on Strengthening Standardisation of Energy Storage Technology to call for public comments to set up a systematic coordination mechanism and standard system of energy storage technology and to lead the development of energy storage technology and industry. All such policy support will boost the energy storage development in China.

According to the data from the China Energy Storage Alliance (CNESA), there were electrochemical energy storage projects completed or under construction between 2016 and June 2017 with the capacity more than 1.35 GW, and the energy storage capacity growth was 9.6 times that of growth between 2000 and2015 (CNESA, 2017).

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China Electricity Council (CEC)—www.cec.org.cn

Energy Research Institute of National Development and Reform Commission (ERI)—www.eri.org.cn

Ministry of Ecology and Environment (MEE)—http://www.mee.gov.cn/

Ministry of Industry and Information Technology (MIIT) — www.miit.gov.cn

Ministry of Housing and Urban-Rural Development—www.mohurd.gov.cn

Ministry of Science and Technology—www.most.gov.cn

National Bureau of Statistics (NBS)—www.stats.gov.cn

National Development and Reform Commission (NDRC)—www.ndrc.gov.cn

National Energy Administration (NEA)—www.nea.gov.cn

National Nuclear Safety Administration (NNSA)—nnsa.mep.gov.cn

Standardisation Administration—www.sac.gov.cn

World Nuclear Association (WNA) —http://www.world-nuclear.org

HONG KONG, CHINA

INTRODUCTION

Hong Kong, China is a special administrative region of the People's Republic of China. It is a world-class financial, trading and business centre comprising 7.3 million people and is located at the south-eastern tip of China. Hong Kong, China has no natural resources and completely relies on imports to meet its energy requirements. The energy sector comprises investor-owned electricity and gas utility services.

In 2016, the per capita gross domestic product (GDP) of Hong Kong, China was USD 54 413 (2011 USD purchasing power parity [PPP]), the third-highest among the APEC economies. The GDP increased by 18% in real terms to USD 399 billion after 2010 (2011 USD PPP) (EGEDA, 2018). The service sector remained the dominant driving force of the overall economic growth, constituting 92% of the GDP in 2016 (Hong Kong Yearbook, 2017). Hong Kong, China is driven by its financial, higher value-added and knowledge-based services. To stay competitive and attain sustainable growth, Hong Kong, China needs to restructure and reposition itself not only in light of the challenges posed by globalisation but also due to its closer integration with mainland China. The Mainland and Hong Kong Closer Economic Partnership Arrangement (CEPA) is a manifestation of the advantages of 'one country, two systems'. As part of the liberalisation of trade in goods under CEPA, all products imported from Hong Kong, China to mainland China enjoy tariff-free treatment.

With the support of mainland China under CEPA and the Framework Agreement on Hong Kong/Guangdong Cooperation, Hong Kong, China is poised to reinforce and enhance its status as an international centre for financial services, trade and shipping, in addition to being an advanced global manufacturing and modern services base. The central government has announced that it will promote the restructuring and upgrading of traditional industries, strengthen emerging industries as well as widen and deepen the external economic and trade relations under the principle of 'one country, two systems'. It will also foster the diversification of its financial services, provide advice on planning concepts and other areas to Guangdong province and continue to negotiate with Macao on the establishment of a closer economic partnership arrangement. Furthermore, it will expand the network and enhance the functions of its offices in the mainland and will establish six more liaison units (Policy Address, 2016).

Table 1: Key data and economic profile, 2016

Key data		Energy reserves	
Area (km^2)	1 106	Oil (million barrels)	–
Population (million)	7.3	Gas (billion cubic metres)	–
GDP (2011 USD billion PPP)	399	Coal (million tonnes)	–
GDP (2011 USD PPP per capita)	54 413	Uranium (kilotonnes U)	–

Source: EGEDA (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Hong Kong, China has no domestic energy reserves or petroleum refineries; it imports all of its primary energy needs. A substantial share of imported energy is converted into secondary energy, such as electricity and gas, for final consumption. The total primary energy supply in Hong Kong, China was 14 million tonnes of oil equivalent (Mtoe) in 2016, 0.34 Mtoe higher than that in the previous year. Coal maintained the highest

share in the total primary energy supply (46%), followed by oil (26%), gas (21%) and other sources (6.2%) (EGEDA, 2018).

In 2016, the total installed electricity generating capacity in Hong Kong, China was 12 650 MW (Hong Kong Energy Statistics, 2017). All locally generated power is thermal-fired. Electricity is supplied by CLP Power Hong Kong Limited (CLP Power) and Hong Kong Electric Company Limited (HKE). CLP Power supplies electricity from its Black Point (2 500 MW), Castle Peak (4 108 MW) and Penny's Bay (300 MW) power stations. Natural gas and coal are the main fuels used for electricity generation at the Black Point and Castle Peak power stations. CLP Power has arrangements with China National Offshore Oil Corporation and PetroChina International Company to procure gas supplies from the mainland. CLP Power has commenced constructing a 550-MW gas-fired generation unit at Black Point Power Station, thereby aiming to commission the unit before 2020. It is proposing to construct an offshore LNG terminal in Hong Kong waters to enable direct access to a range of gas sources from around the world and strengthen the reliability of its fuel supplies. HKE's electricity is supplied by Lamma Power Station, which has a total installed capacity of 3 237 MW. Natural gas used at HKE's power station is mainly imported through a submarine pipeline from the Dapeng LNG terminal in Guangdong, mainland China. HKE has also operated wind turbines (capacity 800 kW) since 2006 and a photovoltaic (PV) system (1 MW) since 2010 (CLP, 2015a; HKEI, 2015a, 2015b, 2015c).

While natural gas and liquefied petroleum gas (LPG) are the main types of gaseous fuels used in Hong Kong, China, town gas serves as another fuel product. Town gas is locally manufactured from naphtha and natural gas and is distributed by the Hong Kong and China Gas Company Limited (Towngas, 2017).

FINAL ENERGY CONSUMPTION

In 2016, the final energy consumption in Hong Kong, China was 6 787 kilotonnes of oil equivalent (ktoe), an increase of 0.39% from the previous year's level. The residential and commercial sectors constituted the largest share of energy used (64%), followed by the transport sector (31%) and the industry sector (4.9%). By energy source, electricity and 'others' constituted 56% of end-use consumption, followed by petroleum products (35%) (EGEDA, 2018).

Town gas and LPG are the main types of fuel gas used in the domestic, commercial and industrial sectors. LPG is also used as fuel for taxis and light buses, while natural gas is used for electricity generation and town gas production.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	66	Industry sector	331	Total power generation	38 199
Net imports and others	31 003	Transport sector	2 112	Thermal	38 153
Total primary energy supply	14 400	Other sectors	4 344	Hydro	1.7
Coal	6 695	Non-energy	0	Nuclear	–
Oil	3 712	Final energy consumption*	6 787	Others	45
Gas	3 028	Coal	0		
Renewables	68	Oil	2 343		
Others	896	Gas	610		
		Renewables	44		
		Electricity and others	3 790		

Source: EGEDA (2018) (data collected in September 2018).

**Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

'Total power generation' does not include electricity generated by hydro and nuclear energy facilities located in the mainland.

ENERGY INTENSITY ANALYSIS

In terms of primary energy or final energy consumption, the energy intensity of Hong Kong, China is the lowest among APEC economies. The primary energy intensity in 2016 was only 36 tonnes of oil equivalent per million USD (toe/million USD), while the final energy consumption was only 17 toe/million USD (EGEDA, 2018).

Hong Kong, China endeavours to achieve sustainable development and fully support APEC's Honolulu Declaration in 2011, seeking to reduce 45% of its energy intensity by 2035. To step-up energy efficiency and conservation efforts, various policies have been implemented. These include the Mandatory Energy Efficiency Labelling Scheme, Energy Efficiency Registration Scheme for Buildings, Building Energy Efficiency Ordinance, Scheme on Fresh Water Cooling Towers and Charter on External Lighting (GHK, 2017).

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	35.98	36.07	0.25
Total final consumption	17.3	17.0	–1.7
Final energy consumption excl. non-energy	17.3	17.0	–1.7

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Despite geographical constraints in developing renewable energy (RE), the government has been implementing various plans to develop its potential. Actions such as developing wind energy, floating PV farms and turning various types of waste into RE have already been taken to address the issue. In 2016, the share of modern renewable energy to the total final energy consumption was approximately 0.68%. The situation is expected to improve with the materialisation of various RE projects.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	6 760	6 787	0.39
Non-renewables (Fossils and others)	6 715	6 740	0.38
Traditional biomass*	3.4	2.4	–29
Modern renewables*	45	46	2.2
Share of modern renewables to final energy consumption (%)	0.67	0.68	1.8

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered to be modern renewables, although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The government of Hong Kong, China has four key energy policy objectives: to ensure that the energy needs of the community are met safely, efficiently and at reasonable prices while minimising the environmental impact on the production and use of energy (ENB, 2017a). The government also promotes efficient use and conservation of energy. In combating climate change, reducing greenhouse gas (GHG) emissions and developing a low-carbon economy, Hong Kong, China's emission reduction strategy emphasises the wider use of cleaner and low-carbon energies and fuels in power generation.

In keeping with the free market economic policy of Hong Kong, China, the government intervenes only when necessary to safeguard the interests of consumers, ensure public safety and protect the environment. The government works with the oil companies to maintain strategic reserves of gas, oil and naphtha. It monitors the performances of the power companies through the Scheme of Control Agreements (SCAs). The current SCAs were signed in 2008 and will expire in 2018. New SCAs were signed in April 2017 to promote quality services, cleaner energy sources, energy efficiency and conservation. In addition, the new SCAs support further development of RE to supplement conventional power generation as well as public awareness and public participation (ENB 2017b, 2017c).

Specifically, Hong Kong, China proposes to optimise the fuel mix for power generation. In 2014, the government conducted a public consultation on the future fuel mix for electricity generation in Hong Kong, China to solicit the public's views on the subject. Two fuel mix options were proposed for public consultation. They were (i) to import more electricity through purchase from the mainland power grid and (ii) to use more natural gas for local generation. Having considered the public's views, the government plans to increase the percentage of natural gas generation to approximately 50% by 2020 and maintain the current interim measure of importing 80% of nuclear output from the Daya Bay Nuclear Power Station so that nuclear imports would constitute approximately 25% of the total fuel mix. Subject to public views on tariff implications, the government is preparing to develop more RE and enhance efforts to promote energy saving. The remaining demand will be met by coal-fired generation. This will help Hong Kong, China achieve the environmental targets for 2020, including its target to reduce carbon intensity by 50–60% in 2020 compared with the 2005 level. Hong Kong, China will also endeavour to enhance energy efficiency, promote green buildings, advocate electricity savings, facilitate low-carbon transport, reduce waste and develop facilities to turn waste into energy (ENB, 2017d, CLP, 2015c).

A major target for the economy's energy policy, as stated in the Energy Saving Plan for Hong Kong's Built Environment 2015–2025+ unveiled in 2015, is to reduce its energy intensity by 40% by 2025 based on the 2005 level. The actions are as follows:

- Promoting energy saving and green building development by enhancing the green performance of government buildings, public housing and public sector developments;Conducting periodic reviews to expand and/or tighten relevant energy-related standards, including the statutory requirements under the Buildings Energy Efficiency Ordinance, Building (Energy Efficiency) Regulation and Energy Efficiency (Labelling of Products) Ordinance;
- Updating schools and public education programmes and strengthening government energy saving efforts by appointing green managers and energy wardens and encouraging public sector institutions to save energy; and
- Supporting community campaigns through government funding schemes and collaborating with key energy consumers in the commercial sector to develop sector-specific campaigns to promote energy saving. More importantly, the Secretary for the Environment is engaging environment leaders to accelerate green building adoption in the private sector.

ENERGY MARKETS

A memorandum of understanding (MOU) was signed by the Hong Kong, China Government and the National Energy Administration of the People's Republic of China on 28 August 2008. To ensure the

prosperity and stability of Hong Kong, China, the central government of China will continue to support energy cooperation between the mainland and Hong Kong, China over the long-term. This will include efforts to provide a stable supply of nuclear electricity and natural gas to the economy. The intergovernmental MOU contemplates the delivery of natural gas to Hong Kong, China from three sources (CLP, 2008a):

- Existing and new gas fields planned for development in the South China Sea;
- A second west-to-east gas pipeline, transporting gas from Central Asia; and
- An LNG terminal to be located in Shenzhen, mainland China.

The MOU also contemplates the ongoing supply of nuclear-generated electricity to Hong Kong, China. An extension of the Guangdong Daya Bay Nuclear Power Station joint venture and supply contracts was approved by the Hong Kong, China Government in September 2009. These contracts will enable the continued supply of non-carbon-emitting electricity to Hong Kong, China for an additional term of 20 years from 2014. CLP Power has successfully negotiated an increase in the portion of electricity supply from the Guangdong Daya Bay Nuclear Power Station to Hong Kong, China, increasing the plant's generation from 70% to approximately 80% from late 2014 to 2018 (CLP, 2015b, 2015c).

ENERGY EFFICIENCY

Buildings consume approximately 90% of the electricity used in Hong Kong, China. Therefore, one of the government's first priorities is to conserve the energy used by buildings. Efforts are being made to improve public awareness regarding energy efficiency to drive behavioural changes.

ENERGY DATA

To help monitor the energy situation, Hong Kong, China has developed an energy end-use database. The database provides useful insight into the energy consumption situation, including the energy consumption patterns, trends and usage characteristics of each sector and segment. A basic dataset is publicly available on the Internet. The government is able to analyse the current system based on the data and develop policy and strategy revisions for future implementation. The private sector can use the data to benchmark its own energy efficiency when seeking improvements in its energy consumption systems (EMSD, 2017a, 2018b).

BUILDINGS

To strengthen its efforts towards building energy conservation, the government has enhanced the regulatory system for building energy efficiency. The Buildings Energy Efficiency Ordinance was fully implemented on 21 September 2012. The three key requirements of the ordinance are as follows (EMSD, 2012):

- The developers or building owners of newly constructed prescribed buildings should ensure that the four key types of building service installations (air conditioning, lighting, electrical and lift and escalator installations) comply with the design standards of the Building Energy Code (BEC);
- When carrying out 'major retrofitting works', responsible persons of prescribed buildings (for example, owners, tenants or occupants) should ensure that the four key types of building service installations comply with the design standards of the BEC; and
- The owners of commercial buildings, including the commercial portions of composite buildings, should conduct an energy audit for the four key types of central building service installations in accordance with the Energy Audit Code (EAC) every 10 years. The first energy audit should be conducted within four years of the commencement of the ordinance in accordance with the timetable set out in Schedule 5 for that ordinance. The EAC 2018 Edition was issued on 16 November 2018, and it will take effect on 16 August 2019.

The BEC is reviewed once every three years to meet public desire, international trends and the latest technological developments. The first comprehensive review was completed in 2015, and the new standards required a further 10% improvement in energy efficiency. The BEC 2018 Edition was issued on 16 November 2018, and it will take effect on 16 May 2019, resulting in a more than 18 per cent improvement

compared with the 2012 edition. By the end of 2028, the implementation of the BEEO is expected to bring about an energy saving of some 27 billion kWh from both new buildings and existing buildings in Hong Kong, equivalent to the total annual electricity consumption of about 5.8 million households and a reduction in carbon dioxide emissions of about 19 million tonnes.

The government continues to utilise government buildings to demonstrate state-of-the-art energy-efficient designs and improve energy conservation technologies. These are based on an environmental performance framework that covers energy efficiency, GHG reduction, RE application, waste reduction, water management and indoor air quality. All newly built government buildings over 10 000 square metres should aim to obtain not lower than the second-highest grade under the Hong Kong Building Environmental Assessment Method (HK-BEAM).

In April 2009, the government promoted a comprehensive target-based green performance framework for new and existing government buildings and set targets for various aspects of environmental performance. It has achieved the target of a 5.0% savings on the total electricity used in government buildings from 2009–10 to 2013–14 after discounting activity changes, using electricity consumption in 2007–08 as the baseline. Building on this success, the government has set a new target of 5.0% savings in the electricity consumption of government buildings in the next five years from 2015–16 to 2019–20 under comparable operating conditions. This target uses electricity consumption from 2013–14 as the baseline.

In April 2009, the government introduced the Buildings Energy Efficiency Funding Schemes totalling HKD 450 million to subsidise environmental performance reviews and upgrades for communal areas in residential, commercial and industrial buildings. These schemes also cover energy/carbon audits and upgradation of the energy efficiency performance of building service installations. The subsidy can cover up to 50% of the expenditures. These funding schemes were closed in April 2012 (EMSD, 2012a).

Since 1998, the government has launched the voluntary Energy Efficiency Registration Scheme for Buildings (EERSB) to encourage building owners to outperform the statutory requirements by conferring upon them recognition and commendation through the scheme. The EERSB 2018 Edition was effective from 1 January 2018. Capital expenditure incurred on the construction of energy efficient building installations (include lighting, air conditioning, electrical and lift and escalator installations) registered under EERSB may be eligible for accelerated tax deduction (EMSD, 2015d).

WATER-COOLED AIR CONDITIONING SYSTEMS

Water-cooled air conditioning systems (WACS) using fresh water cooling towers are generally more energy efficient than air-cooled systems. Examples of adopting the energy-efficient WACS in Hong Kong, China include the WACS using fresh water cooling towers for individual buildings, WACS using seawater cooling for individual buildings and the large-scale district cooling system (DCS) for numerous buildings (EMSD, 2015a).

The government has implemented a DCS in the Kai Tak Development to supply chilled water for centralised air conditioning to buildings in the new development. The DCS is the first project of its kind implemented by the government. It is an energy-efficient air conditioning system as it consumes 35% and 20% less electricity compared with traditional air-cooled air conditioning systems and individual WACS using fresh water cooling towers, respectively. The project is scheduled to be implemented in three phases: Phases I and II were completed in 2013 and 2014, respectively, and the construction of Phase III commenced in 2013 and is expected to be completed by end 2025 (EMSD, 2015c).

ENERGY CONSUMPTION INDICATORS

Since 2001, the government has commissioned the development of energy utilisation indexes and benchmarking tools for the residential (6 groups), commercial (32 groups) and transport (41 groups) sectors. The tools assist stakeholders to compare the energy consumption performances of sectors and provide applicable advice regarding energy conservation (EMSD, 2017a).

ENERGY EFFICIENCY LABELLING

Hong Kong, China has a voluntary Energy Efficiency Labelling Scheme that covers 22 types of household and office appliances, including 13 types of electrical appliances (refrigerating appliances, washing machines,

non-integrated type compact fluorescent lamps (CFLs), dehumidifiers, electric cloth dryers, room coolers, electric storage water heaters, televisions, electric rice cookers, electronic ballasts, LED lamps, induction cookers and microwave ovens). The scheme also includes seven types of office equipment (photocopiers, fax machines, multifunction devices, printers, LCD monitors, computers and hot/cold bottled water dispensers) and two types of gas appliances (domestic gas instantaneous water heaters and gas cookers). The scheme also covers petrol passenger cars (EMSD, 2015b).

To further assist the public in choosing energy-efficient appliances and raise public awareness regarding energy saving, the government has introduced a Mandatory Energy Efficiency Labelling Scheme (MEELS) through the Energy Efficiency (Labelling of Products) Ordinance, Cap. 598. The MEELS covers eight types of products such as room air conditioners, refrigerating appliances, CFLs, washing machines, dehumidifiers, televisions, storage type electric water heaters and induction cookers. Under the MEELS, energy labels must be displayed on the products supplied in Hong Kong, China to inform consumers regarding their energy efficiency performance (EMSD, 2018a).

TRANSPORT

Transport constitutes approximately 18% of the total GHG emissions in the economy and is the second most significant contributor of emissions. To reduce carbon emissions from the transport sector, Hong Kong, China has undertaken the following efforts (EPD, 2018).

EXTENSION OF THE PUBLIC TRANSPORT SYSTEM

An extensive and energy-efficient public transport system in Hong Kong, China is instrumental in helping maintain low levels of GHG emissions. Approximately 90% of commuter trips are made each day via the public transport system. The government is committed to further expanding and upgrading its public transport infrastructure, with an emphasis on the railways (ENB, 2017d).

PROMOTION OF CLEANER VEHICLES

The government actively promotes the wider use of electric vehicles. The first registration tax (FRT) for electric vehicles has been waived until the end of March 2017. The government liaised with electric vehicle (EV) manufacturers and dealers to encourage them to introduce EVs to Hong Kong, China; as a result, the economy is one of the leading APEC economies in terms of EV use. The government has been working with the private sector to expand the charging infrastructure for EVs in Hong Kong, China. There are approximately 1 500 different types of public EV chargers, including over 340 medium chargers and around 220 quick chargers.

The government's ultimate policy objective is to have zero-emission buses running throughout the territory. As such, the government has allocated approximately HKD 213 million to fully subsidise the franchised bus companies to purchase 36 single-deck electric buses and 6 double-deck hybrid buses for trial usage. If the trial results are satisfactory, the government will encourage the franchised bus companies to use these green buses on a larger scale, considering affordability for the bus companies and passengers.

CREATION OF THE PILOT GREEN TRANSPORT FUND

To encourage the public transport sector and non-profit organisations to test green and innovative transport technologies, the government set up a HKD 300 million Pilot Green Transport Fund in March 2011 (GHK, 2015b). The government has been encouraging vehicle suppliers and technology companies to introduce more transport means and related technologies. Furthermore, it encourages the transport sector to carry out trials with subsidies from the fund. At the end of February 2016, 87 trials have been approved under the fund, including 67 electric commercial vehicles (taxis, light buses, buses and goods vehicles), 63 hybrid commercial vehicles (goods vehicles and light buses), 1 solar air conditioning system and 4 electric inverter air conditioning systems. Additionally, a ferry was retrofitted with a diesel-electric propulsion system and a seawater scrubber (ENB, 2017e).

PROMOTION OF BIODIESEL AS A MOTOR VEHICLE FUEL

Since 2007, the government has adopted a duty-free policy for biodiesel to facilitate the use of biodiesel in motor vehicles (Policy Address, 2007-08). In 2010, it introduced regulatory controls for motor vehicle biodiesel to help safeguard its quality and encourage drivers to use it (EPD, 2010).

RENEWABLE ENERGY

Despite the geographical and natural constraints in developing wind energy, both power companies (CLP Power and HKE) have started to explore the feasibility of offshore wind farm projects.

CLP Power is currently conducting a feasibility study for an offshore wind farm. An offshore meteorological wind mast was installed to collect site environmental data. CLP Power completed the installation of an RE power system of approximately 200 kW on Town Island in late 2012. The system now comprises 672 solar panels and 2 wind turbines supplying RE to the island.

The RE assets of HKE also performed well, with Lamma Winds generating an average of 800 to 1 000 megawatt-hours (MWh) of electricity since being commissioned in 2006. A thin-film photovoltaic (TFPV) solar power system of 1 MW was installed at Lamma Power Station, generating 1 100 MWh annually, offsetting 1 715 tonnes of CO_2 emissions together with the wind turbines every year on average (HKEI 2015b, 2015c).

To increase its RE portfolio, HKE plans to install up to 33 offshore wind turbines, each being 3.0 to 3.6 MW with a total generation capacity of around 100 MW, producing 175 gigawatt-hours (GWh) of electricity per year for the consumption of 50 000 four-person households. In 2012, HKE set up a wind monitoring station at its offshore wind farm site to collect meteorological and oceanographic data for detailed design purposes. Data collected indicate that the site is feasible for development of an offshore wind farm. Additional data are being collected for optimising the offshore wind farm design (HKEI, 2015d).

Landfill gas, a waste gas produced at landfill sites, has been used as a waste-to-energy source for onsite electricity generation and leachate treatment as well as for use by the town gas production plant (EPD, 2017a).

In 2007, landfill gas generated at the North East New Territories (NENT) Landfill was treated and transferred to the town gas production plant to replace some of the naptha used as a heating fuel. In 2016, the South East New Territories (SENT) Landfill Gas Treatment Plant was completed. Landfill gas is treated with impurities, removed and converted to synthetic natural gas before being injected into the Towngas supply network. It can offset 56 000 tonnes of CO_2 emissions per year, equivalent to planting 2.4 million trees (Towngas, 2017).

CLP Power is planning to develop Hong Kong, China's largest landfill gas power generation project that would produce 10 MW of renewable power close to one of its power plants (CLP, 2016b).

The government has taken the lead in using RE by installing PV systems at various government premises. More notable installations are a 1 100 kW system at the Siu Ho Wan Sewage Treatment Works, capable of generating 1.1 million kWh annually, a 468-kW system at a swimming pool complex and a 350-kW system on the roof of the Electrical and Mechanical Services Department Headquarters (DSD, 2016) (EMSD, 2017b).

The government has also installed large-scale solar water heating devices on government buildings, including those with swimming pools, to save power in heating water.

The government is studying the practicality of installing floating photovoltaic (FPV) systems on reservoirs. Two pilot projects were commissioned in 2017, each having a capacity of 100 kW and capable of 120 GWh of electricity annually to power the equivalent of 36 households, with a reduction of 84 tonnes of CO_2 emissions. Data gathered will be used as a reference for the future implementation of large-scale FPV farms on reservoirs in Hong Kong, China (WSD, 2017). In its effort to convert waste to energy and reduce GHG emissions, the government has been planning and constructing several waste management facilities.

- Phase 1 of the Organic Resources Recovery Centre (ORRC) will be commissioned in early 2018. It will treat 200 tonnes of organic waste per day for the production of biogas and compost. The biogas

produced will be used to generate electricity with approximately 14 million kWh of surplus electricity supplied to the power grid per year, which is adequate for use by 3 000 households. This will contribute to a reduction of 25 000 tonnes per year of GHG emissions via reduction in the use of fossil fuels for electricity generation. Study on the second phase of the ORRC had already commenced in 2011 (EPD 2017b).

- The government is planning to construct an integrated waste management facility (IWMF). IWMF Phase 1 can incinerate 3 000 tonnes of mixed municipal solid waste per day and is capable of exporting approximately 480 million kWh of electricity (approximately 1% of the total electricity consumption in Hong Kong, China). This project can satisfy the electricity use of more than 100 000 households and help reduce approximately 440 000 tonnes of GHG per year (EPD 2017c).
- Phase 1 of the Sludge Treatment Facility (STF) was commissioned in April 2015 and Phase 2 in April 2016. The STF incinerates 1 200 tonnes of sewage sludge per day (2 000 tonnes by 2030). The heat of the steam is converted to electricity by two 14-MW steam turbine generators to fully meet the energy needs of the entire STF. When running at full capacity, approximately 2 MW of surplus electricity is expected to be exported to the public power grid, enough to supply 4 000 households (EPD, 2017d).

NUCLEAR ENERGY

Despite having no nuclear plant located within the territory, Hong Kong, China has been importing electricity of nuclear origin from mainland China.

Currently, CLP Power is contracted to purchase around 70% of the electricity generated by the two 984-MW pressurised water reactors at the Guangdong Daya Bay Nuclear Power Station in mainland China to help meet the long-term demand for electricity in its service area. This arrangement meets 27% of the electricity demand in Hong Kong, China. In September 2009, the government approved the extension of CLP Power's contract for the supply of nuclear generated electricity from Guangdong Daya Bay Nuclear Power Station for another 20 years, starting 7 May 2014. The extension of the contract ensures a continued supply of cleaner electricity to Hong Kong, China, which will help alleviate air pollution and GHG emissions locally. To ensure that cleaner and more cost-competitive energy is provided to Hong Kong, China, an agreement has been reached wherein Daya Bay will increase its electricity supply from 70% of its output to approximately 80% by the late stages of 2014–18 (CLP, 2015b, 2016a, 2016b).

CLIMATE CHANGE

Responding to the Paris Agreement, which came into force on 4 November 2016, Hong Kong has developed the 4Ts as its operational framework, that is setting Targets with Timelines, ensuring that there are Transparent metrics to track results, and for everyone to work Together (ENB, 2017f). The Hong Kong's Climate Action Plan 2030+ report (ENB, 2017a) released in January 2017 sets out Hong Kong's new carbon emission reduction target for 2030 and action plans to meet it. The ambitious target is to reduce carbon intensity by 65% to 70% from the 2005 level by 2030, which is equivalent to 26% to 36% absolute reduction and a reduction to 3.3–3.8 tonnes on a per capita basis. The carbon reduction actions are as follows:

- Continuing to phase down coal for electricity generation and replacing it with more natural gas and non-fossil fuel sources;
- Optimising the introduction of renewable energy in a more systematic manner, with the government taking the lead, based on currently mature and commercially available technologies.
- Continuing to improve energy saving for new buildings, mainly focusing on existing buildings and public infrastructure. Changing behaviour in energy use and management through partnership.
- Extending rail services, facilitating walking and enhancing the quality of all public transport services. Providing a safe, efficient, reliable and environment-friendly transport system with multi-modal choices that meets the community's needs.
- Continuing to do substantial work to adapt to climate change. Improving city infrastructure planning and management, strengthening the urban fabric and slope safety, enhancing drainage

management and flood control with 'Blue-Green Infrastructure' concept, ensuring water security, and starting to consider how best to meet the challenge of sea level rise.

- Protecting and enhancing ecosystems and appropriate landscaping in urban areas. Expanding country and marine parks and promoting urban forestry and ecology.
- Raising social awareness to climate-related risks and emergencies. Creating an appropriate decision-making structure to implement the Paris Agreement within the government facilitating and encouraging dialogue among stakeholders.

NOTABLE ENERGY DEVELOPMENTS

PUBLIC CONSULTATION ON THE FUTURE DEVELOPMENT OF THE ELECTRICITY MARKET

The current SCAs between the government and the two power companies were signed in 2008 and will expire in 2018. New SCAs were signed in April 2017 (ENB, 2017b, 2017c). To plan for the way forward beyond 2020, the government conducted a public consultation in 2015 to solicit public views on the future development of the electricity market. More specifically, these include public views on the (a) introduction of competition, (b) future regulatory framework and possible areas for improvement and (c) the development of RE and demand-side management (DSM). The government has collated views from the public and will work out specific proposals on future contractual arrangements before commencing negotiations with the power companies. Solicited public views are summarised as follows (ENB 2015b):

- Introduction of competition: The public held different views with regard to introducing competition. The majority of the respondents considered that the current power supply in Hong Kong, China is reliable, safe and affordable and that there is no need for introducing competition for expanding choices available to the public. Some respondents considered that while choice had its merits, the requisite conditions for introducing competition were not present at this stage.
- Development of the future regulatory framework and demarcation of possible areas for improvement: Regarding the regulatory arrangement, almost all respondents considered that the current contractual arrangement by SCAs had mostly worked well and allowed the economy to achieve the energy policy objectives. It was generally agreed that improvements should be made to the current SCAs with respect to areas such as the level of permitted rates of return and mechanisms to promote energy saving and RE.
- Development of RE: The community's views on the development of RE were generally positive. Around half of the respondents supported the further development of RE despite its higher tariff implications. Some respondents suggested that specific measures should be introduced to promote RE, such as improving the grid access arrangements for distributed RE generators and encouraging their connections to the power grids.

FEED-IN TARIFF SCHEME AND RE CERTIFICATE SCHEME

FEED-IN-TARIFF SCHEME

As an important new initiative to promote the development of RE, the Feed-in-Tariff (FiT) Scheme has been introduced by the Hong Kong Government under the post-2018 SCAs. The power generated can be sold to the power companies at a rate higher than the normal electricity tariff rate to help recover the costs of investment in the RE systems and generation of the FiT Scheme, encouraging investment in RE. Individuals who are successful applicants of the FiT Scheme may receive FiT payments from CLP Power and HKE from 1 October 2018 and 1 January 2019, respectively. FiT will be offered throughout the project life of the RE systems until the end of 2033. The electricity generated by the RE systems after 2033 will belong to the RE system owner. Hong Kong, China will further provide support and facilitation to the private sector, including suitably relaxing the restrictions on installation of solar PV systems on the rooftops of New Territories Exempted Houses (also known as 'village houses') and making appropriate relaxations for other private

buildings, in particular the low-rise ones. In addition, Hong Kong, China will introduce a new programme to assist schools and NGOs in installing small-scale renewable energy systems (EMSD, 2018c) (Policy Address, 2018).

RE CERTIFICATES

Hong Kong, China has also introduced renewable energy certificates (REC), which will be sold by the two power utilities (CLP & HKE) for units of electricity generated by renewable energies. The revenue from selling the RECs will help balance the cost of paying FiT and alleviate the tariff impact brought by the introduction of the FiT Scheme. To the public and organisations, purchasing the RECs not only can show their support for RE but also is an increasing pressure on them to demonstrate that through corporate reports (EMSD, 2018c) (Policy Address, 2018).

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USEFUL LINKS

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Environment Bureau—www.enb.gov.hk

Environmental Protection Department—www.epd.gov.hk

The Hong Kong Government—www.gov.hk/en

EMSD— https://re.emsd.gov.hk/english/fit/int/fit_int.html

INDONESIA

INTRODUCTION

Indonesia is the world's largest archipelagic state located south-east of mainland South-East Asia between the Pacific Ocean and the Indian Ocean. Indonesia's territory encompasses 17 504 large and small islands and large bodies of water at the equator over an area of 7.9 million square kilometres (km^2). This constitutes Indonesia's exclusive economic zone. The economy's total land area (25% of its territory) is approximately 1.9 million km^2. The population was around 261 million in 2016.

Indonesia had a gross domestic product (GDP) of around USD 2 811 billion and a per capita GDP of USD 10 766 in 2016 (2011 USD purchasing power parity [PPP]). Indonesia is the largest economy in South-East Asia because of its robust economic growth since overcoming the Asian financial crisis of the late 1990s. Indonesia's sovereign credit ratings are classified into investment grade status by global leading credit rating agencies such as Standard & Poor's, Fitch Ratings and Moody's Investors Service. The Indonesian Government has been continuously making progress in deregulating its economy and removing barriers for investment, indicated by significant improvement of its rankings in the Ease of Doing Business index for 2018, ranking 72nd, a significant increase of 19 places from the 91st place in the previous year (World Bank, 2017).

Indonesia has substantial and diverse energy resources from oil, natural gas, coal and renewable sources. In 2018, Indonesia's proven fossil energy reserves consisted of 7.51 billion barrels of oil, 135.5 trillion cubic metres of natural gas and 39.9 billion tonnes of coal (MEMR, 2019c). Indonesia is one of the largest thermal coal producers in the world. Coal production reached 557.8 million tonnes in 2018, where 64% of the production was exported (MEMR, 2019c). Indonesia exported 21 489 ktoe of liquefied natural gas (LNG) and 6 567.1 ktoe of natural gas through pipeline (MEMR, 2019c). Renewable energy resources include 25.4-gigawatts (GW) energy equivalent of geothermal, 75-GW energy equivalent of hydro power, 208-GW energy equivalent of solar, 33-GW energy equivalent of biofuels and 61-GW energy equivalent of wind power.

Table 1: Key data and economic profile, 2016

Key data[a]		Energy reserves[b, c, d]	
Area (million km^2)	1.9	Oil (billion barrels)	7.51
Population (million)	261	Gas (trillion cubic metres)	135.5
GDP (2011 USD billion PPP)	2 811	Coal (billion tonnes)	39.9
GDP (2011 USD PPP per capita)	10 766	Uranium (kilotonnes U)	6.3

Sources: [a] EGEDA (2018); [b] MEMR (2018a); [c] NEA (2014) d (MEMR (2019c)

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2016, Indonesia's total primary energy supply (TPES) was 224 008 kilotonnes of oil equivalent (ktoe) of commercial energy, consisting of oil (34%), coal (24%), natural gas (15%) and other energy (mainly hydropower, geothermal and biomass) (28%). Indonesia is a net exporter of energy; overall energy exports of crude oil, condensates, natural gas, LNG, petroleum products and coal totalled 200 792 ktoe in 2016. Total energy exports in 2016 decreased by 7.7% from 2015 (217 455 ktoe), a decrease primarily driven by a lower coal demand in China, the biggest coal importer from Indonesia.

OIL

In 2018, Indonesia produced 39 455.64 ktoe of crude oil. Of this, 10 422.86 ktoe (26,42%) was exported, a decrease of -35.27% compared with the 2015 level. Because oil production has significantly declined over the past decade (in 1997, Indonesia produced 80 774.76 ktoe of crude oil and condensates), the economy imported 15 827.63 ktoe of crude oil, a decrease of 17.28% compared with the 2015 level, and 23 265.41 ktoe of

petroleum products in 2018, an increase of 0.20% compared with the 2015 level, to meet its domestic oil requirements (MEMR, 2019c).

Most crude oil is produced onshore from three of Indonesia's largest oil fields: the Minas and Duri oil fields in the province of Riau on the eastern coast of central Sumatra and Banyu Urip oil fields in the East Central Java province. Because these fields are considered to be mature, the Duri oil field in particular has been subject to one of the world's largest enhanced oil recovery efforts. In 2018, Indonesia produced 778 million barrel oil per day (MBOPD) and 1139 million barrel oil equivalent per day (MBOED) (MEMR, 2019a).

NATURAL GAS

Indonesia produced 63 372 ktoe of natural gas in 2016, a slight decrease of 0.58% from the 67 294 ktoe produced in 2015 (EGEDA, 2018). Of the total natural gas production, 34% was converted to LNG for export. The economy produced 24 072 ktoe of LNG in 2016, an increase of 4.4% from 23 345 ktoe in 2015. In 2015, Indonesia also exported 7 billion cubic metres of natural gas through pipelines to Singapore and Malaysia. Overall, 48% of Indonesia's natural gas production was exported in 2016. The balance is made available for domestic requirements (EGEDA, 2018). Domestic gas consumption increases at an average of 7.8% between 2003 and 2017 and it will continue to increase to meet domestic gas demand, mainly from power, petrochemical, business and residential sectors.

Indonesia's large natural gas reserves are located around Badak in East Kalimantan, Corridor in South Sumatra, the Natuna Sea, the Makassar Strait, the Masela Block in Maluku and Bintuni Bay in Papua, with smaller gas reserves offshore in West and East Java. LNG exports from Tangguh, Bintuni Bay, Papua began in 2009 with gas supplied from the onshore and offshore Wiriagar and Berau gas blocks, which are estimated to have reserves of 23 trillion cubic feet (SKKMIGAS, 2014).

COAL

In 2016, Indonesia produced 268 244 ktoe of coal where 73% of coal production was exported (EGEDA, 2018). Approximately 57% of Indonesia's total recoverable coal reserve is lignite, 27% is sub-bituminous coal, 14% is bituminous coal and less than 2% is anthracite. Most of the economy's coal reserves are in South Sumatra and ~~East~~ Kalimantan, with relatively small deposits in West Java and Sulawesi. As a result, while Indonesian coal's heating value can range 5 000–7 000 kilocalories per kilogram, it is generally distinguished by its low ash and sulphur content (typically less than 1%).

ELECTRICITY

Indonesia had 59 659 megawatts (MW) of electricity generation capacity in 2016. This was held by the state-owned electricity company (PLN), independent power producers (IPPs) and private power utilities (PPU). In 2016, 249 terawatt-hours of electricity was generated, of which 23% was supplied by IPPs and 1.5% was imported from Malaysia through cross-border electric transmission lines between Sarawak in Malaysia and West Kalimantan in Indonesia. In 2016, several types of power plants produced electricity; namely, coal-steam power plants (51%), gas power plants (combined gas-steam power plants, gas turbine power plants and gas engine power plants) (27%), renewable energy power plants (geothermal, hydro, biomass, biogas, municipal solid waste, solar and wind) (10%) and oil power plants (diesel power plants and oil-powered thermal plants) (12%) (MEMR, 2018a).

FINAL ENERGY CONSUMPTION

The total final consumption was 157 536 ktoe in 2016, a decrease of 2.9% from 162 297 ktoe in 2015. The share of total final consumption by sector in 2016 was 25% for industry, 30% for transport, 42% for other sectors and 2.6% for non-energy consumption. By fuel source, oil consumption had the largest proportion in the final energy consumption (excluding non-energy consumption) at 39%, whereas renewable energy was the second largest at 34% of final energy consumption (EGEDA, 2018).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	438 688	Industry sector	39 481	Total power generation	247 919
Net imports and others	−200 792	Transport sector	47 010	Thermal	217 970
Total primary energy supply	224 008	Other sectors	66 871	Hydro	18 677
Coal	53 243	Non-energy	4 174	Nuclear	0
Oil	75 472	Final energy consumption*	153 361	Others	11 273
Gas	32 494	Coal	8 905		
Renewables	62 739	Oil	60 437		
Others	60	Gas	13 747		
		Renewables	51 697		
		Electricity and others	18 576		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

ENERGY INTENSITY ANALYSIS

In 2016, Indonesia's primary energy intensity was 80 tonnes of oil equivalent per million USD (tonnes of oil equivalent/million USD), a decline of 2.9% from the previous year's level. This indicates that Indonesia's primary energy intensity has improved in recent years; however, there remains scope for the economy to improve its energy efficiency. In terms of the total final consumption, energy intensity amounted to 55 tonnes of oil equivalent/million USD, a decrease of 6.7% from the 2015 level. This was mostly driven by decreasing energy consumption in industry and transportation and other sectors.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	82	80	–2.9
Total final consumption	58	55	−6.7
Final energy consumption excl. non-energy	61	56	–7.6

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

In 2016, renewable energy's share in Indonesia's final energy consumption was 153 361 ktoe, a decrease of 2.0% from the previous year's level. The share of modern renewables was 11 320 ktoe (7.4%), while traditional biomass was 42 621 ktoe (28%) in 2016. This indicates that Indonesia's renewable energy development has improved in recent years although there remains scope for the economy to accelerate the update of renewable energy in the final energy consumption. On 2 March 2017, the Indonesian Government issued Presidential Regulation No. 22/2017 regarding the National General Plan of Energy that includes a policy target for achieving 23% of renewable energy sources in the energy mix by 2025. In 2018, the electricity generations from renewable energy was accounted at 12.5% of the total electricity generation mix (MEMR, 2019b).

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	156 481	153 361	-2.0
Non-renewables (Fossils and others)	146 765	142 041	-3.2
Traditional biomass*	42 631	42 621	−0.03
Modern renewables*	9 716	11 320	17
Share of modern renewables to final energy consumption (%)	6.2%	7.4%	19%

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (e.g. hydro and geothermal energy), including biogas and wood pellets, are considered modern renewables, but data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

THE ENERGY LAW

On 10 August 2007, Indonesia enacted the Energy Law (Law No. 30/2007), which contains principles regarding energy resilience, security of energy supply, sustainable energy practices, energy conservation, and energy efficiency. It defines the outline of the National Energy Policy (Kebijakan Energi Nasional, or KEN); the roles and responsibilities of the central government and regional governments in planning, policymaking and regulation; energy development priorities; energy research and development; and the role of businesses.

Under the Energy Law, the National Energy Policy addresses the need to have sufficient energy supply to meet the economy's needs, energy development priorities and the utilisation of indigenous energy resources and energy reserves. The Energy Law mandates the creation of a National Energy Council (Dewan Energi Nasional, DEN). The tasks of the DEN are as follows:

- Drafting and formulating the National Energy Policy
- Establishing National Energy Plan;
- Establishing overcome actions toward situations of energy crisis and emergency; and
- Supervising the implementation of energy policies between national and provincial jurisdictions.

The assembly of DEN members is chaired by the President of Indonesia. As an institution, the DEN is headed by the minister responsible for energy affairs and has 15 members: seven ministers and high-ranking government officials responsible for the supply, transportation, distribution and use of energy and eight stakeholder members from industry, academia, expert groups, environmental groups and consumer groups.

After obtaining approval from the parliament (the DPR) on 17 October 2014, the government issued Kebijakan Energi Nasional (the National Energy Policy) under Government Regulation No. 79/2014. This replaced the existing National Energy Policy, which was established by Presidential Regulation No. 5/2006. The new policy is intended to create energy security and resilience through an energy management strategy that will be implemented during 2014–50.

On 2 March 2017, Presidential Regulation Number 22/2017 about Rencana Umum Energi Nasional (RUEN) or the General Plan of Energy was released. The RUEN is the implementation of the KEN. By law,

the RUEN is drafted by the government, namely, the Ministry of Energy and Mineral Resources (MEMR), in a process that involves related ministries and other government institutions, state-owned companies in the energy sector and regional governments. The process also includes academia and other energy stakeholders and pays due regard to inputs from the public. To provide guidance on how to draft the RUEN, the government issued Presidential Regulation No. 1/2014 on 2 January 2014. Under this regulation, the RUEN should be prepared based on the KEN, engagement with local government and consideration of public opinion and inputs. The RUEN will be used by the central and provincial government as a guideline for developing long-term electricity development plan and other relevant energy policies up to 2050.

ENERGY MARKETS

Over the past decade, Indonesia has reformed its energy sector through a series of new laws: the Oil and Gas Law (Law No. 22/2001); Geothermal Energy Law (Law No. 21/2014); Mineral and Coal Mining Law (Law No. 4/2009); and Electricity Law (Law No. 30/2009).

These laws were established to promote an increased role for business in the energy supply chain. They cover issues such as fair competition on an equal playing field, open energy market opportunity as an alternative to previously a monopolistic energy markets, direct contracts between energy producers and buyers and a transparent regulatory framework.

THE OIL AND GAS LAW

Indonesia's oil and gas industry was reformed in 2001 under the Oil and Gas Law (Law No. 22/2001). The regulatory bodies BP MIGAS and BPH MIGAS were created to address oil upstream and downstream activities. Exploration and production activities were conducted on the basis of a fiscal contractual system, which mainly relied on production sharing contracts (PSCs) between the government and private investors. Such investors could include foreign and domestic companies as well as the government-owned oil company Pertamina.

However, on 13 November 2012, the Constitutional Court declared that the existence of BP MIGAS conflicted with the Constitution of 1945 and ordered its dissolution. At the time of writing, the government was drafting a new oil and gas law that will determine a new oil and gas industry structure. Until the enactment of this law, an interim working unit for upstream oil and gas business activities (SKSPMIGAS) has been established. Furthermore, on 14 January 2013, the government issued Presidential Regulation No. 9/2013 as the umbrella regulation for the establishment of the working unit for upstream oil and gas business activities (SKKMIGAS), whose responsibility is to manage the upstream oil and gas business in Indonesia. SKKMIGAS's operation and its strategic decisions are under supervision and control by MEMR whose assumes all BP MIGAS roles and responsibilities.

BPH MIGAS has supervisory and regulatory functions in the downstream oil and gas sector. It aims to ensure the availability and distribution of fuel throughout Indonesia and the promotion of gas utilisation in the domestic market through fair and transparent market competition.

The enactment of the Oil and Gas Law required that the state-owned oil company, Pertamina, should relinquish its governmental roles to the new regulatory bodies, BP MIGAS (which has now passed on its tasks to SKKMIGAS) and BPH MIGAS and mandated the termination of Pertamina's monopoly in upstream oil and gas activities.

THE MINING LAW

On 16 December 2008, the parliament passed a new law on minerals and coal mining to replace Law No. 11/1967, which had been in place for 41 years. The government enacted the new law on 12 January 2009 as Law No. 4/2009 on minerals and coal mining.

In essence, the new mining law ended the concession of work areas by contracts of work (COW) and by work agreements for coal mining businesses known as Perjanjian Karya Perusahaan Pertambangan Batubara (PKP2B). Concessions are now based on permits issued from the central government and regional governments. Since the Law No. 23/2014 regarding regional governments was enacted on 2 October 2014, the authority for regional governments (e.g. provincial and district/city levels) are limited to providing

recommendations to the central governments for the issuance of Mining Business License Area and to supervise the mining operation in their respective authorities.

Prior to the new law, the government arguably had less regulatory control over its concessions. For example, any changes in the concession terms needed to be agreed upon by both the government and the investor. By instituting permits, the government expects to be better positioned to promote investment and regulate mining.

The new law creates greater opportunities for smaller investments in mining and gives regional governments a greater role in regulating the industry and its revenue. The mining law called for regulations on the following:

- Concession areas and concession periods (for exploration permits) and production limits (for production permits) with regard to mining for metals, non-metals and specific non-metals;
- A requirement that prospective investors submit post-mining and reclamation plans before applying for a permit;
- An obligation for permit holders to build smelters;
- An obligation for foreign companies to divest shares to the government or to state-owned businesses and private companies registered in Indonesia;
- Payment of taxes and fees and the allocation of profits; and
- Reclamation and post-mining costs.

A set of government regulations with regard to the mining law was completed in 2010. These are now operational.

THE ELECTRICITY LAW

The government enacted Law No. 30/2009 regarding electricity on 23 September 2009. This new law replaced Law No. 15/1985, which the Constitutional Court had reinstated in December 2004 as a provisional law upon annulment of Law No. 20/2002.

A notable difference between Law No. 30/2009 and the previous electricity Law No. 15/1985 is the absence of a holder of electricity business authority (Pemegang Kuasa Usaha Ketenagalistrikan, PKUK). Under Law No. 15/1985, the government had appointed the state-owned electricity company, PLN, as the sole PKUK and, consequently, had made it responsible for providing electricity to all parts of Indonesia.

Under the Law No. 30/2009, the industry consists of electricity business entities, which are title holders of electricity supply business licences, or Izin Usaha Penyediaan Tenaga Listrik (IUPTL). The IUPTL integrates electricity supply, power generation, transmission, distribution and retailing of electricity. Indonesia's electricity systems retain vertically integrated configurations. However, these consist of several licenced systems, such as PLN's numerous power systems, provincial government-owned systems (to be established, where necessary) and private sector power systems, each operating within their respective business areas. Licence holders of specific electricity supply types (such as the IPPs, which are licence holders in power generation for the supply of electricity to the public) participate in the vertically integrated systems.

By law, the central government and regional governments regulate the electricity industry within their respective jurisdiction and through electricity regulatory authorities. The electricity law allows electricity tariffs to be differentiated by region to allow for different costs of supply. Under the previous law, Indonesia had a uniform electricity tariff regime and applied cross-subsidies among regions. At the time of writing, there was no ruling as to whether PLN will implement tariff differentiation over its extensive power systems across Indonesia.

As mandated by Law No. 30/2009, the MEMR issued three government regulations (GRs), namely, GR No. 14/2012 on electricity supply businesses activity, GR No. 42/2012 on the buying and selling of electricity across Indonesia's borders and GR No. 62/2012 on electricity support businesses.

THE GEOTHERMAL LAW

Geothermal development activities are defined as mining activities under the Geothermal Law No. 27/2003. Furthermore, according to the forestry law, no mining activities are allowed to occur in protected forest areas (protection and conservation forests). Therefore, geothermal energy cannot be developed if it is located in these areas. This situation has been a major barrier to developing geothermal electricity in Indonesia.

To coordinate the development of geothermal resources for electricity generation in conservation forest and protected forest areas, the government issued the New Geothermal Law No. 21/2014 on 17 September 2014. Under the new law, geothermal development activities are not considered as mining activities.

Accordingly, the government has changed the permit scheme from a 'geothermal mining permit' to a 'geothermal permit'. This new law states that geothermal energy can be developed in the areas of production, protection and conservation forests after obtaining a permit from the Ministry of Forestry under the category of the environmental service use permit. Based on the Minister of Environment and Forestry Regulation P46/MenLHK/Setjen/KUM.1/5/2016, the permit holders geothermal environmental services can undertake geothermal activities in national parks, major forest parks, and natural tourism parks.

The new regulation also states that the government sets the tariff on geothermal electricity. This approach offers incentives to developers and affirms that central government holds the authorisation power to conduct tenders for geothermal working areas (GWA) and to control the projects. However, local government is authorised to utilise geothermal energy for direct use (other than electricity generation). The MEMR regulation No. 3/2018 sets the pricing formula of electricity produced from geothermal power plants, consisting of the following provisions:

1. Prices are determined based on reserve capacity after exploration activities completed,

2. The upper ceiling price is subject to the average cost of electricity generation in the respective location of geothermal power plants. If the cost of electricity production (Biaya Pokok Produksi) is higher than the average cost of electricity generation at the national level, the upper ceiling price of geothermal electricity refers to the local BPP. If the local BPP is lower than the national BPP, the ceiling price is determined based on the business-to-business agreement between geothermal IPP developers and PLN, the offtaker electric utility.

Geothermal exploration and exploitation are based on the awarding of licences. The process involves the central government offering GWA for competitive bidding to prospective business investors. Public, private and cooperative entities may submit bids on such GWA, and successful bidders are awarded licenses. The width of the concession areas is determined according to the capacity of the individual geothermal system. Successful bidders have the right to conduct exploration for five years, with two extensions of up to one year each. They also have the right to 30 years for exploitation from the date on which a feasibility study has been approved by the government. The government can approve extensions for the exploitation of geothermal resources for an additional 20 years per extension approval. Working areas are subject to taxes, land rentals and royalties determined by the government. Laws and regulations that govern the electricity industry apply to the utilisation of geothermal energy for electricity generation.

The government has also issued PP 7/2017 concerning Geothermal Utilization for Indirect Use which is the implementing regulation of Law 21/2014. The regulation stipulated the following conditions:

1. Geothermal business entity is entitled to conduct preliminary and exploration surveys in open areas through the assignment from MEMR to the business entity for the Preliminary and Exploration Survey (PSPE). The PSPE activities are carried out in an open area stipulated by MEMR for the preparation of Geothermal Work Areas. The selection of geothermal business entity to conduct PSPE activities is through competitive tendering process (beauty contest).
2. The scheme of the Tender for Geothermal Work Areas (WKP) from the previous one based on the lowest price bid there is a change to be based on the value of the evaluation of the work program and the amount of funds Exploration Commitment.

3. The regulatory mechanism for PSP and PSPE is based on MEMR Regulation No. 36/2017 regarding Procedure for Works Assignment of Preliminary Survey and the Works Assignment of Geothermal and Exploration Survey.

FISCAL AND INVESTMENT REGIME

In late 2008, Indonesia announced an overhaul of its taxation system, effective in 2009, with improvements to tax collection and lower tax rates. The general corporate income tax rate for the 2009 tax year was reduced to a flat rate of 28% from the prior maximum progressive rate of 30%. Tax rates were to be further reduced to a flat rate of 25% in 2010 (ASEAN, 2008).

OIL AND GAS

The PSC regime (outlined in the earlier section on 'The Oil and Gas Law') was introduced in Indonesia in the mid-1960s and reportedly became the fiscal system of choice for many economies over many years. Worldwide, slightly over half of those governments whose economies produce hydrocarbons now use the PSCs (Johnston, 1994), and several types have since emerged internationally.

Technically, the PSCs do not have the type of royalty that applies to royalty/tax systems of concessions or licences in the oil and gas industry. However, industry analysts argue that there are equivalent elements in the PSC and royalty/tax systems and that the major difference is in the title transfer of oil or gas (Johnston, et al., 2008). In a PSC, title to the hydrocarbons passes to the contractor at the export or delivery point.

In 1988, Indonesia's third-generation PSC introduced a new contract feature called 'first tranche petroleum' (FTP). The contractor's share of FTP is taxed, and the remaining production is available for cost recovery. Some industry analysts view FTP as a royalty (Johnston, 1994). Indonesia has other types of joint contract schemes for oil and gas, such as technical assistance contracts (TACs) and enhanced oil recovery (EOR) contracts. A TAC is a variant cooperation contract or a PSC and is typically used for established producing areas; thus, it usually covers only exploitation. Operating costs are recovered from production, and the contractor does not typically share in production. A TAC can cover both exploitation and exploration if it involves an area where the Indonesian Government has encouraged exploration. In accordance with the new oil and gas law, existing TACs will not be extended. In addition, participants in the PSCs, TACs and EOR contracts may also enter into separate agreements known as joint operating agreements and joint operating bodies (JOB). Since 2008, the fifth generation of PSCs has been introduced.

THE GROSS SPLIT SCHEME

On 13 January 2017, the government issued Ministerial Regulation No. 8 of 2017 on PSCs. A gross split was enacted on 22 January 2017, which is a breakthrough scheme for the programme in the upstream oil and gas more efficiently and effectively so as to attract the investors (MEMR, 2017b). The regulation includes the following:

- Contractor Take = Base Split +/- Variable Components +/- Progressive Components
- Government Take = Government share + bonuses + Contractor's Income Tax
- The base split shall constitute the baseline in determining the production split during the Plan of Development ("PoD") approval. These splits are:
    - a) for oil: 57% (Government of Indonesia); 43% (Contractor)
    - b) for gas: 52% (Government of Indonesia); 48% (Contractor)
- The variable components are adjustments which take into account the status of the work area, the field location, reservoir, supporting infrastructure, etc.
- The progressive components are adjustments which take into account oil price and cumulative production.
- The "actual" production split shall be agreed on a PoD rather than Production Sharing Contract basis.
- Depending upon field economics the MEMR has the authority to adjust (to a maximum 5%) the production split in favor of either the Contractor or the Government of Indonesia.

Note that it has been reported that the one Gross Split PSC agreed to date (being for a mature field) was actually set at 42.5% : 57.5% GoI/Contractor. This outcome demonstrates just how flexible these splits might be in practice.

On 29 August 2018, the government revised the Ministerial Regulation No. 8/2017 in response to the feedback from the oil and gas industry association to provide fiscal incentive for the existing upstream oil and gas operators for Plan of Development (POD) Phase II.

Further to the issuance of Ministerial Regulation No. 8/2017 and its subsequent revision of Ministerial Regulation No. 52/2017, the government introduced Government Regulation No. 53/2017 about Tax Rules for Gross Split PSCs. Key features of Government Regulation No. 53/2017 about Tax Rules for Gross Split PSCs for the pre-production period (i.e. exploration and development), exploitation and commercial production are as follows:

- An exemption from import duty on goods used in relation to oil and gas operations;
- A 100% reduction in land and buildings tax;
- Non-collection of value-added tax on the import and local procurement of goods and services used in oil and gas operations;
- An exemption from Article 22 on the import of goods entitled to an import duty; and
- Operating costs as a cost reduction component of the taxable income as a tax loss carry forward entitlement is extended to 10-year period, greater than 5-year period under the general tax law;

Note: in the PSCs scheme, cost recovery is eligible until the end of the PSC contracts.

It is evident that the introduction of regulations on gross split PSCs is accepted by the upstream oil and gas industry. In 2018, 402 oil and gas fields had adopted the gross split PSCs, including Eni SpA for East Sepinggan, West Natuna block, Exploration Ltd in the Duyung block, Medco E&P Tarakan in Tarakan Block and PT Medco CBM Pendopo in Muralim block and Sangan-Sangan Block, PH Sangan-Sangan. In the early February 2019, Chevron has agreed to adopt a gross split scheme for its project of Indonesia Deepwater Development (IDD) of Rapak and Ganal's natural gas fields. The project is expected to produce 1.1 billion of standard cubic feet of gas/day (0.99 Mtoe).

According to IHS publication on the 'Petroleum Economics and Policy Solution (PEPS) Global E&P Attractiveness Ranking', the fiscal regime in the Gross Split Scheme has improved the competitiveness of Indonesia in oil and gas investment to the 25th rank in 2018, the best in South-East Asia. A total oil and gas investment was recorded at USD 13.4 billion in 2018, an increase of USD 1.5 billion from the 2017 level before the Gross Split Scheme was implemented.

UPSTREAM

In 2014, the Directorate General of Oil and Gas, the MEMR signed seven new PSC agreements. Apart from these, the PSC under the control of the upstream oil and gas implementing agency—BP MIGAS (before becoming SKKMIGAS)—numbered approximately 316 by the end of 2014. Of these 316 PSC, 81 were for oil and gas at the exploitation stage and 235 related to the exploration stage. Of the latter, 180 were for conventional oil and gas, 55 were for shale gas, 8 were terminated and 41 were in the termination process (SKKMIGAS, 2014).

To increase production of oil and gas, SKKMIGAS has developed oil and gas in new fields through a number of major projects, including the following (SKKMIGAS, 2017):

- Jambaran Tiung Biru—ExxonMobil Cepu Ltd;
- Indonesia Deepwater Development—Chevron Indonesia Company;
- Abadi—INPEX Masela Ltd;
- Tangguh Train 3—BP Berau Ltd;
- Jangkrik dan Jangkrik North East—Eni Muara Bakau B.V.;

- Pakugajah Oilfield Development—Pertamina EP;
- Madura BD, MDA and MBH projects—Husky—CNOOC Madura Ltd;
- Donggi Matindok—Pertamina EP; and
- Bison Iguana Gajah Puteri—Premier Oil Natuna Sea B.V.

KEROSENE TO LIQUEFIED PETROLEUM GAS CONVERSION PROGRAMME

In December 2009, Phase I of the government's kerosene-to-liquefied petroleum gas (LPG) conversion programme was completed. The programme distributed 23.8 million three-kilogram LPG cylinders to the densely populated provinces of Jakarta, Banten, West Java, Yogyakarta and South Sumatra. The programme eliminated the need for Pertamina to supply 5.2 billion litres of heavily subsidised kerosene for household use in these provinces.

In an extension of the programme, 4.7 million three-kilogram LPG cylinders were distributed by 2010. From 2011 to 2013, some 6.8 million three-kilogram LPG cylinders were distributed. In 2014, the programme distributed 1.629 million cylinders with the same characteristics. Pertamina, the state oil and gas company, produced and distributed 531 131 three-kilogram LPG cylinders to residential households in fourteen cities in North Sumatera, Bangka-Belitung, Riau and West Nusa Tenggara (Pertamina 2018).

CITY GAS NETWORK DEVELOPMENT PROGRAMME

The MEMR has rolled out a city gas development programme that aims to connect 3 million households by 2025 and to reach 5 million households by 2030. The city gas is developed in regions that have indigenous sources and consumption of natural gas. The programme will reduce LPG consumption and substitute it with natural gas through the city gas. The number of households with gas connection has increased from 200 000 in 2014 to 463 619 connections in 2018. Out of the total gas connections in 2018, 325 852 household connections were funded by government budgets and the remaining share (137 767 connections) was developed by the state oil and gas companies (Pertamina and Perusahaan Gas Negara) and private sector.

In 2019, MEMR plans to expand the city gas network to include new 78 216 gas connections to household consumers in nine provinces, from Aceh province to West Papua province. Bontang City in East Kalimantan will be fully integrated with city gas network by 2020.

COAL-BED METHANE

Oil and gas laws and regulations also govern coal-bed methane. The Directorate General of Oil and Gas oversees business activities with regard to coal-bed methane development. The MEMR issues regulations as well as establishes and offers coal-bed methane work areas. Ministerial Regulation No. 36/2008 regards coal-bed methane gas regulation and development, covering exclusively rights and business related to coal-bed methane; the method of determining and offering coal-bed methane work areas; the use of data, information, equipment and facilities; research, assessment and development of coal-bed methane; resolution of disputes; rulings on coal-bed methane as an associated natural resource; and the utilisation of coal-bed methane for domestic needs.

In addition, simplification of licensing was among the efforts undertaken by the Indonesian upstream oil and gas industry to attract investors. By March 2018, the Directorate General of Oil and Gas has revoked 56 regulations and permits that consist of 23 Ministerial regulations and 18 Ministerial permits, 12 regulations at the SKK Migas, and 3 permits at the BPH Migas. To accelerate the licensing process, the MEMR in cooperation with the Investment Coordinating Board (BKPM) has launched quick service delivery and licensing related to infrastructure in the energy and mineral resources in three hours (MEMR, 2017c).

MINERALS AND COAL MINING

Indonesia's minerals and coal mining law (Law No. 4/2009) replaced the COW and PKP2B systems with two types of permits: mining business permits (Izin Usaha Pertambangan [IUPs]) and community mining permits (Izin Pertambangan Rakyat [IPRs]), a small scale mining operated by individual and group of local communities. The IUPs apply to large-scale mining, mainly operated by the public and private sector business entities.

Under the Law No. 4/2009, the mining fiscal regime includes corporate tax under the prevailing taxation law, a surtax of 10% and a mining royalty that is determined according to the level of mining progress, the level of production and the prevailing price for the mineral. The law allows a transition period for current COW and PKP2B holders, some of which are large mining concessions for minerals and coal that will expire between 2021 and 2041. The law's explanation with regard to transition states that existing contracts will be upheld; however, the specific scheme for the transition of existing concessions has not yet been formulated. Until May 2019, there are 2 517 IUPs which are verified to have the Clear and Clean status of their mining business permits.

According to the Geological Agency of the Ministry of Energy and Mineral, proven coal reserves in Indonesia reached 26.2 billion tonnes in 2017. The coal reserve is distributed in three regions of Kalimantan (14.9 billion tonnes), Sumatera (11.2 billion tonnes) and Sulawesi (0.12 billion tonnes). At a production rate of 461 million tonnes per annum, existing coal reserves could last for another 56 years.

Coal production was recorded at 557 million tonnes in 2018, a 21% increase from the total coal production in 2017. Domestic coal consumption was 21% of the total production at 115 million tonnes. The remaining portion of the coal production was exported to 28 countries with the biggest portions to China (48 million tonnes), India (44 million tonnes) and Japan (21 million tonnes) in 2017. The Indonesian Government is maintaining coal export policies while coal supplies for domestic consumptions are secured through the Domestic Market Obligation policy.

PUBLIC–PRIVATE PARTNERSHIP

In late 2011, project documents were signed which enable the Central Java ultra-supercritical coal power plant, consisting of two 1 000 MW units, to be the first project realised under the Public–Private Partnership (PPP) programme by Presidential Regulation No. 67/2005 regarding government partnership with private entities to provide infrastructure. The terms of the PPP include government investments and guarantees on PLN power purchases through a private guarantor established by Presidential Regulation No. 78/2010, Infrastructure Guarantees in Government Partnership Projects with Business Entities Executed through Private Infrastructure Guarantors. Until December 2019, the construction progress of the Central Java ultra-supercritical coal power plant has reached 63%. The first unit of 1 000 MW is expected to reach commercial operation in the early 2020.

GEOTHERMAL

To promote geothermal development, the government has provided some fiscal incentives for income tax, value added tax, import duty and the withholding of income tax for imports under the taxation regulations (MoF, 2014). The details are as follows:

- A tax holiday with exemption from corporate income tax (from five to ten tax years). After the period of corporate income tax exemption has ended, the developers are given a 50% reduction of corporate income tax for two tax years.
- An investment allowance for geothermal energy. The allowance includes reduced net income tax of 30% of the total investment (5% a year for six years), accelerated depreciation and an income tax rate of 10% or lower based on a tax treaty with regard to dividends paid to non-resident taxpayers and compensation for losses in certain circumstances. However, the developers may only have either a tax holiday or an investment allowance.
- Exemption from value added tax for the importation of machinery and equipment, not including spare parts.
- Exemption from import duty for machinery, goods and materials for construction and development as long as the machinery, goods and materials have not been produced in the domestic area, have been produced in the domestic area but their specifications do not meet the criteria or have been produced in the domestic area but in insufficient quantities.
- Exemption from Withholding Income Tax Art. 22 for the importation of machinery and equipment, not including spare parts.

To implement Law No. 21/2014 on geothermal energy, the government issued Government Regulation No. 28/2016 regarding the amount and procedures for geothermal production bonuses (MEMR, 2016b).

The regulation states the following:

- Production bonus is a financial obligation for geothermal developers (geothermal license holders, authorities of geothermal resource utilisation, holders of joint operation contracts of geothermal resource utilisation, and permit holders of geothermal resource utilisation of gross revenue from the sale of geothermal steam and/or power from geothermal power plants) to the local governments.
- The geothermal developers are required to provide bonuses for geothermal production after the completion of the first unit of commercial production to the general treasury account of the local government as determined by the MEMR.
- Production bonuses imposed amount to 1% of the gross revenue from the sale of geothermal steam, or 0.5% of the gross revenue from the sale of electricity.
- Further provisions concerning the procedures for reconciliation and production bonus percentage producer region and assessment parameters and weights are stipulated in the regulations of the MEMR.

ENERGY EFFICIENCY

GOVERNMENT REGULATION ON ENERGY CONSERVATION

As called for by the Energy Law (Law No. 30/2007) on 16 November 2009, the government issued Government Regulation No. 70/2009 regarding energy conservation. The regulation mandates the following:

- The introduction of an energy manager, energy audits and an energy conservation programme for final energy users of 6 ktoe or greater;
- The implementation of energy efficiency standards and energy labelling;
- Government incentives in the form of tax exemptions, fiscal incentives for the importation of energy-saving equipment and low-interest lending rates to encourage investments in energy conservation; and
- Government disincentives in the form of written notices advising compliance, public announcements of noncompliance, monetary fines and reduced energy supply for noncompliance.

To implement Government Regulation No. 70/2009 regarding energy conservation throughout Indonesia, the government issued Ministerial Regulation No. 14/2012 on energy management.

The regulation states the following:

- Energy producer's own utilisation and energy users who consume energy sources and/or energy of 6 ktoe per year or greater shall carry out energy management and have an obligation to establish an energy management team.
- Energy source users and energy users who use energy sources and/or energy of less than 6 ktoe per year shall carry out energy management and/or implement energy savings.
- Energy conservation programmes shall consist of short-term programmes (improvements in operating procedures, maintenance and installation of simple device controls), medium- to long-term programmes (increasing efficiency of equipment and fuel switching) and continuous improvement of employee or operator awareness and knowledge of energy conservation techniques.
- An energy audit shall be conducted periodically on at least the main energy-consuming appliances and equipment at least once every three years.
- An annual report on energy management implementation shall be provided by energy source users and energy users to ministers, governors and regents or mayors within their respective jurisdiction.

- Incentives shall be given to energy source users and energy users who have succeeded in reducing their specific energy consumption by at least 2% per year during a three-year period.

The Government is in the process of revising the Government Regulation No. 70/2009 on Energy Conservation. The new regulation is expected to expand the scope of mandatory energy management. At present, the regulation only specifically targets consumers with energy use above 6 ktoe per year, mostly from the industry sector. In the next revision, the scope of mandatory energy management will include energy users with energy consumption under 6 ktoe so that it would include other demand sectors (e.g. buildings and transport sectors).

As part of the government commitment to increase energy efficiency and conservation, MEMR introduces the nationally appropriate mitigation actions (NAMAs) program which focuses on increasing the efficiency of air-conditioning and process cooling supply in the industry and commercial building sectors (Green Chiller). MEMR has started cooperation with GIZ of Germany for an efficient air-conditioning and process cooling supply since 2014. Through the GIZ cooperative project, safety and energy efficiency standards have been issued for the green chillers. These include the following standards: The National Standard (SNI) ISO 817-2018 : Refrigerant – Designation and Safety Classification; SNI 6500-2018 : Fixed Installation Refrigeration System – Safety and Environmental Requirement; and SNI 8476-2018 : Method of Rating and Testing for Performance of Liquid Chilling Packages Using the Vapour Compression Cycle. Further achievement of from the Green Chiller project is the completion of green chiller (efficient air-conditioning and process cooling supply) in pharmaceutical industry, oil and gas industry, food and beverage industry and universities.

Moreover, with regard to energy efficiency, Indonesia has also issued standards and regulations for energy efficiency in buildings. These include the following: The National Standard (SNI) No. 03-6390-2011: Energy Conservation for Air Conditioning Systems in Buildings; SNI 03-6197-2011: Energy Conservation for Lighting Systems in Buildings; SNI 03-6389-2011: Energy Conservation for Building Envelopes; and SNI 03-6196-2011: Procedures for Energy Audits in Buildings.

The Government has issued Minister of Manpower Decree No.53/2018 on Establishment of Indonesian National Working Competency Standard (SKKNI) for Energy Audit. The implementation of the standards is carried out by provincial and municipality level of governments, such as the City of Jakarta as part of the Governor's Regulations on Green Buildings in Jakarta, which is also part of the implementation of Minister of Public Works and Housing Regulation No.02/2015 on Green Buildings. Each building, whether existing or new, must conform to the green building standard, which includes energy efficiency, to obtain or renew its building permit. Some buildings, new and existing, are also participating in the Greenship Programme of the Green Building Council Indonesia (GBCI). The Greenship Programme has the following six categories:

- Appropriate Site Development;
- Energy Efficiency & Conservation;
- Water Conservation;
- Material Resources & Cycle;
- Indoor Air Health & Comfort;
- Building & Environment Management.

Currently, there are 41 new buildings and three existing buildings registered under this programme.

BARRIER REMOVAL

With regard to the promotion of the establishment of a legal and regulatory basis for the removal from the market of technologies that are less energy efficient and produce more emissions and the subsequent adoption of high-efficiency technologies, some of the achievements in 2018 were as follows:

- The government has revised Ministerial Regulation No. 6/2011 on CFLs with Regulation No. 18/2014 and followed this with a technical guideline, which has been signed and released by the Directorate General of New Renewable Energy and Energy Conservation (DGNREEC);
- Regulation No. 7/2015 on air conditioners has been issued by the Minister of Energy and Mineral Resources and followed by a technical guideline, which has been signed and released by the DGNREEC;
- Drafts of a revised ministry regulation on the implementation of MEPS and Label for air conditioners and CFLs with additional appliances of rice cookers, electric fans, refrigerators and electronic ballast were submitted to the Minister;

RENEWABLE ENERGY

On 17 October 2014, the government issued the new National Energy Policy under Government Regulation No. 79/2014 to replace the existing national energy policy, which was established by Presidential Regulation No. 5/2006. The aim of this policy is as follows:

- achieve energy elasticity for GDP of less than one by 2025;
- achieve a reduction of final energy intensity to 1% per year up to 2025; and
- realise an optimum primary energy consumption mix where the share of new and renewable energy will be at least 23% by 2025 and at least 31% by 2050.

As part of the government's commitment to mitigate climate change, the MEMR has developed a renewable energy project in the form of a NAMA, known specifically as the Debottlenecking Project Financing for Small-scale Renewable Energy (DEEP). The DEEP programme aims to promote on-grid renewable energy, particularly bioenergy-based power plants, by increasing the institutional capacity of financial institutions and project developers. Its activities will include technical assistance as well as financial facilities for renewable energy developers. In addition to this project, Indonesia is currently developing another NAMA project, which focuses on small-scale renewable energy (mini/micro-hydro power plant).

BIODIESEL MANDATORY PROGRAMME

In 2008, Indonesia passed Ministerial Regulation No. 32/2008 regarding the supply, utilisation and trading of biofuel as alternative fuels. The biodiesel mandatory programme has four objectives: i) to increase energy security through increasing the share of domestic fuel utilisation, ii) to reduce consumption and import of oil products, iii) to increase economic added value of agriculture industry through down-streaming biofuel industry, and iv) to support the domestic agriculture-based economy. To reduce consumption and import of oil products, the Government revised Ministerial Regulation No. 32/2008 through Ministerial Regulation No. 12/2015 on 18 March 2015 (MEMR, 2015).

This regulation sets mandatory targets for the percentage share of biofuels with regard to the share of total fossil consumption (biofuel blend), as shown in Table 5.

Table 5: Minimum obligations for biofuel use (% blend)

Sector	April 2015	Jan 2016	Jan 2020	Jan 2025
Biodiesel				
PSO transport	15	20	30	30
Non-PSO transport	15	20	30	30
Industrial and commercial	15	20	30	30
Electricity generation	25	30	30	30
Ethanol				
PSO transport	1	2	~~10~~ 5	20

Non-PSO transport	2	5	10	20
Industrial and commercial	2	5	10	20
Straight vegetable oil fuel				
Industry	10	20	20	20
Marine	10	20	20	20
Aviation	–	2	3	5
Electricity generation	15	20	20	20

Note: PSO = public service obligation fuel means subsidised fuel.
Source: (MEMR, 2015).

Since the Biodiesel Mandatory Program was implemented in 2008, the blending rate gradually increased over the years to 15% of biodiesel (B15) in 2015 and 20% of biodiesel (B20) in 2016. The implementation of 20% biodiesel blend rate (B20) has been widely implemented at the national level in 2016. It has made Indonesia becomes the pioneer in the biodiesel utilization in APEC.

Biodiesel production capacity has increased since the introduction of B20 Mandatory Program. Accordingly, biodiesel production in 2018 almost doubled from 2017 to reach 6.167 million kilolitre (kL). This equals to the avoided costs of USD 2.01 billion for importing crude oil and diesel oil. Biodiesel consumptions is expected to reach 7.58 million kilolitre (kL) in 2019 and 11.7 million kilolitre (kL) in 2020. Biodiesel production capacity was recorded at 12.06 million kL in 2018 (MEMR, 2019c).

Government support mechanism for the implementation of biodiesel blending mandate is regulated through Presidential Decree No. 66/2018 on Collection and Utilization of the Palm Oil Plantation Fund and MEMR Regulation No. 41/2018 on Provision and Utilization of Biodiesel in the Financing Framework of the Indonesian Oil Palm Estate Fund. The Indonesia Palm Oil Estate Fund (BPDPKS) which bail producers of crude palm oil (CPO) from financial loss due to price gap between CPO-based fuel and diesel fuel. Pertamina, the state oil and gas company, is developing biorefinery that can produce 100% biodiesel from crude palm oil. Indonesia is poised to increase biodiesel productions to meet domestic demand for biodiesel and to potentially export biodiesel to other APEC economies.

GEOTHERMAL

In 2018, Indonesia's total geothermal capacity was 1 948 MW, which is 7.4% of the total geothermal potential of 25 387 MW (MEMR, 2019c). The existing geothermal power plants are situated in eleven locations in four islands, e.g. Sumatera, Java, Sulawesi and East Nusa Tenggara. The increased geothermal power capacity has marked a milestone for Indonesia as it becomes the second highest of geothermal installed capacity in the World after the US. Total geothermal capacity is 140 MW higher than that in 2017 from the completion of project construction of Karaha Unit 1 (30 MW) and Sarulla Unit 3 (110 MW). Indonesia has identified 15 128 MW of geothermal power potential from existing geothermal plants through capacity expansion of productive geothermal reserves and from new geothermal projects at 64 sites. Geothermal Working Area in the six Indonesian islands is anticipated to produce a total of 13 042 MWe consisting of 5 194 MWe from 18 sites in Sumatra, 6 032 MWe from 26 sites in Java, 814 MWe in from 6 sites in Sulawesi, 712 MWe from 8 sites in the Nusa Tenggara and Bali and 290 MWe from 5 sites in Maluku (EBTKE, 2018).

Under PLN's Electricity Power Supply Business Plan 2019–28 (*Rencana Usaha Penyediaan Tenaga Listrik,* or RUPTL), a further increase in geothermal capacity by 4 607 MW is expected between 2019 and 2028. Hydropower plants capacity additions is 8 009 MW, and capacity additions for mini hydro power plants is 1 534 MW, solar PV (908 MW), wind power (855 MW), Biomass (794 MW), and biofuel power plants will increase to 2 415 MW from 2019 to 2028. Total capacity additions of renewable power plants will increase to 16 714 (PLN, 2019).

HYDROPOWER

In 2016, Indonesia's total hydropower capacity was 5 124 MW (including 85 MW of micro- and mini-hydro). This was 7% of the total hydropower potential of 75 GW (DJK, 2017). In PLN's RUPTL 2019–28, the total

hydropower capacity additions is 9 543 MW (including mini-hydro and pump-storage plants). Of this capacity, 3 558 MW would be developed by IPPs and 2 688 MW by PLN, and the remainder of the project's 3 001 MW has not yet been decided; however, private participation is still an option for the project.

The additional plan of hydropower projects includes the 88-MW Peusangan hydro-power and 174-MW Asahan III hydro-power in Sumatera considered as strategic power projects to reduce the levelised cost of electricity (LCOE) in the Sumatera power grid. Three pump-storage power plants in Java—specifically the Upper Cisokan (1 040 MW) in West Java, the Matenggeng (900 MW) at the border of West and Central Java and the Grindulu (1 000 MW) in East Java (PLN, 2019)—are considered important for the technical performance and stability of the Indonesian electricity grid, particularly the Java-Bali electricity grid.

Large hydropower projects that have reached contractual agreements include the 900 MW Kayan hydropower project in the North Kalimantan which will provide electricity supply to the Tanah Kuning Industrial Park Integrated Ferronickel Complex. The 2 x 55 MW Jatigede hydropower in West Java is currently under construction and expected to reach commercial operations by the end of 2019. The 55 MW Semangka hydro power in the South Sumatera reached commercial operations on 16 November 2018.

These hydropower plants would increase Indonesia's total large hydropower capacity to 14 480 MW, or 19% of Indonesia's total hydropower potential. The government provides support for hydro power development through various actions, including transmission line expansion as large hydropower potential is located far from the large consumption centres.

WIND POWER

Indonesia has been identified to have wind power potentials especially in Java, South Sulawesi, West Nusa Tenggara, East Nusa Tenggara and Maluku. Some of wind power projects are currently being developed. The 70-MW Sidrap wind power that commenced its operation in February 2018 has marked as a milestone in the development of utility scale of wind power in Indonesia. It is followed by the 72-MW Tolo I wind farm that is currently under construction and the expansion of the 72-MW Tolo II wind farm in the Sulawesi island and 10-MW Sukabumi in the Java island.

The electricity prices of wind power plants that are operated by Independent Power Producers (IPPs) are determined in accordance with the MEMR regulation No. 53/2018 which contains revision of Ministry regulation No. 50/2017 regarding the Utilisation of Renewable Energy Resources for Electricity Generations.

NUCLEAR ENERGY

In 2007, the government of Indonesia established the Nuclear Power Development Preparatory Team, whose task is to take the necessary preparatory measures and create the plans to build Indonesia's initial nuclear energy power plants; however, to date, the team has not conducted any significant activities or performed any related tasks. The legal basis of Indonesia's nuclear energy development includes Law 17/2007 on long-term development, Years 2005–15 and Government Regulation No. 43/2006 on the licensing of nuclear reactors.

According to article 11 of Government Regulation Number 79 Year 2014 regarding National Energy Policy, nuclear energy can be utilized for the consideration to the security of national energy supply and for reduction of carbon emissions. First priority is given to the new energy and renewable energy technology and fuels if their development is economically viable. Accordingly, nuclear power is considered as the last options to support the economy's clean energy and renewable energy ambitions provided the choice of nuclear power shall meet the strict safety regulations.

Indonesia has developed an indigenous nuclear fuel cycle, although certain stages are still at the laboratory stage. The economy has a well-established nuclear research programme, which spans nearly five decades. The National Nuclear Energy Agency (BATAN) currently operates three nuclear research reactors, specifically the GA Siwabessy 30-MW pool-type materials testing reactor in Serpong; the Kartini-PPNY 100-kilowatts (kW) Triga Mark-II reactor in Yogyakarta; and the Bandung 1000-kW Triga Mark-II reactor in Bandung. BATAN is currently finalising detailed engineering design of the 10 MW of Experimental Power Reactor based on High Temperature Gas Cooled Technologies.

Despite the above developments, the Fukushima Daiichi nuclear accident in 2011 generated negative public perceptions, discouraging prospects for building nuclear energy power plants in Indonesia in the near

future. Hence, the government has stated that nuclear energy will be the last option used to achieve Indonesia's energy mix and CO_2 emission reduction policies, which means renewable energy sources are prioritised.

CLIMATE CHANGE

Indonesia strongly supports the objectives of the UNFCCC to prevent atmospheric concentrations of anthropogenic gases exceeding a level that would endanger the existence of life on Earth. To indicate its decisiveness and serious concern about global warming, Indonesia signed the convention on 5 June 1992. On 1 August 1994, the President of the Republic of Indonesia formalised this ratification by enacting Law No. 6/1994 regarding approval of the UNFCCC. Indonesia is legally included as a party to the convention, which implies that Indonesia is bound by the rights and obligations that it stipulates.

As a non-Annex 1 party in the Kyoto Protocol, Indonesia has no obligation to reduce greenhouse gas (GHG) emissions. However, the Indonesian Government is committed to participate in and cooperate with the global effort to combat climate change. This position was expressed by the President of the Republic of Indonesia at the G20 Finance Ministers meeting and Central Bank Governors Summit held in September 2009 in Pittsburgh, the US. In addition, the government of Indonesia has pledged to reduce GHG emissions from forestry and the energy sector by 26% through domestic efforts and by up to 41% through cooperation with other economies.

In December 2015, at the Conference of the Parties (COP) 21 of the UNFCCC in Paris, the government of Indonesia submitted its Intended Nationally Determined Contribution (INDC) in which the economy pledged unconditionally 29% GHG emission reduction by 2030 compared with the business-as-usual (BAU) level and an increase of up to 41% with international support. The BAU level has been projected to be approximately 2869 $GtCO_{2e}$ in 2030 based on its level in 2010 (1334 $GtCO_{2e}$), which has been updated from the National Energy Policy owing to increasing coal-fired power plant utilisation.

In November 2016, the government of Indonesia submitted the first NDC document to the UNFCCC. The document included a target to increase the energy sector contribution from 6% to 38%. The main contribution, around 59% remaining, would come from the forestry sector, including peat fire, whereas around 3% would be contributed from waste, agriculture, industrial processes and product use (UNFCCC, 2016).

To achieve the target of 29% reductions of CO2 emissions in 2030, the government has adopted the following strategies for carbon emissions reduction for the electricity supplies:

- Prioritise electricity supplies from renewable energy sources while ensure cost competitive of electricity;
- Fuel switching from oil to gas and biodiesel; and
- Adopt advanced clean coal technologies such as ultra-supercritical and consider Carbon Capture and Storage (CCS) when the technology has reached a matured stage of development.

NOTABLE ENERGY DEVELOPMENTS

ELECTRICITY

THE 35 GW ELECTRICITY GENERATION PROGRAMME

To provide a sufficient electricity supply for supporting economic growth as well as increasing the economy's electrification ratio, the government launched the 35-GW Electricity Programme for Indonesia in May 2015. The procurement process is expected to be completed in 2019 while commercial operation dates will vary between projects (PLN, 2018). Taking into consideration that the total capacity of 7.4 GW of power plants are in the construction stage, the total additional capacity of the power plants that will be developed is 43 GW (7.4 GW plus 36 GW). In the 35-GW programme, 57% of the capacity comes from coal-fired power plants, 36% from combined cycle gas, 6.1% from hydropower and 1.2% from geothermal.

To realise such an ambitious programme, a policy breakthrough has been prepared by the government. The Presidential Regulation No. 4 Year 2016 was issued and later revised to Presidential Regulation No. 14 year 2017 to accelerate electricity infrastructure development in Indonesia. This is a key regulation that

underlines the 35-GW Electricity Programme. This involves implementing initiatives such as land acquisition secured by the government according to the land law for projects of public interest; establishing a ceiling price for electricity purchase; shortening the procurement process in order to select developers and contractors through direct appointment and direct selection as well as conducting due diligence to assess the developer's and contractor's performance; streamlining the permit process (the number of electricity permits has been reduced from 52 to 29); and establishing a one-stop service for permits under the Investment Coordinating Board Agency (BKPM) (DJK, 2015b).

The subsequent electricity development programmes supported by regulations to accelerate electricity infrastructure development has substantially improved electricity services in Indonesia. There are no longer electricity supply deficits where the electricity reserve margins are varied among electricity grids in Indonesia.

Based on the latest project status update in December 2018, 2.9 GW of power plants are already operating, 18.2 GW are under construction, 11.4 GW has entered into power purchase agreements, 1.6 GW is being tendered by PLN and 954 GW is being planned by PLN (MEMR, 2019b).

ELECTRIFICATION RATIO

The government of Indonesia has rapidly increased the Indonesia's electrification rate from 84.4% in 2014 to 98.3% in 2018. The rate of electrification is projected to reach 99.9% in 2019. The government has a target to achieve nearly 100% electricity access by 2020. The electrification programme includes the expansion of transmission and distribution network in the Eastern Indonesia to reach remote villages. At the same time, the *Lampu Tenaga Surya Hemat Energi* (Energy Efficient Solar Power Lamp) programme has been underway to reach out 2,510 villages that have not have access to electricity, while the grid expansion is being rolled out to reach their regions until the end of 2019. Until end of 2018, 252 552 LTSHE units have been distributed to the villagers in foremost, outermost, least developed regions in 19 provinces in Indonesia (mainly in East Nusa Tenggara, North Maluku, Central Maluku, Papua, and West Papua).

UPDATE OF THE PLN ELECTRICITY SUPPLY BUSINESS PLAN 2018-2027

The MEMR issued the ministry decision number 1567 K/21/MEM/2018 on 13 March 2018 that consists the following changes to the previous electricity supply business plan:

- 23% share of renewable energy in the electricity generation mix in 2025 while the share of coal, gas, and oil will be 54.4%, 22% and 0.4% respectively;
- The plan for additional power generating capacity at total capacity of 56 024 MW;
- The expansion of transmission line capacity of 63 855 kilometer circuits (kms) while distribution network expansion is 526 390 kilometer circuits (kms); and
- The development of 151 424 mega-volt-ampere (MVA) of high voltage substations and 50 216 MVA of distribution substations.

Based on the PLN electricity supply business plan, PLN (the state electric company) would develop centralised solar PV to electrify isolated areas that are far from the existing electric distribution grids. These isolated areas include underdeveloped remote areas/villages, country border areas and outermost small inhabited islands in Indonesia. For areas that have unreliable supply of electricity (less than 12 hours of electricity supply per day), PLN is developing hybrid power system between renewables (solar PV, wind, biomass) and diesel power plants.

PLN is developing smart grid system to increase the penetration of variable renewable energy (solar PV and wind power). For isolated areas where the electric distribution network from the existing grids will not be developed in the next two to three years, PLN will develop micro grid mostly based on solar PV electric supplies. For the existing diesel power plants that accounted for 4% of the total fuel mix in 2018, PLN is planning to increase the share biodiesel blending rate.

UPSTREAM OIL AND GAS

On 19 February 2019, joint venture of Repsol-Mitsui-Petronas discovered natural gas reserve in South Sumatera that has at least 2 trillion cubic feet (Tcf) of recoverable resources, the largest gas discovery in

Indonesia over the past 18 years (Repsol, 2019). The discovery was made in the Sakakemang block in South Sumatera where its location is close to the Grissik gas processing plants and Indonesia's integrated gas transmission system that interconnects gas resources, supplies and demand in Sumatera, West Java and gas export to Singapore. Accordingly, gas production from the Sakakemang block is expected to commence in 2022, three years after the gas discovery.

On the 27 May 2019, the Plan of Development for Masela gas block located in the Arafuru sea in the eastern Indonesia has been agreed between SKK Migas, the Indonesia's oil and gas regulator and Inpex Corporation of Japan. The development of Masela gas block is expected to cost between USD 18 – 20 billion to build a large scale onshore LNG plant with an annual processing capacity of 9.5 million tons and gas processing plant with an annual production capacity of 150 million of standard cubic feet (MMSCF). The LNG and gas plant and processing facilities are expected to operate in the late 2020s.

REGULATIONS

SOLAR ROOFTOP REGULATION

Ministerial Regulation No. 49/2018 regarding the utilisation of solar rooftop by electricity customers of PT PLN (Persero) was issued on 1 December 2018. The regulation allows electricity consumers of PLN to sell the excess electricity production from solar PV to the electricity grid of PLN on a net-meeting basis. The solar rooftop regulation is expected to increase the share of renewable in the electricity generation mix and to meet the 23% renewable share in the generation mix by 2025 (MEMR, 2018b).

The ministerial regulation allows for the electricity customers to install rooftop solar PV at a maximum capacity to the customer's electricity connection. The excess electricity that is exported to the PLN grid is priced at 65% of electricity purchased from PLN. The accumulated energy that is sold to PLN will be used to reduce electricity bills in the following months.

For the industrial consumers that wish to install solar rooftop, PLN will charge the customers fees for capacity and emergency charges. The rate of fees are in accordance with the Ministerial regulation No. 01/2017 regarding the Power Plant Parallel Operation with PT PLN (Persero) electric grids.

POWER PURCHASES FROM RENEWABLE ENERGY POWER PLANTS BY PLN

On 8 August 2017, Ministerial Regulation No. 50/2017 regarding the Utilisation of Renewable Energy Resources for Electricity Generations was issued. The regulation introduced a ceiling price mechanism and electricity purchase mechanisms from renewable energy sources. The regulation has undergone subsequent revisions to the latest Ministerial regulation No. 53/2018 which set a ceiling price and electricity purchase mechanisms of biodiesel for generating electricity.

Under this new regulation, the purchase of electricity from renewable energy such as solar and wind power is carried out through direct selection based on quota capacity. Furthermore, the purchase of electricity from other renewable energy such as geothermal, biomass, biogas, municipal solid waste as well as hydro power will be conducted through the mechanism of the reference price and direct selections.

For areas where the generation cost is above the average national generation cost, the purchase price of electricity is maximum 85% of the generation cost on the local grid of the respective areas. Meanwhile, if the generation cost in the local grid equals or is below the average national generation cost, the electricity purchase price is equal to the generation cost in the local grid.

The generation cost in the electricity system that is used as the purchase price of electricity in the power purchase agreement is the generation cost in the electricity system of the previous year. Electricity is purchased using the scheme of Build Own Operate and Transfer (BOOT). Construction of the grid for power evacuation from the power plant to the point of connection will be carried out between the electric power developer and PLN on a business-to-business basis.

PARTICIPATION OF REGIONAL GOVERNMENT IN UPSTREAM OIL AND GAS BUSINESS

On 26 November 2016, the government issued Ministerial Regulation No. 37/2016 regarding provisions offering participating interest of 10% (PI 10%) in the area of oil and gas works. This regulation was intended to implement the provisions of Article 34 of Government Regulation No. 35/2004 on upstream oil and gas,

which has been amended several times. The most recent amendment was by Government Regulation No. 55/2009 to increase the participation of regional government through the obligation for the contractor (PSC) to offer the PI 10% to the regional-owned enterprise (BUMD). BUMD was established by the regional government whose oil and gas fields are located in its administrative area (MEMR, 2016c).

The regulation mandates include the following:

- Since the approval of the first plan of development (POD1), the contractor (PSC) has an obligation to offer PI 10% to BUMD;
- Onshore fields from 0 to 4 nautical miles involving BUMD districts/cities/provinces coordinated by the governor;
- The fields from 4 to 12 nautical miles for BUMD provinces;
- Onshore or offshore fields located in administrative areas of more than one province are based on the agreement among the related governors. If no agreement exists, then the MEMR determines the number of PI offered to each province;
- In the period of 10 days from date of receipt of the approval of POD1, Chief of SKKMIGAS is obliged to submit a letter addressed to the governor to review the preparation of BUMD that will accept the PI 10% offer;
- During Period 1 year, the governor will deliver, with a copy to the Minister, a letter of appointment to BUMD, which will accept the PI 10% offer indicated by the Chief of SKKMIGAS;
- In case the governor does not submit a letter of BUMD appointment, it will be assumed that the party is not interested and the PI 10% offer will be declared closed;
- In case the PI 10% offer for BUMD is declared closed, a contractor is required to offer it to State-Own Enterprises;
- The contractor (PSC) pre-finances the obligation amount of BUMD;
- SOE has an obligation to finance itself complying with normal business practices; and
- Shareholding enterprises and 10% PI cannot be traded or transferred or pledged.

REGULATION SIMPLIFICATION AND ENERGY SECTOR DEREGULATION

To encourage more investment in energy sector and accelerate economic growth, MEMR has subsequently simplified several regulations and permits in 2018. In total, 186 regulations and permits have been revoked or simplified. These include 56 regulations in oil and gas sector, 96 regulations in coal and mining sector, 20 regulations in electricity sector, and 14 regulations in renewable energy and energy conservation sector. Detailed information on the list of regulations and permits that have been revoked can be found on the MEMR website.

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PT PLN (Persero)—www.pln.co.id

SKKMIGAS, Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi—www.skspmigas-esdm.go.id

Statistics Indonesia (Badan Pusat Statistik, BPS)—www.bps.go.id

UNDP Indonesia—www.id.undp.org

REPUBLIC OF KOREA

INTRODUCTION

The Republic of Korea (Korea) is located in north-east Asia between China and Japan. It has an area of 100 284 square kilometres (km²) and a population of 51 million people as of 2016. Korea's population density is very high, with an average of more than 526 people per km². Approximately 20% of the population lives in Seoul, Korea's capital and its largest city. The economy's geography consists of hills and mountains with wide coastal plains in the west and the south. The climate is relatively moderate with four distinct seasons. Air conditioning is commonly necessary during the tropical hot summers, and heating is required during the bitterly cold winters.

Over the past few decades, Korea has become one of Asia's fastest growing and most dynamic economies. The gross domestic product (GDP) increased at 5.1% every year from 1990 to 2015, reaching USD 1.8 trillion (2011 USD purchasing power parity [PPP]) in 2016. GDP per capita (2011 USD PPP) in 2016 was USD 35 020, approximately three times higher than that in 1990. Korea's major industries include semiconductors, shipbuilding, cars, petrochemicals, digital electronics, steel, machinery and parts and materials.

Korea has few indigenous energy resources. It has no oil resources except for a small amount of condensate, only 309 million tonnes of recoverable coal reserves and 5.7 billion cubic metres of natural gas. Thus, to sustain its high level of economic growth, Korea imports large quantities of energy products. It imported approximately 87% of its primary energy supply in 2016. In the same year, it was the world's fifth-largest importer of crude oil, second-largest importer of liquefied natural gas (LNG) and fourth-largest importer of coal (IEA, 2018 a,b,c)

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c, d]	
Area (km²)	100 284	Oil (million barrels)	–
Population (million)	51	Gas (billion cubic metres)	7.1
GDP (2011 USD billion PPP)	1 795	Coal (million tonnes)	309
GDP (2011 USD PPP per capita)	35 020	Uranium (kilotonnes U)	–

Sources: [a] UN (2018); [b] EGEDA (2018); [c] EIA (2019); [d] KOSIS (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Korea's total primary energy supply was more than tripled between 1990 and 2016 from 93 million tonnes of oil equivalent (Mtoe) to 282 Mtoe. In particular, from 1990 to 2000, energy supply increased at an average annual growth rate of 7.3%, far exceeding the economic growth rate of 6.9% for the same period. Likewise, per capita primary energy supply grew from 2.2 tonnes of oil equivalent in 1990 to 5.5 tonnes of oil equivalent in 2016. This increase was similar to that in Japan and most European economies.

In 2016, Korea's total primary energy supply was 282 Mtoe, a 3.6% increase from the supply in the previous year. In terms of energy source, oil represented the largest share (39%), followed by coal (29%) and gas (15%). The remaining 18% of the primary energy supply came from nuclear and renewable energy sources. Energy imports accounted for approximately a fifth of Korea's total import value in 2016.

The oil supply in 2016 was 110 Mtoe, a 6.9% increase over the previous year's level. In 2016, the economy imported 86% of its crude oil from the Middle East. With regard to coal, the supply in 2016 totalled 82 Mtoe, a 0.80% increase from the previous year's level. Korea has modest reserves of low-quality,

high-ash anthracite coal, which are insufficient to meet its domestic consumption. Thus, almost all of Korea's coal consumption is met by imports. Korea is the world's fourth-largest importer of both steam coal and coking coal. The main coal imports come from Australia; Indonesia; Russia; Canada; China; and the United States.

Since the introduction of LNG in 1986, natural gas use in Korea has grown rapidly. The gas supply reached 41 Mtoe in 2016. Its share of the primary energy supply was 15% in the same year. Most of Korea's LNG imports come from Qatar; Oman; Indonesia; Malaysia; Australia; and Brunei Darussalam. Korea began producing natural gas domestically in November 2004 after a small quantity of natural gas was discovered in the Donghae-1 offshore field in the south-east.

Korea's electricity generation in 2016 was 558 terawatt-hours (TWh), a 1.8% increase from the 2015 level. Generation by thermal sources, including coal, oil and natural gas, accounted for 64% of the total electricity generated, followed by nuclear energy source at 29% and hydropower source and renewables at 3.6%.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	51 279	Industry sector	47 819	Total power generation	557 672
Net imports and others	246 511	Transport sector	34 912	Thermal	358 117
Total primary energy supply	282 261	Other sectors	46 021	Hydro	2 847
Coal	81 467	Non-energy	49 955	Nuclear	161 995
Oil	109 797	Final energy consumption*	128 752	Others	34 713
Gas	41 313	Coal	8 857		
Renewables	4 298	Oil	44 698		
Others	45 386	Gas	21 532		
		Renewables	1 840		
		Electricity and others	51 825		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

Korea's final energy consumption in 2016 was 129 Mtoe, which was a 2.3% increase from the previous year's level. The industrial sector accounted for the largest share at 27%, while the transport sector accounted for 20%. The remainder (26%) was used in others (combined residential, commercial and agriculture sectors). In general, consumption in the industrial sector has weakened since the late 1990s, and consumption in the transport and commercial sectors has increased.

By energy source, electricity and others accounted for 40% of final energy consumption, followed by oil (35%), natural gas (17%) and coal (6.9%). Natural gas consumption has increased because of the economy's policy measures.

ENERGY INTENSITY ANALYSIS

The 2.9% growth of Korean GDP in 2016 resulted in a 0.63% increase in the energy intensity of the economy's total primary energy supply. This was an economy-wide energy intensity level increase of 0.98 tonnes of oil equivalent/million USD. With regard to final energy consumption, the energy intensity level increased by 0.24%, from the 2015 level of 99 tonnes of oil equivalent/million USD to 100 tonnes of oil

equivalent/ million USD in 2016. This was mostly driven by the decreasing energy consumption in the industry sector, which had decreased by 0.5% from the previous year's level.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	156	157	0.63
Total final consumption	72	72	–0.63
Final energy consumption excluding non-energy	99	100	0.24

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

In 2016, the share of modern renewable energy in final energy consumption was 2.3%, an increase of 36% from the previous year's level. Decreased use of fossil fuels and others, especially coal, combined with the expansion of traditional biomass contributed to the increase in the share of modern renewable energy by 19% over the previous year's level.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	125 884	128 752	2.3
Non-renewables (fossils and others)	122 427	125 469	2.5
Traditional biomass*	1 029	337	−67
Modern renewables*	2 428	2 946	−21
Share of modern renewables in final energy consumption (%)	1.9%	2.3%	19%

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass. This is because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial) using inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (e.g. hydro and geothermal energy), including biogas and wood pellets, are considered modern renewables, but data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

In the past, Korea's energy policy has focused on ensuring a stable energy supply to sustain economic growth. The government is currently seeking a new direction in energy policy with the aim of supporting sustainable development that fully considers the 3Es—energy, economy and environment.

The responsibility for energy policy development and implementation is divided among a number of government institutions. The Ministry of Trade, Industry and Energy (MOTIE), which succeeded the Ministry of Knowledge Economy (MKE) in 2013, is the primary government body for energy policy.

In 2006, the Korean Government established the National Energy Committee, which is chaired by the President and includes governmental and non-governmental experts. The committee's role is to deliberate upon and mediate among major energy policies and plans. In addition, it discusses the National Basic Plan for Energy, emergency preparedness, foreign energy resource development, nuclear energy policy, the coordination of energy policies and projects, the prevention and settlement of social conflict related to energy issues, the transportation of energy and the physical distribution plan, the effective execution of the

energy budget, and energy issues within the United Nations Framework Convention on Climate Change (UNFCCC).

As part of its liberalisation efforts in the energy sector, in 2001, the government established the Electricity Regulatory Commission to take charge of regulations in the electric power sector and manage technical and professional competition policy. There is no regulatory commission for the gas industry. The Fair Trade Commission is Korea's anti-trust agency and monitors monopoly problems and unfair business practices in the energy sector.

The Korea Energy Economics Institute (KEEI) develops energy policies related to the production of energy statistics. It also considers policies with regard to consumption and supply overviews, energy conservation and climate change, the petroleum industry, the gas industry, the electricity industry, and the new and renewable energy industry among others. It is directly financed by the government.

The Korea Institute of Energy Technology Evaluation and Planning, funded by the government, is Korea's major energy technology research institute. Its mission is to contribute to growth across the economy by developing industrial core energy technologies and deploying outcomes.

The Korea Energy Agency plays a key role in achieving Korea's research and development (R&D) policy goals for energy efficiency, energy conservation, clean energy and new and renewable energy technologies. It also administers R&D planning, financial support and management.

In August 2008, faced with high energy prices and rising concerns over climate change, Korea announced a long-term strategy, which would determine the direction of its energy policy until 2030.

On 14 January 2014, Korea launched the Second Energy Basic Plan, which is the main official plan in the energy sector, with a timeframe of up to 2035 (MOTIE, 2014a). According to the Second Energy Basic Plan, total primary energy consumption is projected to grow at an annual average rate of 1.3% between 2011 and 2035. Final energy consumption will grow at 0.9% per year. Energy intensity is expected to drop from 0.26 tonnes of oil equivalent/million KRW in 2011 to 0.18 tonnes of oil equivalent/million KRW in 2035 with an improvement of 1.4% per year, resulting in a 30% improvement of energy intensity, which is equivalent to a 13% reduction in final energy consumption.

The government has proposed the following six major policy strategies:

- Moving to an energy management-oriented policy;
- Building a power generation system based on distributed generations (DGs);
- Ensuring harmonisation between the environment and safety;
- Strengthening energy security;
- Building a stable energy supply according to source; and
- Pursuing an energy policy together with the public.

Heavy dependence on the Middle East for its crude oil supply led the economy to pursue a policy of diversifying its oil supply during the outlook period (2011–2035). The state-owned Korea National Oil Corporation (KNOC) will continue to be responsible for the economy's preparedness for an oil emergency by operating oil stockpiling facilities and pursuing stakes in oil projects around the world.

In the natural gas industry, the state-owned monopoly Korea Gas Corporation (KOGAS) will continue to be responsible for managing the import, storage, transmission and wholesale distribution of LNG. The electricity industry will continue to be dominated by the state-owned Korea Electric Power Corporation (KEPCO). It is possible that restructuring and liberalisation may evolve in the future, allowing more private participation in the oil, gas and electricity industries.

ENERGY MARKETS

MARKET REFORM

Korea has been restructuring its energy sector since the late 1990s when it introduced the principle of free competition in industries traditionally considered to be natural monopolies, such as electricity and natural gas. In January 1999, in a move to phase-in competition in the electricity industry, the government announced the Basic Plan for Restructuring the Electricity Industry. The plan included the unbundling and privatisation of Korea's state-owned electricity monopoly, KEPCO.

Part of the plan has been implemented, including the establishment of the Korea Power Exchange and the Korea Power Commission in April 2001. The power generation part of KEPCO was split into six wholly owned companies—five thermal generation companies and the Korea Hydro & Nuclear Power Company Limited. The five thermal generation companies were to be privatised in stages. However, in July 2008, the government announced there would be no further privatisation of KEPCO and its five subsidiaries. At the end of 2015, 51% of KEPCO, a holding company, was owned by the Korean Government. KEPCO is still a dominant player in the electricity sector, controlling 79% of total power generation and 100% of transmission and distribution in Korea (KEEI, 2016).

The Korean Government has also made moves to restructure the gas industry. In November 1999, the government sold 43% of its equity in KOGAS and developed the Basic Plan for Restructuring the Gas Industry to promote further competition in the industry. The plan outlines a scheme to introduce competition into the import and wholesale gas businesses, promote the development of the gas industry and enhance consumer choice and service quality. A detailed implementation plan was announced in October 2001. The plan covers ways to achieve the smooth succession of the existing import and transportation contracts, privatisation of import and wholesale businesses, stabilisation of prices and balance of supply and consumption and revision of related legislation and enforcement (KEEI, 2002).

With regard to competition in the import and wholesale sectors of KOGAS, a final decision on whether to split the sectors from KOGAS or introduce new companies will be made following discussions among stakeholders. Given the strong public interest in this sector, the existing public utility system is expected to be maintained. Competition in the retail sector, which is currently operated under a monopoly system within each region, will be introduced in stages in conjunction with the progress made in the wholesale sector. As of the end of 2017, no decision on the liberalisation of the gas market had been made.

OIL, GAS AND ELECTRICITY MARKETS

OIL

Given Korea's dependence on oil imports, the government has been trying to secure supplies for the short and long terms. To ease short-term supply disruptions and meet International Energy Agency (IEA) obligations, the Korean Government has been increasing its oil stockpile since 1980. At the end of 2017, Korea held 238 million barrels in oil stock. This economy-wide stockpile capacity substantially exceeds the IEA's 90-day requirement.

The state-controlled KNOC has been actively exploring and developing oil and gas, both locally and abroad, to improve energy security. As of the end of 2017, it had conducted 31 projects in 17 countries. Private companies (including SK Energy, GS Caltex, S-Oil and Hyundai Oil Bank) are also active in the oil and gas sector as well as in the downstream market and wholesale imports.

To encourage private companies to invest in development projects overseas, the Korean Government has expanded its policy of supplying long-term, low-interest loans through the Special Account of Energy and Resources.

Korea has also been trying to diversify its crude oil supplies. The number of supply sources increased from 9 in 1980 to 29 in 2016; however, the economy's dependency on oil imports from the Middle East remains high (86% in 2016). Korea is also actively strengthening its bilateral relations with oil-producing economies as well as its multilateral cooperation through the IEA, Asia-Pacific Economic Cooperation (APEC) forum, Association of South-East Asian Nations (ASEAN)+3, International Energy Forum and Energy Charter to enhance its crisis management capabilities. In particular, the government plans to play a

leading role in energy resource development and trade in north-east Asia by creating a collaborative framework on energy cooperation.

NATURAL GAS

Korea introduced natural gas-based city gas to the residential sector in the 1980s to reduce the economy's dependence on imported oil. Since then, gas use has grown rapidly and has replaced coal and oil in the residential sector. KOGAS has a monopoly over Korea's natural gas industry, including the gas import, storage, transport and wholesale businesses. Thirty-two city gas companies operate in the gas retail business in each region of the economy. KOGAS is the world's second-largest LNG buyer, and it also promotes the development of natural gas resources abroad in economies such as Australia, Canada and Iraq.

The Twelfth Plan for Long-Term Natural Gas Demand and Supply, finalised by MOTIE in December 2015, projected natural gas consumption to decrease by 0.34% per year from 2014–29 (MOTIE, 2015). By sector, the city gas sector's consumption of natural gas is projected to increase by 2.1% per year, while the consumption of gas for power generation is projected to decrease by 4.2% per year.

The Korean Government is considering new regulatory reforms on sales restrictions for private LNG importers and on using storage facilities in the duty-free zone to facilitate international trading businesses.

ELECTRICITY

Korea's economic growth has increased its electricity consumption substantially over the past few decades. Throughout the 1990s, the average annual growth rate was 9.5%. Then, between 1990 and 2016, installed capacity increased five-fold, from 21 gigawatts (GW) in 1990 to 106 GW in 2016.

The Eighth Basic Plan for Long-term Electricity Demand and Supply (2017–31), finalised by MOTIE in December 2017, projects that electricity consumption will grow by 2.1% per year from 2017 to 2031 and that additional capacity of 16 GW will be required by 2031 (MOTIE, 2017a). If decommissioning is taken into account, this translates to approximately 124 GW of the total generation capacity for this period.

Korea's electricity industry is dominated by KEPCO, which was separated into six power generation subsidiaries in April 2001: Korea Hydro & Nuclear Power, which owns the economy's nuclear energy power plants and large hydroelectric dams, and five state-owned generating companies, which took over ownership of the economy's thermal power plants. KEPCO retained the economy-wide transmission and distribution grids.

To rectify an energy supply and consumption structure overly dependent on oil, the construction of oil-fired power plants has been strictly controlled and the development of nuclear, coal and natural gas electricity generation units has been promoted. Gas-fired power plants were first introduced in 1986. Korea has been building nuclear energy power plants since the 1970s because nuclear energy is a strategic priority for the government. However, it announced its energy transition roadmap, which aims to replace nuclear and coal generation with renewables and natural gas, in October 2017. During the period of the Eighth Basic Plan, five nuclear power plants are scheduled for construction and 12 nuclear energy power plants are scheduled for decommissioning. The share of total electricity production capacity from nuclear energy power plants is projected to decrease from 19% in 2017 to 12% by 2031.

FISCAL REGIME AND INVESTMENT

In December 2009, the Korean Government approved tax reforms to foster a business-friendly environment and promote investment. The tax changes included a reduction in corporate tax rates and an increase in tax benefits for R&D.

In 2009, the corporate tax rate was 22% on taxable income over KRW 200 million and 13% on taxable income below that amount. Under the tax reforms, these rates were scheduled to be reduced further from 22% in 2009 to 20% in 2010 and from 11% to 10% for the same period, respectively. The tax reduction for the lower bracket was implemented as scheduled, while the implementation for the higher bracket was delayed. Since 2012, the corporate tax rate has been 22% on taxable income over KRW 20 billion, 20% on KRW 200 million to KRW 20 billion and 10% on taxable income below KRW 200 million.

To promote investment in R&D, which will boost economic growth, the government has increased its tax assistance for R&D. The measures include an R&D reserve fund, an increase in investment tax credits for R&D facilities and an increase in the deduction for R&D grants paid by corporations to universities from 50% to 100%.

ENERGY EFFICIENCY

The Korean Government has introduced various policy measures to improve energy efficiency, including energy-consumption management schemes for end users, adjustment of the energy pricing system and the provision of incentives for companies to invest in energy efficiency. These policy measures aim to improve energy efficiency by 8.7% by 2017 compared with the 2012 level and to save 9.3 Mtoe in 2017. Announced in December 2014, the measures are part of Korea's long-term energy plan, which aims to achieve a 1.4% annual energy efficiency improvement by 2035 compared with that in 2011.

RENEWABLE ENERGY

In September 2014, the Korean Government announced the Fourth National Basic Plan for New and Renewable Energy (MOTIE, 2014c). According to the plan, the government aims to replace 11% of the total primary energy supply with new and renewable energy (NRE) by 2035. The development of solar and wind power as the main energy sources will also enable 13% of the total electric energy in Korea to be supplied by NRE by 2035.

In December 2017, the Korean Government made public 3020 Renewable Energy Initiative Implementation Plan (MOTIE, 2017b). According to the plan, the government plans to increase renewable energy's share of the energy mix from its current level of 7% to 20% by 2030 by providing 48.7 GW in new generating capacity. In addition, more than 90% of the new generating capacity will come from solar and wind energy, and the remaining will be supplied by hydro and bioenergy.

CLIMATE CHANGE

On 15 August 2008, Korea announced a new Low-Carbon, Green Growth vision aimed at shifting the traditional development model of fossil fuel-dependent growth to an environmentally friendly model. To realise this vision, the Presidential Commission on Green Growth was established in February 2009. The Basic Act on Low Carbon and Green Growth was subsequently submitted and took effect in April 2010. This legislation provided the legal and institutional basis for green growth. To implement this vision more effectively, the National Strategy for Green Growth was adopted in June 2009 together with the Five-Year Plan for Green Growth in June 2014 (Government of Korea, 2014a).

The National Strategy for Green Growth calls for the construction of a comprehensive, long-term (2009–50) master plan to address the challenges caused by climate change and resource depletion. The strategy consists of three main objectives and ten policy directions:

- Mitigating climate change and achieving energy independence
    - Effectively reducing greenhouse gas emissions (MKE, 2009);
    - Reducing fossil fuel use and enhancing energy independence; and
    - Strengthening the capacity to adapt to climate change.
- Creating new engines for economic growth
    - Developing green technologies;
    - Greening existing industries and promoting green industries;
    - Advancing the industrial structure; and
    - Engineering a structural basis for a green economy.
- Improving the quality of life and enhancing international standing
    - Greening the land and water and building a green transportation infrastructure;

- Bringing the green revolution into people's daily lives; and
- Becoming a role model for the international community as a green growth leader.

NOTABLE ENERGY DEVELOPMENTS

RESPONSE TO CLIMATE CHANGE

NEW BUSINESS MODELS TO RESPOND TO CLIMATE CHANGE

In July 2014, MOTIE introduced six new energy-related businesses based on emerging business models to reduce CO_2 emissions and increase energy efficiency (MOTIE, 2014b). MOTIE also established the Energy Efficiency and Climate Change Bureau for more efficient policy support. Plans for R&D in related technology and regulation reforms were announced in December 2014 and April 2015 (Government of Korea, 2014b and 2015).

The six business models are the following:

- A consumption management service, which collects electricity saved from buildings and factories using electricity-saving devices and sells it to the electricity trading market;
- An integrated energy management service, which connects finance, insurance and an energy management system (EMS) and provides systems maintenance for companies;
- An independent micro-grid, which replaces diesel generators with NRE generators and an electricity storage system (ESS);
- Photovoltaic equipment rental, which lends photovoltaic equipment to households and receives payment through electricity gains;
- A recharging service for electric vehicles, which provides paid recharging; and
- Used-heat recycling from thermal power plants, which utilises used heat in diversified farming.

These business models focus on reducing the consumption of fossil-fuel electricity and on increasing R&D investments to develop related technologies, such as carbon capture and storage (CCS), ESSs and EMSs.

KOREA'S MITIGATION TARGET AND ITS AMBITION

In June 2015, the Korean Government announced its Intended Nationally Determined Contribution (INDC) towards achieving the objective of Article 2 of the UNFCCC. Korea plans to reduce its greenhouse gas (GHG) emissions by 37% from the business-as-usual (BAU 850.6 $MtCO_2$ equivalent) level by 2030 across all economic sectors based on the BAU projection of the Korea Energy Economics Institute and the Energy and GHG Modelling System (KEEI-EGMS).

According to CAIT of the World Resources Institute (WRI), Korea accounts for approximately 1.4% of global GHG emissions, including land use, land-use change and forestry (LULUCF). Korea's mitigation potential is limited because of its industrial structure, which comprises a large share of manufacturing (32% as of 2012), and the high energy efficiency of its major industries. Further, given the decreased level of public acceptance following the Fukushima accident, there are now limits to the extent that Korea can make use of nuclear energy, one of the major mitigation measures available to it.

To meet its INDC, the Korean Government announced the First Basic Plan Responding Climate Change in December 2016 that includes a basic roadmap to national GHG reduction in 2030 (Government of Korea, 2016). It provides comprehensive policy directions for expanding the use of renewable energy, increasing power generation using clean fuel, improving energy efficiency, utilising a carbon market, increasing climate technology investment and fostering new energy-related businesses.

ENERGY TRANSITION FROM NUCLEAR AND COAL TO RENEWABLES AND NATURAL GAS

In October 2017, the Korean Government released its Energy Transition Roadmap that aims to reduce nuclear and coal use and replace them with increased use of renewables and natural gas (Government of Korea, 2017). Under the new energy roadmap, it will nullify plans to construct new nuclear reactors and will not allow life extensions for existing nuclear reactors.

Natural gas and renewable energy sources would have greater shares in the generation mix. The government aims to generate 20% of electricity from renewable energy sources by 2030. The share of natural gas is expected to be 19%, while those of coal and nuclear energy will be 36% and 24%, respectively.

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Korea Energy Economics Institute—www.keei.re.kr

Korea Energy Agency—www.energy.or.kr

Korea Gas Corporation—www.kogas.or.kr

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Ministry of Trade, Industry and Energy—http://english.motie.go.kr

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Statistics Korea—http://kostat.go.kr/portal/english/index.action

World Resources Institute (CAIT Climate Data Explorer)—http://cait.wri.org

MALAYSIA

INTRODUCTION

Malaysia is located in Southeast Asia and lies entirely in the equatorial zone, with an average daily temperature varying between 21°C and 32°C. It has a total territory of approximately 330 323 square kilometres (km^2), covering 11 states and 2 federal territories in Peninsular Malaysia, as well as 2 states and 1 federal territory on the Borneo Island (MEA, 2017). In 2016, Malaysia's population stood at 31.2 million, an increase of 1.5% over the 2015 level of 30.7 million (EGEDA, 2018).

Malaysia's gross domestic product (GDP) reached USD 801 billion (2011 USD purchasing power parity [PPP]) in 2016, an increase of 4% from USD 768 billion in 2015. The GDP increase contributed to a 2.7% improvement in GDP per capita from USD 25 002 in 2015 to USD 25 669 (EGEDA, 2018). In 2016, the largest contributions to GDP were from services (54%), manufacturing (23%), mining and quarrying (8.8%), agriculture (8.1%) and construction (4.5%). In 2016, the main export products were manufactured goods (82.1%), oil and gas (6.9%) and palm oil (6.1%) (MEA, 2017).

Compared with other large economies in the APEC, Malaysia's energy resources can be considered to be moderate in absolute terms. In 2016, data published by the Energy Commission (EC) of Malaysia showed that the East Malaysian states hold nearly two-thirds of Malaysia's energy reserves and that the rest are located in Peninsular Malaysia. The economy's oil reserves (including condensate) were 5.0 billion barrels, 38% of which is found in Sabah (EC, 2018a). The natural gas reserves of the economy are estimated at approximately 2.5 trillion cubic metres (tcm) or 87 trillion cubic feet (Tcf) in 2016. More than half of the reserves are found in the Sarawak Basin. The coal reserves, assessed at 1.9 billion tonnes, are mostly located in Sarawak and Sabah (EC, 2018a).

Malaysia being an equatorial economy enjoys a high irradiance level throughout the year and is well suited for harnessing solar power. Although Malaysia has substantial potential to develop solar power, cloud cover that constantly manifests itself in the region may hamper some of the effort to expand solar photovoltaic (PV) deployment in the economy. According to the New and Renewable Energy Policy and Action Plan (NREPAP) released in 2009, Malaysia's reasonable target for grid-connected solar PV as building integrated PV (BIPV) application is 850 MW by 2030 and may increase to more than 8000 MW by 2050 (SEDA, 2011).

The economy also has potential for biomass as an energy source owing to the presence of palm oil plantations and industries in the economy. As of 2016, Malaysia constituted 30% of the world's palm oil production and 37% of the world's palm oil exports (MPOC, 2016). This production creates abundant agricultural residue, particularly empty fruit bunches.[1]

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c]	
Area (km^2)	330 323	Oil (billion barrels)	5.0
Population (million)	31	Gas (trillion cubic metres)	2.5
GDP (2011 USD billion PPP)	801	Coal (million tonnes)	1 938
GDP (2011 USD PPP per capita)	25 669	Uranium (kilotonnes U)	–

Sources: [a] MEA (2017); [b] EGEDA (2018); [c] EC (2017a).

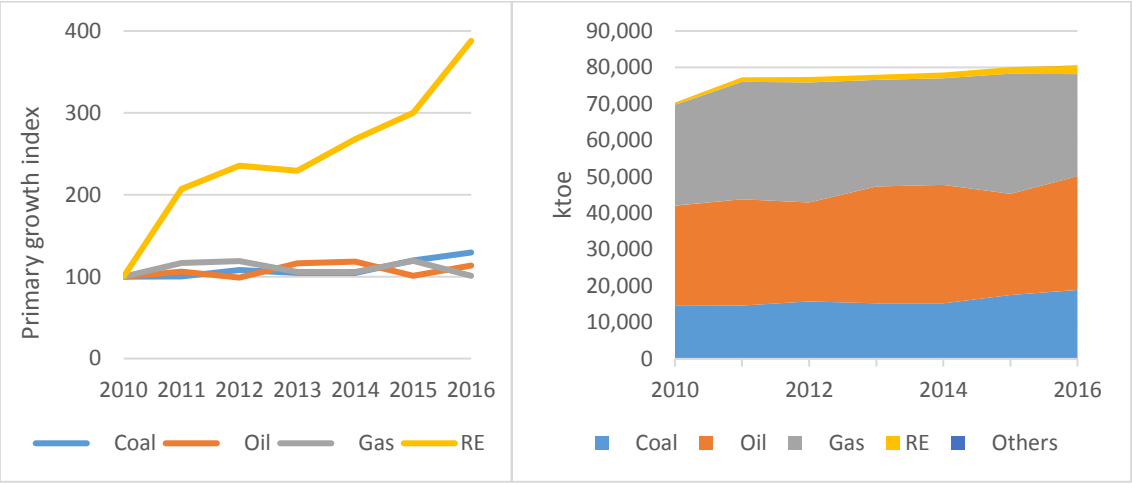
[1] Palm oil production generates large amounts of residue, such as empty fruit bunches (EFBs) of palm. EFBs are a type of woody biomass with a calorific value of 4 400 kilocalories per dry kilogram (kcal/kg-dry); they are regarded as a safe and promising biofuel resource because they have a very low chlorine content (Asia Biomass, 2009).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Malaysia's total primary energy supply was 80 444 kilotonnes of oil equivalent (ktoe) in 2016, an increase of 0.4% from the 2015 level of 80 104 ktoe. This increase is lower than the 2014–15 level, which recorded 1.9%. Compared with the 2015 level, oil is now the largest share of primary energy supply in 2016 at 39% (31 239 ktoe), followed by gas with 35% share (28 002 ktoe) and coal with a 24% share (18 910 ktoe). In 2015, gas contributed the largest share at approximately 41% (32 993 ktoe). Among the primary energy sources, renewables saw the largest year-over-year growth at 29% (from 1 816 ktoe to 2 349 ktoe) while gas decreased by 15% (4 990 ktoe). The growth in renewables has been sustained since 2010, where supply nearly quadrupled from 606 ktoe. This growth has been partly due to the feed-in tariff (FiT) for renewable energy as part of the NREPAP introduced by the government in 2009.

Figure 1: Primary energy growth index and total primary energy supply, 2010–16



Source: EGEDA (2018) and APERC analysis

Traditionally, Malaysia has been an energy exporter of mainly crude oil and natural gas (through pipelines and in the form of LNG). The economy registered total energy exports[2] of 59 730 ktoe in 2016, an increase of 3% from the 2015 level of 57 954 ktoe. During the same period, total energy imports increased by 7% from 46 343 ktoe to 49 670 ktoe in 2016. Gas imports decreased by 18%, while oil increased by 30% (EGEDA, 2018).

OIL

Malaysia's oil reserves are the fourth-largest in the Asia-Pacific Region and are mostly in offshore fields. Malaysia's continental shelf is divided into three producing basins, namely, the offshore Malay Basin in Peninsular Malaysia in the west and the Sarawak and Sabah basins in the east (EC, 2018a). The bulk of the oil reserves are in the Malay Basin, which produces light and sweet crude oil (EIA, 2017). Malaysia's average daily oil production was 627 thousand barrels per day in 2016. In 2016, Sabah yielded 37% of the total oil production, followed by Peninsular Malaysia (36%) and Sarawak (approximately 27%) (EC, 2018b).

Malaysia has five oil refineries with a combined capacity of 566 thousand barrels per day (kbbl/d) (including condensate splitter capacity). Petroliam Nasional Berhad (PETRONAS), the state-owned national oil company, has three refinery facilities that provide more than 50% of the total daily refinery production. Petrol and diesel constituted 79% of the total domestic sales of petroleum products in 2016 (EC, 2018b).

[2] Total energy exports/imports is equivalent to the sum of LNG and piped gas exports/imports, crude oil exports/imports, petroleum products exports/imports and coal exports/imports.

The Malaysian Government, in the wake of the Economic Transformation Program, embarked on a large-scale oil and gas project in Southern Peninsular Malaysia, known as the Pengerang Integrated Petroleum Complex (PIPC). The PIPC is divided into two mega projects: the Pengerang Independent Deepwater Petroleum Terminal (PIDPT) project undertaken by private companies and Petrochemical Integrated Development (RAPID) project with PETRONAS as the major developer. Owing to the size of the project, Platts, an energy information provider that produced the free on board (FOB) Singapore oil benchmark price for the oil trade, will expand the price benchmarking scope to include oil storage terminals from Malaysia and rename it FOB Straits (Platts, 2015a).

Approximately a quarter of Malaysian crude oil production currently originates from the Tapis field in the offshore Malay Basin (EIA, 2017). Tapis crude, which is produced from this field, is very light and sweet. Crude oils that are light (higher degrees of American Petroleum Institute [API] gravity or lower density) and sweet (low sulphur content) are usually priced higher than heavy, sour crude oils. This is partly because petrol and diesel fuel, which typically sell at a significant premium compared with residual fuel oil and other 'bottom of the barrel products', can usually be more easily and cheaply produced using light, sweet crude oil (EIA, 2012). ExxonMobil, one of the world's major oil companies, holds 30% of the equity in the Enhanced Oil Recovery (EOR) project at the Tapis field, while the rest of the equity belongs to PETRONAS. According to ExxonMobil, Tapis Blend is a high-quality, extra light, low sulphur crude. It has a high-quality clean product and conversion feed, with an API gravity[3] of 42.7 and sulphur level of 0.04% (ExxonMobil, 2018).

NATURAL GAS

Most of the gas reserves of Malaysia are offshore in Peninsular Malaysia in the eastern areas of Sarawak and Sabah. Most of the gas reserves are non-associated (87%), while the remaining reserves are associated with oil basins (13%). Sarawak hosts slightly more than half the total reserves, followed by Peninsular Malaysia (31%) and Sabah (15%). In 2016, the average daily natural gas production was 5 901 million standard cubic feet per day (MMscf/d), a decrease of 11% from the 2015 level of 6 654 MMscf/d (EGEDA, 2018). Most of the production (64%) came from Sarawak, followed by Peninsular Malaysia (30%) and Sabah (6%). Besides local production, Malaysia also imports piped gas from the Malaysia–Thailand Joint Development Area (MTJDA), from Indonesia (EC, 2013) and LNG imports from Qatar, Brunei Darussalam and Algeria (EC, 2018a).

Although Malaysia is one of the world's largest LNG exporters, a geographical mismatch between where the gas is produced (Sabah and Sarawak) and the regions of highest consumption (Peninsular Malaysia) prompted Malaysia to build a LNG regasification terminal (RGT) to facilitate LNG imports. In 2016, Malaysia imported approximately 1 392 ktoe of LNG, a decrease of 33% from 2 090 ktoe in 2015 (EGEDA, 2018).

Malaysia has an extensive gas pipeline network running through Peninsular Malaysia, with pipelines connected to offshore fields on the east coast of Peninsular Malaysia. The Peninsular Gas Utilisation (PGU) network, which started in 1984, covers more than 2 500 km of pipelines composed of main pipelines, supply pipelines and laterals, which link most cities in Peninsular Malaysia. The pipelines also have cross-border interconnections to Singapore and Songkhla, Thailand. The PGU network comprises six gas-processing plants with a combined capacity of 56 million cubic metres per day (Mcm/d) (2 000 MMscf), producing methane, ethane, butane and condensate (Gas Malaysia, 2015).

COAL

Malaysia's coal resources mostly comprise bituminous and sub-bituminous coal. Estimated reserves are approximately 1 938 million tonnes (Mt), which are found in Sabah and Sarawak (EC, 2018a). Nearly two-thirds of these reserves have been categorised as inferred. Even with substantial coal resources, domestic coal production has not been that aggressive because most of the coal deposits are far inland, which makes extraction costs high. Likewise, some areas have been declared as protected, such as the Maliau Basin in Sabah, thereby prohibiting coal-mining activities. Only Sarawak allows coal-mining activity, and the areas are Mukah (the largest coal basin) with 1.6 million metric tonnes of production in 2016, Kapit with 0.8 million metric tonnes and Sri Aman with 15 655 metric tonnes (EC, 2018a).

[3] American Petroleum Institute (API) gravity is a measure of the specific gravity of crude oil or condensate in degrees, an arbitrary scale expressing the gravity or density of liquid petroleum products. The measuring scale is calibrated in terms of degrees API (EIA, 2018).

According to IEA Energy Statistics 2017, Malaysia was the eighth-largest coal importer in the world in 2015, with coal consumption reaching 29 Mt (IEA, 2017). This reflects a rapid expansion of coal generation capacity, especially during 2000–15 when coal consumption in the power sector increased from 1.5 million tonnes of oil equivalent (Mtoe) to nearly 16 Mtoe. Coal generation capacity expanded to meet increasing electricity consumption and reduce dependence on natural gas, which previously dominated generation with a share as high as 70% in the 1990s (EC, 2018b).

ELECTRICITY

There are three major electricity grids in Malaysia. The national grid in Peninsular Malaysia and the Sabah grid are both regulated by the federal government; the Sarawak grid is under the jurisdiction of the state government. The national grid is connected to Thailand's grid to the north (with a power transfer capacity of 380 MW) and Singapore's main grid to the south (with a power transfer capacity of 450 MW) (ACE, 2015). The Sarawak grid is connected to the Kalimantan Grid in Indonesia. The power transfer reached 70 MW by May 2016 (The Star, 2016).

Malaysia's total licensed power generation capacity at the end of 2016 was recorded at 33 023 MW, an increase of 8.5% from the 2015 level of 30 439 MW (EC, 2018a). Approximately 55% of the total licensed capacity was owned by the independent power producers (IPPs) and the rest by government-linked utilities, self-generation facilities and cogeneration facilities (EC, 2018a).

In the same year, the total electricity generation was 156 665 gigawatt-hours (GWh), an increase of 4% from the 2015 level. Thermal generation, mostly from natural gas and coal, constituted 88% of the total power generation, while hydropower and other fuels accounted for the remainder (EGEDA, 2018).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	92 137	Industry sector	15 309	Total power generation	156 665
Net imports and others	–10 059	Transport sector	21 540	Thermal	135 571
Total primary energy supply	80 444	Other sectors	8 457	Hydro	20 024
Coal	18 910	Non-energy	8 011	Nuclear	-
Oil	31 239	Final energy consumption*	45 305	Others	1 070
Gas	28 002	Coal	1 783		
Renewables	2 349	Oil	25 270		
Others	-57	Gas	5 488		
		Renewables	377		
		Electricity and others	12 386		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type, do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

In 2016, Malaysia's total final consumption reached 53 316 ktoe, an increase of 9.4% from the 2015 level. This is a marked increase over the period 2013 to 2015 when annual growth was less than 1%. The transport sector was the largest energy consumer, constituting 40% of the total final consumption (21 540 ktoe). It was followed by the industry sector with a 29% share (15 309 ktoe), the non-energy sector with a 15% share (8 011 ktoe) and

other sectors (residential, commercial and agriculture sectors) for a combined share of 16% (8 457 ktoe) (EGEDA, 2018).

In terms of fuel type, oil was still the most consumed fuel, particularly in the transport sector, constituting 56% of the final energy consumption (excluding non-energy uses). This was followed by electricity with a 27% share, gas with a 12% share and coal with a 4% share. Gas increased the most from 2015 to 2016 at 13.8%. Oil consumption reversed its trend in decreasing consumption and increased by 2.2% from 24 717 ktoe in 2015 to 25 270 ktoe in 2016. Modern biomass consumption decreased by 3% (EGEDA, 2018).

ENERGY INTENSITY ANALYSIS

Malaysia's primary energy intensity decreased from 104 tonnes of oil equivalent per million USD (toe/million USD) in 2015 to 100 toe/million USD in 2016, representing a 3.6% reduction. The reduction in 2016 marked the sixth consecutive year of primary energy intensity reduction for Malaysia. However, final consumption intensity increased by 5.0% from 63 toe/million USD in 2015 to 67 toe/million USD in 2016 mostly due to non-energy consumption. Excluding the non-energy sector, the final energy consumption intensity reduction would stand at 0.9% (EGEDA, 2018).

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	104	100	-3.6
Total final consumption	63	67	5.0
Final energy consumption excl. non-energy	56	57	0.9

Source: EGEDA (2018)

RENEWABLE ENERGY SHARE ANALYSIS

Since the introduction of the New and Renewable Energy Policy and Action Plan, Malaysia's consumption of modern renewables has been increasing every year. The share of modern renewables in the final energy consumption increased from 3.5% in 2015 to 4.5% in 2016. Based on year-on-year growth, modern renewables registered a 34.5% increase in final consumption.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	125 884	128 752	2.3
Non-renewables (fossils and others)	122 427	125 469	2.5
Traditional biomass*	1 029	337	−67
Modern renewables*	2 428	2 946	−21
Share of modern renewables in final energy consumption (%)	1.9%	2.3%	19%

Source: EGEDA (2018)

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on) including biogas and wood pellets are considered modern renewables, although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Malaysia's National Energy Policy, which was first formulated in 1979, serves as the overall framework for the development of the energy sector. It consists of the following three principal objectives:

- The supply objective: To ensure the provision of an adequate, secure and cost-effective supply of energy through the development of indigenous energy resources and the diversification of energy supply from domestic and international sources.
- The utilisation objective: To promote the efficient utilisation of energy and discourage wasteful and non-productive patterns of energy consumption.
- The environmental objective: To minimise the negative impacts of energy production, transportation, conversion, utilisation and consumption on the environment (MESTECC, 2015).

This policy has been instrumental in the development of Malaysia's energy sector. Subsequent policies have been designed to support these objectives and their implementation.

In 1980, the National Depletion Policy was enacted to safeguard and preserve Malaysia's energy resources, particularly its oil and gas resources. Under this policy, the total annual production of crude oil should not exceed 3% of 'oil initially in place'. As a result, the production of crude oil was limited to 650 000 barrels per day. The policy also limits the natural gas production to 2 000 MMscf/d in Peninsular Malaysia (UNPAN, 1999).

A year later, Malaysia introduced the Four-Fuel Diversification Policy to expand the fuel mix for power generation. Initially, the focus of the policy was to reduce the economy's dependence on oil as the dominant energy source. The scope of this policy was further expanded in 2001 with the implementation of the Five-Fuel Diversification Policy, which incorporated renewable energy (RE) (for example, biomass, solar and mini-hydro) as the fifth fuel in addition to oil, gas, coal and hydro (MESTECC, 2015).

In support of the Five-Fuel Diversification Policy, Malaysia launched the National Biofuel Policy in 2006 and introduced the NREPAP in 2009 as the policy framework to advance the development of indigenous RE and expand its contribution to the power generation mix. The NREPAP provides long-term goals and a holistic approach for the sustainable development of RE (SEDA, 2011). The RE power capacity is expected to increase to 2 080 MW (11 GWh) by 2020, contributing 7.8% to the total power generation mix (MEA, 2015).

The National Green Technology Policy (NGTP) was launched in 2009 as an initial step towards engendering sustainable development of the economy. The policy has four pillars: energy, environment, economy and society. The NGTP has identified green technology as a key driver to accelerate the national economy and promote sustainable development. Spearheaded by its Ministry of Energy, Science, Technology, Environment and Climate Change (MESTECC, 2017), Malaysia has introduced various programmes and incentives to advocate the use of green technology in key economic sectors. The NGTP aims to facilitate growth of the green technology industry and enhance its contribution to the national economy; increase national capability and capacity for innovation; and enhance Malaysia's competitiveness in the global market. In addition, it aims to conserve the environment and ensure sustainable development for future generations (MESTECC, 2017).

In May 2015, the government launched the Eleventh Malaysia Plan 2016–20 as the final stage in the journey towards realising Vision 2020, a long-term development plan launched in 1991 that envisions Malaysia as a fully developed economy across all dimensions by 2020. Six strategies are outlined in the Eleventh Malaysia Plan. These include pursuing green growth for sustainability and resilience and strengthening the infrastructure to support economic expansion, both of which have implications for energy initiatives (MEA, 2015). In the past, the focus in economic growth was on quantity over quality. The Eleventh Malaysia Plan places greater emphasis on quality growth, considering the economy's natural resources and the impact of their use on the environment.

To pursue the green growth stated in the Eleventh Malaysia Plan, MESTECC launched the Green Technology Master Plan (GTMP) in 2017 to earmark green growth as one of the six game changers that would alter the trajectory of the economy's growth. The GTMP creates a framework for facilitating the mainstreaming of green technology into the planned development of Malaysia while encompassing the four pillars set out in the NGTP (MESTECC, 2017).

ENERGY SECTOR STRUCTURE

The key ministries and government agencies for the Malaysian energy sector are as follows:

- The Ministry of Economic Affairs (MEA) sets the general direction and broad strategies for Malaysia's energy policies, such as formulating and implementing the national policy on energy and developing the oil and gas industry.
- After the 14th General Election (GE-14) in 2018, the entire component of the Ministry of Science, Technology and Innovation (MOSTI), the green energy and technology component of the Ministry of Energy, Green Technology and Water (KeTTHA) and components related to climate change and the environment of the Ministry of Natural Resources and Environment (NRE) have been restructured and have formed the MESTECC.
- The EC is a statutory body established in 2001 to serve as a regulator for the electricity and piped gas supply industries in Peninsular Malaysia and Sabah. The commission's main functions are to establish technical and performance regulations for the electricity and piped gas supply industries; act as the safety regulator; and protect consumers by ensuring high-quality services as well as regular supply of electricity and piped gas at reasonable prices.

Besides the key agencies listed above, other authorities involved in energy development in Malaysia are as follows:

- The Ministry of Primary Industries (MPI) that oversees the biofuel development in Malaysia; and
- The Ministry of International Trade and Industry (MITI) that promotes investment in Malaysia as well as helps the government set gas prices for industrial use.

PETRONAS is Malaysia's national petroleum corporation, wholly owned by the Malaysian Government and created under the Petroleum Development Act of 1974. PETRONAS is vested with exclusive rights for the exploration and production of petroleum whether onshore or offshore in Malaysia. It also has the responsibility for the planning, investment and regulation of the upstream sector. Any foreign or private company wanting to explore and produce petroleum in Malaysia has to enter into a production sharing contract (PSC) with PETRONAS.

Malaysia's power industry is dominated by three vertically integrated utilities: Tenaga Nasional Berhad (TNB) serving Peninsular Malaysia; Sabah Electricity Sendirian Berhad (SESB) in Sabah; and Sarawak Energy Berhad (SEB) in Sarawak. These utilities undertake electricity generation, transmission, distribution and supply activities in their respective areas. Various IPPs, dedicated power producers and cogenerators complement the three utilities.

ENERGY SECURITY

The Tenth Malaysia Plan, launched in 2010, outlines the strategic approaches designed to improve energy supply security. The Eleventh Malaysia Plan, covering the period 2016 to 2020, outlines the strategic approaches designed to improve energy supply security. Demand-side management (DSM), which incorporates energy efficiency and conservation measures together with higher penetration targets of RE, will be implemented to ensure the sustainable management of energy resources and improved energy security.

Another measure to improve energy security is to diversify LNG imports. The economy is faced with the issue of geographic disparity of natural gas supply and demand among its regions. Peninsular Malaysia requires a greater natural gas supply for power and industrial use, while Sarawak and Sabah produce natural gas but lack local demand. To address these concerns, LNG RGTs are being constructed to increase supply security through imports of LNG from the global gas market. Malaysia completed its first RGT in Malacca, which commenced operations in May 2013, with a total capacity of 260 000 cubic metres and an annual storage volume of 3.8 Mt

(PETRONAS, 2012). The RGT will improve the security of natural gas supply in Peninsular Malaysia. The second RGT was built at the southern part of Peninsular Malaysia as part of the PIPC and based on the latest update, the terminal received the first commercial LNG cargo on 1 November 2017 (LNG World News, 2017). In late 2018, PETRONAS signed a 20-year deal with US-based Cheniere Energy to receive LNG deliveries. Under the deal, PETRONAS will purchase 1.1 million tonnes per year at a price reportedly indexed to the US Henry Hub price (Houston Chronicle, 2018).

Regional energy cooperation under the Association of Southeast Asian Nations (ASEAN) framework also addresses energy security. Among the agreements reached on energy security is the ASEAN Petroleum Security Agreement (APSA) signed in 1986 and updated in 2009. Its purpose is to enhance petroleum security in the ASEAN region. ASEAN members, through the Trans-ASEAN Gas Pipeline (TAGP) and the ASEAN Power Grid (APG) projects, have entered into interconnection cooperation agreements on natural gas and electricity. The TAGP will provide the region with a secure supply of natural gas through the interconnection of gas pipelines and associated infrastructure. The APG will integrate the power grids of ASEAN members to enable regional sales of electricity. The APG will also optimise the development of energy resources in the region.

GREEN TECHNOLOGY POLICY

In its pursuit of a low-carbon economy, the Malaysian Government launched the NGTP in July 2009. This serves as the basis for all Malaysians to enjoy an improved quality of life by ensuring that the objectives of the national development policies continue to be balanced with environmental considerations. The policy is built on the following four pillars.

- Energy - Seeking energy independence and promoting efficient utilisation;
- Environment - Conserving and minimising the impact on the environment;
- Economy - Enhancing national economic development through the use of technology; and
- Society - Improving the quality of life for all.

The following four sectors have been identified as the primary focus of the policy.

- Energy - The application of green technology in power generation and in energy supply-side management, including cogeneration by industrial and commercial sectors, in all energy-consuming sectors and in DSM programmes;
- Buildings - The adoption of green technology in the construction, management, maintenance and demolition of buildings;
- Water and waste management - The use of green technology in the management and use of water resources, wastewater treatment, solid waste and sanitary landfill; and
- Transport - The incorporation of green technology into the transportation infrastructure and vehicles, particularly related to biofuels and public road transport (MESTECC, 2011).

Among the policy's long-term goals is the infusion of green technology and a significant reduction of energy consumption. Malaysia has earmarked the promotion of green technology through the establishment of the Malaysian Green Technology Corporation and has become the lead agency of the ministry for the promotion, development and implementation of green technology.

The Green Technology Financing Scheme (GTFS) was established in 2010 to accelerate the expansion of the green technology industry with an allocated government fund of MYR 3.5 billion (USD 813 million)[4] until 2017. The objective behind establishing the fund is to provide a special financing scheme for soft loans to companies that produce and use green technology. As of 31 December 2017, 356 companies had received the GTFS Certification, with financing amounting to MYR 3.64 billion (USD 845 million) (Green Tech Malaysia, 2018).

[4] The exchange rate is based on average daily conversion data from Bank Negara Malaysia in 2017 (BNM, 2018).

The introduction of the MyHIJAU Labelling Programme is intended to ensure the availability of green products and services in accordance with international standards and regulations. Currently, three agencies in Malaysia have been recognised as providing environmentally friendly certification schemes. They are as follows:

- SIRIM Eco Labelling by SIRIM Berhad for certifying the environmental attributes of green products and services;
- Energy Efficiency Labelling by the EC for energy-efficiency labelling of electrical appliances; and
- Water-Efficient Products Labelling by the National Water Services Commission or SPAN.

The Green Building Index (GBI) has been developed as a rating tool to promote green technology in the building sector. It also intends to raise awareness among developers and building owners about the design and construction of green and sustainable buildings. A GBI certificate is granted to developers and building owners who have satisfied the standards in six areas: energy efficiency, indoor environmental quality, sustainable site planning and management, materials and resources, water efficiency and innovation.

To encourage the adoption of green building design, the government intends to establish itself as the market leader. All new government buildings will have to adopt green features and designs, while existing government buildings will be gradually retrofitted. Other initiatives that are being implemented are the Government Green Procurement (GGP) and Green Township projects. The GGP integrates environmental considerations into the public sector procurement process to protect the natural environment, conserve resources and lessen the harmful effects of human activities. By 2020, the GGP will be implemented in all government offices and will ensure that 20% of the public sector's purchases of products and services are green-labelled. The Green Township project advocates the adoption of a Low-Carbon Cities Framework & Assessment System (LCCF) by city councils, developers and town planners. The project provides a systematic process and strategies for reducing carbon emissions in urban developments in accordance with the government flagship and ongoing projects.

As mentioned above, Malaysia launched its GTMP to serve as a guide for the development of action plans, programmes and projects for the Eleventh and (upcoming) Twelfth plans. Under this master plan, six areas have been identified as target areas: energy, manufacturing, transport, building, waste and water. Derived from the NGTP, the GTMP lists five major strategic thrusts to foster a 'green culture' in Malaysia (Table 5).

Table 5: GTMP strategic thrust

Strategic Thrust	Key Areas	Outcomes
Promotion and awareness	• Tailored communication strategy • Industry and business promotion via International Greentech and Eco Products Exhibition and other platforms. • Collaboration with primary and secondary educational institutions	• Improved awareness and receptiveness towards green technology • Increase in business transactions, entrepreneurship and global value chain integration • Improved knowledge of GT among the younger generation to drive behavioural change
Market enablers	• Government Green Procurement (GGP) • Green incentives • Innovative financing • Green cities • International collaborations	• Strengthened industry readiness in the production of green products and services • Improved financial feasibility of green projects and affordability of green products and services • Improved infrastructure readiness for green adoption • Creation of export opportunities through regional collaborations
Human capital development	• Capability building in the public sector • Capability building in the private sector • Collaboration with higher education institutions	• Improved knowledge among government officials • Increase in recognition of skills and competencies • Improved workforce readiness of fresh graduates
Research and development and commercialisation (R&D&C)	• R&D&C funding • Public-private partnership	• Demand-driven, market and result-oriented R&D&C projects • Stronger collaboration between government bodies and research institutes in information sharing to enable efficient strategic planning and resource deployment
Institutional framework	• Governance (policy leadership) • Policy planning • Policy implementation	• Strengthened governance to facilitate cross-sectoral cooperation among Government bodies to improve the ease of doing business

Source: MESTECC (2017)

ENERGY MARKETS

MARKET REFORM

Malaysia's energy market is a regulated one. Furthermore, the government provides subsidies to energy consumers. However, Malaysia intends to implement energy market reforms, as suggested in the Eleventh Malaysia Plan, through the gradual removal of energy subsidies. As a strategy to rationalise subsidies, the plan states that gas prices for power and non-power sectors will be revised every six months to gradually reflect market-based prices. The intention of this approach is to unbundle energy bills to itemise subsidy values.

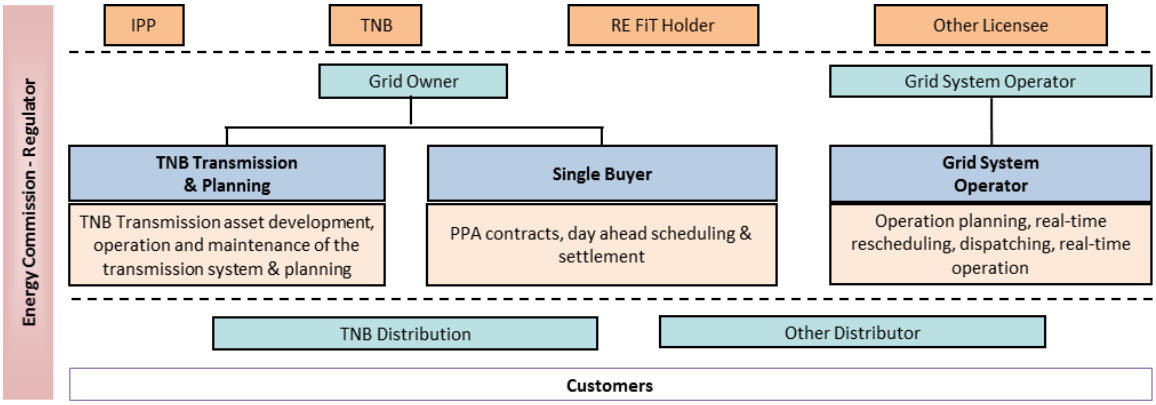
As part of the market reform initiative, the EC subject utilities to an Incentive-Based Regulation (IBR) in 2013. The implementation of IBRs will continue to ensure that utility companies provide efficient services. The IBR framework is designed to incentivise utility companies to reduce costs and improve service levels. The separation of generation, transmission and distribution tariffs with automatic adjustments will consider changes in fuel prices to increase the transparency and efficiency of electricity supply. New power plants and extensions of existing power plants will continue to be undertaken through competitive bidding to ensure greater transparency. This will create healthy competition among industry players, resulting in more competitive tariffs, and benefit end consumers (MEA, 2015).

In addition to IBRs, the Eleventh Malaysia Plan states that the Gas Supply Act 1993 (Act 501), which regulates the supply of gas to consumers through pipelines, will be amended to create a level-playing field for third-party gas players. Such players can then use the natural gas supply pipeline and RGT infrastructure at fair

and transparent fees. The amended act will come into force in 2016 through the EC, which covers the economic regulation of the domestic natural gas market. This will include the RGT, PGU pipeline and distribution pipeline infrastructure. The aim is to unlock additional revenue from the gas industry valued at an estimated MYR 2.9 billion (USD 684 million) per year (MEA, 2015).

As a further commitment to electricity market reform, the EC announced the launching of single buyer (SB) and grid system operator (GSO) websites. Previously, both SBs and GSOs were the same department under the TNB (EC, 2017a).

Figure 2: Latest electricity market regulatory structure in Peninsular Malaysia



Source: APERC analysis

According to an announcement made by the EC, the establishment of SB and GSO was one of the initiatives aimed at creating a more transparent electricity supply industry in Malaysia. The EC separated the operations of SB and GSO from the other activities of the TNB through the enforcement of the Electricity Supply Act (Amendment) 2015, which came into force on 1 January 2016. With the separation arrangement, SB and GSO are now operating autonomously where their functions, operations and performance come under the supervision and regulations of the EC.

SB is responsible for the management of electricity purchases from power generation plants, while GSO is responsible for the day-to-day real-time operation and management of the Peninsular Malaysia grid system, including interconnections with Thailand and Singapore.

ELECTRICITY AND GAS MARKETS

Malaysia's electricity supply industry can be considered to be an oligopoly. The industry is vertically integrated where each state-owned utility company (TNB, SESB and SEB) undertakes the generation, transmission and distribution of electricity in its respective region. However, IPPs provide nearly half the electricity generated to the utility companies. All electricity utilities have a government stake as either a government-owned entity or a main shareholder. The industry is highly regulated and governed by several institutions (MEA, MESTECC and EC), each of which has specific functions and jurisdiction.

In view of the volatility of global energy prices and declining domestic gas production, Malaysia intends to continue its efforts to ensure greater electricity supply and a sustainable electricity supply system as adopted under the Eleventh Malaysia Plan. Further, this plan espouses the importance of enhancing the productivity and efficiency of utility providers. The strategies that the plan has identified for a reliable and stable electricity supply industry include increasing and diversifying generation capacity, strengthening the transmission and distribution networks, restructuring the electricity supply industry and improving customer service delivery.

To lower the cost of energy subsidies and reduce market distortions, the Malaysian Government intends to continue to institute market-based energy pricing. In December 2014, for example, the government abolished petroleum product subsidies. Under the Eleventh Malaysia Plan, the government proposes to remove the special industrial tariff (SIT) for the industrial sector. This tariff was introduced during the Asian financial crisis in 1997–98 to help manufacturers stay competitive. Although launched as a temporary measure, the SIT

has remained in place. The SIT will be abolished in stages and fully removed by 2020. Its removal is intended to encourage industry to be more energy efficient in the future. Similar electricity subsidy rationalisation is also expected to occur during 2016–20 (MEA, 2015).

The gradual reduction of the gas subsidy will eventually enable the adoption of a market-based price for gas. This is expected to have a significant effect on the electricity supply industry. Currently, gas for power generation supplied by the PGU pipeline system is heavily subsidised by the government. Other reforms will also be implemented, such as the introduction of performance-based regulation and the renegotiation of power purchase agreements and separate accounting (unbundling) for generation, transmission and distribution activities. To achieve these goals, the Malaysian Government plans to introduce IBR as an instrument to regulate the gas supply industry to make it more efficient and competitive.

In addition, access to the electricity supply in rural areas will be extended through grid expansion and alternative systems, such as mini hydro and solar hybrid. Under the Eleventh Malaysia Plan, the coverage of electricity supply, on a household basis, is targeted to be nearly 100% in Peninsular Malaysia and 99% in Sabah and Sarawak by 2020 (MEA, 2015).

ENERGY EFFICIENCY

A lack of holistic and long-term policy for DSM has been identified as one of the main barriers in implementing energy efficiency initiatives in Malaysia, even though it is considered to be an important element in Malaysia's energy plan and policy. Energy efficiency initiatives are set to receive renewed attention under the Eleventh Malaysia Plan through a reinvigoration of DSM. This is intended to be achieved by formulating a comprehensive DSM master plan. The MEA will initiate a study on DSM, which covers the whole spectrum of the energy sector (MEA, 2015).

Table 6: Energy efficiency targets under the Eleventh Malaysia Plan

Item	Target
Comprehensive long-term DSM master plan	Formulate policy and an action plan covering the entire spectrum of the energy sector including electrical, thermal, and use in the transport sector
Buildings	Achieve a target of 700 registered electrical energy managers (REEMs)
	Extend EPC to other government buildings
	Ensure all new government buildings adopt energy efficient designs
	Retrofit 100 government buildings
	Register 70 energy service companies (ESCOs)
	Target 100 companies to implement ISO 50001[5]
Industries	Introduce enhanced time of use (EToU) with three different time zones
	Abolish the Special Industrial Tariff (SIT)
	Install 4 million smart meters
	Increase on-grid cogeneration capacity of 100 MW or more by reviewing utility standby charges
Households	Encourage additional appliances with minimum energy performance standards (MEPSs) and extend existing labelling programme

Source: MEA (2015)

RENEWABLE ENERGY

Malaysia's Five-Fuel Policy in 2001 recognised the importance of RE and adopted it as the fifth fuel in the energy supply mix alongside natural gas, oil, hydro and coal. During the Tenth Malaysia Plan (2010–15), the focus was on implementing greenhouse gas (GHG) mitigation measures. Among the measures taken were the introduction of the RE Act in 2011 and the implementation of the feed-in tariff (FiT) mechanism. The Sustainable Energy Development Authority (SEDA) Malaysia, a statutory body established by the government to promote RE and energy demand management, set a target of 415.5 MW of additional RE capacity by 2015 (MEA, 2015). As of 1 February 2018, the total installed capacity of RE (excluding hydropower with capacity above 30 MW and only covering Peninsular Malaysia and Sabah) in commercial operation was 532.3 MW, of

[5] ISO 50001 is a voluntary international standard to provide organisations with a recognised framework to manage and improve their energy performance.

which biomass was 87.9 MW, biogas was 56.2 MW, small hydro was 30.3 MW and solar PV was 357.9 MW (SEDA, 2018).

The government has identified challenges that have affected the growth of RE in Malaysia. Among these are issues that affect the reliability of RE plants and problems in securing adequate feedstock for long-term supply, particularly for biomass. Other challenges are the lack of experts in the sector, including RE project developers, financial personnel and service providers. There are also difficulties in securing financing to develop RE installations. Current RE sources under the FiT portfolio focus on biomass, biogas, small hydro, geothermal and solar PV.

Under the Eleventh Malaysia Plan, the government has set a target for RE capacity to reach 2 080 MW, thereby contributing 7.8% of the total installed capacity in Peninsular Malaysia and Sabah. Strategies have also been identified to boost RE capacity. For example, studies are being conducted to identify new RE sources such as wind, geothermal and ocean energy to diversify the power generation mix.

To complement the current FiT mechanism, a new instrument termed net energy metering (NEM) will be implemented in the Eleventh Malaysia Plan. The objective of NEM is to promote and encourage more Solar PV generation by prioritising internal consumption before any excess electricity generated is fed to the grid. NEM is expected to encourage manufacturing facilities and the public to generate clean electricity. This will further assist the government's effort to increase the contribution of RE in the generation mix. NEM is regulated by the EC and implemented by SEDA and started on 1 November 2016. The total quota allocated for the five-year period (2016–20) is 500 MW.

Solar PV under the FiT will no longer have new quota release post 2017. As a continuation of the government's effort to boost solar PV market in the economy, the EC has been tasked with implementing the large-scale solar (LSS) programme, which is based on a bidding process. The total quota allocated for the LSS from 2017 to 2020 is 1 250 MW_{ac} [6]. Of this, 250 MW_{ac} was granted direct award under the fast track programme, and these projects will go into commercial operations in 2017. The remaining 1 000 MW_{ac} comes under the bidding mechanism.

In August 2017, the EC announced the bid open price for LSS PV Plants for 2019/2020. The bid was divided into three categories based on capacity: from 1 MW to 5.99 MW; 6.00 MW to 9.99 MW; and 10.00 MW to 30.00 MW. The results showed that the lowest bid received was in the 10.00 MW to 30.00 MW category, with a tariff of MYR 0.3398/kWh (USD 0.079/kWh) (EC, 2017b).

CLIMATE CHANGE

Malaysia is a signatory to the United Nations Framework Convention on Climate Change (UNFCCC), and it ratified the treaty on 17 July 1994. Subsequently, the National Climate Committee was established in 1995. This is composed of various government agencies and stakeholders from business and civil society groups. Its purpose is to guide national responses to climate change mitigation and adaption.

At the 2015 United Nations Climate Change Conference in Paris, Malaysia's prime minister made a pledge to reduce the GHG emission intensity of the economy's GDP by 45% by 2030 relative to the emission intensity of GDP in 2005. The 45% figure comprises 35% on an unconditional basis and a further 10% conditional upon receipt of climate finance, technology transfer and capacity building from developed countries (UNFCCC, 2015). The sectors covered under this emission intensity reduction target are energy; industrial processes; waste; agriculture; and land use, land use change and forestry (LULUCF).

Two significant policies approved in 2009 support this goal: the NGTP and the National Climate Change Policy (NCCP). These policies strengthen the national agenda on environmental protection and conservation. The NCCP has three main objectives. First, to mainstream measures to address climate change through the efficient management of resources and enhanced environmental conservation, resulting in strengthened economic competitiveness and improved quality of life. Second, to integrate responses into national policies, plans and programmes to strengthen resilience to the potential impact of climate change. Third, to strengthen

[6] Unless specified, all PV capacities in this report are dc-rated.

institutional and implementation capacity to harness opportunities to reduce the negative impact of climate change more effectively (MESTECC, 2009).

The Eleventh Malaysia Plan also stressed the effort needed to address the challenges of climate change by developing a roadmap for climate resilient growth, which covers adaptation and mitigation approaches. To reduce the economy's carbon footprint, development work will focus on creating green markets, increasing the share of renewables in the energy mix, enhancing DSM, encouraging low-carbon mobility and managing waste holistically (MEA, 2015).

NOTABLE ENERGY DEVELOPMENTS

PENGERANG INTEGRATED PETROLEUM COMPLEX

The PIPC is being developed as part of the Economic Transformation Program to establish a dynamic oil and gas downstream industry. The project is located on a single plot of land (approximately 8 100 hectares) in Pengerang, Johor, at the south-eastern tip of Peninsular Malaysia. This is strategically accessible to major international shipping lanes. To efficiently manage and administer the different projects within the PIPC, a new federal government agency has been created—the Johor Petroleum Development Corporation (JPDC).

The PIPC will house oil refineries, naphtha crackers, petrochemical plants and an LNG RGT. As of January 2013, two projects have been committed to the PIPC area. The first is the PIDPT, a Deepwater oil terminal that is expected to be completed by 2020 with planned total storage capacity of 5 mcm. Another project is PETRONAS's RAPID, which will include a 300 000 barrels per day crude oil refinery that will provide feedstock for RAPID's petrochemical complex and produce petrol and diesel that meet European specifications (MPRC, 2013). The project is also aimed at meeting domestic demand for petroleum products and the Malaysian Government's future legislative requirements for the implementation of Euro 5 specifications (PETRONAS, 2016).

Despite the low oil price, the RAPID project is on track for Phase 2 of the site preparation. The refinery and cracker construction is progressing on schedule. The project will be completed by March 2019, and commercial operations will begin immediately thereafter (Platts, 2015b).

Based on the latest update, the newly commissioned RGT at Pengerang received the first commercial LNG cargo after successfully receiving three commissioning cargoes on 1 September, 23 September and 17 October (LNG World News, 2017). In other updates, PETRONAS celebrated its 10 000th cargo from its Bintulu LNG Complex in Malaysia, delivered to Japan on 4 October (PETRONAS, 2017).

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USEFUL LINKS

Prime Minister's Office—www.pmo.gov.my

Ministry of Finance—www.treasury.gov.my

Ministry of Economic Affair—www.mea.gov.my

Ministry of Energy, Science, Technology, Environment and Climate Change—www.mestecc.gov.my

Ministry of Primary Industries—www.mpi.gov.my

Ministry of Water, Land and Natural Resources—www.kats.gov.my

Energy Commission—www.st.gov.my

Sustainable Energy Development Authority—www.seda.gov.my

Malaysia Green Technology Corporation—www.greentechmalaysia.my

Green Technology Financing Scheme— https://www.greentechmalaysia.my/services/green-technology-financing-scheme/

Malaysian Palm Oil Board—www.mpob.gov.my

PETRONAS—www.petronas.com

Tenaga Nasional Berhad—www.tnb.com.my

Sabah Electricity Sdn.Bhd.—www.sesb.com.my

Sarawak Energy Berhad—www.sarawakenergy.com.my

Single Buyer Department—www.singlebuyer.com.my

Grid System Operator—www.gso.org.my

MEXICO

INTRODUCTION

Mexico is a federal republic bordered by the United States of America to the north, Belize and Guatemala to the south, and the Atlantic and Pacific Oceans on the east and west, respectively. For cultural and historic reasons, Mexico has been commonly regarded as a Latin American economy, whereas its geographical location and economic integration are in North America.

Mexico is rich in biodiversity, with abundant fossil and renewable energy resources over its land area of approximately 2 million square kilometres (km^2) (INEGI, 2018). There are diverse climatic conditions across the Mexican territory that range from very dry with high temperatures in the north to very humid with high temperatures in the south and mild temperatures in the centre and warm coasts. The total population of Mexico is 128 million, the 11th most populated economy in the world and the 6th-most populated economy in the Asia-Pacific Economic Cooperation (APEC) region (UN, 2017). Mexico City, the capital, is the world's fourth-largest urban centre with more than 22 million people (UN, 2018). After Mexico City, the other most important cities are Guadalajara and Monterrey, located in the west-central and north-eastern sides of the territory, respectively.

Economic reforms and free trade agreements introduced since the 1990s have resulted in macroeconomic stability, increased flows of foreign direct investment and the development of a robust manufacturing industry, making Mexico the 15th largest economy of the world and the 5th-largest economy in APEC, economically comparable with Spain or Australia (WB, 2019). Most Mexican exports (83%) are manufactured products (World Bank, 2018b). However, the economy expanded at a compound annual growth rate (CAGR) of only 2.0% between 2000 and 2016, and real gross domestic product (GDP) in 2016 was USD 2 342 billion. Per capita GDP growth was similarly modest (0.58% CAGR) over the same period. Income inequality remains a challenge, as reflected in Mexico's Gini coefficient rating of 48 in 2014 (World Bank, 2018b), and 44% of the population was living in poverty in 2016 (CONEVAL, 2017). Mexico's population and economy are projected to continue expanding, driving up energy demand.

Energy, particularly oil, is a significant component of the Mexican economy. However, in 2017, crude oil accounted for only 6% of Mexico's total export value compared with 15% in 2005 (Banxico, 2018). While crude oil provided 39% of total government revenue in 2005, it contributed 24% in 2016 because domestic production declined, highlighting the risk of exclusively relying on oil revenues (Banxico, 2018). Consequently, Mexico has the lowest rate of tax revenue as a share of GDP among Organisation for Economic Co-operation and Development (OECD) members (OECD, 2019).

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c, d]	
Area (million km^2)	2	Oil (billion barrels)	7.2
Population (million)	128	Gas (billion cubic metres)	200
GDP (2010 USD billion PPP)	2 195	Coal (billion tonnes)	1.2
GDP (2010 USD PPP per capita)	17 207	Uranium (kilotonnes U)	1.8

Sources: [a] World Bank (2019); [b] EGEDA (2018); [c] BP (2018); [d] NEA (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2016, the total primary energy supply (TPES) in Mexico was 185 158 kilotonnes of oil equivalent (ktoe), a marginal increase of 0.15% from the 2015 level, driven by increasing energy imports as domestic oil production continues to wane since it peaked in 2004. Fossil fuels constituted 90% of the primary energy supply of the economy, with other non-fossil sources, such as nuclear and renewable energy, constituting the remaining 9.9% (EGEDA, 2018). With an economy endowed with abundant fossil and renewable energy resources, Mexico's oil reserves stood at 7.2 billion barrels of crude oil (21st in the world) by the end of 2016, whereas gas reserves were around 200 billion cubic meters (bcm) and coal stood at 1.2 billion tonnes of coal (BP, 2018).

OIL

Mexico is a major oil producer, producing around 1.8 million barrels per day (Mbbl/D) of crude oil in 2018, mostly the heavy type (CNH, 2019a). This volume was 7.1% lower than that in 2017, mostly because of the decline in several major fields, despite increasing but still marginal production from oil companies other than state-owned oil company, Petróleos Mexicanos (Pemex). Mexico faces the challenge of replacing the output from its once largest oil asset Cantarell, a supergiant field, which, at its peak in 2004, produced 2.1 Mbbl/D, more than 60% of Mexico's total crude oil production. Mainly owing to Cantarell's depletion, overall oil production also peaked in 2004 and has been declining since then (SIE, 2018). By 2017, Cantarell produced less than 0.2 million barrels, representing only 9% of the economy-wide production (SIE, 2018).

Mexico is a net crude oil exporter, with around half (53% in 2016) of its total indigenous crude oil production being exported, especially to the US (SIE, 2018). Historically, Mexico has been one of the largest crude suppliers to the US after Canada and Saudi Arabia; however, Mexican crude export share has been decreasing sharply since 2011 (EIA, 2019).

Despite Mexico's robust production of crude oil and a domestic distillation capacity of 1.6 Mbbl/D in six refineries located across its territory, Mexico is a net importer of oil-based products, especially gasoline (SENER, 2018b). With increasing domestic demand for oil products (mainly gasoline diesel and liquefied petroleum gas [LPG]) and decreasing production in refineries, net imports for gasoline and diesel have increased from 2010 to 2016 by 66% and 33%, respectively (IEA, 2018).

GAS

Since 2005, natural gas has been the fastest-growing fuel in Mexico's TPES in absolute terms, rising from 46 108 ktoe to 66 181 ktoe in 2016. The primary impetus for this ongoing oil-to-natural-gas shift is power generation. Although natural gas demand has been growing steadily, production declined by 29% from 2010 to 2016. In fact, Mexico's gas production decreased in 2017, reaching only 39 bcm, of which more than three-quarter was associated with the production of crude oil (SENER, 2018d). This is enough to cover only around half of Mexico's growing gas demand, resulting in rapidly increasing and low-priced pipeline imports from the US, especially since 2008 (IEA, 2018).

Natural gas imports increased from 8.7 bcm in 2005 to 41 bcm in 2016, registering a record high every year from 2008 (SIE, 2018). The vast majority (88%) of these imports are piped from the US, and the remainder is imported as LNG, mainly from Peru and the US, to one of Mexico's three regasification terminals: Altamira on the Gulf Coast and Ensenada and Manzanillo on the Pacific Coast. Finally, while Mexico holds the sixth-largest shale-gas reserves in the world, environmental and social concerns, investment uncertainty and cost-competitive imports from the US, among other factors, have prevented major shale gas production in Mexico (EIA, 2013).

COAL

In comparison with the share of coal in most other economies in the APEC region, coal has a small and decreasing share of Mexico's primary energy supply representing only 6.7% of total supply in 2016 (12 383 ktoe) (EGEDA, 2018). Most of Mexico's recoverable coal reserves of 1.2 billion tonnes are in Coahuila in the north-eastern part of the territory, with some significant additional resources in Chihuahua and Sonora in the northwest and Oaxaca in the south.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	180 464	Industry sector	35 059	Total power generation	320 353
Net imports and others	9 451	Transport sector	52 943	Thermal	260 393
Total primary energy supply	185 158	Other sectors	28 372	Hydro	30 698
Coal	12 383	Non-energy	5 390	Nuclear	10 567
Oil	88 185	Final energy consumption*	121 764	Others	18 695
Gas	66 181	Coal	1 767		
Renewables	15 620	Oil	70 436		
Others	2 789	Gas	13 760		
		Renewables	7 165		
		Electricity and others	23 246		

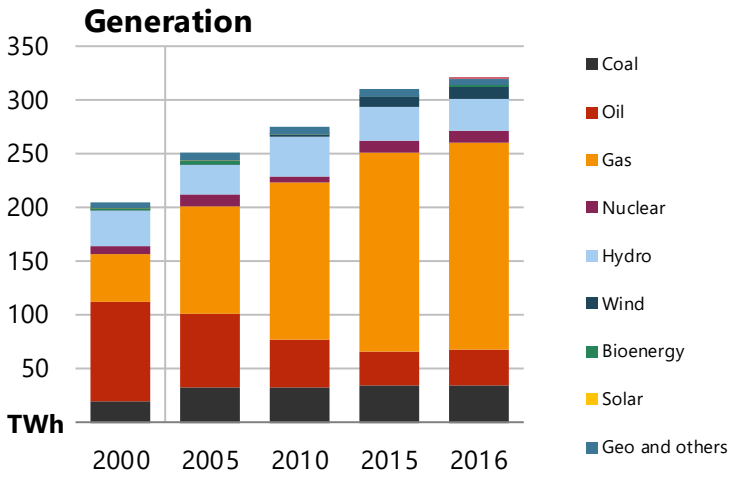
Source: EGEDA (2018) (data collected in September 2018).

**Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

ELECTRICITY

Electricity generation in Mexico amounted to more than 320 terawatt-hours in 2016, mostly derived from thermal power plants (EGEDA, 2018) largely fuelled by natural gas. In 2016, the total installed power capacity was around 74 gigawatts (GW). Natural gas is the dominant fuel in power capacity with 45% of the total share, followed by oil with 20%, hydropower with 17%, coal with 7.3%, wind with 5.5%, other renewables with 2.8% and nuclear with 2.2%.

Figure 1: Mexico's power generation, 2000-16



Mexico's electricity system comprises a main grid covering most of its territory, complemented with one grid in the north and two in the south of the Baja California Peninsula. The interconnection between the three Baja California Peninsula's grids with the main grid is planned to be functional by 2022. It is expected to underpin the optimisation of infrastructure and energy sources across the Mexican territory, and it could have deeper effects on the entire system's configuration in the long term (SENER, 2017c).

Comisión Federal de Electricidad (CFE), Mexico's state-owned and largest power utility, has developed the bulk of the electricity generation infrastructure and currently owns 60% of Mexico's capacity (SENER, 2017c). Mexico's electricity sector is undergoing a profound transition from a monopolistic structure dominated by state-owned utility CFE to a competitive electricity market. The Mexican Wholesale Electricity Market is now operational, and CFE, vertically unbundled along the value chain, now competes with other generation companies. The Mexican government has also created a system for granting clean energy certificates to non-fossil fuel-based energy generators, and the Ministry of Energy requires all load-serving entities to use a certain percentage of clean energy. Non-compliers must procure a required number of clean energy certificates from certified clean energy generators or buy them in a market that was expected to be fully operational by 2019 but has been delayed (IEA, 2016b). From 2006 to 2016, renewable power generation capacity expanded at a CAGR of 4.3%: solar PV increased by 34%, and wind power increased by 110%. Additionally, the 2015 Energy Transition Law established a goal that 25% of electricity generation must be 'clean' by 2018, 35% by 2024 and 50% by 2050.

FINAL ENERGY CONSUMPTION

In 2016, the total final consumption in Mexico reached 121 764 ktoe, a 1.6% increase from the 2015 level, mainly driven by a marginal energy demand increase in the transport sector. By end-use, the transport sector was the largest energy consumer (43%), followed by the industry sector (29%) and the residential, commercial and agriculture sectors combined (23%). The remaining 4.4% comes from feedstock for non-energy purposes. By energy source, oil-based products accounted for 61% of the final energy consumption (excluding non-energy consumption); electricity and others for 20%; natural gas for 12%, renewables for 6.2% and coal for 1.5% (EGEDA, 2018). This structure has remained with a similar trend since 2010.

ENERGY INTENSITY ANALYSIS

In the last couple of decades, Mexico has implemented initiatives to improve its energy efficiency, with a cumulative positive effect on its energy intensity levels. As shown in Table 3, primary energy supply intensity improved by 2.7% from 2015 to 2016. Following the same trend, the total final energy consumption intensity decreased by 1.2% compared with the 2015 level—in contrast with the levels in other years, this share was the same when excluding non-energy consumption such as petro-chemistry, plastics and others.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%)
	2015	2016	2015 vs 2016
Total primary energy supply	87	84	-2.7
Total final consumption	54	53	-1.2
Final energy consumption excl. non-energy	56	55	-1.2

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Demand for modern renewables increased by 4.9% from 2015 to 2016. The share of renewable in the final energy consumption was 4.0% in 2016. Traditional biomass, which decreased by 0.51% in 2016, has been in a slow decline in Mexico for a number of years. However, traditional biomass still retains a share of approximately 5.2% of the final energy consumption, concentrated in the residential buildings sector, particularly in low-income households where it is the main source of energy.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	114 487	116 374	1.6
Non-renewables (Fossils and others)	103 960	105 658	1.5
Traditional biomass*	6 039	6 008	-0.51
Modern renewables*	4 488	4 708	4.9
Share of modern renewables to final energy consumption (%)	3.9	4.0	3.2

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial) using inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (e.g. hydropower and geothermal), including biogas and wood pellets, are considered modern renewables, but data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Mexico's energy policy is led by the Ministry of Energy (*Secretaría de Energía*, or SENER), which is required by law to develop an energy sector programme with the main energy goals and strategies to be enforced at the beginning of every six-year presidential term. Since the landmark energy reform of 2013, Mexico's energy sector has dramatically changed with the introduction of new institutional arrangements and restructuring.

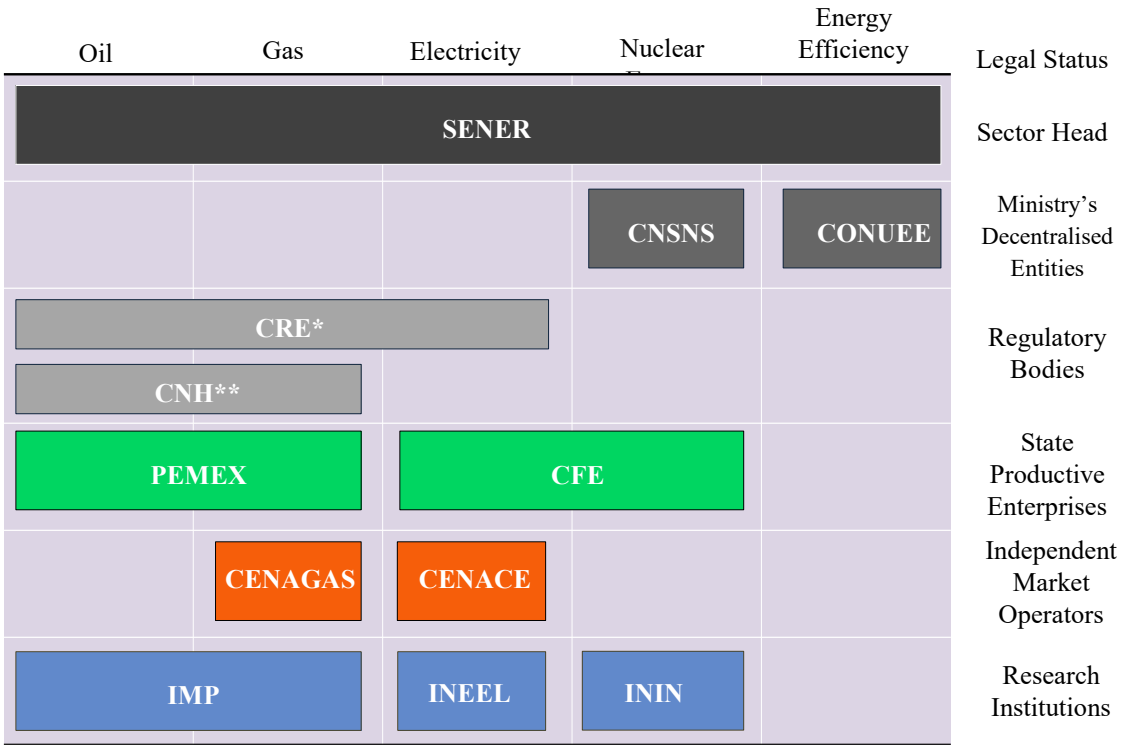
Before the reform, two state-owned companies monopolised most of the value chain of the oil, natural gas and power industries: Pemex in oil and natural gas and CFE in power. A transition to competitive markets for oil products, natural gas and electricity is currently under way, as Pemex and CFE now compete with other companies in different areas of the value chain. The 2013 energy reforms were designed to foster investment in the sector by allowing private companies to participate across the entire value chain of the oil, gas and power industries and compete along the state-owned companies.

As part of this transformation and with the participation of new players as well as with increasing competition in the sector, some new institutions were created and energy regulators had their mandates expanded and capacities strengthened. In other cases, responsibilities that used to be in the hands of the state-owned monopolies were transferred to regulatory bodies. The National Hydrocarbons Commission (CNH) and the Energy Regulatory Commission (CRE) became coordinated regulatory organisations with technical and management autonomy and budgetary self-sufficiency. The CNH is the regulatory body for oil and gas upstream industry, as well as for conducting tenders and administering contracts. The CRE is the regulator for hydrocarbons midstream and downstream operations, as well as the whole electricity value chain. The reforms created other institutions such as independent system operators and other agencies with the intention of fostering a more integrated and sustainable development of the energy sector. The National Centre for Natural Gas Control (CENAGAS) was created as the independent transmission gas pipeline operator. CENAGAS is also responsible for managing natural gas storage. Similarly, an independent electricity grid operator, the National Centre for Energy Control (CENACE), was created by withdrawing it from CFE, becoming responsible for operating the newly created wholesale power market and for ensuring open and non-discriminatory access to the transmission and distribution grids.

In addition, the Agency of Security, Energy and Environment (ASEA) was created as attached to the Federal Ministry of Environment and is responsible for industrial safety and environmental protection in the oil and gas industry. Finally, the Mexican Oil Fund for Stabilisation and Development was established under the management of the central bank and a board comprising the ministers of finance and energy, the chairman

of the central bank and four independent members nominated by the president and ratified by the senate. This oil sovereign fund is in charge of holding all royalties and resource rents from the oil and gas upstream sector. The new institutional arrangement of Mexico's public energy sector and its areas of influence are shown in a schematic representation in Figure 2.

Figure 2: Current institutional arrangement of Mexico's public energy sector



Source: APERC analysis.

* In the oil and gas industry, the regulations are applicable only to the midstream and downstream segments.
** In the oil and gas industry, the regulations are applicable only to the upstream segment.
Note: SENER: Ministry of Energy; CNSNS: National Commission for Nuclear Safety and Safeguards; CONUEE: National Commission for the Efficient Use of Energy; CRE: Energy Regulatory Commission; CNH: National Hydrocarbons Commission; PEMEX: Petróleos Mexicanos; CFE: Federal Electricity Commission (utility); CENACE: National Centre for Energy Control; CENAGAS: National Centre for Natural Gas Control; IMP: Mexican Petroleum Institute; ININ: National Institute for Nuclear Research; INEEL: National Institute for Electricity and Clean Energy.

OIL AND GAS

In the oil and gas sector, private companies are allowed to participate all along the value chain, including exploration, extraction, transportation, distribution and retailing activities. However, upstream activities (namely, exploration and extraction) shall be conducted by auction rounds, organised by Mexico's government through the CNH or in association with Pemex.

Since July 2015, the CNH has awarded 110 contracts to more than 70 companies from 20 countries to explore and extract hydrocarbon resources, with an additional two more bidding processes currently under way. Net revenue from these contracts has amounted to more than USD 850 million for the Mexico government, while committed private investments amounted to USD 3.9 billion from 2015 to mid-2018 (CNH, 2019b). Pemex has reported annual losses since 2012, mainly owing to resource depletion, low international oil prices and a lack of significant new finds (Pemex, 2018). Since implementing its latest strategic plan, its net income has increased and oil production has risen marginally (Pemex, 2018). Currently, international and domestic companies other than Pemex are already conducting hydrocarbon exploration and extraction, and

production rapidly increased to 0.04 Mbbl per day in 2017 (2.3 Mtoe) or 2% of the total crude oil production (CNH, 2019a).

Despite robust crude oil production and a domestic refining capacity of 1.6 Mbbl per day (77 Mtoe per year), Mexico is a major net importer of some oil products, mainly gasoline, diesel and LPG. In 2016, oil product imports were 43 Mtoe, of which 22 Mtoe was gasoline. In that same year, around 60% of gasoline, 47% of diesel and 48% of LPG consumed in Mexico were imported (SENER, 2018b).

The creation of a gas market, currently under way, is another important transformation. As the Energy Regulatory Commission (CRE) now prohibits natural gas companies from simultaneously engaging in both marketing and transporting of natural gas, Pemex transferred its natural gas pipelines—more than 10 000 kilometres (km), which make up around 90% of Mexico's natural gas pipeline network—to the new independent system operator, CENAGAS, in 2015 (Pemex, 2012 and 2015). Since 2011, investment of around USD 12 billion has seen a 75% increase in the gas pipeline network (more than 8 500 km of new pipelines) and the addition of eight interconnections with the US (SENER, 2018c). Pemex was also mandated to transfer 70% of its marketable natural gas volume to other companies, allowing clients to choose another provider or stay with Pemex. However, despite the strong growth in natural gas distribution networks since 2013, most residential consumers still have no access to this fuel.

Natural gas imports increased from 7.7 Mtoe in 2005 (8.7 bcm) to 36 Mtoe (41 bcm) in 2016, registering a record high every year from 2008 (SIE, 2018). The vast majority (88%) of these imports are piped from the US (see Box 11.2), and the remainder is imported as LNG.

ELECTRICITY

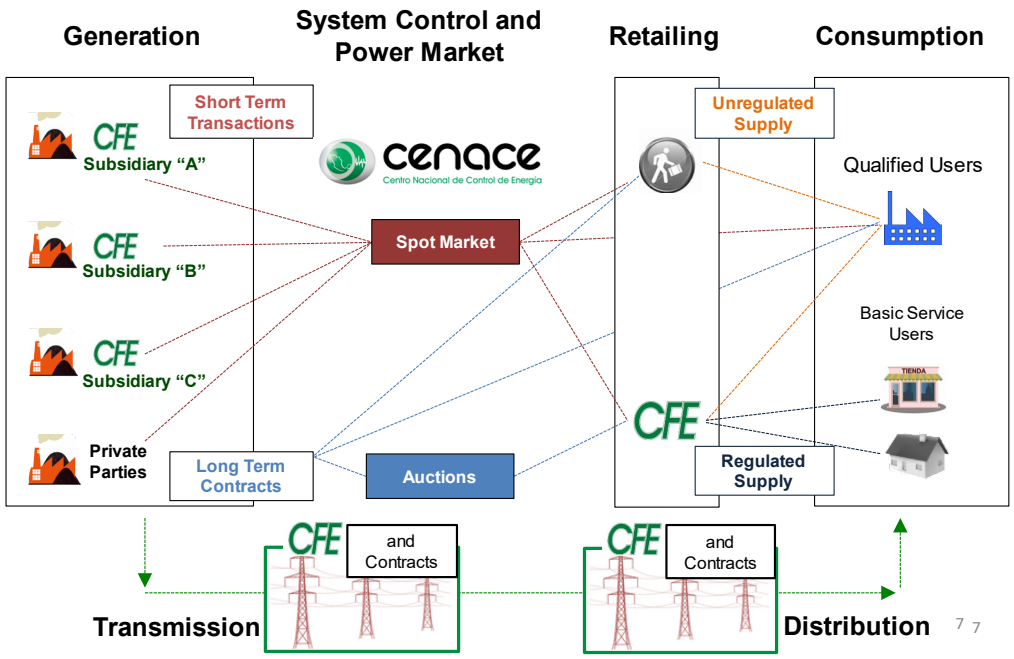
Electricity sector reform has captured less attention, but changes have been equally profound. The current legal framework allows private companies to participate and compete in generation and marketing activities under state regulation. Private companies could participate in the supply segment for large consumers (more than 1 MW). Supply to the rest of consumers, transmission and distribution and nuclear power generation were maintained as a responsibility of CFE. However, private companies, in association with CFE, can participate in the expansion of the transmission and distribution grids. CFE was vertically unbundled and divided into 13 subsidiary and affiliate companies to cover all activities within the sector, including six power generation subsidiaries (SENER, 2017a).

In January 2016, the Mexican Wholesale Electricity Market began operating, with companies other than CFE making up 83% of the 48 participants (SENER, 2017a). Since March 2016, three auctions for long-term contracts have been held by CENACE to purchase energy, capacity and clean energy certificates. As a result, more than 7.5 GW of renewable generation capacity will be added by around 35 companies at a cost of USD 9 billion: wind and solar photovoltaic (PV) power account for more than 90% of the new capacity. Owing to a high level of participation and competition, prices obtained in both auctions were among the best in the world (USD 21 per megawatt-hour in the last auction, held in November 2017) and, in some cases, were more competitive than prices for fossil fuel-fired plants (CENACE,2017).

The 2013 reform also created the clean energy certificates (CELs). These green certificates are granted to companies that produce power from designated clean energy technologies. SENER established requirements to use a percentage of clean energy that all load-serving entities, including retailers and large consumers, must fulfil. Non-compliers must procure required shares of clean energy certificates from CRE-certified clean energy generators. Alternatively, they may buy them in the market that will be put in place in 2018 (IEA, 2016).

Additionally, the 2015 Energy Transition Law established as a goal that 25% of electricity generation must be 'clean' by 2018, 35% by 2024 and 50% by 2050. However, this law considers renewable energy and 'highly efficient' gas-fired combined heat and power (CHP) generation as 'clean' energy, whereas APERC and most international institutions consider CHP to simply be a form of gas-fired power generation disaggregated from renewable or 'clean' energy. As of June 2018, 24% of electricity generation came from 'clean' sources, but only 2.8% of it came from 'highly efficient' CHP.

Figure 3: Mexico's electricity sector structure



NUCLEAR ENERGY

Mexico's experience in the development of nuclear energy for power generation is limited to only one plant with two nuclear reactors (Laguna Verde), operated by CFE since 1990. Mexico has not explicitly published any nuclear projects but plans to expand its nuclear installed capacity by 4 GW by 2030 (SENER, 2017c).

ENERGY EFFICIENCY

Mexico has had energy efficiency programmes since 1989. The institution in charge of promoting these programmes and providing technical advice is the National Commission for Efficient Energy Use (CONUEE). SENER and CONUEE jointly drafted the National Programme on the Sustainable Use of Energy 2014–18 (PRONASE), which frames Mexico's energy efficiency objectives and actions. The PRONASE 2014–18 includes the design of programmes for optimal energy use across sectors; regulations and standards for equipment and appliances made or marketed in Mexico; and a strengthened governance of energy efficiency systems. Finally, SENER established Mexico's energy intensity goals: 1.9% annual reduction from 2016 to 2030 and 3.7% annual rate from 2031 to 2050 (SENER, 2017).

RENEWABLE ENERGY

Owing to its favourable geophysical conditions, Mexico has outstanding potential for renewable energy development (SENER, 2017d). In 2008, laws, policies and regulatory instruments included for the first time the promotion of renewable energy, biofuels and associated research activities. The 2015 Energy Transition Law overrode this law but preserved the goals passed on December 2015.

SENER calculates Mexico's renewable energy potential to be approximately 1 380 GW in a conservative scenario, with more than 80% being solar or wind power. From 2006 to 2016, renewable power generation capacity grew every year at an average 4.3%, solar PV increased by 34% and wind by 110%. Renewable energy potential is conservatively estimated at 397 GW, almost 20 times Mexico's total power generation capacity (SENER, 2017a). Approximately 60% of this potential is in solar power, which is at least 5.5 kilowatt-hours per square metre—double that of Germany. Germany's installed solar capacity was 10 times higher than Mexico's in 2016 (IEA, 2016b) Wind potential is estimated at 158 GW (compared with a capacity of 4.1 GW in 2016), hydro power potential at 12 GW and geothermal potential around 0.25 GW (SENER, 2018b).

ENVIRONMENTAL SUSTAINABILITY

Mexico's greenhouse gas (GHG) emissions represent 1.4% of the worldwide total (UNFCC, 2015). Mexico issued its first specific strategy in 2000. It was one of the first developing economies to exclusively issue a law dedicated to this subject, issued in 2012. Mexico promotes actions that protect the environment through lower carbon intensity in its domestic energy consumption and supply, as well as the reduction of polluting emissions from the electricity industry.

In agreement with the energy reform and its precepts to minimise the negative impact on the environment, SENER coordinated a cross-institutional effort towards the development of the Special Programme for Climate Change 2014–18. According to the programme, the energy sector's impact on climate change is considerable, accounting for 61% of the established mitigation commitments. The programme includes the goal of reducing a quarter of its power generation emissions. The energy sector in Mexico is responsible for reducing methane emissions by 11% and 37% of black carbon mitigation efforts.

Since 2015, the ASEA oversees and sanctions operators across the oil and gas value chain (upstream, midstream and downstream) in their compliance to industrial and operational safety measures; ensures plugging and abandonment of wells and facilities; and guarantees the control of polluting emissions and waste.

RESEARCH AND DEVELOPMENT

As explained in Figure 1, the Mexican Petroleum Institute (IMP) supports the hydrocarbons sector, the National Institute for Electricity and Clean Energy (INEEL) supports research and innovation in electricity and clean energies and the National Institute for Nuclear Research (ININ) supports research and development (R&D) on nuclear-based technology for power generation purposes.

Energy-related R&D in strategic areas has been enhanced by the creation of two trust funds, jointly managed by SENER and the National Technology Council (Conacyt): the Trust Fund for Hydrocarbons and the Trust Fund for Energy Sustainability. These funds are financed by fee payments collected from Pemex. These funds have provided more than 5 000 scholarships for graduate studies in the energy sector.

In addition, the Centre for Training in Development Processes and the Centre for Deep Water Technologies stem from the Trust Fund for Hydrocarbons. Likewise, the Trust Fund for Energy Sustainability has provided approximately USD 160 million for the creation of five Mexican Centres for Energy Innovation, specialising in bioenergy, wind energy, geothermal energy, wave energy and solar energy. Finally, the Trust Fund for Energy Transition and Sustainable Use, financed through the federal budget, aims to promote the use of renewable energy and energy efficiency.

NOTABLE ENERGY DEVELOPMENTS

In late 2018, Mexico's new President, Andres Manual Lopez Obrador, was sworn in, bringing about significant changes in Mexico's energy policy. In its first hundred days in office, the new government has prioritised energy self-sufficiency and state-owned companies while decreasing emphasis on renewable energy capacity additions, transitioning to more efficient and low-carbon technologies and inducing efforts to increase private sector investment.

For example, the government has announced that Pemex will be provided with an additional USD 3.6 billion to develop 20 new fields with the goal of increasing Mexico's crude oil production by 37% by 2024 (Pemex, 2019). However, CNH has recently cancelled two oil and gas production bidding processes—the method by which new companies enter the upstream sector—so that the Ministry of Energy can evaluate the results and progress of current hydrocarbon exploration and extraction contracts (CNH, 2019b). The government has also announced the construction of a 340-Mbbl (50-Mtoe) capacity refinery with a minimum government investment of USD 6.0 billion to reduce gasoline imports (SENER, 2018b). In the downstream sector, an ambitious plan to tackle gasoline and diesel theft, mainly from pipelines, has also begun (SENER, 2019a and 2019b).

Despite the encouraging results of Mexico's 2017 long-term energy auction—which saw prices for renewable energy below USD 20 per MWh—the government recently cancelled the fourth energy auction for renewable energy. No new renewable energy auctions have been announced in their place as CFE instead

delays its capacity retirement programme for existing fossil-fuelled plants (CFE, 2018; RENMX, 2019). CFE also recently cancelled a tender for a USD 2.1 billion direct-current (DC) transmission line that would connect Mexico's main wind power generation region with demand centres (REN21, 2018; BNAmericas, 2019).

OIL AND GAS

Mexico's oil production, still dominated by Pemex, has been in steady decline since it peaked at 3.4 Mbbl per day in 2004, reaching a 25-year record-low in 2018 at 1.8 Mbbl per day (CNH, 2019a). This fall in production responds was mainly due to the depletion of Mexico's largest asset, the Cantarell supergiant field as well as a result of the insufficient resources allocated to exploration activities. Similarly, Mexico has long been a net exporter of crude oil and is the third-largest crude exporter to the US after Canada and Saudi Arabia (EIA, 2018). However, exports have been shrinking since 2011, mainly because of the rapid rise in US tight oil production and falling production in Mexico. In 2018, Mexico exported 1.2 Mbbl per day of crude oil—38% less than that in 2005, but to a more diverse set of customers, including APEC economies such as China and Japan.

However, the Mexican government through the CNH conducted nine tenders for exploration and productions, grouped in 'Rounds' in an effort to boost investment in the oil gas industry. Rounds 1 and 2 had four tenders each, while Round 3 second tender was scheduled for early 2019. However, the incoming administration cancelled the so-called Rounds 3.2 and 3.3, which included some unconventional resources. As mentioned before, these tenders have resulted in around USD 4 billion of committed investment and approximately USD 850 million on net revenue for the Mexico government, as well as a rapidly growing but still marginal oil and gas production (CNH, 2019a).

Since 2012, 19 new gas pipelines and over 4 600 km have been added to Mexico's gas pipeline network. This is equivalent to a 41% increase in the network and six additional interconnections to the US, particularly the Eagle Ford and Permian basins. As of November 2018, eight pipelines are still under construction; however, construction on at least six pipelines has been delayed for more than two years because of opposition from local communities, environmental groups, or indigenous groups resulting from concerns surrounding the Free Prior Informed Consent (SENER, 2018e).

Finally, the exponential rise in oil product theft through illegal tapping of Mexico's pipelines is another major energy security concern: occurrences increased from 324 in 2007 to 10 364 in 2017 (Reuters, 2018). This has resulted in an annual loss of USD 1.6 billion for Pemex, owner of most of the pipelines and still the dominant oil product trader (Pemex, 2017). The government has taken some actions on tackling down this theft, but secure pipeline transportation of oil products (predominantly diesel and gasoline) is a growing challenge (SENER, 2019a and 2019b).

ELECTRICITY

Since January 2016, the Wholesale Electricity Market is operational with the independent system operator, CENACE, and dispatches the lower-cost generation coming from a set of competing companies that includes CFE.

As of June 2018, non-fossil fuel power generation increased to 21% of the total generation (168 TWh) and approximately 29% of installed capacity (22 GW) (SENER, 2018f). Moreover, solar generation grew more than eight-fold and wind generation almost doubled in 2014–17 (SENER, 2018f). This fast growth was mostly due to additions resulting from the first and second long-term energy auctions held by CENACE in 2016 and 2017.

RENEWABLE ENERGY

Since March 2016, CENACE carried out three long-term auctions to purchase energy, capacity and clean energy certificates. This resulted in the committed investment of USD 8.6 billion on renewable energy generation projects that will increase capacity by approximately 7.5 GW in 2020. Wind and solar PV were by far the preferred technologies, and more than 90% of the projects have adopted these technologies. The degree of participation and competition allowed the prices obtained in both auctions to be among the best in the world: less than USD 20 per megawatt-hour in the last auction held in November 2017 (CENACE, 2018).

ENERGY EFFICIENCY

Energy efficiency saving in Mexico is estimated at 9 098 GWh during the first half of 2018 by CONUEE, Mexico's energy efficiency agency. These savings are the result of several efficiency programmes, many of which had been implemented for a long time. These include norms and standards in the energy end-use sectors (e.g. industrial, residential and commercial), savings on facilities owned by the federal government, public lighting and daylight savings (SENER, 2017f).

ENVIRONMENTAL SUSTAINABILITY

SENER issued the requirements for acquiring clean energy certificates, which fundamentally mandate generators, qualified users and end-users to acquire at least 10.9$ of clean energy through this mechanism.

In September 2016, Mexico ratified its Intended Nationally Determined Contribution (INDC), committing to an unconditional reduction of 22% of its GHG emissions by 2030 in comparison with its business-as-usual 2013 baseline. On a conditional basis, this share might increase to 40% if certain global measures to address climate change are put into place (UNFCC, 2015). Non-fossil fuel power generation and energy intensity goals mandated in the Energy Transition Law, if achieved, will positively impact emission reduction by phasing out fossil fuels.

INTERNATIONAL COOPERATION

Mexico is a member and active participant of several multilateral organisations such as the United Nations, IEA, International Atomic Energy Agency (IAEA), Nuclear Energy Agency (NEA), International Renewable Energy Agency (IRENA), International Energy Forum (IEF), Latin-American Organisation (OLADE), Clean Energy Ministerial, G20 and Asia Pacific Economic Cooperation Forum (APEC) (SENER, 2018a). Complementary, Mexico collaborates with the Organisation of the Petroleum Exporting Countries (OPEC).

Through SENER, Mexico has also maintained bilateral strategic cooperation initiatives with several economies across diverse energy topics. These economies are Canada, Cuba, the Dominican Republic, Guatemala, the US and Venezuela in the Americas; Austria, Denmark, Finland, Germany, Italy, the Netherlands, Norway, Sweden and the United Kingdom in Europe; and China, India, Japan, Saudi Arabia and Kuwait in Asia.

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USEFUL LINKS

Banco de México (Banxico)—www.banxico.org.mx

Centro Nacional de Control de Energía (CENACE)—www.cenace.gob.mx

Centro Nacional de Control del Gas Natural (CENAGAS)—www.cenagas.gob.mx

Comisión Federal de Electricidad (CFE)—www.cfe.gob.mx

Comisión Nacional para el Uso Eficiente de la Energía (CONUEE)—www.conuee.gob.mx

Comisión Nacional de Hidrocarburos (CNH)—www.cnh.gob.mx

Comisión Regulatoria de Energía (CRE)—www.cre.gob.mx

Comisión Nacional de Seguridad Nuclear y Salvaguardias (CNSS)—www.cnsns.gob.mx

Instituto Mexicano del Petróleo (IMP)—www.imp.mx

Instituto de Investigaciones Eléctricas (IIE)—www.iie.org.mx

Instituto Nacional de Investigaciones Nucleares—www.inin.gob.mx

Instituto Nacional de Estadística y Geografía (INEGI)—www.inegi.org.mx

Petróleos Mexicanos (PEMEX)—www.pemex.com

Presidencia de la República—www.gob.mx/presidencia

Rondas México— https://rondasmexico.gob.mx/

Secretaría de Energía (SENER)—www.gob.mx/sener

Secretaría de Hacienda y Crédito Público (SHCP)—www.gob.mx/hacienda

Secretaría del Medio Ambiente y Recursos Naturales (SEMARNAT)— https://www.gob.mx/semarnat

Sistema de Información Energética (SIE)—http://sie.energia.gob.mx

NEW ZEALAND

INTRODUCTION

New Zealand is an island economy in the South Pacific comprising two main islands, the North Island and South Island, and numerous outer islands. While its land area is similar to that of Japan, its low population of approximately 4.7 million is similar to the population size of Japan's northern island of Hokkaido. Due to its remote location, New Zealand has no electricity or pipeline connections to other economies. The economy had a per capita gross domestic product (GDP) of USD 35 777 (2011 USD purchasing power parity [PPP]) in 2016.

New Zealand is self-sufficient in all energy forms except oil. Renewables make up a large share of supply, which accounted for 84% of electricity generation in 2016, largely from hydro but with support from geothermal and wind. Fossil energy proven and probable (2P) reserves have been modest, including 409 petajoules (PJ) of oil, 2033 PJ of natural gas and liquefied petroleum gas (LPG) at the start of 2018 (MBIE, 2018). The estimated coal reserves stood at 7.6 billion tonnes at the end of 2016 (BP, 2017).

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c, d]	
Area (km^2)	269 652	Oil (PJ)	409
Population (million)	4.7	Gas (PJ)	2 033
GDP (2011 USD billion PPP)	168	Coal (billion tonnes)	7.6
GDP (2011 USD PPP per capita)	35 777	Uranium (kilotonnes U)	–

Sources: [a] World Bank (2018); [b] EGEDA (2018); [c] MBIE (2018); [d] BP (2017).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2016, New Zealand's total primary energy supply (TPES) was 21 megatons of oil equivalent (Mtoe), a 1.9% increase from the previous year's level. Renewable energy (geothermal, wind, solar and others) was the major contributor to TPES (42%), followed by oil (33%), gas (20%) and coal (5%). The slow growth was the result of the increase in renewables, oil and, gas (1.9%, 4.3% and 2.9%) being balanced by significant decreases in coal (–15.7%) (EGEDA, 2018). As geothermal electricity generation only has an efficiency of around 15% in New Zealand (MBIE, 2016), the geothermal share in the total final energy consumption is significantly smaller than the TPES share. New Zealand's energy self-sufficiency (indigenous production/primary energy supply) in 2016 was 78%, continuing a decreasing trend from the 2010 peak (91%) due to decreasing domestic oil and gas production and increasing demand for transport fuels in recent years. Since 2000, growth in New Zealand's TPES has been modest, increasing at an average annual rate of 1.3% (EGEDA, 2018).

Coal is New Zealand's most abundant fossil energy resource, predominantly available in the form of low-value lignite. However, almost all coal production comprises sub-bituminous and bituminous coals. In 2016, coal production dropped by 16% from 2015. Since the sale of Solid Energy's assets to the private sector, there has been little activity in these assets as they change hands. However, its anticipated activity will rise in the coming years, with most mines now in private hands (MBIE, 2017a).

Oil is sourced from 19 fields in the Taranaki Region in the North Island (MBIE, 2018). The production of crude oil, natural gas liquids and condensate increased by 1.9% on an energy-equivalent basis in 2016 compared with the 2015 level. However, because the fields are depleting, a downward trend will continue unless new fields are discovered and brought on stream (MBIE, 2018). Likelihood of new discoveries has been reduced by the announcement by the government in 2018 of restriction to oil and gas exploration activities to much smaller area than those in the previous years (NZG, 2018). Oil production peaked in 2008, underpinned by the development of the newest fields Pohokura, Kupe, Tui and Maari and from onshore

fields such as Cheal and Sidewinder (MBIE, 2015b). Most of New Zealand's oil is exported due to its high quality (it is 'sweet' and 'light'). The vast majority of domestic oil demand is met by importing heavier crudes and refining it at New Zealand's only refinery at Marsden Point and importing refined oil products. Indigenous production accounted for 26% of the domestic oil consumption in 2016.

Natural gas is sourced from 17 fields currently in production, although 84% of production comes from just four (MBIE, 2018). In 2016, natural gas production grew by 4% compared with the 2015 level. The largest uses for gas are industrial heat, electricity generation and methanol and urea production. All the gas produced in New Zealand is domestically consumed since there are no liquefied natural gas terminals. In 2012, Methanex, which produces methanol with natural gas as a feedstock, signed a 10-year gas supply agreement with the Mangahewa field operator, ensuring that increases in supply will have a secure buyer.

New Zealand has a large renewable energy potential primarily in the form of hydro, geothermal and wind energy. The use of this potential is largely for electricity generation; however, geothermal heat is directly used in industry, and biomass is used in the residential and industrial sectors as a source of heat. The biomass potential for advanced biofuel production is being examined as this technology advances. Finally, solar energy photovoltaic and thermal applications are areas of future development as technology advances make these technologies cheaper for deployment and more effective for grid integration.

In 2016, New Zealand generated 42,974 GWh of electricity, a 2.3% reduction from the 2015 level (EGEDA, 2018). Hydro is the major source of electricity generation, accounting for 60% of the total generation in 2016. Other renewables generation accounted for 24% (EGEDA, 2018). More than two-thirds of New Zealand's hydroelectricity is generated in the South Island, while all the geothermal electricity is generated in the North Island. While most hydro generation occurs in the South Island, the main sources of load are in the North Island, requiring significant investment in the inter-island link.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	16 410	Industry sector	4 651	Total power generation	42 974
Net imports and others	5 835	Transport sector	4 891	Thermal	6 254
Total primary energy supply	20 971	Other sectors	3 451	Hydro	25 730
Coal	1 153	Non-energy	1 622	Nuclear	0
Oil	6 894	Final energy consumption*	12 993	Other Renewable	10 388
Gas	4 209	Coal	550	Others Non Ren	602
Renewables	8 715	Oil	5 994		
Others	0	Gas	1 662		
		Renewables	1 482		
		Electricity and others	3 305		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

In 2016, New Zealand's total final consumption was 14.615 Mtoe, a 4.0% growth from the 2015 level. This increase was due to strong gas demand in the industry sector (both for energy and non-energy uses) primarily from the methanol manufacturing industry due to higher levels of production in 2016. There were modest increases from the transport sector (1.6%) and a small decrease in the other sector (–1.2%) (including residential, commercial and agricultural). The largest consumption sectors were transport and industry at 33% and 32% of the total demand, respectively, while the other sector shrunk to 24%; the remaining 11% was used for non-energy purposes. Oil was the largest component of final energy consumption at 6.0 Mtoe

(46%), followed by electricity and others at 3.3 Mtoe (25%), gas at 1.7 Mtoe (13%) and coal at 0.55 Mtoe (4.2%) (EGEDA, 2018).

Industry energy demand has been dominated by a few large consumers, including one aluminium smelting plant, one steel mill, one oil refinery, two methanol plants, two cement plants, several pulp and paper mills and a large dairy company with several plants. Each of these consumers has a unique consumption profile. In 2015, the aluminium smelter used 13% of all New Zealand electricity and the petrochemical sector consumed 28% of natural gas supply as a feedstock (MBIE, 2016). The pulp and paper industry meets up to half of its energy needs from wood and wood waste.

Transport energy consumption increased by 1.6% in 2016. This continues the trend from 2015 of rising transport demand following several years of a relatively flat demand. Transport energy consumption is dominated by the light passenger vehicle fleet, with significant contributions from heavy freight transport and air transport, while rail and water transport have small shares of consumption.

The transport sector is the main consumer of petroleum products, accounting for 83% of the domestic oil consumption in 2016. Consumption of oil products in the other sectors was shared among the residential, commercial and agricultural sectors (10%) and the industrial sector (7%) (EGEDA, 2018). Besides transport, the residential sector's main oil use is LPG for home heating purposes, while the commercial and agricultural sectors use diesel for machinery, backup electricity generators and motors.

ENERGY INTENSITY ANALYSIS

New Zealand's energy intensity of primary energy in 2016 was 125 tonnes of oil equivalent per million USD (toe/million USD), a drop of 1.5% from 127 toe/million USD in 2015. This was largely due to the increases in gas for non-energy use discussed earlier, offsetting the intensity growth posed by the increase in the transport sector. Similarly, final energy consumption intensity, excluding non-energy, increased by 0.52% to 77 toe/million USD.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	127	125	-1.5
Total final consumption	78	77	-0.62
Final energy consumption excl. non-energy	87	87	0.52

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

New Zealand has been making extensive use of its renewable energy sources for many years, largely through the generation of renewable electricity from hydro. This means that the total share of renewable energy can vary depending on the climate, especially rainfall. In 2016, the total share of renewable energy increased to 31%, an increase of 6.2% over the 2015 share (29%). This was largely due to an increase in renewable electricity generation and all other modern renewables of 9.2% in 2016 from the 2015 level.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	12 636	12 993	2.8
Non-renewables (Fossils and others)	8 913	8 927	0.16
Traditional biomass*	153	153	26.8
Modern renewables*	3 723	4 066	9.2
Share of modern renewables to final energy consumption (%)	29	31	6.2

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on.), including biogas and wood pellets, are considered to be modern renewables, although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Ministry of Business, Innovation and Employment (MBIE), which reports to the Minister of Energy and Resources, is responsible for developing New Zealand's energy policies and strategies with assistance from several agencies, including the Ministry of Transport, Ministry for the Environment, and the Energy Efficiency and Conservation Authority.

On November 7 2018, the government passed the Crown Minerals Amendment Bill, which ends all new offshore oil and gas exploration and limits onshore exploration to the Taranaki Region. The existing 31 oil and gas exploration permits that are active (22 of which are offshore) would be honoured. The announcement of this legislation has increased exploration activities in the areas that remain available for exploration, with the expectation of further restriction on exploration in 2020. New Zealand's oil and gas exploration and production activities are privately owned and open to competition. Oil and gas development shows a mixed international ownership, including New Zealand companies and major international oil companies.

Electricity generation and retailing are also open to competition, and there are over 44 retail brands that consumers can buy electricity from. While five large retailers still have the majority of market share, small and medium-sized retailers are gaining market share. Three of the five large retailers are also generators with majority state ownership. These three were fully state-owned prior to the government privatising 49% of them in 2013 and 2014 to stimulate private investment in the sector.

Transpower, a state-owned enterprise, is the transmission grid owner and operator. Distribution is managed by 29 regulated natural monopolies that are each in charge of a specific region. The New Zealand Electricity Authority oversees the management of the electricity market through the development, administration and enforcement of the Electricity Industry Participation Code, which covers all aspects of the electricity market (EA, 2018a). The authority, however, does not regulate electricity prices.

The New Zealand coal industry was dominated by Solid Energy, a state-owned enterprise (SOE). However, the company failed due to low coal prices and was put into receivership in 2015. Its assets were sold to pay creditors. The assets were sold to private sector interests, effectively ending the direct involvement of government in the industry (MBIE, 2017a).

The New Zealand Energy Efficiency and Conservation Strategy 2017–22 (NZEECS) titled 'Unlocking our energy productivity and renewable potential' was released in 2017 and is a companion to the New Zealand Energy Strategy (NZES) 2011–21: Developing Our Energy Potential (the Energy Strategy) (MBIE, 2012). The NZEECS aims to achieve a productive and low-emission energy economy. It sets the overarching policy direction for government support and intervention and guides the work programme of the Energy Efficiency and Conservation Authority (EECA).

The NZEECS identifies three priority areas: renewable and efficient use of process heat, efficient and low-emission transport, and innovative and efficient use of electricity.

ENERGY MARKETS

New Zealand's energy sector has been subject to major reforms since the mid-1980s, coinciding with the introduction of broader economic reforms. The broader reforms are aimed at improving economic growth through improved economic efficiency, driven by clear price signals and, where possible, competitive markets. The greatest change occurred in the electricity and gas markets, where the vertically integrated utilities were separated into natural monopoly and competitive elements; the formerly government-owned and operated electricity and gas monopolies were either corporatised or privatised, and the electricity market was deregulated. The government is currently undertaking a review of the state of the electricity sector. One driver for this review was to investigate why residential electricity prices have been rising faster than inflation,

while commercial and industrial prices have remained flat. The first discussion document was published in September 2018. It highlighted the extent of the price rises for residential customers as well as the challenges facing the industry such as, generators' ability to exercise market power in time of tight supply, electricity retail competition and the challenges of integrating distributed generation and storage into the grid. This review is not the first to be conducted in response to rising residential electricity prices.

In April 2009, responding to concerns about rising electricity prices, especially for residential customers and governance arrangements in the electricity sector, the government initiated a Ministerial Review. The review made several recommendations that were included in the Electricity Industry Act 2010 (MBIE, 2015a) and resulted in important changes in the market. A key change resulting from this act was replacing the Electricity Commission with the Electricity Authority, which has more independence from government and streamlines its activities to focus on developing a healthy competitive market. Responsibilities of the Electricity Commission that overlapped with those of other agencies were transferred to this agency, for example, the promotion of electricity-related energy efficiency, approval of grid upgrades and management of supply emergencies.

The Electricity Industry Act 2010 includes several stipulations for promoting competition. These include provisions for swapping assets between the three state-owned electricity-generating companies to improve competition in both wholesale and retail markets, making improvements in security of supply, providing a fund to encourage customers to switch electricity providers and providing better electricity market hedging arrangements. The act also has provisions to improve the security of supply. These include rule changes to ensure that electricity retailers do not make profit from supply emergencies and that a state-owned reserve power station, criticised for distorting market incentives, be privatised so that it can be operated on a commercial basis (NZG, 2010a). This plant was sold to Contact Energy in 2011.

Since 2004, New Zealand's gas sector has been co-regulated by the government and the Gas Industry Company, an industry body established under the Gas Act 1992. The Gas Industry Company pursues the government's objectives and outcomes, as outlined in the Gas Act 1992 and the Government Policy Statement on Gas Governance. Its work is driven by ministerial requests and its own engagement with the gas sector (MED, 2014).

FISCAL REGIME AND INVESTMENT

In New Zealand, the ownership of all petroleum resources, including natural gas, rests with the Crown, regardless of the ownership of the land. However, some coal resources are privately owned (Rob Harris, 2004). The New Zealand Petroleum & Minerals (NZP&M) business unit within the MBIE manages the government's oil, gas, mineral and coal resources, known as the Crown Mineral Estate.

NZP&M was formed in May 2011 to maximise the gains to New Zealand from the development of its oil, gas, coal and mineral resources, consistent with the government's objectives for energy and economic growth. Its role is to efficiently allocate rights to prospect, explore and mine Crown-owned minerals. It is also responsible for effectively managing and regulating these rights and ensuring a fair financial return to the Crown for its minerals. NZP&M is instrumental in promoting investments in the mineral estate. It replaces the former Crown Minerals Group. The Resource Markets Policy team of the Energy and Resource Markets Branch of MBIE advises the New Zealand Government on policy and operational regulation in the mineral estate.

Corporations earning income in New Zealand were previously taxed at a flat rate of 30% (Inland Revenue, 2012). The tax rate has dropped to 28% effective from 1 April 2011 (Inland Revenue, 2012). Corporations are also required to pay other indirect taxes such as payroll and fringe benefit taxes.

For petroleum production, companies must pay an ad valorem royalty of 5% (5% of the net revenues obtained from the sale of petroleum) or an accounting profit royalty of 20% (20% of the accounting profit of petroleum production), whichever is greater in any given year. For discoveries made between 30 June 2004 and 31 December 2009, an ad valorem royalty of 1% is applied to natural gas, an accounting profits royalty of 15% on the first NZD 750 million for offshore projects or 15% on the first NZD 250 million for onshore projects (NZP&M, 2014).

For the production of Crown-owned coal, the royalty payable depends on when the initial permit was awarded. For initial permits awarded between 1991 and 2008, an ad valorem royalty of 1% of the net sales revenue is payable between NZD 100 000 and NZD one million. For producers with net sales exceeding NZD one million, the royalty payable is either 1% of the net sales revenue or 5% of the accounting profits,

whichever is higher (NZP&M, 2014). For initial permits awarded between 1 February 2008 and 23 May 2014, a unit-based royalty of NZD 1.4 per tonne is payable for hard and semi-hard coking coal, NZD 0.8 per tonne for thermal and semi-soft coking coal and NZD 0.3 per tonne for lignite. For initial permits awarded since 24 May 2014, an ad valorem royalty of 2% of the net sales revenue or 10% of the accounting profits is payable, whichever is higher.

New Zealand's environmental permitting process, known as 'resource consent', is governed by the Resource Management Act 1991 (RMA) and its subsequent amendments. A resource consent is required for any project that might affect the environment, which essentially includes all energy development projects. Resource consents are generally obtained from regional, district or city councils depending on the nature of the resources affected. The RMA specifies that the guiding principle of decision making is sustainable management (MFE, 2015).

In December 2008, in response to concerns about the slow and costly consenting process under the RMA, the government reviewed the RMA process to address some of the major criticisms. One of the main criticisms was that decision making was with the local governments, where local interests can take precedence over economy-wide interests or where insufficient expertise and resources are available, especially for major complex projects. The RMA amendment in 2009 addressed this criticism by establishing an Environmental Protection Authority (EPA) to receive resource consent applications for proposals of national significance and to support the boards of inquiry (or the Environment Court) in making decisions regarding these proposals (MFE, 2015).

The Resource Management (Simplification and Streamlining) Amendment Act 2009 also includes provisions to streamline the consenting process. These specifications make it more difficult for competitors to challenge a resource consent application, impose stricter deadlines for decisions by local governments and make procedural changes.

In 2017, the Phase 2 Review of the RMA was completed. This phase of the RMA has taken over 5 years to complete as it was comprehensively looking at its relations with other legislations related to environmental management, such as the Conservation Act (1987) and the Exclusive Economic Zone Act (2012). The key change is the refocusing of the decision making at the local government level to follow the established 'national direction' handed down by the central government in National Policy Statements when considering RMA applications. Other changes include streamlining the RMA relation with other legislation, as mentioned above, improvements to procedural requirements and streamlining legal processes around the act (2017a).

ENERGY EFFICIENCY

New Zealand has promoted energy efficiency for over 20 years, and in 2000, it passed the Energy Efficiency and Conservation Act 2000, which led to the economy's first energy efficiency strategy and the establishment of the EECA to spearhead the strategy's implementation (EECA, 2012a).

In August 2017, the government released the latest NZEECS to replace the 2011 document. The overall goal of the new strategy is for New Zealand to continue to increase energy productivity and reduce carbon emissions in accordance with New Zealand's international commitments such as the Paris Agreements and the APEC intensity target. NZEECS also makes strong mentions of renewable energy and the productivity value it can generate. The strategy focuses on three key areas, each having a specific target:

- Area 1: Renewable and efficient use of process heat. Target 1: Decrease industrial emission intensity of at least 1% per year on average between 2017 and 2022.
- Area 2: Efficient and low carbon transport. Target 2: Electric vehicles make up 2% of the vehicle fleet by the end of 2021.
- Area 3: Innovative and efficient use of electricity. Target 3: 90% of the electricity will come from renewable sources by 2025 (MBIE, 2017b). The government is expended to strengthen this to 100% renewable by 2035.

Some of New Zealand's major policies for promoting energy efficiency are as follows:

- In May 2016, an electric vehicle support programme was announced, which involved road user tax exemptions, government/private bulk purchasing programmes and information campaigns. Of specific interest is a contestable fund to match private funding for projects aimed at increasing EV

deployment in New Zealand (MT, 2017). More information can be found in the government-sponsored website https://www.electricvehicles.govt.nz/.

- There is also fuel economy labelling for light vehicles.
- There is no blanket policy for businesses; rather, an individual approach is prevalent to support innovative and replicable projects that demonstrate efficiency opportunities, support energy auditing in larger business and promote awareness of energy efficiency in business by recognising energy efficiency excellence through a highly publicised awards event.
- In relation to residential buildings, a subsidy programme called Warm up New Zealand has delivered insulation retrofits for more than 300 000 homes since 2009. In addition, the government has made amendments to the Residential Tenancies Act 1986 to include a requirement for rental properties to meet a minimum standard of insulation by July 2019.
- In commercial buildings in 2014, a rating tool for the buildings' energy and water efficiency was launched to promote efficiency.
- For appliances and equipment, New Zealand has in place an extensive Minimum Energy Performance Standards (MEPS) and labelling programme. This initiative is coordinated with Australia to have a robust mechanism for both economies (EECA, 2017).

The draft government policy statement on land transport (GPS) that allocates funds primarily raised through levies on petrol sales and road user charges was released in 2018. The new plan refocuses funding from its traditional role of investing in improving road infrastructure to a 'mode-neutral approach'. The approach allows planners to consider alternative modes such as rail, active transport and coastal shipping rather than solely looking at road infrastructure to find the most cost-effective solution to achieve an objective. The GPS introduced two new categories of financing, rapid transit for commuter rail and dedicated busways and transitional rail for other rail projects. Furthermore, there were new policies in the GPS targeting efficiency of the vehicle fleet, rail freight and coastal shipping. The changes are intended to improve the overall efficiency of the New Zealand transport system from an operational and energy perspective. The transport levy was raised by 3.5 cents per litre from 30 September, and increases of 3.5 cents will continue for the next two years to a total of 10.5 cents (New Zealand Government, 2018).

RENEWABLE ENERGY

New Zealand is well endowed with hydro, geothermal, wind, biomass and potentially ocean energy, so much so that all current wind and geothermal capacity was developed without subsidies. Although in the past state-owned electricity-generating companies have played a major role in developing these resources, they are required to operate as commercial businesses and must compete with private generators (The Treasury, 2011). As part of the Energy Strategy, the New Zealand Government set a target of generating 90% of its electricity from renewable sources by 2025, provided that a security of supply is maintained. However, this goal may be extended as the government is in the process of setting up the independent Climate Change Commission, whose work will include how we transition towards 100% renewable electricity by 2035. One of the existing instruments that help ongoing development of renewable energy in New Zealand is the Emissions Trading Scheme, discussed in the 'Climate Change' section (MBIE, 2012).

Hydropower has historically been New Zealand's major source of renewable energy. However, the majority of favourable hydro sites have already been developed, and there is a strong social opposition to further hydro development; thus, New Zealand has been focusing on geothermal and wind energy. Several major renewable generation capacity projects have been consented by government in recent years but have not been developed due to lower-than-expected electricity demand growth. In effect, the next 20 years of the new demand have already been approved and will be mostly wind and geothermal electricity.

Biomass has also been long used in New Zealand for residential heating and industrial process heat in the wood product and pulp and paper manufacturing industries. However, this is largely the productive use of a waste product from the primary industrial activity. Due to lower energy density and cumbersome gathering process, its use has remained limited. In recent years, the EECA has been promoting the conversion of medium-scale industrial or commercial boilers to biomass through the use of denser, relatively inexpensive wood pellets. To promote biofuels, the government is now supporting research, development and demonstration for advanced biofuel projects (i.e. from woody biomass).

Another tool employed by the government was the issuing of a National Policy Statement for Renewable Electricity Generation in April 2011. This policy statement requires decision makers at all levels of government, especially the local level, to recognise the economy-wide significance and make provisions for renewable electricity generation in their plans and policy statements (MFE, 2011).

The government has also considered electric and plug-in hybrid electric light vehicles (EVs and PHEVs) as an option to increase renewables in transport. The Low Emission Vehicles Contestable Fund is the primary mechanism of support for EVs and PHEVs. It provides 50% cofounding for projects that grow the supply and variety of EVs available, improve charging infrastructure availability and increase demand for EVs. The fund will support NZD 7 million worth of projects per year (EECA 2018).

NUCLEAR ENERGY

New Zealand law prohibits the development and use of nuclear energy, and there are no plans to revisit this stance in the foreseeable future.

CLIMATE CHANGE

The New Zealand Government is committed to taking action on climate change. Its stated goal is for New Zealand to be a net-zero emission economy by 2050. This is considerably more ambitious than the current NDC to reduce greenhouse gas emissions by 11 percent below the 1990 levels by 2030 under the Paris Agreement. The Zero Carbon Act is the central tool policy to begin an economy-wide transition to net-zero carbon by 2050. The act is in the drafting phase and is expected to come into force in July 2019. The Zero Carbon Act will implement new nationwide carbon budgets and establish an independent Climate Change Commission. In the meantime, an Interim Climate Change Committee was set up early in 2018 to address key issues in climate change policy of New Zealand, such as agriculture and renewable electricity. The Climate Change Commission will further advise the government on these matters once the bill passes into a law.

The key climate change intervention is the Climate Change Response (Emission Trading) Amendment Act of 2008, which established New Zealand's emission trading scheme (ETS). The ETS places a price on greenhouse gas emissions to provide an incentive to reduce emissions. The scheme came in effect in 2008 and was amended in 2009, 2012 and 2016.

For energy, the point of obligation under the scheme generally lies with energy suppliers, not with the end users. This means that only energy suppliers and a few large industrial facilities are directly involved in the scheme. The government is providing free units to energy-intensive trade-exposed industries to protect them from international competition that does not face a carbon cost (FL, 2012).

The government has signalled that it will strengthen the ETS by including all sectors, removing (or reducing) grandfathering and removing the two-for-one deal. This expected result is higher carbon prices advantaging renewable energy deployment and promoting energy efficiency (especially in industry and transport) and electric transportation.

The government is progressing with work to strengthen and improve the operation of the ETS, with a focus on the following (MFE, 2017):

- how best to implement the in-principle decisions made by the government in July 2017 (such as introducing auctioning and developing a different price ceiling), and
- a package of forestry accounting and operational improvements, any future phase out of free allocation and other operational and technical matters.

NOTABLE ENERGY DEVELOPMENTS

ELECTRICITY MARKET

Tiwai Point Aluminium Smelter (TPAS), which accounted for 12% of New Zealand's total electricity demand in 2014 (MBIE, 2015b), has announced an expansion of its operation with a supply contract of 50 megawatts (MW) with meridian energy. This brings TPAS back to full production after the closure of the line in 2012 due to historically low aluminium prices. This adds 9% to the plant production. TPAS's primary electricity supply contract runs until 2030.

On the supply side, 2015 witnessed a closure of nearly 600 MW of natural gas generation due to a stagnant market. New Zealand still has 480 MW of power generation capacity capable of burning coal as

fuel, though gas may also be used. In 2016, coal only supplied 2% of the generation. Coal use in the power sector is expected to be phased out by 2030 or as early as 2025, considering market conditions (Genesis Energy, 2018). This situation is putting pressure on the grid and market operators to ensure security of supply during dry climate periods when hydro generation will be constrained (NBR, 2015). These closures are partly covered by the construction of the Te Mihi geothermal plant of 166 MW and the Mill Creek wind farm of 60 MW, which were completed in 2014, and the Te Ahi O Maui geothermal plant of 20 MW completed in 2018 (EA, 2018b). Another development includes the deployment of smart metre devices throughout the market. By the end of 2015, over 73% of all households had smart metres installed (EA, 2016). The key driver resides in operational savings for electricity retailers in terms of not having to employ metre readers and control certain processes remotely. The Smart Grid Forum formed in 2014, however, believes that there is potential to expand benefits into streamlining the market, energy efficiency technology adoption and greater adoption of renewables (MBIE, 2014).

NEW PROJECTS

Since the 2014 project mentioned above, only one minor generation project has undergone construction. There are, however, several large-scale wind, geothermal and hydro projects that have regulatory and environmental consents to proceed. However, with relatively stable demand, it is unlikely that these projects will be developed in the short term without significant policy support.

In the past few years, the New Zealand grid system operator Transpower completed several essential major upgrade projects to maintain grid security and keep up with the demand. These include the NZD 417 million North Auckland and Northland Grid Upgrade Project (completed in 2013); North Island grid upgrade project (completed in 2012); NZD 100–300-million Wairakei to Whakamaru Replacement Transmission Line Project, completed in 2013; and the NZD 672-million high voltage direct current (HVDC) Inter-Island Link Project, completed in 2014 (Transpower, 2015). Other grid maintenance and upgrade projects worth around NZD 400 million are currently underway. Transpower is also managing a demand response project aiming to develop a market within the New Zealand electricity system.

In April 2018, the government announced that there would be no new offshore oil and gas exploration permits issued, but the 31 oil and gas exploration permits that are currently active (22 of which are offshore) would be honoured. The government will continue to offer blocks for onshore exploration in the Taranaki Region, and the industry is spending around NZD 300 million in multiple sites to explore further resources. However, at present, no significant funds are being developed for production.

In transport, Z Energy is in the process of commissioning New Zealand's largest biofuel plant with a production capacity of 20 million litres per year.

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Electricity Authority—www.ea.govt.nz

Energy Efficiency and Conservation Authority (EECA)—www.eeca.govt.nz

Environmental Protection Authority—www.epa.govt.nz

Ministry of Business Innovation and Employment (MBIE)— www.mbie.govt.nz

Ministry for the Environment —www.mfe.govt.nz

New Zealand Government (news and speeches from government ministers)—www.beehive.govt.nz

New Zealand Parliament—www.parliament.govt.nz

New Zealand Petroleum & Minerals (formerly Crown Minerals)—www.nzpam.govt.nz

Transpower—www.transpower.co.nz

PAPUA NEW GUINEA

INTRODUCTION

Papua New Guinea (PNG) is an island economy located in the south-western Pacific Ocean. It stretches from south of the Equator to the Torres Strait, which separates New Guinea from Cape York Peninsula to the south, the northernmost extension of Australia. PNG has a total land area of 462 840 square kilometres (km^2) and is the largest of the Pacific Island countries, including the large islands of New Britain, New Ireland and Bougainville and around 600 smaller islands. The economy's capital, Port Moresby, is located in south-eastern New Guinea on the Coral Sea. PNG became totally independent in September 1975 and has since struggled to address one of its principal challenges of governing hundreds of diverse, once-isolated local ethnic groups into a viable single economy (Standish and Jackson, 2017).

PNG sits along the 'Ring of Fire', has many active volcanoes and frequently faces earthquakes and even tsunamis. Amidst the mountainous terrains, tropical rainforests and scattered small islands lie the economy's rich natural resources dominated by gold, copper, oil, gas, timber and agricultural exports (coffee, cocoa, tea, palm oil and copra). High temperatures and humidity throughout the year and wet and dry seasons are characteristics of its climate.

PNG's population is relatively young. Of the 8.08 million strong population in 2016 (EGEDA, 2018), almost 36% was below 15 (World Bank, 2018). PNG is one of the most culturally diverse countries in the world with a representation of 'thousands of different tribes, dances, and traditions and over 800 indigenous languages spoken, more than anywhere else in the world'. PNG's population mostly lives in the rural areas; only approximately 13% of the population lives in urban centres. The population density is also low at 18 people per km^2 (World Bank, 2018).

PNG's economy is characterised by two main sectors: the labour-intensive sector (agricultural, forestry and fishing) and the export-earning sector (minerals and energy extraction). The economy experienced strong economic growth between 2010 and 2016, posting an annual average gross domestic product (GDP)) growth rate of 5.3% (at 2011 prices and 2011 purchasing power parity [PPP]) (EGEDA, 2018). This was because of a significant resource boom, mainly in the extractive minerals and hydrocarbon sector, due to construction of a major liquefied natural gas pipeline (PNG LNG) from the Southern Highlands in 2014. In 2016, PNG's real GDP was estimated at USD 30.87 billion (2011 USD PPP), an increase of 1.9% from the 2015 level. The receipts from mining, together with those from petroleum, constitute the bulk of PNG's export earnings (>70%) and constitute over 20% of the economy's GDP. Despite the strong revenue growth experienced by PNG for the past five years, its GDP per capita in 2016 was the lowest among the Asia-Pacific Economic Cooperation (APEC) member economies at USD 3,818 (2011 USD PPP) (Table 1) and the provision of basic services continues to be a challenge.

PNG became a member of APEC in 1993. Additionally, the economy is a member of the African, Caribbean and Pacific Group of States, Non-Aligned Movement, Pacific Community, Pacific Islands Forum, the United Nations and the World Trade Organization (The Commonwealth, 2017).

Table 1: Key data and economic profile, 2016

Key data [a]		Energy reserves (end 2016) [b]	
Area (km^2)	462 840	Oil (ktoe)	24 000
Population (million)	8.1	Gas (ktoe)	127 000
GDP (2011 USD billion [PPP])	30.9	Coal	–
GDP (2011 USD PPP per capita)	3 818	Uranium	–

Sources: [a] EGEDA (2018); WEC (2016)

ENERGY SUPPLY AND CONSUMPTION

In 2016, primary energy supply was reduced by 12.8% compared with the previous year's level. However, when compared with the 2014 levels of 2770 thousand tonnes of oil equivalent (ktoe), primary energy supply surged to reach 9500 ktoe in 2016. This was mainly because of the more than fivefold increase in the gas supply of 1500 ktoe in 2014 to 6656 ktoe in 2016. Of the total supply, crude oil and petroleum products maintained the largest share in 2016 (61%) and gas was the second-largest fuel source 24% in 2016 from just 10% in 2014. The remaining share (14%) was attributed to other energy sources such as hydro and renewables (EGEDA, 2018). Information on coal and uranium reserves have not been recorded as the economy is not rich in these reserves and has not touched upon these resources. There investigations though indicate that the Sepik Coal Basin has the potential to host economically viable coal resources given its geological and structurally complex setting. However, the full potential can be understood only after extensive exploration work and drilling programmes have been concluded to firm up the coal resources (MRA, 2016).

Oil was discovered in PNG in 1987, and the first commercial production of crude oil started only in 1992. It peaked at over 150 000 barrels per day (bbl/d) the following year. In 2016, oil production was at 55 990 bbl/d (CIA, 2016). The economy has been importing a fluctuating, but unknown, amount of crude oil annually to feed its only refinery, the Napa Napa Refinery (operated by Puma Energy, which acquired InterOil's operations in 2014) with 506 000 cubic metres (m^3) of storage capacity (Puma, 2017).

According to Oil Search, PNG's pioneer partner in exploration, at present, there are approximately 10 trillion cubic feet (Tcf) of gas undeveloped 2C contingent resource within the Elk-Antelope fields in PRL 15 and the P'nyang field in PRL 3. The gas resources are sufficient to support two additional LNG trains with a capacity of 4 million tonnes per annum (MTPA). In addition, its successful appraisal, the recent Muruk discovery, located along the Hides field, approximately 21 km from the nearest PNG LNG infrastructure, could increase the options for development and economic expansion (Oil Search, 2017).

The PNG LNG Project began commercial operations in 2014. This project is an integrated development that includes gas production and processing facilities in the Southern Highlands, Hela, Western, Gulf and Central Provinces of PNG. It will provide long-term supply of LNG to four major customers in the Asia region. There are more than 700 km of pipelines connecting the facilities, which include a gas conditioning plant in Hides and liquefaction and storage facilities near Port Moresby, with a capacity of 6.9 MTPA. Over the life of the PNG LNG, over 9 Tcf of gas is expected to be produced (PNG LNG, 2014).

In 2016, PNG generated 4 445 gigawatt-hours (GWh) of electricity, a 2.8% increase from the 2015 level. The compounded annual growth rate (CAGR) since 2010 was 3.4%. Thermal generation, sourced mainly from diesel, contributed the largest share (68%), followed by hydro (23%) and others (9%) (Table 2, EGEDA, 2018). Power generation from renewables, sourced mainly from hydro and geothermal, accounted for 32% of the total power generation in 2016. The electricity system of PNG is characterised by numerous small regional- or town-level generation and distribution network systems without a central transmission network connecting generation and consumption. The majority of these are thermal generation systems, except for three hydro locations and two hybrid micro-hydro and diesel systems.

The economy's geothermal resources are known to be of high quality since PNG lies in the proximity of the Pacific Rim of Fire. Geothermal wells are scattered all over the northern part of the economy. The economy's first geothermal plant was established at the Lihir Gold Mine with 56 megawatt (MW) capacity. It was developed and owned by the Lihir mining company, and the electricity generated from that plant was mainly for their own use. As this plant is on the island and thus not connected to a major grid, the company sells the excess electricity to the nearby community. There is a plan to first develop a 5-MW pilot project and then a 40-MW one in West New Britain Province, followed by a 50-MW plant in East New Britain Province. The economy's possible proven reserves might be 4 000 MW, as indicated by the Icelander group (APERC, 2017). In 2010, the International Renewable Energy Agency (IRENA) estimated that traditional biomass accounted for more than half of PNG's energy consumption and one-third of the energy supply (IRENA, 2013). However, since there are no recent surveys to track biomass use and it is not commercial in nature, its use is largely undocumented and therefore not well reflected in the statistics below.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	8 282	Industry sector	733	Total power generation	4 445
Net imports and others	-5 186	Transport sector	643	Thermal	3 020
Total primary energy supply	3 178	Other sectors	240	Hydro	1 005
Coal	0	Non-energy	0	Nuclear	0
Oil	1 948	Final energy consumption*	1 616	Others	420
Gas	783	Coal	0	Total renewables	1 425
Renewables	448	Oil	1 273		
Others	0	Gas	0		
		Renewables	0		
	8 282	Electricity and others	343		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

Compared with the 2015 level, the total final energy consumption in PNG in 2016 increased by 1.8% to reach 1616 (ktoe). This is significant compared with the previous years' levels, as consumption has grown by 4.45 per year for the past 5 years. The industrial sector remained the largest energy user, accounting for 45% of the total, followed by the transport sector at 40%. The other sectors, including agriculture and residential/commercial buildings, constituted 17% of the total. Industry consumption grew by 3.1%. All other sectors had a growth rate of less than 1% in 2016. By energy source, petroleum products accounted for 79% of the final energy consumption (excluding non-energy uses), while electricity and other sources accounted for 21%, which has roughly remained the same for the past four years (EGEDA, 2018).

Electrification remains limited to the main urban areas, and 85% of the population that lives in rural areas largely relies on traditional biomass to meet its energy needs. The levels of ownership of electric domestic appliances are, therefore, not high. For example, the coverage of air conditioners in the capital city Port Moresby is only 7% (ADB, 2015a) and is likely to remain low until wealth from the resource sector is translated into improved incomes for the population and infrastructure development. In 2016, the PNG government, with help from Columbia University of the USA, prepared the National Electrification Rollout Plan (NEROP) that targets 70% household electrification access by 2030 (APERC, 2017). Electricity consumption will significantly increase as these projects develop.

The transport sector faces a similar infrastructure challenge, with road services being generally limited to the main centres and intercity roads being few and in disrepair. Many locations can only be accessed through coastal or river barges. As such, transport fuel consumptions will be hampered once road saturation levels are reached. In 2016, transport consumption grew by 0.9% from the 2015 level to reach 643 ktoe.

Petroleum products such as diesel, petrol and heavy fuel oil are used in the transport and electricity generation sectors. PNG Power Limited (PPL) and the PNG Government, with assistance from the World Bank, are continuously extending their rural distribution networks throughout the economy, especially to the outskirts of urban areas.

The significant increase in consumption in the industry sector from 2014 to 2015 is attributed to the growth brought about by the commercial operations of the PNG LNG in 2014.

ENERGY INTENSITY ANALYSIS

Given the small size of PNG's economy, intensity patterns can be significantly affected by individual events or trends and can be volatile. Primary energy intensity in 2015 posted an increase of 17.2% over the 2014 intensity level, reaching 107 tonnes of oil equivalent per million USD (toe/million USD). The increase was probably because of increased energy consumption in the industry sector from the LNG development that started in 2014. Between 2015 and 2016, intensity has reduced by 3.4%.

As there are no data on non-energy consumption in PNG, the estimated energy intensity comes purely from final energy consumption. The final energy intensity in 2016 was estimated at 52 toe/million USD. This is nearly unchanged from the previous two years (see Table 3).

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	107	103	-3.4
Total final consumption	52	52	-0.1
Final energy consumption excl. non-energy uses	52	52	-0.1

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

There are no data available on renewable consumption in PNG. However, the economy largely relies on biomass for cooking and lighting in the residential sector as 87% of its population lacks access to electricity. Nevertheless, 110 ktoe of modern renewables were estimated to be consumed in 2016, which was 6.8% of the total final energy consumption. There was little change in renewables from 2015, with a 1 ktoe absolute decrease and a small reduction in the share.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	1 587	1 616	1.8
Non-renewables (Fossils and others)	1 476	1 506	2.0
Traditional biomass*	0	0	0
Modern renewables*	111	110	-0.42
Share of modern renewables in final energy consumption (%)	7.0	6.8	-2.2

Source: EGEDA (2018)

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables although data on wood pellets are limited.*

STAKEHOLDERS IN ENERGY SECTOR

Prime Minister Peter O'Neill was re-elected for the fourth term in parliament in the July 2017 election. With his re-election, he committed to revitalise PNG's economy, focusing on generating more revenue while simultaneously managing debt levels, slashing unnecessary public expenditure and delivering key projects and services to the people. Among other things, he committed to develop and maintain key productive infrastructure assets, including energy. The Department of Petroleum and Energy (DPE), a ministerial regulatory body in charge of all energy-related issues, especially policy, will undergo a massive restructuring

and follow the Mineral Resources Authority (MRA) structure. The MRA is another governmental agency specialising in the administration of mining activities executed on behalf of the government under the Ministry of Mining. The availability of official information related to the departments is moderate because of limited access to their websites, except the MRA (recorded until January 2017). Besides the ministries, the PNG Chamber of Mines and Petroleum is an active non-profit organisation that offers a wide range of programmes and projects aimed at nurturing PNG's full resource potential.

According to the Chamber, the main players in the petroleum market include Talisman and its joint venture partners (active in the south-west region of the economy), ExxonMobil, Oil Search (focused on the Fold Belt and the Hides, Angore and Juha gas fields), InterOil (Gulf region), Sasol, Mitsubishi and more than 15 other stakeholders. The large mining projects in 22 current mines include Barrick Gold's Porgera gold mine, Ok Tedi copper mine, Newcrest's Lihir gold mine, Newcrest-Harmony's Hidden Valley gold mine and MCC's Ramu nickel-cobalt project (MRA, 2016). Regarding the electricity industry, most thermal and hydropower stations are owned and operated by the corporatised state-owned enterprise PNG Power Limited (PPL), formerly called the PNG Electricity Commission. Details of the functions of some of the energy stakeholders of PNG will be discussed in the 'Policy Overview' section.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The government's long-term vision released in 2015 is outlined in the national development framework called Vision 2050. Vision 2050 aims to create institutions that will equitably distribute resources and opportunities by 2050. Furthermore, it aims to make the economy less reliant on the mining and energy sectors and help create new income-earning opportunities and improvements in human development outcomes. The plan has seven pillars encompassing all areas of development, with energy under the Environmental Sustainability and Climate Change pillar. The Wealth Creation, Natural Resources and Growth Nodes may also influence energy development as infrastructure develops and consumption grows. The key energy-related objectives include the following points:

- Ensuring 100% electricity generation from renewable and sustainable sources by 2050 and
- Reducing greenhouse gas (GHG) emissions by 90% from the 1990 levels

In response to Vision 2050, there have been significant policy reviews of the PNG National Energy policy, PNG National Transport policy and Mining and Petroleum Act to align these low level policies with Vision 2050.

The PNG National Energy Policy 2017–2027 (NEP) lays out the plans for energy sector development in unprecedented detail and signals significant reforms, particularly in the electricity sector. The NEP focuses on four aspects of sustainable development—social, economic, environment and energy security—and incorporates the following principles:

- Strengthening institutional capacity
- Developing an integrated planning process for sustainable energy supply and utilisation;
- Developing all energy resources through the State for the betterment of all citizens;
- Promoting a conducive environment for long-term sustainable economic solutions in the supply of all energy sources;
- Encouraging the involvement of the private sector in the development and provision of energy services;
- Ensuring that energy resources are developed and delivered in an environmentally sustainable manner;
- Promoting efficient systems and safety in energy supply in all sectors (transport, residential, commercial, industrial and agriculture); and

- Diversifying the development and utilisation of energy resources for the economy's well-being and economic prosperity.

The NEP also restructures the DPE into three new governing, regulatory and community service bodies, the National Energy Authority of Papua New Guinea (NEA) Energy Regulatory Commission (ENERCOM) and the Community Service Obligation Company. The NEA will be responsible for domestic energy provision and for developing and implementing national energy policy. This includes regulation of oil exploration and development, energy transport and distribution, renewables development, electricity distribution and transmission infrastructure and energy data collection. The NEA will report to the Minister for Petroleum and Energy. ENERCOM replaced the Independent Consumer and Competition Commission (ICCC) as the party responsible for promoting competition in domestic energy markets by setting tariffs and licencing market participants. It is also responsible for energy safety through the creation and enforcement of electrical and petroleum safety standards.

To support the work of these new bodies, a national energy fund will be established to aid in the following:

· Energy infrastructure development;

· Energy sector environmental disaster mitigation and response;

· Hydroelectricity disaster risk mitigation;

· Energy efficiency and conservation programmes; and

· Promotion of renewable energy (RE) initiatives.

In addition to the formation of the new agencies, there are plans for significant reforms to the state-owned enterprise PPL. The NEP was highly critical of PPL for the slow growth in electrification, the low quality of electricity infrastructure and the high price of electricity. The NEP details a plan to realign PPL's objectives and make the state-owned enterprise more commercially orientated with long-term plans for establishing a competitive electricity market.

Mining and Petroleum Act has been reviewed in consultation with PNG's stakeholders, such as the foreign investors and land owners. This is to ensure that the benefits prescribed in project agreements with regard to royalties and infrastructure grants are fully realised. Part of this review will lead to the decentralisation of the functions responsible for managing resource owner funds, such as the royalties and infrastructure funds. A bill is expected to be introduced in 2019 to implement the proposed changes.

In March 2010, the government launched the Development Strategic Plan (DSP) 2010–2030, which will provide a strategic planning framework focusing on extending economic growth benefits to the most disadvantaged regions and communities. In 2014, an addendum to the DSP was launched, called the National Strategy for Responsible Sustainable Development (StaRS) 2010–2030. This addendum emphasises the government's desire to reduce the economy's reliance on non-renewable resource extraction and encourages the development of environmentally sustainable industries and low-carbon technologies in pursuing a more inclusive economic growth path (ADB, 2015a). This will be discussed further in the section on Renewable Energy.

Since 2011, the DPE, together with other stakeholders, has authored several draft energy policies pursuant to the strategies and objectives mentioned above. The key draft policies included Rural Electrification Policy and Strategy, Geothermal Energy Policy, Renewable Energy Policy and the Electricity Industry Policy (IRENA, 2013), although not all of them have been finalised and passed by the government, such as the policy for geothermal power.

In October 2010, the PNG Government announced its Medium-Term Development Plan (MTDP) 2011–15. This plan focused on increasing access to electricity for all households in the economy. New investments from the private sector in solar technology were also expected during the period of the first MTDP. The succeeding MTDP 2016–2017, published in 2015, closely follows the National Strategy for Responsible Sustainable Development and PNG Vision 2050. It is expected to place PNG in a better economic position in the long term. Cleaner energy or electricity is highlighted to ensure less impact on the environment, while

mineral and gas industries will continue to play an important role in benefiting development. The MTDP3 will cover the years 2018 to 2022.

In 2014, PPL published its Fifteen-Year Power Development Plan 2014–28 with projected areas of growth. It is worth noting that according to this report, to achieve the targets indicated in the strategy documents, the government will need a coordinated effort with the private sector to develop infrastructure, generate consumption, and source funding.

In 2016, the PNG Government, with the help from Columbia University of the USA, prepared the NEROP that targets 70% household electrification access. It details the programme to achieve this target (75% by grid and 25% off-grid) by 2030 (APERC, 2017).

ENERGY MARKETS

PPL is PNG's state-owned vertically integrated company created under the PNG Power Act 2002 to act as the economy's main utility providing electricity to all consumers. It has been granted the following licences by the ICCC now ENERCOM (1) Generation, (2) Transmission, (3) Distribution and (4) Retailing of electricity. PPL operates three separate urban grids (isolated) and 14 other independent provincial systems. In addition, there are a number of small rural electricity systems (C-centres) and privately owned facilities in rural areas. The three separate urban grids operated by PPL are 1) Port Moresby System (POM), 2) Ramu System and 3) Gazelle Peninsula System. PPL's 14 independent provincial systems (stand-alone systems) can be developed and expanded into separate small grid systems. These mini grids can be made ready to integrate into the larger grids, such as the POM, Gazelle and Ramu, in the near future (APERC, 2017).

PPL has an exclusive licence until 31 December 2017 to sell electricity within 10 km of its existing networks and sell individual customer loads of up to 10 MW within its network areas (PPL, 2014). This may have been the first step towards retail competition because the maximum size of loads can be decreased over time as retail competition is extended (Lawrence Craig, 2017). The government continues to play an important role in the regulation of retail competition, including issues of price control and market ownership in the Electricity Supply Industry and allowing for a lower tariff for rural electricity users based on long-run marginal cost. Any control mechanisms in ICCC shall be gradually transferred maybe to an energy regulatory commission when it is established.

FISCAL REGIME AND INVESTMENT

Following the 2017 election, the O'Neill–Abel Government announced the 100-Day Economic Stimulus Plan to reinforce macroeconomic resilience and support inclusive growth. It establishes an ambitious set of 25 priority objectives aimed at strengthening confidence in the medium-term sustainability of the economy and public finances. Key elements include limiting the budget deficit to 2.5% of GDP in 2017, strengthening payroll management and identifying 18 priority capital projects. The plan serves as a strong signal of the incoming administration's likely policy orientation over the coming years. It does not include any changes to tax rates, removal of exemptions or other revenue-raising measures. One of the priorities of the plan states that USD 100 million will be released by the Bank of PNG, presumably running down international reserves by the same amount, and mentions a deal to settle purchases of crude oil for the Napa Napa Refinery in Kina, which could mean freeing up around USD 20 million a month (World Bank, 2017b).

Kumul Consolidated Holdings (KCH, formerly called IPBC) was formed by the Government of PNG under an Act of Parliament (2002, amended in 2012) for the benefit of the State to act as the trustee, owner and all-encompassing authority for State-owned assets and enterprises. KCH, under its energy sector, has embarked on delivering new major hydroelectric projects identified as critical to the long-term energy security of the economy. The Ramu 2 Project (180 MW) launched in December 2016 is one such project. Other projects, in various study and design stages, include the Naoro Brown Hydropower Project (60 MW), Karimui Hydro Dam Study (1 800 MW) completed in January 2016, POM IPP Project, Port Moresby Transmission Upgrade Project and Purari Hydro Project (2 500 MW).

Kumul Petroleum Holdings Limited (KPHL) is PNG's national oil and gas company (NOC). The NOC was created by an Act of Parliament through the Kumul Petroleum Holdings Limited Authorisation Act 2015.

KPHL is mandated to protect and maximise the value of the economy's petroleum assets such that it can contribute to the maximum wealth for its ultimate shareholders, the people of PNG. KPHL is currently responsible for managing the State's 16.57% equity in the US $19 billion PNG LNG Project through its subsidiary Kumul Petroleum (PNG LNG) Limited.

The Konebada Petroleum Park Authority (KPPA) was set up by the government under the KPPA Act 2009 as a 'free trade zone'. The role of KPPA is to facilitate, regulate and manage the park, which includes planning and coordinating development by engaging the current and future stakeholders and bringing in investment. Land being declared as a free trade zone comes with tax incentives to lure investors and that land ultimately acts as a one-stop shop for foreign and domestic investment purposes (APERC, 2017). Taxation of the mining and petroleum sectors is generous compared with other resource-rich countries and has eroded potential government revenues. An example of this is the discretionary 10-year tax exemption for the Ramu Nickel mine and near-zero fiscal revenues from the new PNG LNG investment. The result is that the project is not expected to generate significant tax revenues until the mid-2020s, largely because of a profit-based royalty regime and generous capital allowances cancelling out any tax liabilities. Discretionary exemptions granted to specific firms or projects create precedents that in turn build pressure to grant further exemptions to new investors and existing firms who feel they are disadvantaged because of the exemptions enjoyed by their competitors (World Bank, 2017b).

The International Monetary Fund provided technical assistance to the PNG Department of Treasury to review the economy's mining and petroleum taxation in 2013. The review's purpose was to determine the 'appropriateness of the mining and petroleum taxation arrangement compared to similar resource-rich countries' (CTR, 2014). In 2015, the government started a review of the electricity tariff methodologies to improve the competitiveness of the electricity system, which was priced from USD 0.24 per kilowatt-hour (USD 0.24/kWh) to USD 0.47/kWh in 2012 (ADB, 2015b). Revenues to the government from energy project originate from the following four principle sources (World Bank, 2017b):

1. Royalties: 2% of the well-head value (payable to landowners and the affected provincial and local governments);
2. Development levy: 2% of the well-head value (payable to the affected provincial and local governments);
3. Income tax: 30% tax on the profits of the project (payable to the central government);
4. Dividends: government's share of profits from its 16.6% shareholding through Kumul Petroleum and 2.8% shareholding by the Mineral Resources Development Company held on behalf of landowners.

ENERGY EFFICIENCY

PNG does not submit data to the Expert Group on Energy Data Analysis (EGEDA). As such, EGEDA estimated the economy's energy data using various reference sources such as JODI Oil and JODI Gas data, the annual report of Oil Search Limited (an oil company based in the economy) and information from the economy's privately operated geothermal power plant. Specifically, EGEDA estimated the final energy consumption, electricity generation and inputs as well as imports of petroleum products from these sources. PNG is also not known to have any existing policy on energy efficiency.

The NEP mentioned above, meanwhile, indicates some principles relating to the promotion of energy efficiency, among others (APERC, 2017). These are as follows:

Principle 7 - Promote efficient systems and safety in energy supply in all sectors (transport, residential, commercial, industrial and agriculture).

(a) Ensure minimum energy performance standards for electrical equipment and adoption of building energy codes and other standards for safety.

(b) Ensure safe transportation of energy products and wastes.

(c) Promote solar power, solar thermal systems and LPG for residential, commercial and public institutions.

Principle 9 - Promote energy efficiency and conservation measures and wise use of energy.

(a) Draft and enforce an energy efficiency Policy within one year of National Energy Authority's creation

(b) Promote energy efficiency measures in all sectors (industrial, residential, agriculture and transport) of the economy in end-use of equipment and appliances.

(c) Promote minimum energy performance standards and appliance labelling for all electrical equipment and appliances in collaboration with PNG Customs Services, National Institute of Standards and Industrial Technology, ICCC and other relevant stakeholders.

(d) Promote the concept of energy-efficient buildings in accordance with the Building Act and Regulations.

(e) Promote energy audits in factories and industrial locations and demand-side management programmes in all sectors of the economy.

There have also been efforts by other international agencies to gather information on energy efficiency indicators. For example, in 2014, the Asian Development Bank (ADB) funded the Promoting Energy Efficiency in the Pacific (phase 2) Project conducted by the International Institute for Energy Conservation. Through this project, several activities were conducted in the Pacific to improve energy efficiency, including lighting, solar power generation, energy efficiency in hotels and the commercial and public sectors and data collection. Analysis revealed that in an aggressive efficiency scenario, PNG could save more than 30% on the current level of consumption (ADB, 2015b). When the potential growth of PNG is considered, this level of savings would improve the possibility of meeting its targets as it would significantly reduce the generation and distribution requirements. The energy efficiency performance of the appliances surveyed in the project were indicative of the manufacturer, as these were mostly imported from a neighbouring economy in APEC.

RENEWABLE ENERGY

In August 2017, PNG hosted the fourth phase of the APEC Peer Review on Low Carbon Energy Policy (PRLCE) project. In the background information provided by the economy for the peer review, several plans and programmes relating to renewable energy were identified. These plans were already mentioned in the preceding sections with PNG Vision 2050 as the economy's guiding framework. Among these plans were the 1) National Strategy for Responsible Sustainable Development for Papua New Guinea (StaRS under DSP 2010–2030) and 2) Renewable Energy Plan (under the Electricity Industry Policy and NEROP) (APERC, 2017).

The StaRS seeks to increase the renewable energy -based power capacity of the economy to 100% by 2050. It indicates several plans to achieve this target, including the following pointers (DNPM, 2014):

- Inclusive green growth policy instruments to tap specific opportunities within spatial and resource systems;
- Green energy investment frameworks and incentives require significant government support for renewable energy to establish an initial market share, to gain access to the national electricity grid and other energy infrastructure and to attract investment.

Meanwhile, the RE Plan is initially focused on adding renewable energy -based capacity for power generation. Specifically, it intends to deliver the following pointers (APERC, 2017):

- For geothermal, to extend the Gazelle Grid and cover the West New Britain Province. An additional 95 MW should be added to the Gazelle Grid by 2030 and another 110 MW to the Ramu Grid by 2050;
- For hydropower, to increase capacity by 1 483 MW by 2030 and another 3680 MW by 2050 for the POM and Ramu grids;
- To deliver additional 62 MW of biomass power to the Ramu Grid by 2 030 and another 34 MW by 2050;

- To add 30 MW of wind power capacity to the POM and Ramu grids by 2030 and another 20 MW by 2050;
- To have new 65 MW of solar power capacities by 2030 and pursue the achievement of another 35 MW by 2050; and
- To develop the first 5 MW of ocean energy facility for the economy by 2022 and connect this to the POM grid.

The background information also covers a full range of potential energy resources for PNG, including the 15 000 MW of hydropower and 4 000 MW of geothermal possible proven reserves, among others. However, the economy faces several challenges that hamper the development of these resources. Recent renewable development is limited to privately developed hydro and geothermal generation in mining sites to support their mining operations. For example, the peer review team visited an ongoing development of the 50-MW hydropower project, which will be added to the Port Moresby system by 2020.

NUCLEAR ENERGY

PNG has no nuclear energy industry, and there are no current plans to develop one.

CLIMATE CHANGE

PNG is a global leader in pushing climate change negotiations forward. It is a member of many multilateral environmental agreements, including the Rio+20, the United Nations Convent to Combat Desertification and the Convention on Biological Diversity. Over the past two decades, the PNG Government has also demonstrated good efforts to address global climate change issues. For example, PNG ratified the United Nations Framework Convention on Climate Change in 1993 and the Kyoto Protocol in 2002. It is also the first economy to respond to the Paris Agreement (COP 21), successfully submitting its Intended Nationally Determined Contribution (INDC) in 2015. In 2016, it changed its INDC into a nationally determined contribution. The PNG Vision 2050 is committed to significantly reduce GHG emissions with good forest management and through the development of renewable energy resources. In 2015, PNG established the Climate Change and Development Authority to implement the Climate Change (Management) Act 2015. All of these demonstrate the determination of the PNG Government to reduce GHG emissions (APERC, 2017).

In October 2017, in cooperation with the United Nations Development Program (UNDP), PNG launched the National REDD+ Strategy 2017–2027, which is a key part of the StaRS mentioned above. Its implementation will strengthen the sustainability of PNG's forest industries, support agricultural development and improve land-use planning and management to ensure that the most important environments are protected. The strategy will also help reduce emissions of GHGs and the vulnerability of rural communities to climate change (UNDP PNG, 2017).

NOTABLE ENERGY DEVELOPMENTS

LNG PROJECTS

As mentioned above, the PNG LNG Project began commercial operation in 2014, providing a long-term supply of LNG to four major customers in the Asia region. LNG output from the project reached 8.6 million tons (Mt) in 2016, which is 32% higher than the planned 6.5 Mt nameplate capacity (World Bank, 2017b). The second LNG project (Elk-Antelope) is in the final review stage (Government of PNG, 2015). PNG is now in negotiations for a USD 10 billion expansion of ExxonMobil's LNG project (Reuters, 2016). The project has secured long-term supply contracts for LNG with China Petroleum and Chemical Corporation (Sinopec), Osaka Gas, Tokyo Electric Power Company and CPC Corporation (WEC, 2016).

RENEWABLE ENERGY DEVELOPMENT AND RURAL ELECTRIFICATION

PPL is the primary agency responsible for rural electrification in PNG. The government will fund and implement the Rural Electrification Policy with the help of international funding from Australia, Japan, New Zealand and the USA, who committed funding support during the 2018 APEC leaders meeting in PNG (Freddy Mou, 2018).

To help realise the targets set in DSP 2010–2030, the NEROP was formulated with the support of the World Bank. One of the strategies set out in the plan was conducting geospatial access analysis to determine the extent of lack of access to electricity to understand how to best approach electrification in an efficient and cost-effective manner. The following strategies were indicated in the plan (APERC, 2017):

- USD 150 million per year will be required to electrify 70% of the households by 2030
- 75% of the households electrified will be using a grid connection, while the remaining 25% will be electrified via off-grid electrification;
- Funding for this programme could come from connection charges of USD 15 million per year, government commitment of USD 23 million per year, development partners' grants and concessional loans of USD 91 million per year;
- The institutional framework for the project will have PPL responsible for the grid extension. The private sector may participate to provide off-grid or mini-grid solutions through a new entity that will be established to manage implementation of the NEROP. The DPE will be responsible for policies, planning and monitoring of both grid and off-grid operations. The treasury will be responsible for administering donor funds to the appropriate implementing agencies via a transparent process.
- With implementation of the NEROP, 300 MW will be needed by 2030, which excludes additional commercial, mining and industrial projects. A tariff of USD 0.10–12/ kWh is projected. A separate parallel exercise will be undertaken to analyse the additional investments needed in generation and transmission.

Several partners are already active in the sector and are eager to support the NEROP implementation. Aside from the World Bank, several partners are supporting PPL, namely, ADB, JICA, the Australian Government and the New Zealand Government, in the areas of planning, grid reinforcement and extension and financing of connections to households (World Bank, 2017c). For example, the ADB, together with DPE, formulated the PNG National Distribution Grid Expansion Plan to boost the government's efforts to connect the people living in rural areas to the electricity grid. In partnership with the private sector, the project includes the following pointers (SMEC, 2016):

- Upgrading and rehabilitating two hydropower plants (Rouna 1 and Sirinumu Toe-of-dam);
- Developing the 11 kilovolts (KV) distribution mesh network to extend the grid to approximately 3 000 additional households;
- Strengthening the distribution network;
- Constructing a new substation (Kilakila) with interconnecting 66 KV transmission lines; and
- Upgrading the existing substations.

INTERNATIONAL COOPERATION AND COMMITMENT TOWARDS SUSTAINABLE DEVELOPMENT

After his re-election, Prime Minister Peter O'Neill together with other key PNG leaders signed the Alotau Accord II, with the theme '*Strongim wok na Sindaun bilong ol Pipol*', which embodies the commitments of the O'Neill Government from 2017 to 2022. It will continue to uphold the directive principles reflected in the PNG Vision 2050 and StaRS. To further ensure that the government continues to develop the economy, their plans are spelled out in the current MTDP plan of 2016–17, which will be updated for 2018–2022. These documents and all other strategies formulated under Vision 2050 are geared towards achieving sustainable development of PNG (Government of PNG, 2018b).

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USEFUL LINKS

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Papua New Guinea Chamber of Mines and Petroleum—http://pngchamberminpet.com.pg/

Peter O'Neill: Prime Minster of Papua New Guinea—http://www.pm.gov.pg/

The World Bank, http://www.worldbank.org/en/country/png

PERU

INTRODUCTION

Peru is a constitutional republic located on the west-central coast of South America, bordered by the Pacific Ocean, with Chile to the south, Ecuador and Colombia to the north and Brazil and Bolivia to the east. With a land area of 1.3 million square kilometres (km²), Peru is divided into three main geographical regions: the coast to the west, the mountain region (Andes Mountains) and the Amazonian region. Peru is divided into 25 political departments (administrative regions).

In 2016, Peru had a total population of approximately 32 million, an increase of 1.3% from the previous year's level (EGEDA, 2018). In 2015, approximately 22% of Peru's population was considered to be poor and 4.1% to be extremely poor (INEI, 2015a). The major population centre of Peru is Lima, with 9 million people, which is nearly one-third of the total population (INEI, 2015b). The urbanisation rate of Peru is 76% (INEI, 2011).

Figure 1: Map of Peru



Between 2000 and 2016, Peruvian economy grew fast, with an average annual rate of 5.2%. This rate was higher than the level in 2015–16 (4.0%) owing to the deceleration of emerging economies and global uncertainty. This resulted in negative growth rates in private and public investments (−4.4% and −7.5%, respectively) and a reduction in the private consumption growth rate from 4.1% in 2014 to 3.4% in 2015 (BCRP, 2015). In 2016, Peru's gross domestic product (GDP) was USD 384 billion (2011 USD purchasing power parity [PPP]), whereas its GDP per capita grew by 2.7%, reaching USD 12 082 (EGEDA, 2018). In addition, foreign reserves reached a record USD 61 billion, whereas the fiscal balance was 2.1% of the GDP (BCRP, 2015).

Since 1990, Peru's economy has been driven by its internal consumption, mainly private investments, exports and domestic consumption. Peru has a market-oriented economy, and in 2015, its key segments were services (49%), manufacturing and construction (18%) and mining and energy (12%) (BCRP, 2015).

Mining is especially important for the economy because Peru is a major global producer of several metallic and non-metallic minerals, ranking third in silver, zinc, copper and tin; fourth in lead; and sixth in gold production (USGS, 2016). Consequently, mineral exports have consistently accounted for a significant share of the export revenues, contributing as much as 55% in 2015 (BCRP, 2015). During 2015, around 20% of the USD 24 billion of foreign direct investments was dedicated to the energy, oil and transport sectors (Proinversion, 2015).

Table 1: Key data and economic profile, 2016

Key data[a]		Energy reserves[b, c, d]	
Area (million km²)	1.3	Oil (billion barrels)	1. 2
Population (million)	32	Gas (trillion cubic metres)	0.40
GDP (2011 USD billion PPP)	384	Coal (million tonnes)	9.9
GDP (2011 USD PPP per capita)	12 082	Uranium (kilotonnes U)	42

Sources: [a] EGEDA (2018); [b] BP (2018); [c] MEM (2014); [d] NEA (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Peru's total primary energy supply (TPES) in 2016 was 23 916 kilotonnes of oil equivalent (ktoe), marginally increasing by 0.23% from the 2015 level. This was because of a decrease in oil supply (–6.7%), driven by a decrease in the import of both crude and oil products, which was more than proportional to the increase in oil, coal and natural gas domestic production. Per energy source, in 2016, around 44% (10 547 ktoe) of the TPES was from oil, 31% from natural gas (7 467 ktoe) and 3.6% from coal (863 ktoe). Other energy sources, including hydro, wood, bioenergy, wind and others constituted the remaining 21% (5 040 ktoe) (EGEDA, 2018).

Owing to its scarce oil resources, Peru is a net oil importer because domestic production is insufficient to meet consumption. However, because most crude oil produced is of extra-heavy quality and domestic refineries are unable to process it, a substantial share of the domestic production is exported.

The proven gas reserves of the economy were 0.40 trillion cubic metres (tcm) in 2016 and are expected to increase to 0.80 tcm by 2025 based on the information from the Ministry of Energy and Mines (MEM) (MEM, 2014). In 2004, the development of the Camisea gas field and associated 730 km pipeline to Lima drastically changed the Peruvian energy sector. This has allowed Peru to meet growing domestic demand and become a net natural gas exporter. All natural gas exports are sent as liquefied natural gas (LNG) through the Peru LNG Melchorita export terminal (4.4 million tonnes per annum), one of only two LNG export terminals on the Pacific coastline of the Americas (the other is Alaska's Kenai LNG terminal). In 2016, 41% of total natural gas production was exported via LNG. Since 2012, more than 95% of Peru's total gas production comes from the Camisea field.

Peru's proven coal reserves are around 9.9 million tonnes (Mt), with approximately 95% consisting of anthracite and the remainder of bituminous coal. Most of the reserves are located in the La Libertad, Ancash and Lima departments. Peru is a net importer of coal, with 80% of its coal consumption in 2014 being met by imports and 20% by domestic production (MEM, 2014).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	23 072	Industry sector	5 141	Total power generation	51 970
Net imports and others	464	Transport sector	9 456	Thermal	25 973
Total primary energy supply	23 916	Other sectors	4 832	Hydro	24 172
Coal	863	Non-energy	0	Nuclear	0
Oil	10 547	Final energy consumption*	19 429	Others	1 825
Gas	7 467	Coal	615		
Renewables	5 040	Oil	10 663		
Others	-1.3	Gas	1 712		
		Renewables			
		Electricity and others	2 538		

Source: EGEDA (2018) (data collected in September 2018).

* *Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

The other energy sources category, which represents 21% of Peru's TPES, includes different types of biomass, manly firewood, but also charcoal, dung and yareta (a moss-type plant dried and then burned) and

are mostly used for heating and cooking. In 2015, renewable sources used for energy supply included firewood (38%) and hydropower (48%), but the remainder was from other biomass sources (MEM, 2015).

In 2016, Peru's electricity generation totalled 51 970 gigawatt-hours (GWh), a 7.2% increase from the 2015 level. Hydropower and thermal (mostly gas-fried) generation contributed almost by halves, with 50% and 46.5%, respectively. The remainder 3.5% power generation share came from solar photovoltaic (PV), biomass and wind (EGEDA, 2018).

FINAL ENERGY CONSUMPTION

Peru's total final consumption increased by 5.4% in 2016, reaching 19 698 ktoe. Transportation represented 48% of the total final consumption in 2016, rapidly increasing by 6.6% on an average from 2000 to 2016, reaching 9 456 ktoe. The industrial sector share was 26%, whereas the 'other' sector share, including residential, commercial and agricultural energy consumption, was 25%. The remaining 1.0% share was attributed to non-energy consumption. Final energy consumption, excluding non-energy consumption, was 19 429 ktoe. Oil products dominated the final energy consumption in 2016 with 55% of the total share, most of which was consumed as diesel, gasoline and liquefied petroleum gas (LPG) (MEM, 2015). Electricity constituted 20% of the final energy consumption, whereas gas and coal accounted for the remaining 8.8% and 3.2%, respectively (EGEDA, 2018).

ENERGY INTENSITY ANALYSIS

Peru's energy intensity, measured as total primary energy supply intensity, has been decreasing since 2010. From 2015 to 2016, primary energy supply intensity decreased by 3.6%. Following a different trend, the total final energy consumption intensity increased by 1.6% compared with the 2015 level; when the non-energy is excluded, energy intensity also increased but by 1.4% compared with the 2015 level. Peru's energy intensity increase could be explained by continued and accelerated demand in the transportation sector, mainly of oil products but also natural gas.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	65	62	-3.6
Total final consumption	50	51	1.6
Final energy consumption excl. non-energy	51	51	1.4

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Consumption of modern renewables increased by 23% from 2015 to 2016, predominantly driven by hydropower generation. Its share in final energy also increased at a fast pace by 17%. Traditional biomass consumption decreased by 1.8% in 2016. However, it remains the most consumed fuel in the residential sector.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	18 390	19 429	5.7%
Non-renewables (Fossils and others)	16 368	16 936	3.5%
Traditional biomass*	2 034	1 996	-1.8%
Modern renewables*	2 022	2 493	23%
Share of modern renewables to final energy consumption (%)	11.0	13%	17%

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial) using inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (e.g. hydro and geothermal energy), including biogas and wood pellets, are considered modern renewables, but data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Peru's Ministry of Energy and Mines is responsible for the formulation and evaluation of energy and mining policy and strategies as well as for environmental issues in these activities. The MEM was reorganised in 2018, dividing the former Vice Ministry of Energy in two new Vice Ministries, leaving the current structure with three Vice Ministries: the Vice Ministry of Hydrocarbons, the Vice-Ministry of Electricity and the Vice-Ministry of Mines. The Vice-Ministry of Hydrocarbons covers essentially all the value chain and activities related to the oil and gas industry. On the other hand, the Vice-Ministry of Electricity, despite its name, oversees a number of areas other than the electricity sector, such as energy efficiency, planning, rural electrification, environmental affairs, among others.

In addition to the MEM, the Supervisory Agency for Investments in Energy and Mining (OSINERGMIN) is Peru's autonomous regulatory agency, created in 1996. OSINERGMIN is responsible for setting electricity tariffs and gas transportation rates. Its goal is to promote efficiency in the power and gas sectors at the lowest possible cost for the customer by designing and implementing effective regulations.

The government published the National Energy Plan 2014–25 (MEM, 2014) detailing the policies and objectives to guide the energy policy of Peru. According to the plan, Peru's overarching goal is to have a reliable, continuous and sufficient energy system that can support sustainable development partly by promoting investments in infrastructure (e.g. transport, refinery and production) and exploration. The National Energy Plan's main goals are to provide energy security and universal access to energy supply and develop energy resources under a social and environmental perspective (MEM, 2014). Under the same plan, the government also set energy efficiency goals, focusing on the following:

- Establishing new labelling rules for electrical appliances, water heaters, lighting, engines and boilers;
- Promoting an energy efficiency culture;
- Strengthening and making more energy efficient the public transportation system;
- Maximising the use of natural gas in power generation;
- Promoting the substitution of LPG and diesel to natural gas; and
- Striving to maintain energy prices in real terms, avoiding price distortions.

However, this plan has not been updated or reissued since 2014. Peru's overarching energy policies and goals have not changed significantly since the last edition of this Overview, highlighting the lack of a long-term and specific energy plan. Some of the Energy Plan's goals are to increase the share of natural gas to 35% of total primary energy supply (TPES) by 2025 and expand access to natural gas networks along the coastal region (MINEM, 2014).

One of the aspirational goals under this plan is to improve the electrification rate to 99% by 2025 through the implementation of the Social Energy Inclusion Programme (Table 5). Furthermore, the Social Energy Inclusion Fund aims to provide 1.2 million low-income families access to LPG through discount coupons, as well as the distribution of improved cook stoves aims to encourage a more efficient use of traditional biomass among low-income families. These improved cook stoves are 50% more efficient in the consumption of traditional biomass, reducing CO_2 emissions and respiratory diseases (APERC, 2017).

Table 5: Energy social inclusion indicators of Peru, Energy Plan 2014–25

	2013	2016	2025
Electricity Access (% population)	90	96	99
LPG Discount Coupons (Families)	645 000	1 200 000	1 200 000
Improved Cooking Kits (Families)	72 000	144 000	500 000

Source: MEM (2014).

Although Peru aims to become an energy hub by developing integration projects with Ecuador, Colombia and Chile in electricity, Brazil in hydro power and Bolivia in gas, no concrete projects have materialised to realise this vision. Currently, Peru has electricity interconnections with Ecuador via two transmission lines (500 kilovolts [kV] and 220 kV).

OIL AND GAS

Peru's energy production was relatively stable during the 1990s and early 2000s, with some crude oil and minimal natural gas production (Figure 14.7). Development of the Camisea natural gas field in 2004 revolutionised Peru's energy market, however, providing more than 98% of the economy's natural gas production and 60% of the natural gas liquids used for LPG production (Osinergmin, 2014). Primary energy production more than doubled from 2005 to 2016 (reaching 26 Mtoe) owing to the development of the Camisea field.

In 2016, Peru's TPES was dominated by oil (43%) and natural gas (38%). Natural gas production is used primarily for electricity generation and LNG exports, while most oil is consumed in transport. Traditional biomass remains the main fuel in buildings, accounting for roughly 8.3% of TPES in 2016. Peru's crude oil production is unable to meet refining needs, while at the same time refining capacity is unable to meet domestic demand for oil products.

As domestic crude oil production is unable to keep up with demand, around 70% of refinery intake is imported (MEM, 2016). Additionally, the total capacity of Peru's seven refineries (200 000 barrels per day or 9.6 Mtoe per year) is not enough to meet demand, resulting in net imports of some oil products as well. Diesel is the most imported liquid fuel, with net imports growing more than five-fold from 2005 to 2016, driven predominately by rapid transport growth. Conversely, gasoline, jet fuel and fuel oil production exceed domestic demand, resulting in Peru being historically a net exporter of these oil products.

ELECTRICITY

In Peru's National Integrated Electrical System (SEIN), which consists of more than 40 competing power generation companies, electricity rates are mostly based on marginal costs and free-market forces. The SEIN accounts for 96% of electricity generation in Peru, the remainder coming from isolated systems and own-energy consumption (MEM, 2016). Total power generation capacity was 15 GW in 2016, mainly gas-fired (51%) owing to the development of the Camisea gas field in 2004, but hydro power-based capacity also accounts for a large portion (35%) (Figure 14.5). Peru's power generation fuel mix is therefore not diverse, as it relies mainly on these two sources and only marginal amounts of oil, coal and non-hydro renewables. In 2016, hydro resources accounted for 47% of power generation and natural gas for 46%. The rest was divided almost evenly among oil, wind, coal, biomass and solar.

RENEWABLE ENERGY

While the electricity system has a significant amount of renewable energy by 2050, only 6.7% is generated from renewable sources other than hydro power (2.7 GW of installed capacity), despite the economy having non-hydro renewables potential of more than 35 GW (Osinergmin, 2017a). Peru has, however, enacted laws and regulations to promote renewable energy and set minimum renewables power shares every year (El Peruano, 2008). Moreover, the Osinergmin has successfully conducted four renewable energy auctions since 2015, which have resulted in wind, solar and modern biomass renewable projects. Nevertheless, much of the non-hydro renewable energy potential remains untapped.

In 2006, the Law to promote the use of renewable energy provided a tax reimbursement on electricity sales coming from renewable sources. In 2008, Peru Congress passed another law (1058), giving tax benefits

to investing participants in electricity generation based on renewable energy, including hydropower. Finally, the Law on Promotion of Investment for Electricity Generation with Renewable Energies was enacted in 2008 with relevant regulations for implementing this law. Some of the incentives provided by the law are as follows (El Peruano, 2008a, 2008b):

- The Ministry of Energy will impose every five years a minimum share of power generation coming from "new renewable" sources. This definition excludes hydropower plants bigger than 20 MW; therefore, this definition excludes most of the hydropower plants currently in operation;
- However, during the first five years, the renewable power generation share could not be bigger than 5% of the total power generation;
- A firm price guaranteed for bidders who are awarded energy supply contracts for up to 20 years;
- Priority in dispatch and access to networks;
- The drafting of a Peruvian Renewable Energy Plan.

In September 2015, a legislative decree modified the regulation on electricity distribution, including the possibility of a feed-in-tariff system for those who generate their own electricity based on non-conventional renewable technologies (El Peruano, 2015).

Table 9: Generation potential

Renewable energy source	Installed capacity (MW)	2017 Generation (GWh)	2017 share of total generation
Photovoltaic	280	287	0.5%
Wind	358	1 072	2.0%
Hydropower	4 896	29 090	55%
Biomass	33	401	0.8%

Sources: MEM (2018).

CLIMATE CHANGE

Peru's GHG emissions account for 0.11% of the world's total (CAIT, 2018) and its nationally determined contribution (NDC) 1 targets a 30% reduction in GHG emissions below a 2030 projection using 2010 emissions levels as the base year, 10% of which is conditional on receiving international financing (UNFCCC, 2015) (Figure 14.14). This translates into a GHG emissions reduction of 90 million tonnes of carbon dioxide (MtCO2), 53% of which comes from the forestry sector, including land use, land use change and forestry (LULUCF) activities. Peru's increases in energy demand have meant a 35% increase in energy-related CO2 emissions from 2005 to 2016.

Table 10: INDC for reduction of GHG emissions

	Emissions Mt CO2eq including LULUCF	Emissions Mt CO2eq excluding LULUCF
2010 (baseline year)	170	78
2030 (target year)	298	139

Source: MINAM (2016)

In parallel to the national goals expressed in the Peruvian INDC, several sectors have presented significant advances in regulations and programmes aimed to reduce carbon emissions and foster sustainable development.

[1] The Nationally Determined Contributions (NDCs) reflect policy action to support the agreement reached during the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change, or 'COP21 Paris Agreement'.

- The National Energy Plan 2014–25 projects providing natural gas access to residential users across Peru, as it is currently concentrated in Lima and a handful of other cities. LPG demand is expected to diminish in urban areas while increasing in rural regions (by substituting traditional biomass);
- In addition, the Ministry of Energy and OSINERGMIN are promoting the use of non-conventional renewable energies through annual auctions, giving priority to dispatching into the national electricity grid and ensuring price stability during the contract;
- In the transport sector, in 2014, the construction of Line 2 of Lima's Metro started with the goal of connecting 15 districts with an extension of 27 kilometres, projecting a daily consumption of 665 000 passengers by 2020;
- Industrial and Fishing Sectors: The regulation establishes that wherever natural gas connection is possible, fishmeal factories must use it instead of oil products. The MEM estimates that currently one-third of energy demand in this sub-sector uses natural gas as consequence of the new regulation;
- Forestry Sector: Since 2010, the forestry sector has a new regulatory framework, which aims to reduce deforestation and promote sustainable and efficient use of forestry resources; and
- Waste Management: The National Environmental Action Plan (PNAA) promotes the reuse, recycling and appropriate handling of solid municipal waste. The PNAA was implemented in 210 municipalities, recovering around 10 974 tons of solid waste per month.

Finally, Peru is designing eight nationally appropriated mitigation actions (NAMA's) as part of the National Strategy for Climate Change.

ENERGY SECURITY

Peru's heavy reliance on crude oil and oil product imports, lack of strategic diversification, heavy dependence on the Camisea gas and lack of redundancy of its transportation system are the main threats to energy security. Peru's widening crude oil reserve gap also highlights an opportunity to incentivise investments on the oil and gas upstream sector. Over half of domestic refining capacity is concentrated in a single refining complex, La Pampilla, while almost all other refineries and import terminals are located on the coast, where earthquakes and floods are common. In the natural gas sector, the Camisea field is responsible for 95% of natural gas production and 60% of LPG production. A limited network of pipelines transport both natural gas, which provide around 45% of Peru's electricity. These sectors are therefore severely exposed to disruption risks, particularly in the Amazon region, where there are no other transport alternatives and access to the region is extremely challenging.

According to the final report recommendations of the APEC Oil and Gas Security Exercise in Peru held in November 2017, the MEM and Peru's other relevant energy security institutions should work cooperatively to enhance energy security (APEC EWG, 2018). Recommendations also include enhancing data quality collection, diversifying crude oil and refined product import sources, and fully implementing and updating the Law to ensure energy security and to promote the development of the petrochemical industry (Law 29970) (El Peruano, 2012).

ENERGY ACCESS

The National Plan for Rural Electrification 2016–25 was established to provide energy access to vulnerable populations in remote rural areas. Peru has a diverse geography, with almost 25% of the population living in the Andes Mountain and the Amazon Region. Approximately 75% of the rural population has access to electricity. These regions gather the population with the lowest income levels and, accordingly, the highest poverty rates. The plan expects to generate energy access to 3.3 million people until 2025, investing around USD 1.2 billion in transmission and distributed generation systems.

Table 8: Investments according to the National Plan for Rural Electrification

	Investment (USD MM)	Population (Thousand)
2016	346	1000
2017	230	606
2018	136	351
2019	173	538
2020	94	226
2021	41	160
2022	60	230
2023	24	87
2024	24	87
2025	24	87
Total	**1 152**	**3 372**

Source: MEM (2015)

ENERGY EFFICIENCY

In 2000, the government passed the Law for the Promotion of the Efficient Use of Energy (Law 27345). Consistent with this legislation, the Peruvian Government promoted energy-saving measures in the public sector, such as by replacing less-efficient incandescent lamps with compact fluorescent lamps and acquiring equipment with energy efficiency labels.

In 2009, the MEM presented the Benchmark Plan for Efficient Use of Energy from 2009 to 2018. The plan aimed to reduce energy consumption by 15% from the 2007 levels by 2018 through energy efficiency measures. The plan included an analysis of energy efficiency in Peru and identified sector programmes that could be implemented to achieve the proposed targets. Actions outlined in the plan include lighting systems, replacement of boilers and engines as well as implementation of a labelling scheme for computers. To date, the implementation of the plan has been delayed owing to a shortage of audit firms and lack of incentives for the main stakeholders.

In May 2010, the Peruvian Government created the General Directorate for Energy Efficiency (DGEE), within the Vice-Ministry of Electricity (after the Ministry's restructure), as the technical regulatory body, proposing and assessing energy efficiency. The DGEE also leads the energy planning of the economy and is responsible for developing the National Energy Plan.

NUCLEAR

Although Peru does not use nuclear energy for electricity generation, a government-run nuclear energy programme has been operational since 1975. This programme includes constructing a basic infrastructure, human resources training and establishing the Peruvian Institute of Nuclear Energy. Peru has been a member of the International Atomic Energy Agency since its creation in 1957.

NOTABLE ENERGY DEVELOPMENTS

OIL AND GAS

Peru is expected to become more dependent on both crude oil and oil product imports as the rapid growth of the transport sector increases the consumption. To address this challenge, the government is overhauling the existing facilities of the Talara Refinery so that heavy oil can be refined domestically. The project, with a cost of around USD 3.5 billion, is expected to increase the refinery capacity from 65 to 95 thousand barrels per day (Mbbl/D).

The government is also encouraging state-owned companies to become more active in hydrocarbon exploration and production projects. MEM's plan for this includes reducing the time required to obtain

exploration permits and facilitating communication with local communities to help reduce protests against exploration and production of extractive activities.

As already stated, almost the totality of gas production in Peru is transported by a single pipeline, the Camisea gas pipeline. To diminish the vulnerability of depending on a single gas transport system and provide other regions access to this fuel, the Peruvian Government conceived the construction of an alternative gas pipeline transporting the Camisea field's gas to the South of Peru. The Peruvian Southern Gas Pipeline project involves the transport of gas produced in the Cusco Region to the southern coastal city of Ilo through a 1 000 km, 32-inch diameter pipeline system divided into three sections, making it one of the largest infrastructure projects in the economy's history (El Peruano, 2014). The project originally had thermal power plants, a petrochemical complex, industry and residential users as potential clients.

In 2014, the Peruvian Government awarded the contract to a consortium integrated by Brazilian company Oderbrecht and Spaniard Enagas. Construction started in 2015, but in January 2017, with 40% of construction complete, the Peruvian Government ended the contract after the consortium failed to meet its financial deadline. The consortium lost trust from banks financing the construction because of the ongoing investigation on alleged corruption cases of Oderbrecht in Brazil, Colombia, Mexico, Peru and other countries. As of March 2019, construction has not resumed, leaving this key energy sector project in limbo. The Peruvian While the government announced it will start a new bidding process, not concrete progress has been made public so far.

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Banco Central de Reserva del Perú—www.bcrp.gob.pe

Comité de Operación Económica del Sistema Interconectado Nacional—www.coes.org.pe

Instituto Nacional de Estadística e Informática—www.inei.gob.pe

Instituto Peruano de Energía Nuclear—www.ipen.gob.pe

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THE PHILIPPINES

INTRODUCTION

Owing to the recent discoveries, the Philippines archipelago now comprises 7 641 islands (Primer, 2017), covers a total land area of 343 448 square kilometres (km^2) (Government of the Philippines, 2018) and has a coastline of approximately 36 289 kilometres. The Philippines is located in the south-eastern part of Asia and is bordered by the Philippine Sea to the east and west, the Luzon Strait to the north and the Celebes Sea to the south. It has three major geographical divisions: Luzon, Visayas and Mindanao islands. Manila City, located in Luzon, is the capital of the Philippines. In 2016, the total population of the economy reached 103 million, an increase of 1.6% from the 2015 level (EGEDA, 2018). As per the 2016 World Population ranking, it is the 13th-most populated economy in the world (WB, 2017).

The Philippines maintained the 6.9% growth rate in its gross domestic product (GDP) from USD 699 billion in 2015 to USD 747 billion in 2016 (2011 USD purchasing power parity [PPP]) (EGEDA, 2018). Strong capital investment and robust domestic demand have helped secure the Philippines' position as the leading growth performer among major economies in East Asia and the Pacific, such as China; Indonesia; Malaysia, Thailand and Viet Nam. In 2016, the Philippines' economy was driven by the industry sector, overtaking the service sector. The government has also maintained a sound fiscal balance along a sustainable debt path (Briones, 2016). Continued high economic growth in the past few years is necessary for the fight against poverty. The GDP per capita also displayed a 5.2% growth, from USD 6 875 in 2015 to USD 7 233 in 2016 (EGEDA, 2018).

With a better economic outlook, the government faces a great challenge in ensuring energy supply stability to meet growing domestic consumption. Central to the policy of the government is the aggressive development and utilisation of indigenous energy resources for both fossil fuels and renewable energy (RE). The government has continued the Philippine Energy Contract Round (PECR) to attract investments in oil, gas and coal exploration. The economy has modest proven reserves of around 79 million barrels of oil (including condensate), 3.7 trillion cubic metres of natural gas and 468 million tonnes (Mt) of coal (DOE, 2017a).

Passing of the Renewable Energy Act of 2008 (RA 9513) offered fiscal and non-fiscal incentives to promote and encourage more investments in RE development and expand its share in the energy mix. Under the National Renewable Energy Programme (NREP), the government has set an aspirational target of more than doubling the RE-based installed capacity in power generation by 2030 from the 2010 levels or achieving 15 299 MW (2030 level) in comparison with 5 542 MW (2010 level). The government likewise intends to increase RE contribution for non-power applications in the primary energy mix by 2030 (DOE, 2011).

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c]	
Area (thousand km^2)	343	Oil (million barrels)	79
Population (million)	103	Gas (trillion cubic metres)	3.7
GDP (2010 USD billion PPP)	747	Coal (million tonnes)	468
GDP (2010 USD PPP per capita)	7 233	Uranium (kilotonnes U)	–

Sources: [a] Government of the Philippines (2018); [b] (EGEDA, 2018); [c] (DOE, 2017a).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

The economy's total primary energy supply (TPES) in 2016 significantly increased by 4.5% in comparison with the 2015 level, from 52 962 ktoe to 55 349 kilotonnes of oil equivalent (ktoe). Approximately 55% of

the energy requirement was produced locally, and the TPES was largely from RE (37%) and oil (34%). The economy's self-sufficiency level slightly increased from 53% in 2015 to 55% in 2016 (EGEDA, 2018).

Renewables—comprising hydro, geothermal, biomass and others—formed the bulk of TPES of the economy in 2016. Renewables decreased by 0.4% from 20 518 ktoe in 2015 to 20 445 ktoe in 2016. For the last seven years from 2010 to 2016, renewables has increased by 2.1% from 18 022 ktoe to 20 445 ktoe (EGEDA, 2018).

Oil remained the second dominant energy source, accounting for 34% of the TPES. The economy's oil supply requirement significantly grew by 3.4% in 2016, reaching 18 548 ktoe from 17 933 ktoe in 2015 (EGEDA, 2018).

Coal provided the third-largest share to the TPES at 24%, which was an increase of 12% from the 2015 level to reach 13 086 in 2016. The coal industry has never been so robust than the past few years. Domestic production continues to increase at a steady rate and reached 5 917 ktoe in 2016, the largest since 2002 (EGEDA, 2018). This uptrend may be attributed to the conversion of exploration contracts into production agreements, as well as the development of production contracts into full-blown operations. Consumption, likewise, steadily increased as new coal-fired power plants were installed and industries switched to coal because of the highly volatile price of oil (DOE, 2016a).

FOSSIL ENERGY

The economy heavily relies on fossil fuels imports, specifically oil and coal, to meet its energy consumption requirement. The net imports in 2016 slightly grew by 2.0% from 26 118 ktoe in 2015 to reach 26 645 ktoe in 2016. Oil constituted nearly 70% of the total energy imports, whereas coal represented 33% and bioethanol constituted. The increase in oil imports was due in part to high demand for oil in the transport sector (EGEDA, 2018).

The increase in coal production consequently resulted in the remarkable rise of coal exportation in 2016 (120.0%) compared with the 2015 level. However, due to the poor quality of indigenous coal, the Philippines needed to import coal which likewise posted an expansion of 16.0% to 10 571 ktoe in 2016 from 9 120 ktoe in 2015 (EGEDA, 2018). While more than 50% of domestic coal went to China, more than 50% of imported coal came from Indonesia in 2016, which was mainly used for power generation (78%) (DOE, 2016a).

RENEWABLE ENERGY

RE has long been a significant contributor to the economy's energy supply requirement, providing 37% to the TPES in 2016 although it declined from 20 518 ktoe in 2015 to 20 445 or equivalently –0.35%. Renewable sourced from biomass and geothermal were the largest, with both comprising 32% of the total RE in 2016 (EGEDA, 2018).

While the total RE witnessed a break from the past two years' increases, wind and solar continued to register a robust growth in 2016 by 134% to reach 178.21 ktoe from 76.28 ktoe in 2015. Biofuels and geothermal likewise posted positive growth at 17.0% and 0.2%, respectively. Biomass declined by 2.0% in 2016 compared with the 2015 level to reach 9 571.8 ktoe, which offset the increases posted by RE sources mentioned above in view of its significant share from the total RE (32%). Hydro also contributed to the contraction of RE in 2016, with –6.4% dip from the 2015 level (EGEDA, 2018). The significant expansion in wind and solar may be attributed to the numerous projects awarded for implementation in 2016—59 and 166, respectively— under the RE Law (DOE, 2016b).

ELECTRICITY GENERATION

In 2016, the economy's total electricity generation was up by 10% from 82 413 GWh in 2015 to 90 798 GWh. The Philippines mostly relied on fossil fuels for power generation, with more than 70% of its power generation in 2016. Coal was still the dominant fuel for the economy's baseload requirement, accounting for 45% of the total power supply in 2016 (EGEDA, 2018) Natural gas also continued to provide a substantial share at 22%. Almost all the natural gas power-generation capacities are located in Luzon Island, supplying around 23% of the Luzon grid requirement (DOE, 2016c). Meanwhile, oil-based power plants had a modest share of 6% during the same period.

Renewables in electricity generation increased by 4.8% to 21 979 GWh in 2016 from 20 963 GWh. The significant progression of wind and solar contributed to the growth of power generation from RE, with more than twofold increase (123.1%) in 2016. This had offset the 6.4% slide recorded by electricity output from hydro—from 8 665 GWh in 2015 to 8 110 GWh in 2016 (EGEDA, 2018). The El Niño phenomenon continued to cause the decline in hydropower generation, which adversely affected Mindanao area, the region that mostly relied on hydro for power generation (DOE, 2016c). The remarkable surge of power generation from solar, wind and biomass (244%) from 2014 to 2015 can be attributed to the feed-in-tariff (FiT) race brought by the economy's RE Law (DOE, 2015).

Table 2: Energy supply and consumption, 2016

Primary Energy Supply (ktoe)		Total Final Consumption (ktoe)		Power Generation (GWh)	
Indigenous production	30 163	Industry sector	7 450	Total power generation	90 798
Net imports and others	26 645	Transport sector	11 460	Thermal	68 818
Total primary energy supply	55 349	Other sectors	13 351	Hydro	8 111
Coal	13 068	Non-energy	1 306	Nuclear	0
Oil	18 548	Final energy consumption*	32 261	Others	13 869
Gas	3 270	Coal	2 677		
Renewables	20 445	Oil	15 463		
Others	0	Gas	65		
		Renewables	7 679		
		Electricity and others	6 377		

Source: (EGEDA, 2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

The 6.9% growth of the Philippines economy in 2016 translated to an 8.9% increase in the total final consumption (TFC—including non-energy), reaching 33 567 ktoe in 2016 from 30 834 ktoe in 2015. All economic sectors posted an increase in their fuel consumption during the same period. The TFC was driven by the transport sector, with 12% expansion from 10 194 ktoe in 2015 to 11 460 ktoe in 2016. The buildings sector (residential, commercial and agriculture and others combined) comprised the bulk of TFC, with 40% share of the total.

The transport sector's energy use accounted for 34% of the TFC in 2016. Of the total oil products, diesel formed the major share at 56% followed by gasoline at 37%. Consumption in the industry sector reached 7 450 in 2016 and, if non-energy was included, 8 756 ktoe or 26% of the TFC. Coal continued to form the dominant fuel in the industry sector (36%), with cement manufacturing (77%) as the major user (EGEDA, 2018).

In the buildings sector consumption, while the residential sector occupied 27% (9 035 toe) of the sector's total consumption, the commercial sector grew the largest at 14.6% to reach 3 865 in 2016. RE, which formed the bulk of the buildings consumption (63%), posted a contraction (–5.6%) in 2016. Oil and electricity offset the decline in RE use in the buildings sector with a robust 15.4% and 12.7% increases, respectively.

In 2016, fossil fuel consumption remarkably grew, with gas posting the biggest growth at 29.1%, followed by coal and oil at 20.7% and 13.7%, respectively. Oil continued to account for the dominant fuel in the Philippines in 2016 at 48% of the total final energy consumption (TFEC). RE, which was the second-largest fuel (24%) in the economy, seen a 3.5% decline in 2016 from 7 955 ktoe in 2015 (EGEDA, 2018).

ENERGY INTENSITY ANALYSIS

In 2016, while primary energy intensity improved by 2.2%, final energy intensity was positive at 1.8% compared with the 2015 level (EGEDA, 2018). The positive final intensity can be attributed to the significant increases in the fuel consumption in 2016. The increasing power to purchase vehicles and major appliances had boosted the consumption in the transport and buildings sectors. Consequently, final intensity reached 43 toe/million USD in 2016.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	76	74	-2.2
Total final consumption	42	43	1.8
Final energy consumption excl. non-energy	44	45	1.9

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Owing to the RE Act of 2008, which aimed to triple the level of RE sources in the Philippines by 2030 in comparison with the 2010 level, renewables use in the economy has significantly accelerated. Between 2010 and 2015, modern renewables posted an upward trend of 4.1% compounded annual growth rate. In 2016, modern renewables posted a 4.4% expansion to reach 3 175 ktoe from 3 041 ktoe in 2015. Considering the share of the TFEC, however, it contracted to 9.8% from the 2015 level of 10%. The substantial upswing in the share of fossil fuels to the final energy consumption may have offset the share of renewables in TFEC in 2016 (EGEDA, 2018)

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	29 655	32 261	8.8
Non-renewables (Fossils and others)	20 217	23 038	14
Traditional biomass*	6 397	6 049	–5.5
Modern renewables*	3 041	3 175	4.4
Share of modern renewables to final energy consumption (%)	10	9.8	–4.0

Source: EGEDA (2018)

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The government recognises the importance of energy to boost the economy's inclusive growth and development. The Department of Energy (DOE) has been at the forefront of formulating responsive energy plans and programmes to address the many issues and challenges of ensuring energy supply security and expanding access to energy for the greater public to improve local productivity and fuel rural development. In line with President Rodrigo Duterte's *Ambisyon Natin 2040*, envisioning a 'stringly-rooted, comfortable,

and secure life' for all Filipino's by year 2040, the DOE laid down eight Energy Sector Strategic Directions (ESSDs) to set the tone of the department's policy track for the next 22 years (Figure 1).

Figure 1: Eighth Energy Sector Strategic Directions



Under the guidance of the ESSD, the government through DOE aims to achieve the following indicative targets:

- Ensure basic electricity access for all by 2022;
- Adopt a technology-neutral approach to achieve an optimal mix;
- Improve power supply reliability to meet demand needs by 2040;
- Develop LNG in anticipation of the forthcoming depletion of Malampaya Gas;
- Facilitate the completion of transmission projects by 2020;
- Ensure a pro-consumer distribution framework for affordability, choice and transparency;
- Streamline domestic policy to cut red tape;
- Privatise the Power Sector Assets and Liabilities Management Corporation; and
- Promote efficient energy use among consumers through information, education and communication campaigns.

Meanwhile, the Philippine Energy Plan (PEP) 2017–2040 serves as DOE's blueprint to secure the economy's energy future. The PEP was created after a thorough review of the current energy agenda as well as inclusion of inputs from regional consultation conducted by the DOE. The formulation of the PEP paved the way for the identification of sectoral energy roadmaps, consisting of short-term (2017–2018), medium-term (2019–2022) and long-term (2023-2040) strategies, which will be discussed under the respective sectors (DOE, 2017b).

ENERGY MARKETS

OIL AND GAS

To promote and encourage investments in the exploration of the economy's 16 sedimentary basins (with combined oil and gas reserves of 4 777 million barrels of oil equivalent or 690 million tonnes of oil equivalent [Mtoe]), the government through the DOE issues petroleum service contracts (PSCs) to oil and gas investors. As of the end of 2017, there were 23 PSCs, of which 7 PSCs are in the production stage and the remaining 16 PSCs in the exploration stage (DOE, 2017c).

The economy's existing oil fields produced 1.587 million barrels (Mbbl) in 2017, a 21.2% drop from the 2016 level (2.014 Mbbl). The reduction is attributable to the lower production output reported from the

economy's major oil fields—Matinloc, Galoc and Malampaya (DOE, 2017d). Similar trends were observed from gas and condensate production in the same year. Malampaya produced 138.5 Tcf of gas (-1.4% drop from the 2015 level) and 3.914 Mbbl of associated condensate (–5.4% lower than the 2015 level). Gas produced from Malampaya is mostly used to fuel three natural gas power plants (with an aggregate capacity of 2 861 MW) located in Luzon Island (DOE, 2017d).

There are two existing petroleum refineries in the Philippines with a combined capacity of 285 000 barrels per day. During the first half of 2017, 272 players and investments in the downstream oil industry were recorded (DOE, 2017c). In the same year, the refining output reached 77.2 million barrels (MMB), down from 79.0 MMB in 2016 (DOE, 2017h).

The government continued to enforce the minimum inventory requirement (MIR) given the continuing risks faced by the downstream oil industry sector, such as geopolitical instability and supply delivery problems to areas affected by calamities. Current MIR for refiners is in-country stocks equivalent to 30 days, while an equivalent of 15 days stock is required for the bulk marketers and 7 days for the LPG players (DOE, 2017b).

COAL

The economy has 13 coal basins with an estimated total resource potential of 2.4 billion metric tonnes. The largest coal resources are found in Semirara, Antique, with a total potential of 570 million metric tonnes (Mmt). However, the economy's coal resources are low-ranking coal. Therefore, there is a high dependency on imported coal (high-ranking), which is used by the coal power plants. To reduce dependency on imported coal, the government has been pursuing efforts to expand the utilisation of indigenous coal as well as the adoption of local coal quality upgrading technologies such as coal washing, preparation and blending to meet the environmental standards. Further, the government is exploring alternative uses of local coal through assessing the coalbed methane potential of selected coal fields. A significant portion of local coal production is mostly exported to China.

Prior to the Philippine Conventional Energy Contracting Program (PCECP), the government issued Coal Operating Contracts (COCs) for coal exploration and development, and in 2017, there were 70 active COCs—40 in the exploration stage and 30 in the development and production stage.

MARKET REFORMS

ELECTRICITY

Electric Power Industry Reform Act of 2001 (or Republic Act 9136)

The government continuously oversees the implementation of power sector reforms, as mandated in the Electric Power Industry Reform Act (EPIRA) of 2001 (or Republic Act 9136). Among the current accomplishments of the power sector under EPIRA was the privatisation of remaining National Power Corporation (NPC) generating assets and independent power producer (IPP) contracts, including other disposable assets continued to be undertaken by Power Sector Assets and Liabilities Management Corporation (PSALM) with indicative target to complete the disposal by 2019 (DOE, 2017g). Under EPIRA, Rule 14 of the EPIRA introduced the Qualified Third Party (QTP) Program to allow private sector participation, as alternative service providers in areas deemed unviable by the distribution utilities. There are currently four QTP projects that are already operational and managed by two private firms. The government is likewise working on a draft circular amending previous QTP circulars to streamline the processes and guidelines for the participation of QTPs in remote/missionary electrification (DOE, 2017b; DOE, 2017g).

Wholesale Spot Market

The Reform Act of 2001 likewise calls for the establishment of an independent market operator (IMO) to ensure the competitiveness and transparency of the Wholesale Electricity Spot Market (WESM). In this regard, the DOE has drafted the circular, 'Adopting Policies for the Effective and Efficient Transition to the IMO for the Wholesale Electricity Spot Market', which lays down the general policies for the Philippine Electricity Market Corporation (PEMC) to abide by in establishing the IMO. One of the important development in the WESM was the issuance of Department Circular No. DC2017-05-0009 on 4 May 2017, declaring the launch of the WESM in Mindanao and its transition guidelines (DOE, 2017b). The DOE

assessed the possibility of implementing a 'demand aggregation and supply auctioning policy' (DASAP) for the electric power industry. The objective of this policy is to achieve greater transparency and reasonableness in electricity tariffs and encourage greater participation from the generation sector in providing adequate power supply in each franchised area served by the distribution utility. In lieu of the non-issuance of the DASAP, the DOE issued a Department Circular (DC 2015-06-0008) in June 2015 entitled 'Mandating All Distribution Utilities to Undergo Competitive Selection Process (CSP) in Securing Power Supply Agreements (PSA)' (DOE, 2016c). The circular mandates all distribution utilities to undergo CSP through a third party duly recognised by the DOE and Energy Regulatory Commission (ERC). In Electric Cooperatives (ECs), the National Electrification Administration (NEA) should recognise the third party (DOE, 2016a).

Household Electrification

The household electrification level as of October 2017 is around 90.7%. (DOE, 2017g). To support the government's goal to achieve total electrification in the economy, the DOE launched the Nationwide Intensification of Household Electrification (NIHE) in partnership with distribution utilities and local government units (DOE, 2017b).

OIL AND GAS

Upstream Oil and Gas Roadmap 2017–2040

The roadmap has an overall goal of increasing indigenous petroleum reserves to 57.12 MMB of oil, 5.87 of TCF gas and 56.81 MMB of condensate and producing 115.37 MMB of oil, 4.04 TCF of gas and 45.93 MMB of condensate to contribute to the economy's energy requirements.

The government introduces a new scheme for perspective investors— the PCECP. The PCECP aims to maximise the exploration and development of indigenous petroleum and coal resources through the transparent and competitive evaluation, as well as awarding of PSCs and COCs.

Downstream Oil Industry Roadmap 2017–2040

The roadmap aims to improve the policy governing the downstream oil industry to ensure continuous supply of high quality and right quantity of petroleum products in the market. One of its strategies is the development of fuel quality standards.

Downstream Natural Gas Roadmap 2017–2040

The roadmap of downstream natural gas industry aims to establish a world-class, investment driven and efficient natural gas industry that makes natural gas the preferred fuel by all end-use sectors.

To help realise the objectives of the roadmap, the DOE issued the Department Circular No. DC2017-11-0012 or the Philippine Downstream Natural Gas Regulation (PDNGR), establishing the rules and regulations governing the downstream natural gas industry in the economy. This includes infrastructure siting, design, construction, expansion, modification, operation and maintenance. It also seeks to ensure the continued operations of other gas-fired power plants once Malampaya runs dry. In addition to promoting the use of natural gas to meet the growing energy demands in Asia Pacific, PDNGR also intends to transform the Philippines as a regional LNG trading and transhipment hub. In anticipation of the eventual depletion of the Malampaya gas field by 2024, an integrated LNG receiving and distributing facility with a reserve initial power plant capacity of 200 MW will be constructed to ensure the continuity of power supply from natural gas (DOE, 2017b).

The final draft of the Natural Gas Quality Standard was published in February 2015 and was endorsed by the Bureau of Philippine Standards. This standard is necessary for more efficient supply acquisition and distribution of natural gas in the economy. In November 2015, the DOE signed a memorandum of understanding with other government agencies to establish the Inter-Agency Health, Safety, Security and Environment Inspection and Monitoring Team for natural gas facilities (DOE, 2016).

The economy has not yet promulgated a comprehensive policy and regulatory frameworks to govern the development of the downstream natural gas industry. The Natural Gas Bill is still pending in both the Houses of Congress.

The Philippine National Oil Company (PNOC) commissioned the Public–Private Partnership Centre (PPPC) for the detailed feasibility study of the 105-km Batangas–Manila pipeline (BatMan 1) to supplement the JICA (Japan International Cooperation Agency) study completed in June 2014 (DOE, 2016a). The JICA performed a feasibility study for the entire natural gas supply chain in the economy, which covered the LNG facility, regasification facility, pipeline and offtake facilities, among others. The PNOC availed upon the Project Development and Monitoring Facility (PDMF)1 from the PPPC to source funds in engaging the expertise of the Rebel Group International as its transaction advisor. The pipeline potential route corridors were identified by the transaction advisor. From the results of the route analysis, the most appropriate route will be proposed to bring the natural gas from Batangas' proposed LNG terminal to the nodal gas consumption located alongside the pipeline route through the Manila metropolis (DOE, 2016a).

COAL

Coal Roadmap 2017–2040

This roadmap aims to increase indigenous coal reserves of the economy to 766 milion metric tonnes (MMMT) and 282 MMMT production by 2040 to contribute to the Philippines' energy requirements. As mentioned in the upstream oil sector, a PCECP will also be issued to prospective investors for coal exploration. On 13 September 2017, the PCECP for coal has already been issued through Department Circular No DC2017-09-0010 (DOE, 2017b).

ALTERNATIVE FUELS

Alternative Fuels and Energy Technologies Roadmap 2017–2040

The roadmap indicates government's overall long-term plans and strategies to attain the efficient management of energy resources through fuel diversification and adoption of new and advance energy technologies. It also envisions the successful adoption and commercialisation of alternative fuels and energy technologies through strong and collaborative partnership with the private sector and full government support in providing enabling mechanism and building-up local capacity for research and development in emerging energy technologies (DOE, 2017e).

The enactment of the Biofuels Act in 2006 mandates the current 2% biodiesel blend (B2) and 10% bioethanol blend (E10) in all diesel and gasoline fuels sold in the economy. The DOE in cooperation with the University of the Philippines–Los Baños conducted a study entitled 'Economic Impact in the Increased Use of Biodiesel in the Philippines' to evaluate the effect of increasing the utilisation of biodiesel and the impact of the nationwide implementation of 5% biodiesel blend (B5) in the economy. The economy has also planned to increase the biodiesel blend to 20% (B20) by 2025 and the bioethanol blend to 20% (E20) in 2020.

Under the government's Natural Gas Vehicle Programme for Public Transport (NGVPPT), the DOE is closely working with the Department of Transportation (DOTr) and the Land Transport Franchise Regulatory Board to issue franchises for 169 CNG buses. In March 2015, the DOTr declared the availability of these franchises under the NGVPPT. Likewise, the DOE is coordinating with the natural gas suppliers for the supply of CNG fuel until 2023. The DOE also directed the PNOC-Exploration Corporation (PNOC-EC) to take over the operation of the CNG refuelling station.

As for the Auto-LPG programme, the DOE signed a MOA (Memorandum of Agreement) with two academic institutions in December 2014 to train proficient technicians who will be involved in migrating from gasoline-fed to auto-LPG vehicles, including the repair and maintenance of such vehicles. The DOE has been coordinating with the concerned national government agencies for the promotion and mainstreaming of auto-LPG in the transport sector to diversify the economy's utilised fuel sources.

[1] The Philippine government, with assistance from Asian Development Bank (ADB), has established a PDMF to fund transaction advisory services for the development of PPP projects, which include energy and social projects, such as road networks, school buildings, airports and hospitals, among others.

ENERGY EFFICIENCY

ENERGY EFFICIENCY AND CONSERVATION ROADMAP 2017–2040

The DOE approved the implementation of the Energy Efficiency and Conservation Roadmap in July 2014 and revised the roadmap in 2017 to ensure the achievement of the overall energy efficiency and conservation objective by 2040. The roadmap will provide more sustainable and long-term policy directions on energy efficiency and conservation.

The government has continuously implemented the National Energy Efficiency and Conservation Programme, launched in 2004, as the banner programme on various initiatives on energy efficiency and conservation. This programme includes the following projects (DOE, 2015):

- Energy Efficiency Standards and Labelling Programme;
- Government Energy Management Programme;
- Energy Management Services/Energy Audits;
- Fuel Conservation and Efficiency in Road Transport; and
- Power Conservation and Demand Management (Power Patrol), among others.

The DOE has pursued the accreditation of energy service companies (ESCOs) to promote emerging business industries in the economy. As of 2105, the economy had 15 accredited ESCOs to help accelerate the implementation of energy efficiency and conservation measures in the private sector. The DOE also offers audit services to manufacturing plants, commercial buildings and other energy intensive companies to evaluate the energy utilisation efficiencies of equipment, processes and operations and to recommend energy-conservation measures for adoption by these companies.

The DOE has implemented the Philippine Industrial Energy Efficiency Project in partnership with the United Nations Industrial Development Organisation and the Department of Trade and Industry. The Global Environmental Fund provided funding for this project. The project will introduce the application of ISO 50001 to selected industrial sectors, such as chemicals, food and beverage, iron and steel and pulp and paper. The project could save approximately 2 million megawatt-hours of energy (DOE, 2016a).

In its ongoing efforts to promote awareness on fuel efficient vehicle technology, the DOE in coordination with Petron Corporation conducted the 13th DOE Fuel Economy Run on 20–21 November 2017. A total of 55 participants using various vehicles participated in the event (DOE, 2017b).

RENEWABLE ENERGY

RENEWABLE ENERGY ROADMAP 2017–2040

The roadmap aims to increase RE installed capacity to at least 20 000 MW by 2040. Government efforts to promote and expand the use of RE as a clean and sustainable energy source for the public became evident with the formulation and adoption of the NREP in 2011. The NREP outlines the strategy and measures to facilitate greater private sector investment in RE development, including addressing the challenges and gaps to effect wider application and utilisation of renewables. Other policy mechanisms as stipulated in the RE Act of 2008 have been implemented or are in the process of on-going implementation, such as

- FiT;
- Renewable Portfolio Standards (RPS);
- Green Energy Option Programme; and
- Net Metering for RE

Upon recommendation of the DOE, the ERC promulgated the FiT rules and FiT rates based on the set installation targets. The ERC approved the initial FiT rates in July 2012. FiT rates are subject for review and readjustment after three years of implementation or once the DOE installation targets have been achieved. In August 2014, the DOE issued a certification for an increase in the FiT installation target for

solar energy from 50 MW to 500 MW, including lower FiT rates for the additional capacity. The FiT installation target for wind was also increased in April 2015 from 200 MW to 400 MW. The increases in solar and wind installation targets brought the total targets to 1 410 MW, which are as follows:

- 250 MW Run-of-River Hydropower
- 250 MW Biomass
- 400 MW Wind
- 500 MW Solar
- 10 MW Ocean

The RPS is a market-based policy requiring mandated electric power industry participants to restore RE share in the national energy mix to 35% by 2030–2040. In the RPS, the mandated industry participants are the generators, distribution utilities and electric suppliers. The Green Energy Option Programme enables end-users to choose RE resources as their primary source of energy. Net Metering is a consumer-based RE incentive scheme wherein the electric power generated by an end-user from an eligible on-site RE generating facility and delivered to the local distribution utility can be used to offset electricity provided by the distribution utilities to the end-user during the applicable period. On 22 December 2017, the Philippine On-Grid Rules was published through Department Circular No. DO2017-12-0015, while the RPS rules for off-grid areas drafted by the National Renewable Energy Board was in circulation for comment (DOE, 2017b). As of December 2017, there were 869 RE service contracts awarded for different RE projects (including 41 projects for own-use) with 23 780.69 MW of potential capacity (DOE, 2017f).

NUCLEAR

It has long been a policy of the government to study all possible and potential energy resources to diversify the economy's energy supply mix and provide high-quality, reliable, adequate, secure and reasonably priced energy. As such, the present government administration is open to studying nuclear energy as an option for power generation. In November 2016, Secretary Alfonso Cusi signed an order creating the Nuclear Energy Programme Implementing Organisation (NEPIO). The NEPIO is headed by a steering committee with the DOE officials at the helm, whereas the DOE bureaus will create technical working groups to ensure effective and timely implementation of its functions and responsibilities. Soon, NEPIO will come up with a roadmap for nuclear power development in the economy. It will also study the possibility of reopening the Bataan Nuclear Power Plant, which has been in 'mothball' status since 1986 (GMA News, 2016).

Advancements in nuclear energy technology and enhancements in safety and safeguard standards, based on the lessons learned from the Fukushima incident in Japan, could encourage the economy to adopt a nuclear energy policy in the future.

CLIMATE CHANGE

In 2009, the government created the Climate Change Commission via the Philippine Climate Change Act of 2009 (RA 9729). The Climate Change Commission serves as the policymaking body under the office of the President and carries the status of national government agency. The Commission's primary functions are to monitor and evaluate programmes and action plans related to climate change.

In the twenty-first session of the Conference of Parties (COP21) of the United Nations Framework on Climate Change, the Philippines expressed an intention to reduce CO_2 emissions by 70% by 2030 relative to the level in 2000. This is relative to its BAU scenario of 2000–30, as indicated in the economy's Individual Nationally Determined Contributions. The abovementioned commitment is conditionally based on the availability of financial resources, technology development and transfer and capability building. Energy is one source of CO_2 reduction together with the transport, waste, forestry and industry sectors (UNFCCC, 2015).

NOTABLE ENERGY DEVELOPMENTS

POWER AND RENEWABLE ENERGY

The Access to Sustainable Energy Programme (ASEP) aims to support the Philippine Government in implementing policies and programmes that will generate more electricity from RE and implement innovative approaches to increase access to electricity for the poor and unenergised households through reasonable and disaster-resilient energy technologies. It involves capacity building and institutional support to key agencies such as the DOE, ERC and NEA in implementing reforms in policies and programmes for rural/household electrification, RE development, and promotion of decentralised energy solutions for climate-vulnerable communities, particularly in Visayas and Mindanao.

The photovoltaic (PV) mainstreaming is one of the projects of ASEP providing investments for rural electrification using solar home systems for an estimated 40 500 households within the coverage areas of the participating electric cooperatives. Another project is Geographic Information System (GIS) for rural electrification and RE projects. Some of the functions of this GIS platform are as follows:

- Preparing maps showing the existing electricity infrastructure and the locations of non-electrified households in EC franchise areas;
- Preparing maps showing the RE potential for electricity production; and
- Trying to compute, if possible, indicators for electrification planning (screening models).

Meanwhile, the Greening the Grid Project intends to conduct a grid integration study for variable RE to identify the potential grid reliability concerns with the scaling of variable RE and the options for improving system flexibility and power system balance.

In the last EWG 53 Meeting held in November 2017 in Wellington, New Zealand, the Philippines reported their hosting of the ASEAN summit in August 2017. The Philippines also mentioned the recent executive order issued by the President where energy projects are categorised as a national priority.

ENERGY EFFICIENCY

On 16 January 2019, the Energy Efficiency and Conservation (EE&C) Act was finally approved after 30 years during the Bicameral Conference Committee Hearing held at the Senate of the Philippines. The Act aims to standardise energy efficiency and conservation measures in the economy by regulating the use of energy efficient technologies in buildings. It provides for the Local Energy Efficiency and Conservation Plan as well as includes Energy Conserving Design on Buildings in the issuance of building permits. An Inter-agency Energy Efficiency and Conservation Committee will also be created for the implementation of the Government Energy Management Program (GEMP), which aims to reduce government agencies' consumption of electricity and petroleum products (DOE, 2019).

The DOE is the finalising the Philippine Energy Standards and Labelling Programme (PESLP), which will significantly contribute towards achieving the target to reduce energy intensity by 40% in 2030 with 2005 as the base year. The PESLP will cover a wide range of appliances and lighting systems to include even light duty motor vehicles. Currently, the PESLP only covers room air conditioners, split-type air conditioners, refrigerators with 5–8 cubic feet storage capacity, three types of fluorescent lamps (compact fluorescent, linear and circular) and electronic ballasts. In April 2016, the DOE issued a Department Circular prescribing the guidelines for minimum energy, 'Performance Standards and Strengthening the Philippine Energy Standards and Labelling Programme (PESLP)'.

PENDING ACTIONS

The DOE has been pursuing several legislative agendas to enhance the economy's energy policies and regulatory frameworks. The following energy bills have been filed or will be re-filed in both the Houses of Congress:

- Downstream Natural Gas Industry Development Act;

- Liquefied Petroleum Gas (LPG) Industry Regulation and Safety Act;
- Amendments to the EPIRA of 2001 or Republic Act No. 9136;
- Amendments to the Petroleum Act of 1949 or Republic Act No. 387; and
- Amendments to Presidential Decree (PD) 87 or the Oil Exploration and Development Act of 1972.

Some of the energy bills are simply amendments to provide the existing framework and additional fiscal and non-fiscal incentives to encourage private investments.

ENERGY SECTOR INNOVATION

E-POWER MO CAMPAIGN

The DOE initiated the E-Power Mo campaign in partnership with the Presidential Communications Operations Office, the Philippine Information Agency and United States Agency for International Development's (USAID) Building Low Emission Alternatives to Develop Economic Resilience and Sustainability (B-LEADERS) Project.

The campaign takes on a more inclusive approach in securing the economy's energy future by calling for the participation of all energy stakeholders—government agencies, members of the private sector and the academe as well as consumers in developing and utilising energy resources.

E-Power Mo consists of three subcampaigns:

- E-Safety Mo reminds consumers of safety measures to be used and the promotion of energy savings through efficient energy use;
- E-Secure Mo safeguards the delivery of quality, reliable and affordable energy services; it also supports the energy resiliency efforts of the government; and
- E-Diskarte Mo empowers consumers with a wide range of options in utilising conventional, renewable and alternative energy sources by utilising current and emerging energy systems being pursued by the DOE

The campaign was launched on 12 July 2017 during the Energy Consumers and Stakeholders Conference held at the Philippine International Convention Centre, which was attended by 800 participants (DOE, 2017b).

POLICY INITIATIVES

EXECUTIVE ORDER (EO) NO. 30

An order signed by the President of the Philippines on 28 June 2017 created the Energy Investment Coordinating Council (EICC) to streamline the regulatory procedures affecting energy projects. Specifically, the EO features the following (DOE, 2017b):

- Classification of Energy Projects of National Significance (EPNS);
- Establishment of a simplified approval process and harmonisation of the relevant rules and regulations of all government agencies;
- Preparation of rules governing the resolution of inter-agency issues affecting the timely and efficient implementation of EPNS; and
- Maintenance of a database of information and web-based monitoring system.

POLICY ON RESILIENCY PLANNING AND PROGRAM

The Philippines is among the most disaster vulnerable countries in the world. Recognising this situation, the DOE pursued the creation of an energy resiliency policy namely, "Adoption of Resiliency Planning and Program in the Energy Industry to Mitigate Adverse Effects Brought About by Disasters". This policy requires all energy players to mainstream disaster risk reduction programmes into planning and investment.

This would safeguard the delivery of energy services and strengthen existing energy infrastructure. It is guided by the following principles:

- Acknowledge the need to strengthen existing energy infrastructure, facilities and systems to prepare/mitigate the impact of disasters;
- Build back better in the reconstruction and rehabilitation of damaged infrastructure;
- Improve existing operational and maintenance procedures to preserve energy supply and assure continued operations; and
- Develop resiliency practices, systems and standards as future basis for the construction of energy facilities.

The policy was formally launched on 12 July 2017 at the E-Power Mo campaign. In October 2017, a series of nationwide public consultations with various energy stakeholders were conducted (DOE, 2017b).

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USEFUL LINKS

Asian Development Bank—www.adb.org

Climate Change Commission (CCC)—climate.gov.ph/

Department of Energy, Republic of the Philippines (DOE)—www.doe.gov.ph

Department of Science and Technology (DOST)—www.dost.gov.ph/

Department of Transportation and Communication (DOTC)/Land Transportation Franchising and Regulatory Board (LTFRB)—www.dotc.gov.ph

National Power Corporation (NPC)—www.napocor.gov.ph/

National Transmission Corporation (TransCO)—www.transco.ph/

Philippine National Oil Company (PNOC)—www.pnoc.com.ph/

Wholesale Electricity Spot Market (WESM)—www.wesm.ph/

RUSSIA

INTRODUCTION

Russia is the world's largest economy, spanning over 17 million square kilometres (km²) (GKS, 2018a). It is located in both Eastern Europe and Northern Asia, surrounded by the Arctic and the North Pacific oceans. It spans over 4 000 km from north to south and nearly 10 000 km from west to east. On land, Russia borders with 16 economies and with two economies on sea. Its territory is characterised by broad plains west of the Urals, vast coniferous forests in Siberia, tundra along the Arctic seaboard and uplands and mountains in the southern regions. Russia's vast natural resources include major deposits of coal, natural gas, oil and other minerals. Despite its land-area advantage, two-thirds of the economy is a zone of high-risk agriculture, primarily owing to its continental climate, which is either too cold or too dry.

From 1990 to 2008, the Russian population declined from 148 million to 143 million; however, from 2009 to 2016, the population increased to 144 million (EGEDA, 2018). Approximately 74% of the population resides in urban areas. Russia's average population density is 8.4 people per km², with nearly 80% of the population living in the European part of the economy (GKS, 2018a).

Following the global financial crisis and dropped crude oil prices, Russia's GDP declined by 7.8% in 2009 from the 2008 level. Then, it grew at 3.2% per year in 2010–14, until structural issues with the economic system, sharp decline in the price of crude oil on international markets and unavailable foreign capital owing to international sanctions imposed by the European Union and the USA led to decline at –2.8% in 2016 and –0.22% in 2017.

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c, d]	
Area (thousand km²)	17.1	Oil (billion barrels)[b]	106
Population (million)	144	Gas (trillion cubic metres)[b]	35
GDP (2011 USD billion PPP)	3 581	Coal (billion tonnes)[c]	160
GDP (2011 USD PPP per capita)	24 811	Uranium (kilotonnes U)	328

Sources: [a] GKS (2018a); [b] EGEDA (2018); [c] BP (2018); [d] NEA (2018).

Note: Data from Nuclear Energy Agency (NEA) is used for uranium reserves recoverable at a production cost of less than 260 USD per kg.

Russia's major industries include oil and gas production, petroleum refining, mining, iron and steel, chemicals and machinery. The economy's energy sector accounts for 25% of the GDP, 55% of the total exports, 40% of the total capital investment and 45% of budget revenue.

In terms of proven reserves, as of 2016, Russia has significant natural gas reserves (18% of the world), coal (15%), oil (6.3%) (BP, 2018) and uranium (5.0%) (NEA, 2018). The proven reserves of natural gas, estimated at 35 trillion cubic metres (Tcm), should last for 55 years at current production level. Domestic reserves of coal estimated at 160 billion tonnes (Gt) should be sufficient for 390 years of production. Crude oil and natural gas liquids, estimated at 14.5 Gt, should last for 26 years and roughly double that if yet-to-be explored fields are included. Out of 3 030 known oil fields, 1 926 produce oil, 663 are under assessment and 441 remained to be auctioned for exploration (MNRE, 2017). In 2017, 75 new oil and gas fields were discovered with 550 million tonnes (Mt) of crude oil and 890 billion cubic metres (Bcm) of natural gas reserves (MNRE, 2018).

The refining industry in Russia includes 80 refineries, which processed approximately 285 Mt of crude oil and gas condensate in 2017 (ME, 2018a).

Russia has the world's largest and one of the oldest district heating system with centralised heat production and distribution networks in most major cities. The system has a high number of combined

heat and power (CHP) installations. Heat losses, due to aging infrastructure, account for 8.9% of heating energy, and this indicator is growing (ME, 2018b). However, experts estimate that adoption of relatively accessible technologies and cost-effective energy saving practices leads to considerable savings.

Russia's energy sector is crucial for global energy security. The economy is the world's largest exporter of energy overall, the largest exporter of natural gas and the second-largest exporter of crude oil (BP, 2018). Furthermore, Russian-labelled nuclear fuel is used at 75 commercial reactors (17% of the global market) and provides 36% of the world's uranium enrichment services (Rosatom, 2017).

In 2017, exports of coal and lignite, crude oil, including natural gas liquids, petroleum products and natural gas accounted for 57% of the total exports of the economy by value. Russia holds significant uranium enrichment capacity (NEA, 2017) and actively exports the product. It accounts for 20% of the global natural gas trade, 13% of crude oil trade, 8% of petroleum products trade and 14% of coal trade (BP, 2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Russia's total primary energy supply in 2016 was 732 million tonnes of oil equivalent (Mtoe), comprising natural gas (51%), crude oil and petroleum products (24%), coal (15%) and others, including nuclear and hydro (10%) (EGEDA, 2018).

Most of Russia's energy exports go to Western and Eastern Europe, including the Commonwealth of Independent States (CIS)[1]. Since 2008, Russia has been actively diversifying its export routes towards the Asia-Pacific region, aiming to deliver crude oil, petroleum products, natural gas and coal to China; Japan; Korea; and South-East Asia.

Russia produced 546 Mt of crude oil and gas condensate in 2017 (ME, 2018c). The oil heartland is the Ural Federal District, which accounts for over half of the total oil production. In that year, refineries consumed 278 Mt of crude oil as feedstock, supplying domestic market with gasoline (35 Mt), diesel (37 Mt), fuel oil (15 Mt) and kerosene (9.7 Mt). The yield of refining increased from 72% in 2008 to 81% in 2017. Crude oil exports, including natural gas liquids reduced from 255 Mt in 2016 to 253 Mt in 2017, and exports of petroleum products dropped from the peak of 172 Mt in 2015 to 148 Mt in 2017 (GKS, 2018a).

Natural gas production increased from 641 Bcm in 2016 to 691 Bcm in 2017, the highest in 10 years (ME, 2018d). Exports of natural gas steadily increased from 174 Bcm in 2014 to 213 Bcm in 2017 (GKS, 2018a) or 30% of the production, including 11 Mt of liquefied natural gas (LNG) exports (ME, 2018e).

In 2017, Russia produced 411 Mt of coal, an increase of 6.0% from 2016, with 59% produced in the Kuznetsk Basin (ME, 2018f). In 2017, coal and lignite exports reached 190 Mt, growing by 62.4% from 2010 (GKS, 2018a). From 2000 to 2017, the share of coal for export increased from 17% to 44% despite the fact that the main coal-producing areas (the Kuznetsk and Kansk–Achinsk basins) are landlocked in the south of Siberia, 4 000–6 000 km from the nearest coal-shipping terminal for the Atlantic/Pacific markets.

Electricity production reached 1 091 terawatt-hours in 2016, of which 65% was from thermal power plants, 17% from hydropower and 18% from nuclear energy. Russia has significant potential for renewable energy, including 27 000 Mtoe of solar, mainly in the Rostov Region and Krasnodar Territory (in the south-west); 5 400 Mtoe of wind, mainly in Kalmykia Republic and the Stavropol Region (near the Caucasus); 800 Mtoe of forest biomass, mainly in the Irkutsk Region and southern Krasnoyarsk Territory (in Eastern Russia); 77 000 Mtoe of geothermal in Kamchatka; and 200 Mtoe of small-scale hydro in Siberia and the Russian Far East (HSE, 2017).

[1] CIS includes Azerbaijan, Armenia, Belarus, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Turkmenistan (associated member) and Uzbekistan.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	1 373 678	Industry sector	132 833	Total power generation	1 088 945
Net imports and others	–624 438	Transport sector	94 293	Thermal	697 674
Total primary energy supply	732 358	Other sectors	160 578	Hydro	184 612
Coal	113 289	Non-energy	82 062	Nuclear	196 614
Oil	173 261	Final energy consumption*	387 704	Others	10 045
Gas	371 313	Coal	11 432		
Renewables	18 955	Oil	86 810		
Others	55 540	Gas	116 629		
		Renewables	2 261		
		Electricity and others	170 572		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

In 2016, the total final consumption in Russia was 470 Mtoe, including 82 Mtoe of non-energy use, an increase of 2.9% compared with the 2015 level. By sector, industry, transport and others accounted for 28%, 20% and 34%, respectively. By energy source, electricity and others (including heat) accounted for 44% of the final energy consumption (excluding non-energy), followed by natural gas (30%), oil and petroleum products (22%), coal (2.9%), and renewables (0.58%).

The traditional energy-intensive industrial structure has been one of the major drivers of economic development in Russia. State and regional energy efficiency programmes aim to reduce overall energy intensity to 44% by 2020 compared with the 2007 level. The government is implementing policies designed to attract investment in energy efficiency and realise large savings potential.

ENERGY INTENSITY ANALYSIS

The 0.22% decrease in Russia's GDP in PPP in 2016 coincided with a 3.4% increase in economy's primary energy intensity at 204 tonnes of oil equivalent per million USD (toe/million USD). For the total final consumption intensity, the indicator grew by 3.0% from 105 toe/million USD in 2015 to 108 toe/million USD in 2016. For final energy intensity excluding non-energy, the indicator grew by 3.1% from 127 toe/million USD to 131 toe/million USD in the same period.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%)
	2015	2016	2015 vs 2016
Total primary energy supply	198	204	3.4
Total final consumption	105	108	3.0
Final energy consumption excl. non-energy	127	131	3.1

Source: EGEDA (2018) (data collected in September 2018).

RENEWABLE ENERGY SHARE ANALYSIS

In 2016, energy consumption of modern renewables in Russia was 11 408 ktoe or 2.9% of the economy's final energy consumption, higher than 2.8% in 2015, driven by increased hydropower generation. Modern renewables in electricity and heat grew by 8.4%.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	377 387	387 704	2.7
Non-renewables (Fossils and others)	366 832	376 296	2.6
Traditional biomass*	1 985	2 197	11
Modern renewables*	10 555	11 408	8.1
Share of modern renewables in final energy consumption (%)	2.8	2.9	5.2

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Under Russia's 'Energy Strategy 2030', adopted in 2009, its key objective is to use nature's energy resources in the most efficient way and expand the energy sector's potential for stable economic growth, improvement in the quality of people's lives and strengthening of the economy's foreign trade (IES, 2010). The strategy sets a policy framework within which more detailed industry-oriented medium-term and short-term programmes are developed.

As of 2018, the government continued its work on the new 'Energy Strategy 2035', but the strategic objective of Russia's external energy policy has not changed: to use economy's energy potential to effectively maximise its integration into the world's energy markets, strengthen its position in these markets and maximise the benefits of energy resources to the economy (ME, 2017f).

To achieve these objectives, the government is implementing several measures to improve the security of domestic energy supply and energy export obligations and to make efficiency improvements both on the demand and along the entire energy supply chain. This includes the development of new hydrocarbon provinces in remote areas and offshore; the rehabilitation, modernisation and development of energy infrastructure, including the construction of additional trunk oil and gas pipelines, to enhance the energy export capacity; and integration into the world energy markets through diversification of export markets.

Russia's nuclear energy industry remains a priority for the economy's development—the share of domestic nuclear power generation is expected to continue increasing, with many units being constructed abroad. The economy intends to remain a key player in the practical implementation of improved nuclear fuel technology. Existing programmes for renewable energy development outlined in the Energy Strategy 2030 are designed to support the electricity generated from renewable energy and establish renewable industry for domestic and export markets (IES, 2010).

Energy Strategy 2030 calls for a 40% reduction in the energy intensity of the economy by 2030 (IES, 2010). Reducing Russia's relatively high energy intensity should be one of the main objectives of the economy's energy policy to improve the competitiveness of the domestic industry in the global market and stimulate economic development.

One of the key measures in the Energy Strategy 2030 is the development of energy market institutions, such as fair pricing mechanisms and transparent trading principles, while ensuring the availability of a sufficient energy transportation infrastructure. State participation in energy sector development will mainly comprise supporting innovative developments in the energy sector as well as providing a stable institutional environment for effective functioning of the sector (IES, 2010).

Under the general framework of the Energy Strategy 2030, medium- and long-term programmes and industry-wide schemes are being developed. These include the Federal Programme for Development of the Nuclear Industry up to 2015, approved in 2006, and the general scheme of electric infrastructure development—a scheme relating to electricity network infrastructure and electricity plant locations—up to 2020, approved in 2008 and later extended to 2030.

In 2014, a general scheme for the development of the oil industry up to 2030 was approved. This provides for the comprehensive development of the oil sector through exploration and utilisation of associated petroleum gas, crude oil and petroleum products, crude oil refining and transportation infrastructure.

The general scheme for the development of the gas industry up to 2030 was reviewed and approved in October 2010. The document represents a complex project, which defines a path for Russian's long-term gas industry development. This strategic document covers all components of the gas industry: exploration, drilling, production, storage and transportation to consumers of hydrocarbons and refined products.

In June 2014, a long-term programme for developing the coal industry up to 2030 was approved. This document specifies the basic provisions of the energy strategy 2030 relating to the coal industry. The main task of the programme is to realise potential competitive advantages for Russian coal companies while implementing the government's long-term energy policy.

Additionally, the Mid-Term Scheme on the Unified Energy System Development is a tool to coordinate federal, regional and local governments with private businesses and industry regulators. The scheme is annually updated and serves as a seven-year outlook for generation and transmission line projects (ME, 2018g). It includes an outlook for electricity consumption by region, maximum loads, generation capacity reserves, power exchange, retirement of old facilities, maintenance, retrofitting and commissioning of new generation and transmission facilities with more than 5 megawatts (MW) capacity/110 kilovolts (kV) and higher voltage.

LAWS AND AUTHORITIES

The main federal legislation on specific energy-related industries include laws in the following areas: subsoils (1992), functioning of the power industry (2003), power industry (2003), natural monopolies (1995), production sharing agreements (1995), energy conservation and energy efficiency increases (2009), gas supplies (1999), nuclear energy (1995) and heat supply (2010). The latter is the logical extension of the power industry law, because of the large share of CHPs, where electricity and commercial heat are produced simultaneously.

As a rule, the Ministry of Energy of the Russian Federation is responsible for issuing regulations, instructions and so on to enforce smooth implementation of the basic energy laws and coordinate current economic development with the long-term energy policy, except for the nuclear power industry. Other major government institutions actively participate in the development and implementation of the regulatory framework regarding the production, supply, consumption, exports and imports of energy. These include the Ministry of Natural Resources and Environment of the Russian Federation; Federal Environmental, Industrial and Nuclear Supervision Service; Ministry of Industry and Trade of the Russian Federation; Ministry of Economic Development of the Russian Federation; Federal Agency on Technical Regulating and Metrology; Federal Antimonopoly Service; Federal Customs Service; and Federal Tariff Service.

ENERGY SECURITY

Russia considers issues related to energy security to be a global phenomenon. Owing to increasing interdependence among energy exporters, importers and transition economies, improving international

relations is considered as an effective mechanism for improving international energy security. The key approach is to coordinate the actions of energy exporters and importers in emergency and/or crisis situations.

To facilitate international energy security cooperation, Russia has made a proposal to develop a Convention on International Energy Security that would cover all aspects of global energy cooperation, considering the balance of interests of all actors in the international market. The infrastructure projects, including new oil and gas export trunk lines from Russia to its European and Asian markets, provide a solid contribution in improving the global energy security. The development of an international infrastructure for reliable maintenance of the nuclear fuel cycle, under strict International Atomic Energy Agency (IAEA) supervision, is another Russian contribution towards improving global energy security.

ENERGY MARKETS

MARKET LIBERALISATION

One of the main issues in Russia is the gradual liberalisation of the natural gas and electricity markets. Coal and petroleum prices have already been fully liberalised. The government controls tariff setting for natural monopolies—power transmission lines and pipelines (gas, crude oil, petroleum products transportation systems and heat supply for the residential and commercial sectors) as well as energy tariffs in remote and isolated areas. The authorities are authorised to set maximum regional tariffs for natural gas, electricity and centralised heat supply. One of Russia's objectives in the Energy Strategy 2030 is to complete the full liberalisation of domestic energy markets, where at least 20% of the energy is expected to be traded on commodity exchanges.

In 2006, the simultaneous liberalisation of natural gas and electricity prices by 2011 was approved; however, the implementation was delayed, and as of 2017, the electricity tariff for residential sector is still regulated by the government. The Federal Antimonopoly Service is planning to launch the natural gas price liberalisation programme, except for industry, in three pilot regions in 2017.

The oil market in Russia has been deregulated since the 1990s, but crude oil and petroleum trading are not based on commodity exchanges. Most crude oil in the domestic market is traded on a term basis, in which prices are linked to international benchmarks. Petroleum is traded in irregular tenders, which allows producers to control the market. Regional petroleum storage plays an important role in establishing fuel markets. The government intends to make up to 25% of the compulsory purchases of the government's petroleum products supply through commodity exchanges, such as the St. Petersburg Oil Exchange established in late 2006. The Federal Antimonopoly Service has an element of control over oil and gas prices through its role in monitoring the market share of sellers, but it has no responsibility for regulating prices.

The government removed control over coal pricing in the early 1990s, and the coal market has since been liberalised, like the crude oil and petroleum product markets. The transition to transparent, free-trading pricing mechanisms in domestic markets was originally scheduled to be completed in 2011, but the transition period has since been extended. The government will maintain control over the residential and commercial energy tariffs to eliminate cross-subsidies gradually.

OIL AND GAS

Russia's oil and gas industry was privatised in the 1990s. However, the government retained control over major oil and gas companies and crude oil and petroleum trunk pipelines. It owns 73% of the shares of Russia's biggest gas company, Gazprom.

As of 2018, the oil industry in Russia comprised 104 enterprises forming 11 vertically integrated companies (VICs) constituting 86% of the crude oil output and 181 small-scale independent enterprises, along with operators of three production sharing agreements. The refining sector comprises 80 refineries with the total refining capacity of over 310 Mt of crude oil per year.

The shift towards Euro-V emission standards has encouraged significant investment into the refining industry. Currently, only limited use of fuels non-compliant with this standard is allowed. Despite a small year-on-year decline in crude oil throughput by –0.8%, the depth of refining has increased from 74% to

79% in the same period. New installations and modernisation of existing equipment are expected to help increase the yield to 81%.

The federal government remains the key shareholder in the economy's gas monopoly, Gazprom, which extracted 67% of the natural gas in Russia in 2014 and owns the economy-wide gas pipeline system. The remainder of the Russian natural gas supply comes from independent producers (7.3%), NOVATEK (8.4%), joint operators (4.3%) and VICs (13%).

In 2017, the Ministry of Energy in cooperation with the Ministry of Finance, with active participation of the oil sector, introduced an oil excess profit tax. This new tax is designed to help sustain existing or attract new investment in oil mining. This is especially important for Russia as the production of its main oil-producing province, Western Siberia, is declining, from nearly 308 Mt per annum in 2010 to nearly 286 Mt oil per annum in 2016 (ME, 2017b).

COAL

The Russian coal sector was restructured in the 1990s, and foreign participation in the sector is practically absent. Unlike the oil and gas sector, the coal industry has no large state-controlled companies.

Industry development is based two-thirds on equity and one-third on loans. In recent years, there has been an active renewal of the fixed assets of the coal industry. There are no policy restrictions on coal exports; however, the high transportation cost of coal lowers its competitiveness in external markets. Coal is the single-largest commodity transported by rail, accounting for nearly 30% of its total freight volume. Steam coal accounts for 78% of the total coal production.

In 2014, the government approved the coal industry development programme until 2030. Its primary objective is to ensure that domestic coal companies are reliable suppliers to the domestic market and develop their exporting potential (ME, 2017c).

As of the end of 2017, 161 coal enterprises were operational in the Russian coal industry (53 mines and 108 open-pit mines), with a total annual production capacity of 453 Mt per annum. Coal processing is performed by 65 processing plants and mechanical installations (ME, 2018h).

ELECTRICITY

Russia started restructuring its power industry in 2000. Federal laws and government decrees identified the main principles for the future functioning of the power industry under competitive conditions. All thermal generation and regional power distribution companies were privatised before July 2008. From July 2008, the generation and transmission assets in Russia were separated under binding regulations. Generation assets were consolidated into interregional companies of two types: seven wholesale thermal power plant generation companies (WGCs) and 14 territorial generation companies (TGCs). Six thermal WGCs were constructed according to extraterritorial principles along with one state-owned holding company, RusHydro, which manages 53 hydropower plants. TGCs manage facilities in the neighbouring regions. The initial design of the WGCs provided them with roughly equal starting conditions in the market, with respect to installed capacity, asset value and average equipment. Each WGC has power plants located in different regions of Russia to prevent possible monopoly abuse.

Backbone transmission lines are assigned to the Federal Grid Company, whereas distribution grids are owned and operated by 11 interregional distribution grid companies. The Federal Antimonopoly Service is responsible for monitoring the long-distance power transportation market, whose threshold is less than 20% of the transmission line capacity per company. The wholesale power market infrastructure includes the following organisations:

- Non-profit Partnership Administrator of Trading System;
- System Operator–Central Dispatch Administration of the Unified Energy System; and
- Federal Grid Company of the Unified Energy System.

The Non-Commercial Partnership, Administrator of Trading System of the Wholesale Power Market (NP ATS), was established in November 2001. The main objectives of NP ATS are to organise trade and arrange financial payments in the wholesale electricity and power markets, increase the efficiency of power

generation and consumption, and protect the interests of both buyers and suppliers. NP ATS provides infrastructure services, which are related to organisation of trade, the wholesale power market, ensuring the execution and closing of transactions, and the fulfilment of mutual obligations. The System Operator, with 100% state ownership, exercises technological control within the power grids and provides dispatching services to wholesale market participants. The Federal Grid Company, established in 2002, with 78% state control, owns and operates the transmission lines, provides consistent technological management and is responsible for the reliability of power transmission services.

The free electricity trading market (one-day forward) was launched in November 2003 within the framework of the Federal Wholesale Electricity Market (FOREM). In September 2006, the regulated sector of the wholesale market was replaced by a system of contracts to be concluded between the buyers and sellers of electricity and electric power. In the FOREM, power generators and importers sell electricity and power to guarantor suppliers and distribution companies as well as to large consumers and exporters. In the distribution market, guarantor suppliers and distribution companies sell electricity and power to end-use consumers in the residential, commercial and industrial sectors.

Since 2008, the share of tariffs established by the regulatory asset base methodology for distribution grids has been increasing and is expected to become the major method for calculating middle-term tariffs. The methodology is transparent and provides incentives for investors to rehabilitate and improve the operations of the energy service companies.

HEAT SUPPLY

Residential and commercial heat supplies have important social implications and are a major concern for local governments in Russia. Historically, the heat-supply industry was subsidised by local budgets and thus has scope for considerable efficiency improvements. The Law on Heat Supply introduced in 2010 was designed to create investment opportunities, minimise energy losses and subsidies and provide business incentives.

In July 2017, the government adopted changes to the above law, now allowing regional and municipal authorities to establish localised heat-supply markets. In these liberalised markets, however, the government still regulates the maximum heat price for the final consumer, commonly referred to as 'alternative boiler house price' (ME, 2017d).

NUCLEAR

Russia's nuclear industry restructuring started in 2001, when the state-owned company Rosatom took over all civil reactors, including those under construction, and their related infrastructure. In 2007, the new Law on Nuclear Industry was adopted, which provided a legal framework for industry restructuring by separating military and civil facilities and by introducing regulations for nuclear materials management. Russian business entities are now allowed to hold civil-grade nuclear materials, but they still fall under state control.

In April 2007, a single, vertically integrated, state-owned nuclear energy company was established. The operations of this new corporation, AtomEnergoProm (AEP), include uranium production, engineering, design, reactor construction, power generation and research facilities. AEP holds a significant share of the world's enriched uranium and nuclear fuel supply, has 24 GW of existing Russian nuclear energy plants and manages the construction of 14 reactors. There are seven reactors under construction in Russia, including one floating-type unit to power remote areas and seven reactors in four Asian and European economies. AEP provides the full production cycle of nuclear energy engineering, from uranium extraction to nuclear fuel services to nuclear energy plant construction and electricity production. The company has up to 16% of the world's market for new nuclear energy plant construction and is affiliated with Tenex (40% share of the world's uranium enrichment services market), TVEL (17% share of the world's nuclear fuel market) and Atomredmetzoloto (9% share of the world's uranium mining).

TRANSPORT

Russia's economy faces challenges caused by the underdevelopment of its transport infrastructure. The condition of Russian airports and air-transport facilities has improved significantly, and rail and air fleets were modernised as a part of preparation for the 2018 Football World Cup and the 2020 World Expo.

The total length of Russian public roads in 2017 was 1 507 790 km, 71% of which are paved (GKS, 2018b). The economy has just over 30 000 km of high-speed divided highways connecting big cities. Further development of highways will be necessary to connect big cities.

Russia has a state railway system with a total length of 86 534 km in 2017, but only few cities have high-speed rail service. Nevertheless, extensive urban and regional bus services are available throughout Russia, and subway systems operate in seven cities. The recent key developments in rail freight and passenger transportation are as follows:

- development of Ust–Luga freight rail terminal and associated shipping terminal—its throughput was approximately 100 Mt in 2018 (Ust-luga, 2019);
- freight rolling stock renovation plans announced by Russian Railways company (RZD, 2018) include the wider use of LNG locomotives, specifically for mining operations in non-electrified areas (RZD-expo, 2017); and
- renovation of suburban and regional passenger trains, which includes upgradation of the current rolling stock with new stock with high local content. A significant project is the launch of Moscow Central Ring, a train service integrated with the city's underground and surface transportation systems.

Russia's pipeline transport is underdeveloped relative to the potential oil and gas supply. In 2017, the total length of the pipeline system in the economy was 250 521 km, of which 72% is gas pipeline, 21% oil pipeline and the remainder is petroleum products pipeline.

FISCAL REGIME AND INVESTMENT

In 2007, dozens of oil and gas fields were decreed as 'strategic' fields. The strategic status makes the hydrocarbon deposits inaccessible to foreign companies unless they establish joint project operations with Russian companies. Under the current regulations, the strategic status has been applied to oilfields with reserves exceeding 70 Mt and gas fields with reserves exceeding 50 Bcm. In March 2009, regulations were adopted to compensate costs associated with the discovery and exploration of deposits under exploration licenses, the further development of which is prohibited because of their strategic status.

Beginning in January 2009, tax holidays from the mineral extraction tax for crude oil production in East Siberia were extended to areas north of the Arctic Circle, Sea of Azov, Caspian Sea and Nenetsk and Yamal regions. In addition to the existing tax reductions for East Siberian oil, this enables the development of new capital-intensive projects in remote areas that lack energy infrastructure. From 1 January 2010, zero export duty was introduced for crude oil extracted from East Siberia oilfields to maintain a stable market for Russian crude exported eastward to the Asia-Pacific region.

A draft plan for a new tax regime was prepared in 2011 as a part of the development of the new Law on Oil. On 1 October 2011, a new tax regime for the oil industry called the '60–66' came into force in Russia. Under these rules, the duty on oil exports decreased by 7.4% to USD 411 per tonne, and fees for light and heavy petroleum products were set at 66% duty on crude oil. For several fields in Eastern Siberia and the North Caspian, a preferential export duty was enacted, which, as of October 2011, was set at USD 204 per tonne. A reduced duty on crude oil was achieved by changing the formula for calculating it. According to the norms of the '60–66', duty on crude oil was assessed at 65% and 60% of the difference between the market price and standard price of oil at a rate of USD 182 per tonne.

The size of the duty on exports of gasoline is currently set at 90% of the duty on crude oil. Before May 2011, the duty on export of gasoline was 60% of the duty on oil, but because of the sharp rise in domestic prices and gasoline shortages in some regions, it was increased to 90%. It is believed that such new fees will allow oil companies to obtain additional funds for exploring new fields and will thereby increase current oil production. In addition, the unification of tariffs on export of petroleum products at 66% will make exports less competitive for dark petroleum products and more profitable for light petroleum products; it will also encourage companies to increase the refining depth at their existing plants.

To facilitate coal exports, rare subsidies to the coal industry are provided under the railway's cargo tariff regulations for some export routes.

ENERGY EFFICIENCY

The energy intensity of the Russian economy is considerably higher than those of most developed economies. The introduction of energy efficiency (EE) measures is estimated to save over 300 Mtoe, including more than 160 Mtoe from energy extraction, transformation and transportation.

EE has become a critical factor in the government's energy policy since 2008, when a presidential decree set a target to reduce the energy intensity of Russia's GDP by 40% by 2020 compared with the 2005 level. Improving EE and energy savings has become a priority area of the Energy Strategy 2030.

On 23 November 2009, the federal government adopted the Law on Energy Conservation and Increase of Energy Efficiency, which took effect on 1 August 2010. To supplement and make the new EE law more effective, approximately 40 sub-laws amending some existing laws and technical regulations were drafted. The federal law sets a legal framework and targets the use of energy resources in Russia by promoting the rational use of energy resources and alternative fuel resources for electricity and heat generation. The law introduces various measures to improve EE and energy conservation across all sectors of the economy. A few of these measures are as follows:

- EE standards for equipment and buildings, including mandatory energy passports;
- EE labelling of goods and the compulsory commercial inventory of energy resources;
- improvements in EE monitoring, focusing on mandatory energy audits and the compulsory installation of metering systems;
- creating a single and unified inter-agency information network and analytical EE system; and
- other measures to help achieve energy savings (promoting energy service contracts, prohibiting incandescent light bulbs, introducing incentives and tax benefits for Russia's heavy industries to replace highly energy-inefficient machinery and equipment and so on).

In accordance with the EE federal law and the programme, all regions are required to prepare their own respective regional programmes on EE improvements. Regional governments and the federal government will jointly finance the implementation of these programmes.

On 22 December 2009, the government established the Russian Energy Agency, which has 70 regional branches, with the Ministry of Energy of the Russian Federation. Its key tasks focus on operating the federal EE and energy-saving information system and on administering, monitoring and coordinating efforts for effective implementation of the EE law, the Federal Programme and other measures for improving EE and energy conservation efforts in the budgetary, power generation, industrial and residential sectors of Russia's economy. In addition to these measures and policies for strengthening the EE legal framework, the federal government launched the following six pilot presidential energy efficient projects in several regions:

- metering (installing metering devices and automation);
- EE in the government sector (piloting energy performance contracting in schools and public buildings);
- energy-efficient districts (targeting the residential sector);
- energy-efficient lighting (replacing street lighting and other measures);
- small-scale cogeneration; and
- new energy sources (renewable and other non-carbon energy resources).

Upon their successful completion, these projects are expected to be implemented across all regions. In addition, the technical potential exists to save almost half of Russia's primary energy consumption through energy conservation (ME, 2015). However, a major impediment for businesses to improve their EE is the absence of appropriate financial mechanisms.

RENEWABLE ENERGY

Russia's technical potential for renewable energy (RE), excluding large hydro, is estimated at 4 400 Mtoe per year or almost eight times more than Russia's current total final consumption. However, the economic potential is much smaller (approximately 240 Mtoe per year, nearly 250% of the total electricity production).

The government's policy goals and mechanisms to promote RE were introduced in January 2009 through the federal government order, 'The Basic Directions of a State Policy of Renewable Energy Utilisation up to 2020'. The major mechanisms to increase the share of renewables are feed-in tariffs and subsidies for grid connection. The government is expected to develop regulations for feed-in tariffs and grid connection subsidies for the compulsory share of RE in the wholesale market to be purchased by electricity consumers and for bringing together RE generators, transmission lines and guarantor suppliers of energy. By 2030, Russia is expected to generate from 80 to 100 billion kWh of RE, excluding large hydro, or roughly 4–6% of the economy's total generation.

In October 2010, the government published a ruling on federal subsidies for connecting renewable energy generators to the power grid that would encourage 'green' energy production in Russia. Conditions of the ruling include that the nominal capacity of a single RE installation should not exceed 25 MW and that owners should not be under bankruptcy proceedings. This ruling paves the way for financial mechanisms for RE.

NUCLEAR ENERGY

Russia holds important stakes in the international nuclear fuel market. Tenex, the state company responsible for the nuclear fuel cycle business, supplies all the Russian, Commonwealth Independent States and Eastern European nuclear reactors. In addition, Tenex meets 40% of the nuclear fuel requirements of the US, 23% of Western Europe and 16% of the Asia-Pacific region.

Nuclear safety is a major concern for world energy development, which has become a key agenda item following the Fukushima accident in Japan. Russia has adopted a 'closed' fuel cycle, which includes spent nuclear fuel processing and the mandatory return of fissionable nuclear materials to the fuel cycle. To provide the legal framework for managing spent nuclear fuel and radioactive waste, the laws on environmental protection and the use of nuclear energy were amended in June 2010.

Rosatom's long-term strategy up to 2050 involves moving to inherently safe nuclear energy plants, using fast reactors with a closed fuel cycle and mixed oxide fuel. In the period 2020–25, fast neutron reactors are expected to play an increasing role in Russia. The improved design will lead to an extended operating life of up to 60 years, a shorter construction period of up to 46 months and operating costs at less than RUB 1 per kilowatt-hour (kWh). After the successful commissioning of an 800-MW fast breeding reactor (UNIT 4, Beloyarskaya Nuclear Power Plant), Rosatom is planning to construct a 1 200 MW unit after 2020. Further development of this technology is expected to broaden the range of acceptable fuels as well as reduce the amount of toxic nuclear waste by establishing a closed nuclear fuel cycle (Rosatom, 2018).

The prospects for future international cooperation in the nuclear energy industry are promising; the construction of 35 reactors in 15 economies is in the pipeline, and contracts have been signed for 19 reactors in 7 economies. For the development of the nuclear energy for the next 20 to 25 years Russia has chosen three core reactor technologies:

- water–water energetic reactors (VVER) and their modifications and advanced development;
- sodium fast neutron reactors; and
- high-temperature helium reactors.

CLIMATE CHANGE

Russia's key environmental and climate policy has been outlined in the Climate Doctrine (Kremlin, 2009) and Fundamentals of state policy in the field of environmental development of the Russian Federation for the period until 2030 (Kremlin, 2012) and implemented in the State Environmental Protection Programme for 2012–2020[2]. In 2017, the Year of Ecology in Russia, the President signed the 'Strategy for Environmental Protection in Russia until 2025'. This document includes the assessment of the status of and threats to the environment and highlights the key government targets, indicators and methods of environmental monitoring (Pravo, 2017).

On 21 July 2014, N 291-FZ Federal Law 'On amendments to the Law on Environment protection' adopted by the government initiated the process of transition to the best available technologies. This would stimulate the rational and environmentally minded use of energy and natural resources. This was followed by the development of 50 subsector-specific guidelines, which were adopted by respective federal agencies and ministries (BuroNDT, 2019).

In April 2016, the Russian Government signed a directive approving the Paris Agreement of the Conference of the Parties to the UNFCCC (UN Framework Convention on Climate Change) (RG, 2016), also known as UN COP21. Russia's INDC of 'limiting anthropogenic greenhouse gases in Russia to 70–75% of 1990 levels by the year 2030' might be a long-term indicator, subject to the maximum possible account of absorbing capacity of forests (UNFCCC, 2015). However, as of early 2019, the agreement has not been ratified.

NOTABLE ENERGY DEVELOPMENTS

ENERGY POLICY

EnergyNET roadmap, adopted in late 2016, is a part of Russia's Technological Initiative (NTI). It highlights several objectives for Russia's energy industry until 2035. This includes target indicators for Russia's share of global markets, engineering and software solutions, educational facilities, pilot projects and testing facilities for intelligent distribution networks.

POWER MARKET DEVELOPMENT

The Ministry of Energy of the Russian Federation presented concepts for a programme of power sector modernisation up to 2020. The central theme of this modernisation is to introduce new technologies (both domestic and imported), increasing the reliability of electricity supply.

OIL AND GAS DEVELOPMENT

The Ministry of Energy highlights the positive results of an OPEC plus non-OPEC agreement (ME, 2018a). This is aimed at reducing the oil market supply excess by voluntarily limiting the maximum levels of production. The agreement has been further extended until the end of 2018.

RENEWABLE ENERGY DEVELOPMENT

Russia joined the International Renewable Energy Agency (IRENA) in 2015. The key objectives of this cooperation are to develop Russia's Renewables Roadmap until 2030 and provide better assessment of domestic Renewable Energy resources. In early 2017, Russia was elected as a member of IRENAs Council to further facilitate consultations and cooperation among IRENA members (IRENA, 2018).

[2] The State Environmental Protection Program does not include the indicators related to GHG emission.

CLIMATE CHANGE

In accordance with the Decree of the President of the Russian Federation, 2017 was announced the Year of Ecology in Russia. As a result of extensive work of academia, industry and government, the 'Strategy for Environmental Protection in Russia until 2025' was signed as a presidential decree.

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USEFUL LINKS

OFFICIAL BODIES OF RUSSIA

The Russian Government—http://government.ru/en/

Ministry of Energy of the Russian Federation—http://minenergo.gov.ru/en

Ministry of Natural Resources and Environment of the Russian Federation—https://www.mnr.gov.ru/english/

Federal Environmental, Industrial and Nuclear Supervision Service of Russia—http://en.gosnadzor.ru/

Ministry of Economic Development of the Russian Federation—http://economy.gov.ru/en/home/

Federal State Statistics Service of the Russian Federation—http://www.gks.ru/wps/wcm/connect/rosstat_main/rosstat/en/main/

Ministry of Industry and Trade of the Russian Federation—http://minpromtorg.gov.ru/

Federal Agency on Technical Regulating and Metrology—http://www.gost.ru/wps/portal/en

Federal Antimonopoly Service—http://en.fas.gov.ru/

Federal Customs Service—http://eng.customs.ru/

Federal Tariff Service—http://www.fstrf.ru/eng

ENERGY-RELATED NON-PROFIT AND STATE-OWNED BUSINESS INSTITUTIONS

AtomEnergoProm—http://atomenergoprom.ru/en/

Federal Grid Company (PJSC FGC UES)—http://www.fsk-ees.ru/eng/

Rosseti, Public Joint Stock Company (PJSC ROSSETI)—http://http://www.rosseti.ru/eng/

Association NP Market Council—http://www.en.np-sr.ru/index.htm

Gazprom—http://www.gazprom.com/

Rosneft—https://www.rosneft.com/

RusHydro—http://www.eng.rushydro.ru/

Transneft—http://www.en.transneft.ru/

Transnefteproduct, JSC—http://en.transnefteproduct.transneft.ru/

STATE ENERGY-POLICY-RELATED RESEARCH CENTRES

Russian Energy Agency—http://rosenergo.gov.ru/

Analytical Centre for the Government—http://ac.gov.ru/en/

Institute of Energy Strategy—www.energystrategy.ru/

Centre for Energy Policy—http://www.energy.ru/

Centre for Energy Efficiency—http://www.cenef.ru/art_11207_114.html

The Energy Research Institute of the Russian Academy of Sciences (RAS)—https://www.eriras.ru/eng

Melentiev Energy Systems Institute (Siberian Branch of RAS) —http://isem.irk.ru/en/

MAJOR ENERGY-RELATED MEDIA IN RUSSIA

Official newspaper, *Rossiyskaya Gazeta*—https://rg.ru/

State information system on energy conservation and energy efficiency improvement—https://gisee.ru/

Central Dispatching Department of Fuel Energy Complex—http://www.cdu.ru/en/

SINGAPORE

INTRODUCTION

Singapore is a city-state located in the south of the Malay Peninsula between the Strait of Malacca and the South China Sea. This Southeast Asian economy's land area was 720 square kilometres (km²) in 2016, with a population of 5.6 million.

Singapore is completely urbanised and highly industrialised, with a robust and growing diversified economy despite its lack of domestic energy and mineral resources and small land size, a significant part of which is reclaimed land. The economy's impressive economic success is attributed to several factors, including being a regional hub for tourism, financial activities, shipbuilding, petroleum and related equipment, and biotechnology, as well as its expanding role in international cargo and fuel shipping.

From 2015 to 2016, the economy's gross domestic product (GDP) grew by 2.4% to USD 463 billion. The services industry accounted for the bulk of GDP share at 71%, goods-producing industries (manufacturing and construction) accounted for 25% and ownership of dwellings [1] accounted for the remaining 4.2%. Manufacturing represented the largest sub-sector by percentage share of GDP (19%), followed by wholesale and retail trade (17%) and business services (16%) (SingStat, 2018).

Table 1: Key data and economic profile, 2016

Key data [a; b]		Energy reserves	
Area (km²)	719	Oil (million barrels)	–
Population (million)	5.6	Gas (billion cubic metres)	–
GDP (2011 USD billion [PPP])	463	Coal (million tonnes)	–
GDP (2011 USD [PPP per capita])	82 622	Uranium (kilotonnes U)	–

Source: [a; b] Department of Statistics Singapore (2018); EGEDA (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Singapore has no indigenous natural resources and imports all its fossil fuel requirements. Its total energy imports (crude oil, petroleum products, natural gas, coal and other energy products) in 2016 were 179 479 kilotonnes of oil equivalent (ktoe). These were used to meet domestic energy requirements and serve the needs of its oil refineries whose refined products are mainly exported to the Asia-Pacific Economic Cooperation (APEC) region. More than half of these imports and refined products (98 316 ktoe) were exported in the same year (EGEDA, 2018). Other than having a vibrant oil refining scene, Singapore also plays an important role in international shipping and aviation. This is evident from the large proportion of international marine bunkers (48% of exports or 46 826 ktoe) and aviation bunkers (7.9% of exports or 7 815 ktoe) in the economy's energy balances (EGEDA, 2018).

The economy's total primary energy supply (TPES) in 2016 was 27 353 ktoe, 2.3% higher than the 2015 level. Oil constituted the largest share of the TPES at approximately 64% (17 440 ktoe), followed by natural gas at 32% (8 749 ktoe), coal at 1.6% (427 ktoe) and renewables at 1.5% (409 ktoe) (EGEDA, 2018).

In terms of power generation, the economy generated 51 667 gigawatt hours (GWh) of electricity in 2016, an increase of 2.5% from that in 2015 (50 415 GWh) (EGEDA, 2018). Peak demand for electricity stood at 7 149 megawatts (MW), a 2.7% increase over that in 2015 (6 960 MW) (EMA, 2018a). There are seven main

[1] Ownership of dwellings refers to housing services provided by owner-occupiers and individuals who let out their residential properties.

power producers in Singapore that contributed to the bulk of the total power generation (91%) in 2016, while auto-producers accounted for the remaining 9.0% (EMA, 2018a).

Total licensed generation capacity reached 13 445 MW in 2016. With the economy repowering steam turbine plants into more efficient combined-cycle gas turbine (CCGT) power plants, the share of CCGT in overall generation capacity significantly increased from 46% (4 534 MW) in 2005 to 77% (10 356 MW) in 2016. Conversely, the share of steam turbine plants dropped from 48% (4 640 MW) in 2005 to 19% (2 556 MW) in 2016. Open-cycle gas turbine plants comprised 1.3% (180 MW) of the generation capacity in 2016, while waste-to-energy (WtE) plants accounted for the remaining 1.9% (257 MW) (EMA, 2018a).

With the shift away from steam turbine plants towards CCGTs, the share of natural gas in Singapore's fuel mix for power generation substantially rose to 95%, where it has remained since 2014. In 2016, petroleum products accounted for 0.7% and coal for 1.2%, while other fuels accounted for 2.9% of the fuel mix (EMA, 2018a).

Total grid-connected solar PV installed capacity in Singapore increased by 16% from 126 megawatt peak (MWp) in 2016 to 146 MWp in 2017. Solar capacity has since grown to 149 MWp by the end of the first quarter of 2018 (EMA, 2018a).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	668	Industry sector	6 208	Total power generation	51 667
Net imports and others	81 163	Transport sector	2 366	Thermal	50 089
Total primary energy supply	27 353	Other sectors	2 582	Hydro	–
Coal	427	Non-energy	7 266	Nuclear	–
Oil	17 440	Final energy consumption*	11 156	Others	1 578
Gas	8 749	Coal	168		
Renewables	409	Oil	5 632		
Others	328	Gas	1 175		
		Renewables	0		
		Electricity and others	4 181		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

Singapore's final energy consumption was 11 156 ktoe in 2016, a 2.3% increase from that in 2015. Oil remained the bulk of final energy consumption (5 632 ktoe), with a share of approximately 50%, followed by electricity and others (37%, 4 181 ktoe), natural gas (11%, 1 175 ktoe) and coal (1.5%, 168 ktoe). In terms of the total final consumption, the most significant portion was attributed by non-energy uses (39%). By sector, the industrial sector accounted for 34% of total final consumption, other sectors (including residential and commercial sectors) accounted for 14% and the transport sector accounted for 13% (EGEDA, 2018).

ENERGY INTENSITY ANALYSIS

Singapore is fully committed to contributing to APEC's objective of a 45% energy intensity reduction by 2035 below 2005 levels as set by APEC leaders in 2011. The economy's efforts to reduce energy intensity began in 2009 when the economy set an ambitious target to reduce energy intensity by 35% by 2035. Subsequently, Singapore's Inter-Ministerial Committee on Sustainable Development (IMCSD) formulated the Sustainable

Singapore Blueprint as a guiding strategy for the economy's sustainable development (MEWR, 2014). In 2015, Singapore strengthened its commitment to efficiency through its nationally determined contribution (NDC), which pledged to reduce energy intensity by 36% below 2005 levels by 2030 (NCCS, 2018a).

Various government initiatives have aimed at helping the economy achieve its commitment to APEC's 2011 target. Recent examples include the Energy Conservation Act 2013 (ECA) that focuses on a range of interrelated energy issues, including improving energy conservation, efficiency and intensity while reducing CO_2 emissions (GBS, 2014). The act aims to help Singapore achieve its intensity reduction target by improving the energy performance of the economy's companies. Other initiatives, including seeking improvements in energy conservations and efficiencies, are discussed later in this chapter.

Compared with the 2015 level, Singapore's energy intensity in 2016 marginally declined in terms of primary energy as well as final consumption. Primary energy intensity decreased to 59 tonnes of oil equivalent per million USD (toe/million USD) in 2016, a 0.09% reduction from that in the previous year. Final energy intensity decreased to 40 toe/million USD, a 0.89% reduction from the 2015 level. These reductions were mostly driven by decreasing energy consumption in the industry and transport sectors.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	59	59	-0.1
Total final consumption	40	40	-0.9
Final energy consumption excl. non-energy uses	24	24	-0.1

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Land scarcity and the absence of suitable geological conditions limit Singapore's options for renewable energy. Solar power and WtE are the main forms of viable renewable sources for the economy, and it has made a great effort in pursuing these available options. Singapore aims to increase its solar deployment to 350 MWp by 2020 and to 1 GWp beyond 2020. This has helped accelerate the adoption of solar PV systems in the economy. In 2016, the share of modern renewable energy in final energy consumption increased by 6.4% compared with the 2015 level.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	10 901	11 156	2.3
Non-renewables (Fossils and others)	10 827	11 077	2.3
Traditional biomass*	0	0	0
Modern renewables*	74	79	6.4
Share of modern renewables in final energy consumption (%)	0.68	0.71	4.0

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Singapore's 2007 National Energy Report sets out the strategies[2] to balance the objectives of energy security, economic competitiveness and environmental sustainability. The economy has since sought to secure this balance through a range of measures.

To reduce dependence on piped imports from Malaysia and Indonesia for gas requirements—which has accounted for 95% of its power mix since 2014 (EMA, 2018a) and a tenth of its energy demand since 2009—Singapore began operating its first liquefied natural gas (LNG) terminal in May 2013. The expansion has enabled it to increase volumes of LNG into the energy mix (SLNG, 2018). This has enabled the economy to diversify its gas supplies by importing LNG from over 20 economies in the last five years, including significant cargoes from Australia, Qatar, Indonesia, Equatorial Guinea and Trinidad and Tobago (OEC, 2018) while securing additional gas for its growing gas demand and adding LNG to the energy mix. In 2018, LNG imports made up 28% of the natural gas imports (EMA, 2018a).

Singapore is exploring more ways to diversify its energy mix by scaling up deployment PV panels regarded as the 'most economically and technically viable renewable energy option' (GOS, 2015). It launched the SolarNova programme to aggregate demand for solar energy 'across government buildings and spaces, to yield savings from economies of scale' while seeking to 'demonstrate solar energy's viability in Singapore [to] catalyse further adoption by the private sector' (GOS, 2015). Singapore has also become a global leader in floating solar PV research as it seeks innovative ways to overcome its land constraints and increase its solar potential. More details on Singapore's progress are discussed later in this chapter.

Singapore is also intensifying its efforts to promote more efficient energy use and decrease CO_2 emissions. As part of its contribution to the post-2020 climate change agreement, Singapore intends to 'reduce its emissions intensity by 36% from 2005 levels by 2030 and to stabilise emissions with the aim of peaking around 2030' (NCCS, 2018a). This pledge builds on its existing commitment to reduce greenhouse gas (GHG) emissions by 16% from the business-as-usual (BAU) level by 2020; the economy is well on track to meet this. It is a remarkable objective as Singapore is already one of the least carbon-intensive economies in the world, ranking 127 out of 142 economies (IEA, 2018).

In 2016, the government formed the Committee on the Future Economy (CFE) to review and develop economic strategies for Singapore over the next decade. This review was conducted in the face of a changing global environment, technological changes and the slower growth of the economy's labour force. The CFE was tasked to build on the 2010 Report by the Economic Strategies Committee and to recommend strategies to maintain sustainable economic growth for Singapore. Recommendations made by the CFE, including energy-related strategies, will lay the foundation for Singapore's policy development over the next decade. In the Report of the CFE submitted in February 2017, the following recommendations relevant to Singapore's energy developments were made (CFE, 2017):

1. **Become a model city in sustainability.** The report recommends more aggressive investment in Research and Development (R&D), test beds and commercialisation of new energy solutions. On the supply side, Singapore should ramp up the deployment of solar PVs and invest in R&D for energy storage solutions and solar forecasting. These could support cost-effective deployment of solar energy and enhance energy grid resilience. On the demand side, Singapore should continue to push for greater efficiency in energy usage through more energy 'smart meters' to encourage energy-saving behaviour through real-time feedback. Real-time information will also facilitate easier implementation of demand-side management (DSM) initiatives and will allow for the development of new business models.

2. **Strengthen competitiveness as a trading hub.** Singapore is a successful regional trading hub for agri-commodities, metal and minerals and energy-related commodities. It should diversify trade flows and

[2] Diversify Energy Supplies; Enhance Infrastructure and Systems; Improve Energy Efficiency; Strengthen the Green Economy; Price Energy Right.

deepen its ecosystem of supporting services and financing. These will help grow a liquid commodity derivatives marketplace and strengthen commodity trade financing.

3. **Aggregate demand for sustainable technologies to help enterprises build a track record.** Lead demand has resulted in the development and adoption of smart and sustainable technologies. The government should use lead demand to build expertise and track records of enterprises in areas such as energy management and industrial water solutions.

4. **Raise ambitions in the adoption of sustainable urban solutions**. To raise Singapore's renewable energy and urban mobility ambitions, the government should leverage the Green Mark standards to encourage solar PV adoption; explore large-scale floating PV deployment; develop standards to track renewable energy production/consumption; and craft urban mobility adoption plans.

ENERGY MARKETS

The electricity and gas industries in Singapore were once vertically integrated and owned by the government under the responsibility of the Public Utilities Board (PUB). Singapore began restructuring its electricity industry in 1995 to liberalise the market and promote competition. Major activities in this regard have included corporate and industry structural reforms, the creation of an institutional regulatory framework and market rules for the contestable parts of electricity generation and retail sales of electricity, separate from the natural monopoly of electricity transmission at the ownership level. Later, in 2001, the gas market was also restructured to support the parallel liberalisation of the electricity market.

ELECTRICITY

In October 1995, PUB's electricity and piped gas undertakings were corporatised to introduce competition into the energy sector. The SP Group (formerly known as Singapore Power Ltd) was established under Temasek Holdings as a vertically-integrated group of companies to take over these undertakings. This includes two power generation companies, namely PowerSenoko and PowerSeraya, an electricity transmission and distribution company (PowerGrid, now known as SP PowerAssets Ltd), and an electricity supply and utilities support services company (PowerSupply, now known as SP Services Ltd). In the same year, PUB took on the role of regulator for the electricity and gas sectors and Tuas Power was set up as an independent company directly under Temasek Holdings. In 2008, all three power generation companies previously under Temasek Holdings were divested as private companies.

The Singapore Electricity Pool (SEP) commenced operations in 1998 as a day-ahead electricity market to facilitate the trading of electricity between generation companies in a competitive environment. Additional reforms were made in 2000 to further liberalise the electricity industry. Key restructuring initiatives included the separation of ownership of the non-contestable part of the electricity market (the transmission and distribution grid) from the contestable part (power generation and retail), the establishment of a system operator and market operator, and the establishment of a real-time wholesale market.

In April 2001, the Energy Market Authority (EMA) was established to regulate the electricity and gas industries and promote competition in these industries. Under EMA, the Power System Operator, or PSO, is responsible to ensure the secured operations of the power system. The Energy Market Company was established in the same year as the market operator, responsible for the operation and administration of the wholesale electricity market. In 2003, the National Electricity Market of Singapore (NEMS) was established to allow generation companies to compete to sell electricity at half-hour intervals in the wholesale electricity market.

EMA has progressively opened up the retail market to competition since 2001 to give consumers the choice to buy electricity from retailers of their choice to give consumers the choice to buy electricity from retailers of their choice. The Open Electricity Market (OEM) is the final phase of this process, targeted at opening the retail market to small consumers. A soft launch of the OEM was conducted in April 2018. A total of 108 000 residential consumer accounts and 9 500 small business consumer accounts in the Jurong area were able to choose to buy electricity from a retailer with a non-regulated price plan that best meets their needs or continue paying the regulated rate. This was followed by a zonal roll out of the OEM from November 2019 to

May 2019. This completes the liberalisation of the Singapore retail market, benefiting 1.4 million accounts, mainly households (OEM, 2018).

GAS

The passage of the Gas Act (Act 11) in 2001 marked the beginning of the restructuring of Singapore's gas industry. The act sets the legal basis for separating the contestable part of the gas industry (gas retail and gas imports) from the monopolistic part (gas transportation). PowerGas Ltd, a subsidiary of SP Group, is the only gas transporter in Singapore and owns both the natural gas and town gas pipeline networks. It provides open and non-discriminatory access to the gas pipeline networks. EMA licenses and closely works with PowerGas to annually review the natural gas transmission network plan.

The Gas Network Code (GNC), which came into effect on 15 September 2008, marked Singapore's newly restructured gas market operation. The EMA developed and enacted the GNC in consultation with industry players. GNC governs the activities of gas transportation, providing open and non-discriminatory access to Singapore's onshore gas pipeline network. The GNC outlines the common terms and conditions between the gas transporter (PowerGas Ltd) and gas shippers (that is, industry players who engage the transporter to convey gas through the pipeline network). To ensure that the gas transporter is not in commercial conflict with common interests, PowerGas Ltd is banned from participating in electricity and gas businesses open to competition, such as gas importing, trading and retailing. Other gas industry participants are not allowed to transport gas.

In 2017, Singapore imported 9.9 Mtoe of natural gas, comprising 72% piped natural gas (PNG) and 28% LNG (EMA 2018a). Before the introduction of LNG in 2013, Singapore fully depended on PNG supplies from Indonesia and Malaysia.

Four offshore natural gas pipelines—two from Malaysia and two from Indonesia—supply Singapore's PNG needs. Keppel Gas Pte Ltd currently imports 43 million cubic feet per day (MMcf/D) of Malaysian gas, while Senoko Energy Ltd imports 40 MMcf/D of piped gas from Malaysia for its power generation plant. From Indonesia, Sembcorp Gas Pte Ltd currently imports 325 MMcf/D of gas from west Natuna, while Gas Supply Pte Ltd imports another 350 MMcf/D of gas from Sumatra (Business Times, 2014).

Given the growing significance of natural gas in Singapore's power mix, the Government of Singapore announced a plan in 2006 to import LNG to meet the rising demand for electricity generation and to diversify its sources of natural gas. The first Singapore LNG terminal, operated by Singapore LNG Corporation (SLNG) commenced operations on 7 May 2013, with an initial capacity of 3.5 million tonnes per annum (Mtpa), located at an approximately 40-hectare site on the south-west part of Jurong Island. This capacity increased to 6 Mtpa in January 2014 when the third LNG tank, the fourth open rack vaporiser and two high-pressure booster pumps were completed and brought into service. Additionally, the secondary berth and the gas engine generator were completed at that time (SLNG, 2014).The terminal's capacity rose further to 9 Mtpa in 2018 when its fourth tank and additional regasification facilities become operational (SLNG 2018). The LNG terminal is also capable of providing small-scale ancillary services, such as LNG trucking, cool-down and LNG break-bulk services. In addition, the terminal has also commissioned a nitrogen blending facility, which will enable SLNG to receive LNG with varying specifications from more diverse sources. SLNG is currently assessing if demand exists to facilitate the construction of the fifth LNG tank for commencement in 2022 or 2023 (SLNG, 2018).

In terms of LNG supply, Singapore has been appointing its LNG importers through a competitive Request-for-Proposal (RFP) process and by awarding them exclusive 'franchises' to sell LNG in Singapore. In 2008, BG Singapore Gas Marketing, now part of Royal Dutch Shell, emerged as the winner of the RFP process and was selected to be the sole LNG importer to supply the first tranche of LNG to Singapore. Subsequently, in October 2016, Pavilion Gas Pte Ltd and Shell Eastern Trading (Pte) Ltd were appointed to meet the second tranche of Singapore's LNG demand. The second tranche of LNG imports commenced on 23 October 2017. Both the appointed importers will have the exclusive right to sell up to 1 Mtpa of term LNG in Singapore or for three years, whichever is earlier (EMA, 2017a). To encourage greater gas-on-gas competition, the government now allows spot LNG imports, albeit all spot transactions are restricted to 10% of Singapore's long-term contracted gas supply, and eliminated controls of PNG imports (EMA, 2016a).

ENERGY TECHNOLOGY/RESEARCH AND DEVELOPMENT

Singapore catalyses energy R&D to meet Singapore's national needs and spur new economic opportunities. There are several energy research centres in Singapore today. They include the Solar Energy Research Institute of Singapore (SERIS), which conducts industry-oriented R&D in solar energy technologies for the tropics, the inter-disciplinary Energy Research Institute at Nanyang Technological University (ERI@N) and the Experimental Power Grid Centre (EPGC), which features a 1 MW experimental power grid capable of simulating different power network configurations in grid-like conditions.

Since 2011, the EMA has awarded over $100 million to address industry-relevant challenges in areas such as power generation, energy storage, smart grids and gas (EMA, 2016c). In 2013, a test-bed was established at Pulau Ubin, an island north-east of Singapore, to assess the impact of intermittent solar energy on the reliability of electricity supply within a micro-grid infrastructure. As a "Living Lab", the test-bed also showcases how micro-grid technologies and solutions could be adopted for off-grid communities in the region (EMA, 2017g). The EMA is also collaborating with the Singapore Institute of Technology (SIT) to establish Singapore's First Experimental Urban Micro-grid. This national infrastructure will enable the local research and business community to test new technologies and solutions in a controlled environment, while providing students the opportunity to work with industry partners and energy start-ups (EMA, 2017h).

In 2017, EMA awarded $6.2 million in grants to a consortium led by the National University of Singapore (NUS) and Meteorological Service Singapore to develop a solar forecasting model, customised to Singapore's tropical weather condition (EMA, 2017b). Another $17.8 million in grants was jointly awarded with SP Group to implement Singapore's largest grid-level Energy Storage System Test-bed. This is to better understand the feasibility of deploying grid-level energy storage technologies in Singapore's hot, humid and highly urbanised environment (EMA, 2017d).

In 2018, the EMA awarded a total of $15 million in research grants for seven energy innovations to strengthen the resilience of our power system and energy market. These will involve the use of technologies such as block chain, data analytics, artificial intelligence and machine learning.

To ensure industry relevance of R&D efforts, EMA has partnered agencies and industries to improve commercialisation, market translation of energy technologies. Examples of these efforts include:

- ACCelerating Energy Storage for Singapore (ACCESS): EMA launched the ACCESS programme to facilitate the deployment of energy storage systems (ESS) in Singapore. This initiative aims to spur the adoption of ESS by promoting use cases and business models and to facilitate regulatory approvals for ESS deployment to help Singapore achieve its solar target (EMA, 2018h).
- Inaugural EMA-ESG Joint Grant Call: the EMA and Enterprise Singapore (ESG) jointly launched a Grant Call in 2018 for Small and Medium Enterprises (SMEs) to develop solutions for deploying solar energy and optimising energy consumption (EMA, 2018g).
- Sembcorp-EMA Energy Technology Partnership (SEETP): EMA and Sembcorp refreshed a $10 million R&D partnership that aims to encourage the translation and commercialisation of energy research into technologies and solutions for Singapore's energy challenges via test-bedding at Sembcorp facilities (EMA, 2018i).
- Collaboration with Korea Institute of Energy Technology Evaluation and Planning (KETEP): this is a joint R&D collaboration as part of the MOU between MTI and Republic of Korea Ministry of Trade, Industry and Energy, to pursue and promote partnerships in the areas of smart grid and energy technologies.
- National Cybersecurity Grant Call: EMA partnered public agencies such as NRF, CSA, MHA and IMDA to launch a cybersecurity Grant Call to highlight the cybersecurity capability opportunities and research areas to address the specific national security, smart nation and critical information infrastructure needs.

Against a fast-evolving energy landscape impacted by various innovative technologies, EMA would need to ensure the workforce is competitive and equipped with the relevant skillsets to meet the sector's needs. To do this, EMA established close partnerships with various stakeholders, such as the industry partners, the Union of Power and Gas Employees (UPAGE), and education institutions to not only attract the next generation of

professionals but also to retain and develop the existing workforce through training programmes, scholarships, and other initiatives.

Finally, the National Environment Agency (NEA) also supports environmentally focused energy research as part of the efforts to help Singapore achieve environmental sustainability. To this end, the Singapore Environment Institute acts as NEA's training and knowledge division (NEA, 2018). Additionally, the NEA, in its capacity as Singapore's designated national authority for clean development mechanism (CDM) projects under the Kyoto Protocol to the United Nations Framework Convention to Climate Change (UNFCCC), issued 'a Letter of Approval (LoA) to CDM projects that meet Singapore's sustainable development criteria. The LoA supports the registration of the project by the UNFCCC CDM Executive Board (EB)' (NEA, 2015).

ENERGY CONSERVATION

Singapore has taken measures to decrease its energy consumption through conservation. To this end, the Parliament of Singapore passed the ECA 2013 to be jointly administered by the Ministry of the Environment and Water Resources and the Ministry of Transport; it came into effect in 2013.

The ECA requires companies that are large users of energy to implement energy management initiatives. Companies that annually consume 54 terajoules (TJ) or more of energy in at the least two out of the three preceding years are required to appoint at least one energy manager to monitor and report their energy use and GHG emissions and to submit plans for energy efficiency improvement to the relevant agencies.

The ECA also consolidates energy-efficiency-related legislation currently found in different acts, including the Mandatory Energy Labelling Scheme, Minimum Energy Performance Standards and the Fuel Economy Labelling Scheme for passenger cars and light goods vehicles under the Environmental Protection and Management Act**.** In March 2017, enhancements to the act were announced to come into effect from 2018 to help Singapore achieve its pledge under the Paris Agreement. These include strengthening the measurement and reporting requirements for GHG emissions, requiring companies to undertake regular energy efficiency opportunity assessments and introducing minimum energy performance standards for common industrial equipment and systems.

Apart from the ECA, the economy has also sought to decrease energy consumption by improving the energy efficiency of its industry, transportation, buildings and household sectors.

ENERGY EFFICIENCY

Singapore's geographical constraints limit the extent of alternative energy deployment. Energy efficiency has hence been identified as a key strategy to mitigate GHG emissions. It also helps improve competitiveness, energy security and environmental sustainability. Singapore has adopted several measures to improve its energy efficiency and reduce the energy use of various sectors of its economy.

In 2007, the government established the Energy Efficiency Programme Office (E^2PO), a multi-agency committee led by the NEA and the EMA, to implement energy efficiency to promote energy efficiency in both public and private sectors through legislation, incentives and information (NCCS, 2018b). These energy efficiency efforts are targeted at various sectors, such as power generation, industry, transport, buildings and households.

The E^2PO promotes and facilitates the adoption of energy efficiency in Singapore and has identified the following action areas for developing an energy efficiency strategy for Singapore (E^2PO, 2014):

- Promoting the adoption of energy efficient technologies and measures by addressing the market barriers to energy efficiency
- Building capability to drive and sustain energy efficiency efforts and to develop the local knowledge base and expertise in energy management
- Raising awareness to reach out to the public and businesses so as to stimulate energy efficient behaviour and practices
- Supporting research & development to enhance Singapore's capability in energy efficient technologies

The E²PO has targeted Singapore's main energy consumers, namely, industry, transportation, buildings and households, through its various programmes aimed at improving energy efficiency and reducing their CO_2 emissions. Recent examples include programmes for buildings through the Building Control Act's Chapter 29 Part IIIB—Environmental Sustainability Measures for Existing Buildings (E²PO, 2015a); for industry through the 2013 Mandatory Energy Management Requirements (E²PO, 2015b); and for households through the 10% Energy Challenge of 2008, which is aimed at encouraging households to save at least 10% (E²PO, 2015c). Expanding the mass rapid transit system has been the major emission-reduction policy for the transport sector (E²PO, 2015d).

Together with SP Group, EMA had been raising energy efficiency awareness amongst primary and secondary school students though learning journeys at the SP EE Centre, as well as a mobile education unit programme (i.e. interactive game exhibits) and community outreach events. In particular, the mobile education unit programme had reached out to more than 72,000 students to date.

INDUSTRY

The industrial sector is the largest energy-consuming sector in Singapore. The Industry Energy Efficiency Roadmap, launched in June 2016, identifies and prioritises the technological potential and opportunities to reduce energy use below BAU levels up to 2030. It also serves as a reference to provide guidance and insight to policymakers, industry leaders, academia and research institutes and other relevant stakeholders (NCCS, 2016). In October 2018, Singapore released its Enhanced Industry Energy Efficiency Package to encourage the industrial adoption of energy efficient technologies and reduce carbon emissions (EMA, 2018d).

Among the various government initiatives to improve the industry's energy efficiency are the following:

- Energy Efficiency Fund (E2F): this fund supports energy efficiency efforts at industrial facilities, namely, facilitating the efficient design of new facilities, conducting energy assessments and adopting energy-efficient equipment and technologies. E2F provides up to 50% co-funding for industrial companies to review the design of their new facilities to integrate energy and resource efficiency improvements as well as to carry out periodic energy assessments to understand their energy consumption patterns and identify potential energy improvement opportunities. In 2018, through the Enhanced Industry Energy Efficiency Package, the cap for subsidising the project costs related to the replacement of existing equipment with more energy-efficient technology was increased from 30% to 50% (EMA, 2018d). .
- Energy Efficiency National Partnership (EENP) Programme: introduced by NEA, EMA and the Economic Development Board (EDB) in 2010, the EENP serves as a platform to help companies reduce energy consumption by conducting relevant courses and workshops as well as providing energy efficiency-related resources, incentives and recognition. It is a voluntary partnership programme for companies that wish to be more energy-efficient, thereby enhancing their long-term business competitiveness and reducing their carbon footprint. Since 2011, a National Energy Efficiency Conference has been annually held to provide partners with opportunities to learn and exchange energy efficiency technologies and best practices. As of January 2019, 277 companies have joined as partners. The EENP Awards also accords recognition to companies and individuals who excel in the areas of energy management through annual awards.
- The Singapore Certified Energy Manager training programme and grant: this programme provides a thorough understanding of the key energy issues faced by the building and industry sectors. It helps participants develop the technical skills and competencies needed to manage energy issues in the organisations that they serve. A training grant is also offered to cover approximately 80% of the training costs.

- Energy Efficiency Financing Programme: to encourage industrial and manufacturing facilities to adopt energy-efficient equipment or technologies, a third-party financier pays for the cost of energy efficiency projects and the energy savings are shared among all stakeholders.
- The Accelerated Depreciation Allowance Scheme: this tax incentive scheme allows for early write-offs or depreciation of capital expenditures on qualifying energy-efficient equipment.
- The Investment Allowance Scheme: this tax incentive scheme encourages companies to invest in productive and energy-efficient construction equipment with a 30% investment allowance deduction from the companies' taxable income. The allowance is 50% for construction companies if the equipment achieves a 20% productivity gain at the project or trade level (BCA, 2019).
- The Energy Efficiency Improvement Assistance Scheme (EASe): EASe encourages and helps companies identify potential energy efficiency improvement opportunities. Under EASe, up to 50% of the cost of appraisals for buildings and facilities will be co-funded.
- Energy Service Company Accreditation Scheme: the objective is to enhance the professionalism and quality of services offered by energy services companies. This will, in turn, enhance confidence in the energy services sector and help promote the growth of the industry.
- Design for Efficiency Scheme (DfE): introduced in 2008, this initiative encourages investors to incorporate energy and resource efficiency considerations into the development plans of their facilities early in the design stage. Under the DfE, up to 80% of the cost to conduct design workshops will be co-funded.
- Grants for implementation of energy efficiency improvements: The Grant for Energy Efficiency Technologies (GREET), and it subsequent schemes such as the Resource Efficiency Grant for Energy, are co-funding schemes launched to incentivise owners or operators of industrial facilities to invest in energy-efficient technologies or equipment.
- Small and Medium Enterprise (SME) Energy Efficiency Initiative: launched in 2013, this SGD 17 million initiative brings together existing government grants to help SMEs reduce their energy costs, increase productivity and promote energy efficiency. The grant provides funding for Energy Audit, Energy Monitoring System, Energy Efficiency Project Implementation and Energy Efficiency Thought Leadership (SEAS, 2017).
- Energy Efficiency Grant Call for Power Generation Companies (Genco EE Grant Call): Launched in 2018, this initiative aims to help power generation companies to improve their overall generation efficiency and reduce carbon emission.

TRANSPORT

Singapore has sought to increase the energy efficiency of its transport sector through various measures. This objective is embedded in the economy's land transport strategies which seek to integrate transport and land-use planning, promote greater use of public transport and apply intelligent transport systems to manage road use. Roads occupy 12% of Singapore's land area, and with limited space, an integrated approach to land use planning and transport development is essential. To this end, the government has pioneered innovative policies such as a vehicle quota system and electronic road pricing to reduce congestion and a green vehicle rebate to encourage more fuel-efficient vehicles and trials of green technologies such as diesel-hybrid buses and electric vehicles (EVs).

Singapore's major efforts to increase sector efficiencies include the following:

- Investing in active mobility and public transport infrastructure with the aim of achieving 75% of all journeys in peak hours taken on public transport. These include the construction of cycling networks, the expansion of the rail network to 360km by 2030, and the expansion of the public bus fleet by 1 000 new buses under the Bus Service Enhancement Programme.

- Managing car ownership and usage by limiting the growth of vehicle numbers through the Vehicle Quota System, refining the Electronic Road Pricing (ERP) system with the ERP 2.0, which is a satellite-based ERP system, and further developing Intelligent Transport System solutions. Singapore reduced the growth rate of the Vehicle Quota System to zero in 2018, effectively capping vehicle ownership, and plans to review the policy in 2020 (LTA, 2017a).

- Testing new technologies such as the Diesel Particulate Filter, diesel-hybrid buses, electric buses and electric cars.

- Developing a Green Framework for the Rapid Transit System (RTS). The Green Mark provides a systematic and structured approach to evaluating and rating the environmental performance of the RTS for existing and future lines.

- Vehicular Emissions Scheme (VES): the VES became effective on 1 January 2018, replacing the Carbon Emissions-Based Vehicle Scheme. The scheme is meant to encourage buyers to choose car and taxi models that are more fuel efficient and emit less pollutants. Cars and taxis enjoy rebates or are levied surcharges based on their carbon dioxide, carbon monoxide, hydrocarbons, particulate matter and nitrogen oxides emissions (LTA, 2017b).

- Vehicular Emissions Label: cars and light goods vehicles sold in Singapore must show a Fuel Economy Label that provides information on its fuel efficiency and carbon dioxide emissions to help buyers make better decisions. In 2018 the NEA and LTA replaced the Fuel Economy Label with the Vehicular Emissions Label for cars, which, in addition to fuel efficiency, provides information on vehicular emissions to help potential car buyers make informed decisions in choosing cleaner, more fuel-efficient car models (LTA, 2017b).

- Green Mark for RTS: the RTS is the backbone of Singapore's public transport system and is also the most energy-efficient means of transporting a large number of commuters. By 2020, the RTS network is expected to double to 278 km. The objectives of the Green Mark for the RTS framework are to promote sustainable and environment-friendly RTS designs as well as to provide guidance in the formulation of engineering standards for conceptualisation, design and construction of new RTS lines. The framework has three key pillars—effective use of energy, water conservation and environmental protection and sustainable development—and covers various aspects of an RTS line (rolling stock, electrical and mechanical systems, civil works, station design as well as operational considerations).

- EVs: An inter-agency EV taskforce (EVTF) led by the EMA and the Land Transport Authority (LTA) launched an EV test-bed (EV Phase 1) from June 2011 to December 2013 to determine the feasibility of EVs in Singapore (EMA, 2014a). Findings from the test-bed have shown that EVs are technically feasible in Singapore but are still limited by issues such as high upfront costs. In December 2014, the EDB and the LTA announced the next phase of the EV test-bed (EV Phase 2), which will focus on vehicle fleets such as EV car sharing, E-taxis and E-buses (LTA, 2014). As part of the focus on vehicle fleets;
    - Singapore launched an EV car-sharing program in collaboration with the Bolloré Group in December 2017 (BlueSG). Under this programme, 1,000 shared EVs and 2,000 charging points will be deployed island wide by 2020 (Straits Times, 2018a).
    - HDT Singapore Taxi Pte. Ltd launched their first fleet of 50 electric taxis for trial in February 2017 and were subsequently issued a full taxi service operator license in August 2018. They will increase their fleet size to 800 electric taxis by July 2022.
    - LTA has awarded a tender for the supply of 60 electric buses. These electric buses will be progressively delivered from end-2019 and will be deployed for service by 2020.

- Promoting Cycling: To promote a cycling-friendly city, Singapore has extended its cycling network and enhanced the cycling infrastructure. By 2030, all HDB towns will have a cycling network, taking the total cycling paths across Singapore to 700 km. Other bicycle-friendly infrastructure such as bicycle crossings and bike parking facilities are being added to further encourage a cycling culture (LTA, 2018).

To encourage the use of shared Active Mobility devices, Singapore has allowed bicycle and Personal Mobility Device (PMD) sharing services in 2018 and 2019, respectively.

BUILDINGS

The Building and Construction Authority (BCA), a statutory board under the Ministry of National Development, spearheads energy efficiency improvements in the building sector. In its third and latest Green Building Masterplan launched in September 2014, the BCA set out ambitious plans to accelerate its green building agenda and meet the target of greening 80% of the buildings in Singapore by 2030 (BCA, 2014). Energy efficiency initiatives in Singapore's building sector include the following:

- BCA Green Mark Scheme: launched in January 2005, this scheme is a green building rating system that promotes sustainability in the established environment and raises environmental awareness among developers, designers and builders. Under this benchmarking scheme, buildings are assessed for energy efficiency, water efficiency, indoor environmental quality and environmental protection as well as other green features and innovations.
- Building Control (Environmental Sustainability) Regulations: these regulations took effect in 2008 and require new buildings and existing ones undergoing major retrofitting with a gross floor area (GFA) greater than 2 000 square metres to achieve the minimum green mark certified level.
- Building Control Act's Chapter 29 Part IIIB—Environmental Sustainability Measures for Existing Buildings: introduced in 2012, this act requires building owners to comply with the minimum environmental sustainability standard (green mark standard) for existing buildings; submit periodic energy efficiency audits of building cooling systems and submit information with respect to energy consumption and other related information, as required.
- Building Control (Environmental Sustainability Measures for Existing Buildings) (Amendment) Regulations 2016: since January 2017, all buildings (except industrial buildings, railway premises, port facilities or airport facilities, religious buildings, data centres, utility buildings and residential buildings other than serviced apartments) with centralised cooling systems and GFA greater than 5 000 square metres must comply with the revised act, when installing or replacing the building cooling system.
- S$50 Million Green Mark Incentive Scheme for Existing Buildings and Premises: launched in 2014, this is targeted to encourage SME tenants and building owners or building owners with at the least 30% of SME tenants, to adopt energy efficiency improvement measures. The scheme co-funds up to 50% of the retrofitting cost for energy improvements or up to S$3 million for building owners and S$20 000 for tenants.
- Building Retrofit Energy Efficiency Financing Scheme: this scheme was introduced in 2011 to offer financial aid through an energy performance contract arrangement to offset high upfront costs of energy efficiency retrofits. With the scheme, applicants can obtain financing from participating financial institutions and service the loans through energy savings.
- Green Mark GFA Incentive Scheme: to encourage the private sector to achieve higher-tier Green Mark ratings, additional floor area will be allowed to private developments with Green Mark Platinum or Gold Plus marks from April 2014 to April 2019.
- S$5 million Green Mark Incentive Scheme, Design Prototype: valid from December 2014 to December 2018, this scheme aims to encourage developers and building owners to strive for greater energy efficiency in buildings at the design stage by providing funding support to engage consultants during the design phase for green buildings.
- S$100 Million Green Mark Incentive Scheme for Existing Buildings: this is aimed at owners of existing private commercial developments to help them implement energy-efficient solutions and to conduct energy audits in their existing buildings.

- Public Sector Sustainability Plan: launched in 2017, the government aims to achieve electricity savings of 15.0% by 2020 from the baseline electricity consumption in 2013. These include 'hardware' improvements, such as replacing or upgrading air-conditioning systems and lightings, and 'software' actions, such as promoting organisational habits that minimise electricity consumption. The annual energy savings from the government's committed measures amount to 290 GWh. This is sufficient to power 50,000 households for an entire year. Each ministry is required to submit reduction targets and management plans to meet the targets. In addition, new public sector buildings with an air-conditioned area of greater than 5 000 square metres must attain the Green Mark Platinum rating, while existing public sector buildings with an air-conditioned area of greater than 10 000 square metres must attain the Green Mark GoldPLUS rating by 2020.

HOUSEHOLDS

Improving energy efficiency of households has been a major target for Singapore as part of its commitment to sustainable development that demands reductions in fossil energy consumption and CO_2 emissions. Accounting for about one-sixth of the electricity consumed in Singapore, households are encouraged to purchase energy-efficient appliances and adopt energy-efficient habits. Energy efficiency programmes for households include the following (NEA, 2019):

- Mandatory Energy Labelling Scheme (MELS): under the ECA, registrable household appliances that are sold in Singapore must show the mandatory energy label which displays the energy rating of an appliance by the number of ticks (from 1 to 5, with 5 being the most energy-efficient). MELS was introduced to help consumers compare the energy efficiency of different appliances and make more informed purchasing decisions. It currently covers household refrigerators, air conditioners, clothes dryers, television sets and lamps. In 2019, Singapore will introduce an MELS for other lamps with the goal of making LEDs the minimum standard for light bulbs by 2023 and will require the display of energy labels in all print and digital publicity materials used by retailers and suppliers to promote appliances (Straits Times, 2018b).

- Minimum Energy Performance Standards (MEPS): the objective of setting MEPS is to raise the average energy efficiency of regulated goods in the market. This is done by prohibiting the sale of appliances that fall short of specified minimum energy efficiency levels and by encouraging suppliers to bring in more energy-efficient appliances as technology improves. Household refrigerators, air conditioners, clothes dryers and lamps supplied in Singapore must meet the MEPS. In 2019 Singapore will the MEPS for incandescent bulbs and introduce its first MEPS for fluorescent lamp ballasts.

- Residential Envelope Transmittance Value Standard: Established in 2008, residential buildings with a GFA of 2 000 square metres or more must comply with the BCA residential envelope transmittance value standard.

RENEWABLE ENERGY

Singapore has very limited options in terms of renewables because of its geological and geographical location. Hydro, wind, geothermal and tidal energy are not feasible, leaving solar PV systems and WtE as Singapore's main renewable energy sources. The economy has also been producing biodiesel since 2010 to help diversify its liquid energy demand.

In terms of WtE, Singapore currently has four electricity-generating incineration plants (Tuas IP 46 MW, Senoko WTE Plant two x 28 MW, Tuas South IP 80 MW and Keppel Seghers Tuas WtE Plant 22 MW) that incinerated a total of 2.83 million tonnes (Mt) of waste in 2016 (MEWR, 2017). In 2015, Singapore announced plans to build a new 120 MW WtE plant by 2019. More details can be found under 'New Generation Capacity' in the section on 'Notable Energy Developments'.

In terms of solar power, Singapore has put in place a series of initiatives to pursue its target of raising the adoption of solar power to 350 MWp by 2020 and to 1 GWp beyond 2020. At the end of 2018 there were 2 712 grid-connected PV installations with a total capacity of 203 MWp, comprising 926 residential (7.1 MWp) and 1 786 non-residential (149 MWp) installations (EMA, 2018e). The list of solar initiatives by the economy includes the following:

- In support of Singapore's solar energy plans, HDB has committed to the roll-out of 220 MWp of solar panels in about 5 500 HDB blocks by 2020. As of December 2018, HDB has held four solar leasing tenders under the SolarNova programme and has committed a total solar capacity of 230 MWp, exceeding its 2020 capacity commitment, for 4 550 HDB blocks (HDB, 2018).

- The SolarNova programme was initiated in 2014 to aggregate demand for solar energy across government agencies in order to achieve economies of scale and drive the growth of Singapore's solar industry (HDB, 2014). This programme is estimated to generate 420 GWh of solar energy annually, equivalent to about 5% of Singapore's total energy consumption; HDB's current solar commitments can generate an estimated 277 GWh of solar energy annually (HDB, 2018). Under the solar leasing business model, private solar PV system developers will design, finance, install, operate and maintain the solar PV systems. Town councils managing the HDB blocks with solar panels will then enter a service agreement with these developers to pay for the solar power generated at a preferential rate not higher than the retail electricity tariffs (HDB, 2016). The power produced could be used to power lifts, corridors and staircase lights in common areas.

- With effect from May 2017, all future public housing blocks with at the least 400 square metres of open roof space will be designed with solar-ready roofs to enable more productive and efficient installation of solar panels on HDB rooftops. In addition, HDB will also review developments currently under construction to assess if solar-ready roofs can be incorporated into their design.

- Added to HDB's efforts to expand solar energy, the EDB and PUB also conducted a pilot floating PV system test-bed project at Tengeh Reservoir in October 2016. The test-bed was aimed at assessing the feasibility of installing floating solar PV systems as an alternative to rooftop-based installations (PUB, 2017). It is the world's largest test site for floating solar panels and the first project of this nature in Southeast Asia. Results from the test-bed showed that the system performed better than a typical rooftop solar PV system in Singapore because of the cooler temperatures of the reservoir environment. Building on these successful results, PUB announced plans in September 2017 to expand its trials to explore the feasibility of deploying a 50 MWp floating solar PV system at Tengeh Reservoir and a 6.7 MWp floating solar PV system in Upper Peirce Reservoir (PUB, 2017). In October 2018, EDB launched a Request for Information (RFI) to explore the possibility of a 100 MWp floating solar PV system for private sector consumption, starting with studies at Kranji reservoir. (EDB, 2018).

- The EMA is crafting policy to help integrate solar into Singapore's electricity system. Integrating intermittent supply sources presents the risk of destabilizing the electricity system if back-up generators are not available to balance out potential supply shortfalls. Furthermore, without a pricing mechanism in place to compensate backup capacity in the event of an intermittent shortfall, conventional generators are bearing the full costs of this risk. Because of this, the EMA has introduced the Intermittency Pricing Mechanism (IPM) built on a causer-pays principle, where intermittent generators, renewable or conventional, pay for reserve capacity if their production shortfall requires back-up from the electricity system. The IPM will also send the price signal to encourage investors to reduce reserve capacity costs by manage intermittency through measures such as demand-side management and the use of battery storage (EMA, 2018f). Recognising that Energy Storage Systems (ESS) is a key enabler to support higher level of solar deployment, EMA has also published a policy paper on ESS in October 2018 to provide clarity on the treatment of ESS in the regulatory framework.

In terms of biodiesel production, Finnish oil refining and marketing company, Neste, built the world's largest diesel refinery in Singapore at a cost of EUR 550 million in November 2010. The refinery has a capacity of one million tonnes per annum and uses Neste's proprietary NExBTL technology to produce renewable diesel products (Neste, 2018). In December 2018, Neste announced plans to expand add about two million tonnes per annum of renewable diesel capacity to its Singapore refinery.

SUSTAINABLE DEVELOPMENT

Singapore's IMCSD unveiled its first blueprint sustainable development on 27 April 2009. This plan contains strategies and initiatives for achieving both economic growth and a good living environment for Singapore over the next 20 years.

The document details new targets and initiatives to improve resource efficiency and to enhance Singapore's urban environment. Improved efficiency in the use of resources such as energy, water and land will contribute to enhancing the city-state's competitiveness in the long run. Under the blueprint, efforts will be made to improve air quality, expand and open up green and blue spaces, conserve biodiversity, and enhance public cleanliness. These efforts will contribute to making the city a more liveable and attractive place, even as Singapore continues to grow and develop. Targets have been set to measure the progress in these areas. The blueprint has a 20-year timeframe, with identified key goals for 2030. The blueprint's goal for the energy sector is to reduce energy intensity by 35% by 2030 from 2005 levels, with an intermediate goal of 20% by 2020 from the 2005 levels (BCA, 2010).

In 2015, Singapore released 'an extension of the efforts outlined in the 2009 edition', namely, the Sustainable Singapore Blueprint 2015 (MEWR, 2015). This document takes into consideration the feedback obtained from more than 130 000 people of recent initiatives, including the Land Transport Master Plan 2013 and the Urban Redevelopment Authority's Master Plan 2014. Its emphasis is on sustainable housing and transportation aimed at reducing waste to zero through the reduction of consumption, recycling, reuse of all materials and the adoption of greener practices by businesses. The objective is to turn Singapore into a 'hub for the cutting-edge business of sustainable development' and to achieve three objectives: a liveable and endearing home; a vibrant and sustainable city and an active and gracious community.

As part of its sustainable development objective, Singapore has taken steps to increase the solar share of its electricity generation. Among others, the EMA has adopted a policy of proactively enhancing the required market and regulatory framework to facilitate the deployment of solar units (EMA, 2014c).

NUCLEAR ENERGY

Singapore currently does not have a nuclear energy industry. In 2010, the economy embarked on a pre-feasibility study of nuclear energy to objectively evaluate the opportunities, challenges and risks of nuclear energy and its feasibility as a long-term energy option for Singapore. The study, finalised in 2012, concluded that nuclear energy technologies currently available, although safer than the older designs still in use in many economies, were unsuitable for deployment in Singapore given the economy's small size and high population density).

CLIMATE CHANGE

Singapore is a small and completely urbanised city-state whose CO_2 emissions account for less than 0.2% of global emissions. The economy has made major progress in reducing its CO_2 emissions although its options for non-CO_2 emitting energy are very limited (mainly confined to WtE and a very small amount of solar) and nuclear energy is not an option as mentioned earlier (EMA, 2014c).

Hence, in 2009, Singapore pledged in the context of the UNFCCC negotiations to reduce emissions by 16% from 2020 BAU levels in the event of a legally binding global agreement under which all economies will implement their commitments. The economy set up the National Climate Change Secretariat on 1 July 2010 as a dedicated agency under the Prime Minister's Office to coordinate its domestic and international policies, plans and actions on climate change (NCCS, 2018c). Singapore ratified the Paris Agreement in September 2016, formalising its pledge to reduce emissions intensity by 36% from 2005 levels by 2030 and to stabilise emissions with the aim of peaking around 2030.

Apart from increasing the share of solar in its power generation energy mix, it has significantly reduced its grid-generated emissions through greater use of natural gas for electricity generation by increasing its share of the power mix. Singapore has switched from fuel oil to natural gas as the main energy source for such generation because it produces the least carbon emissions per unit of electricity generated, among fossil fuel-fired power plants. By increasing the share of natural gas used in electricity generation from only 19% in 2000 to 95% currently, Singapore has substantially reduced its emissions growth over the past 10 years. Singapore's

efforts have resulted in improving its average operating margin grid emission factor from 0.5255 kg CO_2/kWh in 2005 to 0.4192 kg CO_2/kWh in 2017 (EMA, 2018a).

NOTABLE ENERGY DEVELOPMENTS

CARBON TAX FROM 2019

Following its climate change pledge, Singapore has been stepping up on efforts to reduce energy use and carbon emissions. In 2017, the Government of Singapore announced the intention to implement a carbon tax on the emission of greenhouse gases starting from 2019. This marks Singapore as the first Southeast Asian economy to implement a carbon tax. The policy aims to enhance Singapore's existing and planned mitigation efforts under the Climate Action Plan and stimulate clean technology and market innovation. In February 2018, the government finalised the details of the carbon tax mechanism as follows (NCCS, 2018d):

- The carbon tax will generally be applied upstream, for example, on power stations and other large direct emitters, rather than electricity users, on all facilities producing 25 000 tonnes or more of greenhouse gas emissions in a year. This represents about 30 to 40 large emitters that contribute 80% of Singapore's greenhouse gas emissions. The government will further assess how to account for the remaining 20% of the emissions.

- The initial carbon tax rate is SGD 5 per tonne of greenhouse gas emissions for a five-year period from 2019 to 2023 to allow companies time to adjust to the carbon tax and implement energy efficiency projects. The government will review the rate by 2023, with an intention to increase it to between SGD 10 and SGD 15 per tonne of emissions by 2030, depending on international climate change developments, the progress of Singapore's emissions mitigation efforts and economic competitiveness.

- The carbon tax will apply uniformly to all sectors, without exemption. Taxable facilities will pay for the carbon tax through the purchase of carbon credits corresponding to their emissions, with the first payment in 2020, based on their 2019 emissions.

- Over the initial five-year period, the government expects to generate about SGD 1 billion in carbon tax revenue (Singapore Budget, 2018). This will be used to support companies in improving energy efficiency, such as funding existing green initiatives via the Resource Efficiency Grant for Energy (which replaced the Productivity Grant for Energy Efficiency in 2019) and the Energy Efficiency Fund.).

REGULATORY SANDBOX TO ENCOURAGE ENERGY SECTOR INNOVATIONS

In October 2017, EMA implemented a regulatory sandbox framework in the electricity and gas sectors. The framework allows regulations to be relaxed, within defined parameters, in a sandbox that can accommodate new products and services for testing. It will also allow EMA to assess the impact of new products and services before deciding on the wider regulatory treatment (EMA, 2017e).

DEMAND-SIDE MANAGEMENT

In October 2016, EMA signed a Memorandum of Understanding with 16 partners for a pilot programme, Project OptiWatt, to test the viability of DSM. Through DSM, energy consumption can be shifted from peak to non-peak hour, thereby reducing the maximum load that the energy system needs to cater to, yielding system-wide benefits. The project partners comprise institutes of higher learnings (IHLs), government agencies, companies, electricity retailers, research institutions and the electricity grid operator (EMA, 2017f). EMA published the success stories and infographic on the key learning outcomes from this initiative on its website to increase consumer awareness and encourage adoption of DSM. It also introduced a Demand Response (DR) Programme to entice contestable consumers to bid prices where they are willing to reduce electricity consumption in exchange for incentive payments. Incentive payments currently repay a third of the total savings back to DR providers (EMA, 2016b).

POST-3 MTPA LNG IMPORT FRAMEWORK

On 30 June 2014, the EMA launched a competitive RFP process to appoint up to two importers to supply Singapore with LNG beyond the first 3 Mtpa from Shell (previously BG Singapore Gas Marketing Pte. Ltd.). The RFP was conducted in two stages and concluded in October 2016, with Pavilion Gas and Shell Eastern Trading (Pte) Ltd being appointed as the next LNG importers for Singapore. Each of the companies was awarded an exclusive right to import and sell LNG in Singapore up to 1 Mtpa each, or for a period of three years, whichever is earlier (EMA, 2016a).

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USEFUL LINKS

Department of Statistics Singapore—www.singstat.gov.sg

Economic Development Board—www.edb.gov.sg/

Energy Efficiency Programme Office—http://www.e2singapore.gov.sg/

Energy Market Authority—www.ema.gov.sg

Housing & Development Board—http://www.hdb.gov.sg/cs/infoweb/homepage

Land Transport Authority—www.lta.gov.sg

Ministry of National Development—http://app.mnd.gov.sg/

Ministry of the Environment and Water Resources—www.mewr.gov.sg

Ministry of Trade and Industry—https://www.mti.gov.sg

National Environment Agency—www.nea.gov.sg

National Climate Change Secretariat—https://www.nccs.gov.sg/

Singapore LNG Corporation (SLNG)—www.slng.com.sg/website/index.aspx

Solar Energy Research Institute of Singapore (SERIS)—www.seris.nus.edu.sg

Temasek Holdings—www.temasekholdings.com.sg

CHINESE TAIPEI

INTRODUCTION

Chinese Taipei is an archipelago comprising Taiwan, Penghu, Kinmen and Matsu, located off the southeast coast of China and the southwest coast of Japan. With an area of 36 197 square kilometres (km^2) (Department of Statistics, Ministry of the Interior, 2019), Chinese Taipei represents a natural gateway to east Asia. Although only one-quarter of the land is arable, the subtropical climate permits multi-cropping of rice and the perennial growth of fruit and vegetables.

In 2016, Chinese Taipei's gross domestic product (GDP) was USD 1 127 billion and its per capita income was USD 47 855 (2011 USD purchasing power parity [PPP]). Its GDP grew on an average at a rate of 3.9% during 2000–16. Within the past few decades, Chinese Taipei's economic structure has substantially changed, shifting from industrial production to the services sector, wherein the latter constituted 63% of the GDP, followed by industry (36%) and agriculture (1.8%) in 2016 (BOE, 2018a). Chinese Taipei is one of the most densely populated areas in the world, but its population growth rate has been relatively flat; the economy's population of 24 million grew at a rate of 0.35 % during 2000–16 (EGEDA, 2018).

Lacking natural resources, Chinese Taipei is highly dependent on energy imports to meet domestic energy demand. According to the US Energy Information Administration, Chinese Taipei holds only 2.4 million barrels of oil reserves (EIA, 2016). Coal reserves in the economy are rather scarce, and owing to the high mining cost, there has been no coal production in the economy since 2000.

Table 1: Key data and economic profile, 2016

Key data		Energy reserves [c]	
Area (km^2)[a]	36 197	Oil (million barrels)[c]	2.4
Population (million)[b]	24	Gas (billion cubic metres)	N/A
GDP (2011 USD billion PPP)[b]	1 127	Coal (million tonnes)	–
GDP (2011 USD PPP per capita)[b]	47 855	Uranium (kilotonnes of U)	–

Sources: [a] Department of Statistics, Ministry of the Interior (2019); [b] EGEDA (2018); [c] EIA (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

As mentioned earlier, Chinese Taipei heavily relies on overseas energy resources for its needs. In 2015, imported energy accounted for 98% of the total energy supply in Chinese Taipei (BOE, 2018a), indicating a low energy self-sufficiency rate as well as a fragile energy security.

The growth of total primary energy supply (TPES) in Chinese Taipei is stable and has remained stable over the past few years, increasing by 1.6% from 107 160 kilotonnes of oil equivalent (ktoe) in 2011 to 109 045 ktoe in 2016. Regarding the composition of the TPES, fossil fuels continue to be the dominant fuel consisting of 90% of the total supply. By fuel type, oil contributes the largest share (40%), followed by coal (34%), natural gas (17%), renewable energy (RE) (1.7%) and other fuels (8.0%) (EGEDA, 2018).

In 2016, Chinese Taipei imported nearly 314 million barrels of crude oil, 2.0% higher than the 308 million barrels imported in 2015. The Middle East is the major supplier, accounting for 78% of the total oil imports, followed by Angola (9.1%) (BOE, 2019). To prevent supply disruption, the Petroleum Administration Act 2001 requires Chinese Taipei's refiners to maintain stocks of more than 60 days of sale volumes.

Australia and Indonesia are the major suppliers of coal, accounting for 52% and 31%, respectively, of the total coal imports totalling up to 55 million tonnes in 2016. Most of this fuel is used for power generation.

Because indigenous natural gas only accounts for 1.4% of the total natural gas supply in Chinese Taipei, almost the entire gas demand is met by liquefied natural gas (LNG) imports. Qatar, Malaysia and Indonesia are the largest suppliers, accounting for 42%, 17% and 14% of the supply, respectively, in 2016. The total LNG import in 2016 was 15 million tonnes (Mt), 4.1% higher than the 14 Mt imported in 2015 (BOE, 2018a).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	10 876	Industry sector	22 920	Total power generation	264 108
Net imports and others	101 617	Transport sector	12 515	Thermal	212 255
Total primary energy supply	109 045	Other sectors	12 445	Hydro	9 855
Coal	37 197	Non-energy	23 106	Nuclear	31 661
Oil	43 151	Final energy consumption*	47 879	Others	10 337
Gas	18 091	Coal	7 615		
Renewables	1 878	Oil	16 582		
Others	8 728	Gas	3 145		
		Renewables	188		
		Electricity and others	20 350		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

In 2016, electricity generation in Chinese Taipei reached 264 108 gigawatt-hours (GWh). Of the total electricity production, hydropower generated by the Taiwan Power Company (TPC) comprised 3.7%, thermal power comprised 53% (25% coal, 4.0% oil and 24% LNG), nuclear power comprised 12%, solar comprised 0.01%, wind power comprised 0.24%, cogeneration comprised 15% and independent power producers (IPPs) comprised 16%. In terms of the generating capacity, the TPC dominates Chinese Taipei's electric power sector with 65% and IPPs account for 16% of the total capacity. IPPs are required to sign power purchase agreements with the TPC, which distributes power to consumers. To expand foreign participation, the government permitted foreign investors to own up to 100% of an IPP in January 2002 (BOE, 2018a).

FINAL ENERGY CONSUMPTION

The total final consumption in Chinese Taipei was 70 985 ktoe in 2016, 2.6% higher than that in 2015. The non-energy sector is the largest energy consumer at 33%, which is mostly used by chemical and petrochemical industries. The second-largest energy consumer is the industrial sector, accounting for 32% of the total energy used, followed by the transport sector (18%) and other sectors, including residential and services, which consumed 18% of the total energy used. By energy source, electricity and others accounted for 43% of the final energy consumption (excluding non-energy), followed by oil (35%), coal (16%), gas (6.6%) and RE (0.39%) (EGEDA, 2018).

ENERGY INTENSITY ANALYSIS

In terms of energy intensity by the TPES, Chinese Taipei showed an improvement with a reduction of 5.4%, declining from 102 tonnes of oil equivalent per million USD (toe/million USD) in 2015 to 97 toe/million USD in 2016. However, energy intensity in terms of the total final consumption showed a 3.1% improvement from 44 toe/million USD in 2015 to 43 toe/million USD in 2016, which shows that the transformation is more efficient now.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	102	97	–5.4
Total final consumption	44	43	1.0
Total final energy consumption excl. non-energy	65	63	1.5

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Chinese Taipei has been promoting the use of RE to reduce carbon emission as well as to increase power generation. The use of modern RE, including use for heat and electricity, increased by 40% from 1 240 ktoe in 2015 to 1 742 in 2016. The share of modern RE in the final energy consumption also showed an increase from 2.7% in 2015 to 3.6% in 2016.

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	46 568	47 879	2.8
Non-renewables (fossils and others)	45 327	46 137	1.8
Traditional biomass*	0	0	0
Modern renewables*	1 240	1 742	40
Share of modern renewables to final energy consumption (%)	2.7	3.6	37

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Bureau of Energy (BOE) was established under the Ministry of Economic Affairs (MOEA) in 2004 and is responsible for formulating and implementing Chinese Taipei's energy policy. To cope with the austere energy situations in Chinese Taipei, the new government elected on 20 May 2016 announced a new policy 'New Energy Policy' on 25 May 2016 (BOE, 2016). Later in April 2017, the MOEA revised 'Guideline on Energy Development' released in 2012 (BOE, 2017a).

The main vision of 'New Energy Policy' is to initiate energy transition and reform power market regulation. It has two main objectives:

- Enlarge clean energy share of power mix: increase RE share to 20% and natural gas share to 50% in the total power mix in 2025. Reduce coal share in the total power mix to 30% in 2025.
- Nuclear-free homeland: decommission the three existing nuclear plants when their authorised 40-year lifespan expires between 2018 and 2025. Achieve nuclear-free homeland by 2025.

There are nine major strategies under 'New Energy Policy', including the following:

- To stabilise power generation source and strengthen consumption management, ensuring stability of power supply
- To promote energy efficiency and energy savings
- To diversify energy mix, especially developing clean energy
- To accelerate energy-saving system and strengthen the stability of power grid
- To promote smart grid and smart metre
- To integrate domestic resources and a system to promote clean energy
- To reform power market regulation and improve power supply efficiency and quality

The revised 'Guideline on Energy Development' serves as the superior policy guidance for national energy development, energy policy programmes, standards and action plans. The guideline is based on paragraph 2 of Article 1 in the 'Energy Administration Act'; it aims to ensure balanced development in energy security, green economy, environmental sustainability and social equity to achieve nuclear-free homeland target by 2025 as well as to attain sustainable energy development. There are four main guiding principles:

- **Energy security:** strengthen energy saving on the consumption side, such as adopting a new economic development model of 'innovation, employment and equitable distribution' to continue with the optimisation and transition of industrial structure. Furthermore, diversify the energy mix, increase the share of self-produced energy as well as expand RE installation to enhance the supply and security of low-carbon energy. Establish smart system integration, including the deployment of smart metres, and promote an overall improvement of regional power transmission and distribution systems.
- **Green energy:** construct a green energy industrial ecological system, including regulatory incentives, land acquisition, financing mechanism and so on. Establish environmental cost pricing mechanism through policy tools or market mechanism such as cap and trade and create new green service economy to foster green production and green energy investment. Promote regional green energy application, and, in particular, integrate the development of smart cities and agriculture villages in conjunction with opportunities of Internet-of-Things development. Innovate in green energy and carbon-reduction technologies, strengthen the research and development (R&D) of technologies and the deployment of energy storage and smart gird as well as accelerate the development of a cloud intelligent energy management system.
- **Environmental sustainability:** improve the air quality by taking the cap of total emissions from air pollutants as the basis for the planning of new power plants. Select an appropriate site for energy facility construction to avoid or reduce the impacts on environmentally sensitive areas. Continue greenhouse gas (GHG) emissions control and the reduction to establish a low-carbon environment. Achieve nuclear-free homeland target while proposing plans for short-, mid- and long-term management and disposal policies for high-level and low-level radioactive wastes.
- **Social equity:** promote energy democracy and justice by establishing mechanisms and incentives for public participation and risk communication as well as introduce the participatory governance approach to energy policymaking. Additionally, the government should contribute to equity within and across generations while assuring the basic energy services for vulnerable groups and the equity and justice in energy use to avoid energy poverty. Promote domestic power market reform by phases, aiming to achieve the goal of 'diversified supply, equity in usage and freedom of choice'.

The guideline also announced to formulate an 'Energy White Paper' as a promoting mechanism for energy transition. The 'Energy White Paper' will include more detailed measures and policy tools for future energy development. The government aims to submit an annual accomplishment report to summarise the achievements and conduct periodic review for every five years.

ENERGY SECURITY

As Chinese Taipei heavily relies on energy imports, the government has put in multiple measures to enhance energy security. In terms of oil supply, the Petroleum Administration Act requires refiners and importers to maintain 60 days of sales volumes (calculated from the average domestic sales and private consumption over the preceding 12 months) as stockpiles. The government uses the petroleum fund to finance the storage of oil and stockpiles 30 days of oil consumption. The Act mandates that a liquid petroleum gas stockpile lasting more than 25 days be maintained (BOE, 2017b).

For many years, the Chinese Petroleum Corporation (CPC) has engaged in cooperative exploration with governments and large international oil companies in operations throughout the Americas, the Asia-Pacific region and Africa under the banner Overseas Petroleum and Investment Corporation. As of the end of 2017, CPC has engaged with international oil companies in joint exploration of 17 fields in seven countries, involving the operation of 1 000 producing wells. CPC's share of the output of 13 producing fields in Ecuador, Indonesia, Niger and the US amounted to over 4.5 million barrels of crude oil and 137 million cubic metres of natural gas. The output includes both conventional and tight oil and gas.

To boost domestic energy production, state-owned oil and gas company CPC completed 2D seismic surveys on 113 km^2 of the Pingtung Plain, a high-precision gravity survey of the Fengshan mud structures and geological surveys covering 73 km^2, and repaired three production wells in 2016. There are currently 33 oil- and natural gas-producing wells spread over Chan Mountain and Qing Cao Lake in Taichung City, Jing Shui and Chu Kuang Keng in Miaoli Prefecture and Guang Tien in Tainan City, yielding 266 million cubic metres of natural gas and 5 407 kilolitres of condensate annually. CPC is also cooperating with Husky Energy of Canada on exploration of deep-water blocks in the Tainan Basin, as well as with China National Offshore Oil Corporation (CNOOC) and France's TOTAL to start a 2D seismic survey in deep-water areas of the Taiwan Strait (CPC, 2018).

ENERGY MARKETS

ELECTRICITY MARKETS

Chinese Taipei has three interconnected power grids: north, central and south. The north area, where Taipei is located, has the largest demand in peak hours, so it is common for power to flow north from the central grid. Until 1990, the TPC was responsible for all power generation, transmission, distribution and sales. Since then, the sector has been opened up to allow private companies to establish power plants, creating competition in the generation sector. As of December 2018, there are 25 IPPs[1] in Chinese Taipei.

The government of Chinese Taipei aims to secure a total electricity supply with a reserve capacity of 15% (BOE, 2017b) based on peak consumption. As a state-owned power company, TPC is responsible for power supply in Chinese Taipei according to the Electricity Act. As of the end of 2017, the installed capacity of TPC is 31 750 MW, comprising thermal power generation and nuclear power generation as well as pumped hydropower and RE (BOE, 2018a).

To become a nuclear-free economy and achieve the goals stipulated in the Greenhouse Gas Reduction and Management Act by reducing GHG emissions to 50% below 2005 levels by 2050, the MOEA formulated a two-stage plan to amend the Electricity Act. The premise of the amendment is to ensure stable power supply, and the goals are 1) multiple supplies and green energy first; 2) fair usage for the electricity grid and 3) free power purchasing choices for users (BOE, 2017b).

The first-stage amendment includes the amendment of power generation, transmission and distribution and retailing enterprises (BOE, 2017b).

- **Generating enterprise:** RE-generating corporations can sell electricity in three different ways: wholesale, wheeling and direct supply. The traditional generating corporation is not allowed to sell the electricity to the end user and can only sell to a retailing utility corporation.
- **Transmission and distribution enterprise:** a utility corporation installs the power transmission and distribution networks to wheel the electric power. No more than one state-owned corporation exists,

[1] 25 IPPs include three hydro companies, nine solar PV companies and thirteen wind power companies.

and the scope of its business operation covers the entire economy. This enterprise is responsible for fair dispatch and to be a 'common carrier'.

- **Retailing enterprise:** RE-retailing corporations can only purchase electricity generated by RE-generation equipment for wheeling to the users. A retailing utility corporation is a public utility company and has the obligation to supply.

The second-stage amendment will allow the new traditional generating corporation, joined in the first stage, to perform wheeling and provide direct supply to customers, introducing generation market competition and allowing the general retail companies to set up. The traditional generating corporation existing before the first stage of the amendment still can only sell their electricity to the retailing utility corporation. However, the second stage will not start until the mechanism and the operations of the first amendment are mature.

FISCAL REGIME AND INVESTMENT

Chinese Taipei has limited indigenous energy resources, and thus, it has no formal policy on investment in upstream assets. However, to secure new energy sources, Chinese Taipei has invested in oil exploration both in the Taiwan Strait and abroad through the state-owned enterprise—the CPC. Chinese Taipei also welcomes the participation of foreign investors in bidding on the IPP electricity market.

ENERGY EFFICIENCY

As a promoting mechanism of 'Guideline on Energy Development', the BOE started drafting an 'Energy White Paper' to help facilitating energy transition. In February 2018, the BOE released the 'Energy Saving Target and Roadmap' implementation plan, aiming to improve energy intensity by 2.4% every year and electricity intensity by 2% every year between 2017 and 2025. The roadmap includes implementation plans for building envelopes, residential and services[2], industry and transport sector. It aims to reduce energy consumption to 5 Mtoe or 17 terawatt-hours (TWh) in these four sectors below the 2016 level by 2025 (BOE, 2018b).

- **Residential and services (BOE, 2018c)**
  - Target: improve energy efficiency to reduce electricity demand by 6.5 TWh and oil consumption by 0.03 Mtoe from the 2016 levels by 2025.
  - Roadmap: promote energy audits and provide consumption reduction counselling for services. Improve energy efficiency management for residential and services sector. Strengthen basic consumption reduction measures in local areas and expand public participation.
- **Industrial sector (BOE, 2018d))**
  - Target: reduce energy intensity by 45% below the 2005 level by 2025. Reduce energy consumption by 2.3 Mtoe and CO_2 emissions by 7.0 $MtCO_2$ in 2016–25.
  - Roadmap: promote transition to lower-intensity industry by increasing the efficiency of manufacturing processes and retrofitting factories to use low-carbon fuels. Provide energy saving and CO_2 emissions reduction counselling for manufacturers. Promote regional resource integration and establish incentive mechanisms.
- **Building envelopes (BOE, 2018e)**
  - Target: improve and strengthen consumption reduction-related regulations and measures. Reduce energy demand by 0.63 Mtoe or 3.2 TWh below the 2016 level by 2025.
  - Roadmap: improve design index by 10% for new building envelopes and add 500 green building materials and candidate certificates every year. Strengthen current measures for reducing the energy consumption of existing buildings. Promote transparency of building energy

[2] The buildings sector classification in Chinese Taipei's Energy Saving Roadmap is different from APERC's classification, which splits buildings between residential and service subsectors. Chinese Taipei's roadmap also includes building envelopes as a separate sector.

consumption. Develop Internet-based demand reduction simulation tools to estimate consumption. Conduct zero-energy building feasibility studies.

- **Transport sector (BOE, 2018f)**
  - Target: reduce gasoline consumption by 0.85 megalitres (ML) and diesel consumption by 0.10 ML (640 toe and 84 toe) from the 2017 level by 2020. Increase electricity use by 406 megawatt-hours above the 2017 level by 2020. Reduce transport CO_2 emissions by 2 $MtCO_2$ below the 2017 level by 2020.
  - Roadmap: withdraw 80 000 first- and second-phase heavy-duty diesel vehicles by 2019. Expand public transport capacity by 2% above the 2015 level by 2020 to serve 1.2 billion passengers per year. Improve fuel economy standards above the 2014 level by 10% for scooters, 30% for passenger cars and 25% for trucks by 2022. Complete rail electrification by 2022. Have 10 000 electric buses operating by 2030. Sell only electric scooters by 2035. Sell only electric cars by 2040.

RENEWABLE ENERGY

The two main RE sources in Chinese Taipei are photovoltaic (PV) systems and wind power. To promote RE, the government announced the 'Renewable Energy Development Act' in July 2009. The core strategy of the Act is the feed-in-tariff (FiT) system. The current tariff is effective for 20 years with annual review.

Table 5: Feed-in-tariff in Chinese Taipei

Item	Type	Capacity (kW)	2016 FiT (US ¢/kWh)	2017 FiT (US ¢/kWh)
PV	Roof Type	≥1~<20	20.3	19.07
		≥20~<100	16.3	15.56
		≥100~<500	15.0	14.18
		≥500	14.6	13.78
	Ground Type	–	14.6	14.2
	Floating Type	–	–	15.4
Wind Power	Onshore	≥1~<20	26.6	28.0
		≥20	8.78	8.99
	Offshore	–	17.9	18.89
Hydropower	Stream Type	–	9.09	9.22
Geothermal	–	–	15.4	15.4
Biomass	No biogas equipment	–	8.49	8.12
	With biogas equipment	–	12.3	15.7
RDF	–	–	9.2	14.4
Others	–	–	8.5	8.13

Source: (ITRI, 2017).

RE development in Chinese Taipei is aiming to increase renewable supply and achieve 20% of renewable electricity generation by 2025 with 27 423 MW.

Table 6: Renewable energy target by 2025

	Power Capacity (MW)			Electricity Generation (TWh)		
	2016	**2020(f)**	**2025(f)**	**2016**	**2020(f)**	**2025(f)**
Solar PV	1 210	6 500	20 000	1.1	8.1	25.0
Onshore Wind	682	800	1 200	1.4	1.9	2.76
Offshore Wind	–	520	5 500	–	1.9	19.8
Geothermal	–	150	200	–	1.0	1.3
Biomass	741	768	813	3.6	5.6	5.9
Hydro Power	2 089	2 100	2 150	6.6	4.7	6.6
Fuel Cell	–	22.5	60	–	0.2	0.5
Total	4 722	10 861	27 423	12.7	23.4	51.5

Source: (ITRI, 2017) and (Energy White Paper, 2018).

PHOTOVOLTAIC SYSTEMS

There are short- and long-term plans for PV promotion projects. In the short-term plan, the strategy is to establish a foundation, and therefore, the BOE proposed a 'Two-Year Solar PV Promotion Project' in 2016 with a target of 910 MW for rooftop type and 610 MW for ground type, totalling up to 1 520 MW of solar PV installation capacity. The long-term plan is to improve the environment and expand the installation over the economy with establishing fundamental measure. The target is to reach 6.5 GW in 2020 and 20 GW (3-GW for rooftop and 17 GW for ground system) in 2025 (ITRI, 2017).

WIND POWER SYSTEMS

The wind power promotion project is divided into two parts—onshore wind power and offshore wind power. For onshore wind power, the strategy is to develop best wind farms and then secondary ones. By the end of 2016, Chinese Taipei installed 682 MW of onshore wind turbines and will continue to expand the installation capacity to reach the target of 1 200 MW in 2025. For offshore wind power, the government already installed 8 MW of demonstration offshore wind turbines. It is expected to install up to 520 MW of wind farms in shallow sea area and then develop wind farms in deep sea area to reach the target of 5 500 MW in 2025 (Energy White Paper, 2018).

NUCLEAR ENERGY

Currently, there are four nuclear power plants in Chinese Taipei, of which, three are operational and one is sealed. In 2015, the total installed capacity of the three operational nuclear power plants was 5 144 MW, with an output of 36 471 GWh accounting for 14% of the economy's total power generation mix, 3% lower than the 2013 level.

In 2011, the nuclear disaster at Fukushima led to public fears regarding nuclear safety in Chinese Taipei. The government at the time released an energy policy aimed at steadily reducing nuclear dependence by lowering electricity consumption and peak loads and by promoting alternative energy sources to ensure a stable power supply. In 2016, the newly elected government released the 'New Energy Policy', reassuring a nuclear-free homeland in 2025. This policy prohibits lifespan extensions for existing nuclear plants and outlines a decommissioning plan as follows: Units 1 and 2 of the first plant will be decommissioned in 2018 and 2019, respectively; Units 1 and 2 of the second plant in 2021 and 2023, respectively, and Units 1 and 2 of the third plant in 2024 and 2025, respectively.

In November 2018, a referendum was held to ask voters whether they agree that 'all nuclear-based power-generating facilities shall completely cease operations by 2025'. The referendum overwhelmingly found that voters were against the plan to remove nuclear from the power mix target (World nuclear news, 2018). This

result has created significant uncertainty around Chinese Taipei's energy policy, with the government yet to establish whether it will continue pursuing the nuclear-free target.

CLIMATE CHANGE

GREENHOUSE GAS EMISSIONS

Chinese Taipei produces CO_2 emissions that account for approximately 1% of the global emissions. Therefore, the government believes that it has a moral obligation to reduce emissions although the economy is not a member of the UN and is consequently not eligible to sign the Kyoto Protocol. It is also not directly required to adhere to the emission reduction requirements. Unlike other UN members, Chinese Taipei is unable to conduct carbon emission trading in the international market to achieve cross-border cooperation in carbon reduction or to pursue cost-effective carbon-reduction plans. It is therefore necessary for Chinese Taipei to seek alternative ways to reduce the impact of its carbon emissions.

Chinese Taipei has followed the UN Framework Convention on Climate Change as well as its domestic Basic Environment Act and Greenhouse Gas Reduction and Management Act (hereafter referred to as the Greenhouse Gas Act) in proposing its Intended Nationally Determined Contribution (INDC) to cutting GHG emissions. This has demonstrated Chinese Taipei's ambition to actively and steadily reduce its carbon emissions and use of nuclear energy (Executive Yuan, 2015).

The government's INDC goal is for Chinese Taipei's 2030 GHG emissions to be 50% lower than what they would be if it conducted business as usual and 20% lower than its 2005 total. This should pave the way for meeting the ultimate target stipulated by the Greenhouse Gas Act: reducing annual GHG emissions to less than half of the 2005 levels by 2050 (Executive Yuan, 2015).

NOTABLE ENERGY DEVELOPMENTS

NEW LNG RECEIVING TERMINALS

Chinese Taipei currently has two LNG-receiving terminals: Yung-An Kaohsiung (7.5 million tons per annum [Mtpa] receiving capacity) and Taichung (4.5 Mtpa receiving capacity), amounting to 12 Mtpa, which is not enough to meet rising demand. Chinese Taipei's LNG imports hit 17 Mt in 2017, a record high since LNG imports started in 1990—most (more than 86%) used for power generation. The natural gas share in the power mix was 35% in 2017, indicating that more LNG imports are needed to meet the 50% target and gently rising power demand (BOE, 2018a).

To support the transition towards a cleaner power mix, the government has announced that the construction of a coal-fired power plant in Shen Ao will cease and has instead approved a third LNG-receiving terminal in Taoyuan's Kuantan Industrial Park to add an additional receiving capacity of 6 Mtpa (starting with 3 Mtpa in phase I). It is scheduled to start commercial operation in 2023, along with Datan gas-based power plant (Focus Taiwan, 2018) (Radio Taiwan International, 2018).

TPC has announced plans for the fourth LNG-receiving terminal (0.9 Mtpa) in Hsieh-Ho, with the deployment of a floating storage and regasification unit (FSRU) with a 170 000 cubic metres of capacity, scheduled for completion in 2024 (LNG World News, 2018). The fifth receiving terminal (1.8 Mtpa) in Taichung port terminal is also scheduled for completion in 2024. The current Yung-An and Taichung terminals are expected to expand further to 10.5 and 10 Mtpa in 2025, which results in a total receiving capacity of 26 Mtpa in 2025 (APEC Workshop on LNG Trade Facilitation, 2018).

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USEFUL LINKS

Bureau of Energy, Ministry of Economic Affairs—www.moeaboe.gov.tw

Chinese Petroleum Corporation—www.cpc.com.tw

Directorate General of Budget, Accounting and Statistics, Executive Yuan—www.dgbas.gov.tw

Ministry of Economic Affairs—www.moea.gov.tw

Taiwan Power Company—www.taipower.com.tw

THAILAND

INTRODUCTION

Thailand is known as 'the window to South-East Asia' as it is surrounded by other rapidly developing economies such as Myanmar, the Lao People's Democratic Republic (Lao PDR) and Cambodia to the north and east and shares a border with Malaysia to the south. Thailand has an area of 513 120 square kilometres (km^2) and had a population of approximately 69 million in 2016. Its gross domestic product (GDP) in 2016 reached USD 1082 billion (2011 USD purchasing power parity [PPP]), a 3.3% increase from USD 1 047 billion in 2015. In the same period, the GDP per capita increased by 3.0%, from USD 15 252 (2011 USD PPP) to USD 15 706 (2011 USD PPP). The largest contributors to its GDP were services (56%) and industry (36%) (UN, 2018).

Thailand has limited domestic energy resources. At the end of 2016, Thailand had proven reserves of 350 million barrels of oil (bbl), 200 billion cubic metres (bcm) of natural gas and 1 063 million tonnes (Mt) of coal. Based on current rates of production, domestic supply will be depleted in the near future—oil resources within two years and natural gas within five years (BP, 2018). Most coal-fired power plants in Thailand use low-quality, domestically produced lignite. Notwithstanding its resources, Thailand is highly dependent on energy imports, particularly oil, with approximately 84% of its oil and 25% of its gas supply coming from imports (EPPO, 2018).

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c]	
Area (km^2)	513 120	Oil (million barrels)	350
Population (million)	69	Gas (billion cubic metres)	200
GDP (2011 USD billion PPP)	1 082	Coal (million tonnes)	1 063
GDP (2011 USD PPP per capita)	15 706		

Sources: [a] UN (2018); [b] EGEDA (2018); [c] BP (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Thailand's total primary energy supply in 2016 was 138 810 kilotonnes of oil equivalent (ktoe), which represented an increase of 6.0% from the 2015 level. Oil accounted for 39% of the total primary supply, while gas, coal, and renewables and others accounted for roughly 30%, 10% and 21%, respectively. As most of Thailand's proven coal reserves are lignite coal with lower calorific values, imported stock is needed to meet the energy demand for both the power and industry sectors. In 2016, coal supply was 13 403 ktoe, an increase of 14% from the previous year's level.

Natural gas supply in 2016 was 41 305 ktoe, a 0.9% decrease from 41 661 ktoe in 2015. Although natural gas is mostly used for power generation in Thailand, it is also promoted in the transport sector as a replacement for conventional petroleum products, such as diesel and gasoline. Thailand has increased its reliance on imported natural gas in the form of piped gas from Myanmar and liquefied natural gas (LNG) from Qatar and Malaysia.

In 2016, total electricity generation was 187 640 gigawatt-hours (GWh). Thermal generation, mostly from natural gas and coal, accounted for 87% of its power generation, with hydropower and others accounting for the rest. In addition to its domestic capacity, Thailand purchased power from the Lao PDR via transmission grid connections.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	80 775	Industry sector	29 504	Total power generation	187 640
Net imports and others	64 237	Transport sector	25 960	Thermal	162 231
Total primary energy supply	138 810	Other sectors	20 473	Hydro	3 653
Coal	13 403	Non-energy	12 570		
Oil	54 448	Final energy consumption*	75 937	Others	21 756
Gas	41 305	Coal	5 262		
Renewables	28 072	Oil	33 834		
Others	1 581	Gas	6 091		
		Renewables	14 448		
		Electricity and others	16 302		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

NATURAL GAS

Thailand's proven gas reserves at the end of 2017 amounted to 6.4 trillion cubic feet (Tcf), consisting of 6.2 Tcf in gas fields in the gulf and 0.18 Tcf in onshore areas. Compared with the previous year's level, the proven gas reserves fell by 0.42 Tcf (approximately 6.1%), resulting in no additional exploration in 2016 (DMF, 2017). In 2017, domestic natural gas production (including Thailand-Malaysia Joint Development Area, JDA) was at 3 620 million standard cubic feet per day (MMscfd), accounting for 72% of Thailand's gas. The remaining 28% (915 MMscfd) was imported from Myanmar, and along with the imported LNG of 511 MMscfd, the total natural gas supply in Thailand stood at 5 047 MMscfd (EPPO, 2018).

CRUDE OIL AND CONDENSATE

At the end of 2017, Thailand's proven reserves of oil and condensate reserves stood at 323 Mbbl, with 156 Mbbl of crude and 166 Mbbl of condensate, respectively, of which 275 Mbbl came from the gulf and 48.0 Mbbl from onshore areas. The total proven reserves fell by 26.9 Mbbl (8%) from the previous year's level. Rising oil prices had caused the concessionaires to increase their production over the reserve replacement and resulted in a reduction of proven reserves (DMF, 2017). However, the total investment expenditure in petroleum exploration in 2017 (Baht 113 765 million) has not improved and has declined for four consecutive years since 2014 (Baht 221 617 million). The accumulated domestic oil production in 2017 was 141 248 barrels per day (bbl/d). The major crude oil fields in Thailand are Erawan, Sirikit, Tantawan and Jusmin (EPPO, 2018).

COAL/LIGNITE

Thailand has lignite (low-grade coal), which can be used for approximately 70 years. The total indigenous lignite output in 2016 was 16.3 Mt. Domestic lignite production comes from two major sources. One source is the mine of the Electricity Generating Authority of Thailand (EGAT), and the other is private mines. EGAT's lignite is produced from the Mae Moh mine in Lampang Province and is used as fuel for power generation at the Mae Moh Power Plant for the northern part of Thailand. Lignite from private companies is depleting and is mainly used in the cement, paper, food and textile industries. In 2017, based on the heating value, the proportion of lignite/coal combustion in the power sector was 49% and in the industrial sector was 51%. Most of the imported coal is sub-bituminous and bituminous. The amount of coal imports have been continuously increasing because domestic lignite concessions have begun to expire and coal is inexpensive compared with other energy sources (EPPO, 2018).

ELECTRICITY

The EGAT used to be the sole power producer in Thailand. Later, the government promoted the private sector's role in power generation to encourage competitiveness in the power generation business. Since 1994, a number of independent power producers (IPP) and small power producers (SPP) have taken part in the power supply industry, which has led to an improvement in power generation and service quality. Currently, the use of renewable energy in power generation is being promoted and has resulted in a growing number of very small power producers (VSPP) using renewable energy as the main fuel to supply power to the grid. Over the past decade, Thailand's overall electricity capacity has been increasing. While the electricity capacity of EGAT decreased from 60% in 2005 to 38% in 2017, there was a large increase in IPP, SPP and imported electricity. In 2017, the economy's power generating capacity stood at 42 433 megawatts (MW), an increase of 877 MW from 2016, with EGAT contributing 38%; IPP at 35%; SPP and VSPP at 18%; and imported electricity from Lao PDR and exchange with Malaysia at 9% (EPPO, 2018).

FINAL ENERGY CONSUMPTION

Thailand's total final consumption in 2016 was 88 507 ktoe, an increase of 2.5% from the previous year's level. The transport sector was the largest energy-consuming sector, accounting for 29 504 ktoe or 33% of the total final consumption. The second-largest energy consumer was the transport sector, which consumed 25 960 ktoe in 2016, an increase of 1.4% from the 2015 level. Besides the energy-consuming sectors, non-energy products, mostly used in the industry sectors, such as feedstock for petrochemicals, accounted for 14% of the total final consumption or 12 570 ktoe. By fuel type, oil accounted for 45% (33 834 ktoe) of the final energy consumption (excluding non-energy uses) in 2016, followed by electricity and others (22%), renewables (19%), gas (8.0%) and coal (6.9%).

Natural gas consumption increased by 0.4%, from 6 070 ktoe in 2015 to 6 091 ktoe in 2016. Oil consumption also increased by 1.8%, from 33 234 ktoe in 2015 to 33 834 ktoe in 2016. In comparison with natural gas and oil, coal consumption significantly increased by 20%, from 4 403 ktoe in 2015 to 5 262 ktoe in 2016. Domestic electricity and other energy consumption in 2016 increased by 4.2%, from 15 687 ktoe in 2015 to 16 340 ktoe in 2016 (EGEDA 2018).

ENERGY INTENSITY ANALYSIS

Thailand's energy intensity (energy consumption/GDP) in terms of primary energy in 2016 was 128 tonnes of oil equivalent per million USD (toe/million USD), which increased by 2.7% from 125 toe/million USD in 2015. The energy intensity of final energy consumption excluding non-energy was relatively unchanged at 82 toe/million USD in 2016 in comparison with the intensity in 2015.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (tonnes of oil equivalent/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	125	128	2.7
Total final consumption	72	70	-2.5
Total final energy consumption excl. non-energy	82	82	-0.76

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Consumption of modern renewables increased by 1.7% from 2015 to 2016, whereas that of traditional renewables decreased by 13% in the same period. The increase in total non-renewables by 0.55% had caused the share of renewables to final energy consumption to improve slightly by 0.93% after dropping by 2.5% during 2014–2015. This indicates that the increasing crude oil prices, which have turned around to regain the market, have resulted in the favourable renewables demand again.

Table 4: Renewable energy share analysis, 2015 vs 2016

Energy	2015	2016	Chang (%) 2015 vs 2016
Final energy consumption (ktoe)	75 399	75 937	0.71
Non-renewables (Fossils and others)	58 141	59 287	2.0
Traditional biomass*	6 291	5 502	-13
Modern renewables*	10 967	11 149	1.7
Share of modern renewables in final energy consumption (%)	15%	15%	0.93%

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Ministry of Energy's aim is to support sustainable energy management that ensures the economy has sufficient energy to meet its needs. The ministry is responsible for the following:

- establishing energy supply security;
- promoting the use of alternative energy;
- monitoring energy prices and ensuring that prices are at levels appropriate to the wider economic and investment situation;
- effectively saving energy and promoting energy efficiency;
- supporting energy research and development domestically and internationally while simultaneously protecting the environment and mitigating climate change; and
- structuring the energy database centre to systematically consolidate and standardise Thailand's energy related information.

The Ministry of Energy is the main government institution responsible for energy policy in Thailand. Under it are six departments and four state enterprises, as listed below:

- Office of the Minister coordinates with the cabinet, the parliament and the general public;
- Office of the Permanent Secretary establishes strategies, translates policies of the ministry into action plans and coordinates international energy cooperation;
- Department of Alternative Energy Development and Efficiency (DEDE) promotes the efficient use of energy, monitors energy conservation activities, explores alternative energy sources and disseminates energy-related technologies;
- Department of Energy Business (DOEB) regulates energy quality and safety standards, environment and security and improves standards to protect consumers' interests;
- Department of Mineral Fuels (DMF) facilitates energy resource exploration and development;
- Energy Policy and Planning Office (EPPO) recommends economy-wide energy policies and planning;
- Electricity Generating Authority of Thailand (EGAT) is the state power generating enterprise;

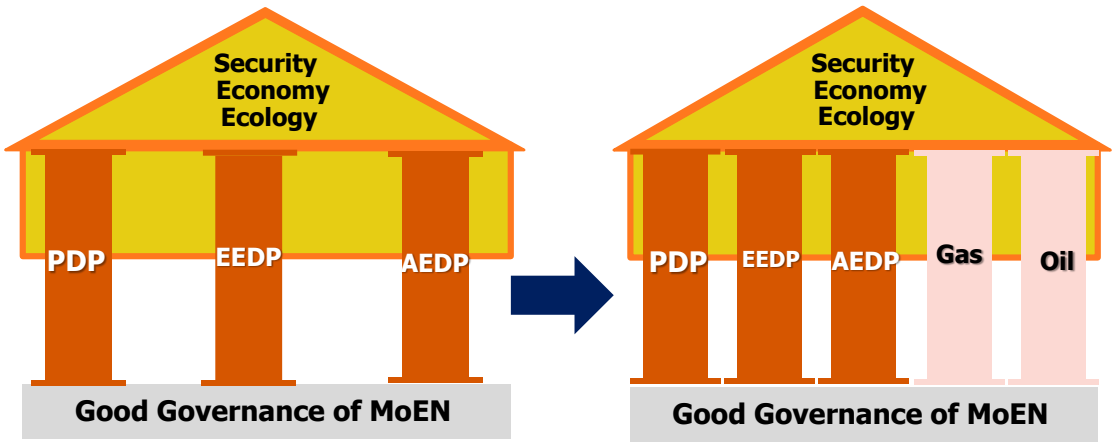
- PTT Public Company Limited (PTT) and the Bangchak Petroleum Public Company Limited (BCP) are two autonomous public companies;
- The Energy Fund Administration Institute (EFAI) is a public organisation; and
- The Energy Regulatory Commission (ERC) and the Nuclear Energy Study and Coordination Office (NESC) are two independent organisations.

According to the energy policy established under the government of Prime Minister Prayut Chan-o-cha and presented to the National Legislative Assembly of Thailand on 12 September 2014, the energy price structure will be reformed to reflect actual costs and taxes for different types of fuels and different groups of consumers. This reform will lead to energy efficiency, consumer awareness and behaviour changes.

On the supply side, the government will proceed with new surveys and exploration for oil and gas, both onshore and offshore. Additionally, the construction of new power plants using fossil fuels and all renewable energy initiatives by state-owned enterprises and the private sector will be continuously pursued through open consultation with the public, with transparency and fairness as well as accounting for environmental concerns. The development of energy resources together with neighbouring economies is also one of the prioritised policies (The Royal Thai Government, 2014).

In 2015, Thailand achieved an important milestone in energy policy development by integrating all major energy policy plans into a single comprehensive plan, namely, the Thailand Integrated Energy Blueprint (TIEB) (EPPO, 2016a) aimed at balancing economic, ecological and security concerns. TIEB consists of five long-term plans, which are the Power Development Plan (PDP2015) (EPPO, 2016b), Energy Efficiency Plan 2015 (EEP2015) (EPPO, 2016c), Renewable and Alternative Energy Development Plan (AEDP2015) (EPPO, 2016d), Gas Plan 2015 (Kaewtathip, S, 2017, DMF, 2016) and Oil Plan 2015 (EPPO, 2016e). All the proposals have been updated and synchronised to cover the period from 2015 to 2036. The PDP2015 incorporates the EEP2015 energy efficiency target to reduce energy intensity by 30% from the 2010 levels and includes a target of the AEDP2015 to develop renewable energy generating capacity of approximately 20 gigawatts (GW) or 20% of the total generating capacity by 2036.

Figure 1: Thailand's Integrated Energy Blueprint



Source: Sutabutr (2015).

ENERGY SECURITY

The government's energy security policy will intensify energy development for greater self-reliance, with a view towards achieving a sufficient and stable energy supply. This will be done by the following:

- advancing the exploration and development of energy resources at domestic and international levels;
- negotiating with neighbouring economies at the government level for the joint development of energy resources;
- developing an appropriate energy mix to reduce supply, price volatility and production cost risks;

- encouraging electricity production from potential renewable energy sources, particularly from small-scale or very small-scale electricity generating projects; and
- investigating other alternative energy sources for electricity generation.

All of the plans under the TIEB contribute to energy security. The PDP2015 aims to strengthen the energy security of power-generating systems in Thailand by diversifying the fuel mix to be less natural-gas dependent, less electricity-import dependent and setting reserve margins at a minimum of 15%. The PDP2015 has already included energy savings from the EEP2015, which identifies 89 672 GWh of electricity savings. The largest share of savings is expected to be delivered through a variety of compulsory measures such as building energy codes, factory and service energy codes, minimum energy performance standards (MEPS) or high energy performance standards (HEPS), and promotion of LED use.

Electricity consumption will be reduced through the EEP2015 by 89 672 GWh or 22% compared with business-as-usual (BAU) levels. The targets of power generation from renewable energy under the AEDP are also included in the PDP2015. Generating capacity of 20 GW from solar, biomass, wind, hydro and waste-to-energy are expected by 2036. The share of renewable energy in power generation will be 20% by 2036. The new gas and oil plans will help to ensure a long-term energy supply along with the PDP2015.

As Thailand has limited energy resources, it will deplete its domestic supply soon—oil resources within two years and natural gas in five years. To maintain a degree of energy security, the economy must quickly pursue new explorations. Since 1971, the Department of Mineral Fuels (DMF) has launched 20 concession bidding rounds, with the latest announced in 2007. In 2014, the DMF invited bids for exploration and production rights for the Erawan and Bongkot gas exploration concessions; however, the initiative was halted. The Petroleum Act was subsequently amended along with the government's energy reform, and in late 2018, the re-bidding for both concessions was successfully accomplished with PTT Exploration and Production Plc (PTTEP) and its partner, the UAE's Mubadala Petroleum, winning the concession contract for Erawan (G1/61) starting from 2022 and PTTEP winning contract for Bongkot (G2/61) starting from 2023.

To secure a natural gas supply for the long term, Thailand has entered into several contracts to buy LNG from LNG suppliers such as the Qatar Liquefied Gas Company Limited (Qatargas), with its first cargo of 20-year 2 Mt per year LNG delivered to Thailand in January 2015, and Petronas, with its first cargo of 15-year 1.2 Mt annually brought into Thailand in July 2017. In addition, PTT is preparing to enter into a gas sales agreement (GSA) to acquire 2.6 Mt of LNG per year from Area One in Mozambique to be delivered to Thailand around 2022–2023 (Reuters, 2017; African Century, 2017). The Ministry of Energy has also entered into a power purchasing agreement (PSA) with Lao PDR to import 9 000 MW of electricity, mostly hydropower. Under the previous MoU signed in 2007, Thailand has agreed to buy 5 421 MW of electricity from Lao PDR, 3 578 MW of which comes from hydropower and coal-fired power plants and the remaining 1 843 MW comes from hydropower, Xe Pien Xe Namnoy (354 MW), Xayabury Dam (1 220 MW) and the Nam Ngiep (269 MW), scheduled to be delivered in 2019 (The Nation, 2016).

FISCAL REGIME AND INVESTMENTS

ENERGY PRICES

The government's energy price policy aims to supervise and maintain energy prices at appropriate, stable and affordable levels. It will do this through the following:

- setting a transparent and justifiable fuel price structure that supports the development of energy products and that best reflects actual production costs;
- managing prices through market mechanisms and the oil fund to promote the economical use of energy; and
- encouraging competition and investment in energy businesses, including the improvement of service quality and safety.

The strategy to achieve this involves monitoring energy prices through market mechanisms to ensure that domestic energy prices are stable, fair and affordable and reflect the actual production costs. The domestic energy costs must be reasonable when compared with those in the neighbouring economies. The

government is supervising the pricing policies and price structure of oil, LPG and natural gas for vehicles (NGV) to align them with world market mechanisms and to reflect actual costs; ensuring fairness for the general public through the efficient use of the oil fund; and monitoring refining and marketing margins to maintain them at appropriate levels. The recent decline in oil prices has created an opportunity for Thailand to restructure fuel pricing and reduce energy cross-subsidies.

INVESTMENT

The government is keen to encourage competition and investment in energy businesses by creating a favourable environment for investment, transparent competition and internationally accepted energy-related standards. It will do this by designating an agency, the Thailand Board of Investment, to be responsible for investment procedures and processes in the energy industry and by creating a mechanism for a company to be a service company in the operations and maintenance of the electricity industry, refineries, gas separation plants and both domestic and overseas oil and gas exploration and production.

ENERGY EFFICIENCY

The first long-term energy policy on energy efficiency, namely the EEDP, was launched in 2011 with a target of reducing energy intensity (EI) by 25% in 2030 from the 2010 levels, equivalent to a reduction in the final energy consumption of 20% by 2030 (38 200 ktoe). Furthermore, the Energy Efficiency Action Plan (EEAP) has been developed under the strategic framework of the EEDP. The EEAP was approved by the National Energy Policy Committee (NEPC) and endorsed by the Cabinet in early 2013. The plan includes 67 major measures or projects.

Most of the measures are sector-wide. The rest are sector-specific measures that include 18 in the transport sector and 5 measures in each of the following sectors: industry, large and small commercial buildings and residential. The total amount of energy saved by the plan is expected to be 38 845 ktoe, with 16 257 ktoe from the industrial sector, 15 323 ktoe from the transport sector, 3 635 ktoe from the small commercial building and residential sector and 3 630 ktoe from the large commercial building sector. Moreover, the EPPO has completed the development of a 10-year R&D master plan for energy efficiency to guide R&D in line with the EEAP and EEDP framework.

The EEDP has been updated using the same timeframe as for other energy plans (e.g. 2015–36) and is known as the Energy Efficiency Plan 2015 or EEP2015. The EEP2015 has set a target to reduce EI by 30% by 2036 from the 2010 levels. This savings target equals 56 142 ktoe, which consists of 7 641 ktoe of electricity (or 89 672 GWh) and 44 059 ktoe of heating in addition to what has already been achieved through 2013 at 4 442 ktoe. It also equates to a 30% reduction in BAU energy consumption in 2036 (EPPO, 2016c).

The EEP2015 set the targets of energy reduction for four major economic sectors—industry; commercial and governmental buildings; residential; and transportation. They are categorised into three strategic areas with 10 specific measures as follows:

COMPULSORY PROGRAMME

- Enforce the Energy Conservation Promotion Act B.E. 2550 (2007), which would put into effect an energy management system based on energy consumption reporting and verification imposed on 7 870 designated buildings and 11 335 factories with transformer sizes of 1 000 kW (1 175 kVA) and up;
- Impose mandatory energy efficiency evaluations for the newly built and renovating buildings such as building energy codes (BEC), leadership in energy and environmental design (LEED) and Thailand's rating of energy and environmental sustainability (TREES);
- Enforce HEPS and MEPS for equipment or appliance labelling to provide options for consumers to buy or use highly energy-efficient equipment or appliances;
- Implement energy efficiency resource standards (EERS) or minimum standards for large energy businesses, including power producers and distributors, to implement energy conservation measures and encourage their customers to use energy efficiently, which would be an important mechanism for providing both technical and financial assistance to small and medium enterprises (SMEs).

VOLUNTARY PROGRAMME

- Support the operation of energy service company (ESCO) using financial tools such as an EE revolving fund, tax incentives and soft loan and grants to alleviate the technical and financial risks of entrepreneurs wishing to implement energy conservation measures;
- Promote the wider use of LEDs for street lights and households through public relations campaigns and price mechanisms;
- Promote energy conservation programmes in the transportation sector by setting up an effective pricing structure, economising automobile engines, increasing efficient infrastructure and logistics systems and launching electric vehicle fleets to replace inefficient older generation cars; and
- Promote R&D that improves energy efficiency and reduces technological costs for equipment or appliances, production processes and materials.

COMPLEMENTARY PROGRAMME

- Support the development of professionals in energy conservation fields so that they will have the ability to be responsible for energy management and operations, verification and monitoring, consultancy and engineering services as well as for the planning, supervision and promotion of the implementation of energy conservation measures;
- Introduce measures that will have a wider impact in terms of fostering public awareness and changing energy consumption behaviour related to the energy consumption of consumers.

The breakdown of this target is shown in Table 5.

Table 5: The EEP2015's Targets by 2036

Energy Efficiency Measures	Saving Targets in 2036, ktoe
Compulsory Programme	**10 972**
1. Enforcement of the Energy Conservation Promotion Act B.E. 2550 (2007).	5 156
2. Energy efficiency evaluations for buildings (BEC, LEED and TREES).	1 166
3. Enforcement of HEPS and MEPS for equipment or appliances.	4 150
4. Implementation of EERS for energy businesses.	500
Voluntary Programme	**40 728**
5. Support ESCO companies by using financial tools.	9 524
6. Promote the wider use of LED for street lights and households.	991
7. Promote energy conservation programmes in the transport sector.	30 213
8. Promote R&D to improve energy efficiency and technological costs.	-
Complementary Programme	
9. Support the development of professionals in the energy conservation field.	-
10. Introduce measures that foster public awareness.	-
Total Programme	**51 700**

Source: DEDE (2015).

RENEWABLE ENERGY

The Ministry of Energy is keen to develop alternative and renewable energy to secure new energy resources and provide affordable energy to all Thais. There have been several revisions of the renewable and alternative development plan during the past decade. The 10-Year Renewable and Alternative Energy Development

Plan 2012–21 (AEDP), formerly the 15-Year Renewable Energy Development Plan 2008–22 (REDP), set as a target an increase in the share of renewable and alternative energy to 25% of the total energy consumption by 2021.

The plan states that the Royal Thai Government will encourage the use of indigenous resources, including renewable and alternative energy (particularly for power and heat generation), and support the use of transport biofuels such as ethanol-blended gasoline (gasohol) and biodiesel. The plan also strongly promotes community-scale alternative energy use, encouraging the production and use of renewable energy at the local level through appropriate incentives for farmers. It also rigorously promotes R&D in all forms of renewable energy.

To achieve these targets, Thailand has set up incentive programmes and mechanisms to encourage investments, such as the Fund for Energy Services Companies, which acts as a special-purpose vehicle for renewable energy development projects, with additional investment grants available from the Energy Conservation Fund. Some of the earlier successful self-working measures, such as the revolving fund, which provides low interest rates, will be terminated.

Recently, the AEDP timeframe has been updated to 2015–36 and is now called AEDP2015. The AEDP2015 has set a target for a renewable energy share of 30% of final energy demand (FED) by 2036. This target is equal to 39 388 ktoe, which can be divided into power generation of 19 684 MW (5 588 ktoe), heating of 25 088 ktoe and biofuels of 8 712 ktoe. Thailand has over the years shown excessive development in renewable energy focusing on several high potential renewables especially solar, biomass, and biofuels. The breakdown of this target is shown in Table 6.

Table 6: The AEDP's Targets by 2036

Type of Energy	Targets in 2036	
Electricity	**5588**	**Ktoe**
	19 684	**MW**
1. Municipality Waste	500	MW
2. Industrial Waste	50	MW
3. Biomass	5 570	MW
4. Biogas (Sewage/Waste)	600	MW
5. Small Hydropower	376	MW
6. Biogas (Energy crop)	680	MW
7. Wind	3 002	MW
8. Solar	6 000	MW
9. Large Hydropower	2 906	MW
Heating	**25 088**	**ktoe**
1. Waste-to-Energy	495	ktoe
2. Biomass	22 100	ktoe
3. Biogas	1 283	ktoe
4. Solar	1 200	ktoe
5. Others (for example, geothermal, pyrolysis gas, and so on)	10	ktoe
Biofuels	**8 712**	**ktoe**
1. Biodiesel	14	million litre/day
2. Ethanol	11.3	million litre/day
3. Pyrolysis Oil	0.5	million litre/day
4. Compressed Biogas (CBG)	4 800	tonne/day
5. Others (for example, bio oil, hydrogen, and so on etc.)	10	ktoe
Renewable Energy Consumption	**39 388**	**ktoe**

Sources: AEDP2015, DEDE (2016).

NUCLEAR ENERGY

Nuclear power is recognised as an alternative energy resource that is associated with low emissions and is less expensive than fossil fuels and renewable energy. The Thailand 20-Year Power Development Plan (PDP2010) had included 5 GW of nuclear power, aimed at ensuring sufficient energy supply and diversifying the power energy mix. After the Fukushima Daiichi Nuclear Power Plant disaster caused by the earthquake and tsunami in March 2011, the second revision of PDP2010 postponed the scheduled commercial operation date (SCOD) of the first unit of the nuclear power project by three years (from 2020 to 2023). Subsequently, the third revision of PDP 2010 further shifted the SCOD of the first unit to 2026 and scheduled the second unit to begin operations in 2027. By 2030, the last year of the plan, nuclear power would comprise 5% of the total generation capacity. The PDP2015, which encompasses the time frame 2015–36, includes 1 GW of nuclear power in the grid in 2035 and another 1 GW in 2036. Under the recent development to revise PDP2015, the government is considering to withdraw the nuclear project from the future power plan. The schedule to release the new version of the power development plan is expected to be in 2019.

CLIMATE CHANGE

Climate change is an important issue in Thailand even though in 2012, Thailand contributed to only 0.8% of the global GHG emissions. In terms of GHG emissions per capita and per GDP, Thailand's contribution is lower than the world average. In Thailand's Second National Communication, it indicated that 67% of its total GHG emissions is derived from the energy sector. At the COP20 in Lima, Thailand pledged a pre-2020 contribution of 7–20% GHG emission reduction from BAU levels in the energy and transport sectors.

Thailand also recognises that long-term and continuous effort is required to address climate change, as stated in its Climate Change Master Plan 2015–50. The master plan provides a continuous framework for measures and actions over the long term to achieve climate-resilient and low-carbon growth in line with a sustainable development path by 2050. This framework plan has already been approved by the Cabinet, and now relevant agencies in various sectors are formulating specific sector plans to address climate change. Recently, Thailand submitted its Intended Nationally Determined Contribution (INDC) to the United Nations Framework Convention on Climate Change. Thailand's INDC indicates its intention to reduce its GHG emissions by 20% from the current BAU levels by 2030 (ONEP, 2015). The ambitious targets in the PDP2015, AEDP2015 and EEP2015 will significantly contribute to this national intention.

NOTABLE DEVELOPMENTS

SUCCESS OF BIDDING ROUND FOR NATURAL GAS EXPLORATION AND PRODUCTION OF ERAWAN AND BONGKOT

The natural gas exploration and production of the soon-to-expire Erawan and Bongkot fields is crucial to Thailand's energy supply security and sustainability since both fields currently produce up to 0.06 bcm per day or account for 75% of natural gas supply in Thailand. In December 2018, the Ministry of Energy conducted the 21th bidding round process for a production sharing contract (PSC) with rights for natural gas exploration in the offshore exploration blocks of the Erawan (G1/61) and Bongkot (G2/61) fields. With careful planning and evaluation ahead of time, the bidding has been proved to be successful with PTTEP and its partner, the UAE's Mubadala Petroleum winning the concession contract for Erawan (G1/61) starting from 2022 and PTTEP winning contract for Bongkot (G2/61) starting from 2023.

THIRD PARTY'S ACCESS

The Gas Plan 2015 focuses on the implementation of third party access (TPA) and is designed to promote greater competition in the natural gas industry. The ERC has issued TPA codes allowing other energy companies access to PTT's natural gas transmission pipelines and LNG regasification terminal facilities in a fair and non-discriminatory manner, aiming to reduce market monopoly in the natural gas industry. The EGAT is currently preparing to implement the TPA by importing a 1.5 Mt of LNG through the PTT system in 2019. This will be an important step for Thailand to ensure that TPA is workable and that the best practice and market competition can be achieved in Thailand gas business.

REVISED POWER DEVELOPMENT PLAN

Since the Ministry of Energy introduced a comprehensive energy plan, namely the TIEB, consisting of five long-term plans including the PDP 2015, EEP 2015, AEDP 2015, Gas Plan 2015 and Oil Plan 2015, many energy developments and projects have been implemented through these plans. In 2019, the Ministry of Energy will introduce a revised PDP and design strategies of the new plan to reflect any recent changes in power generation, which will have impacts on energy business in Thailand.

The formulation of the new plan has been delicately designed during 2018 to ensure that public opinion and the environmental impact of local pollution are taken into consideration when the new power plants are to be installed. Original plans detailed in PDP 2015 to increase coal as a major fuel and to install nuclear power plants are currently being re-justified in the scope of this revision.

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USEFUL LINKS

Department of Alternative Energy Development and Efficiency (DEDE)—www.dede.go.th

Department of Mineral Fuels (DMF)—www.dmf.go.th

Electricity Generating Authority of Thailand (EGAT)—www.egat.co.th

Energy Policy and Planning Office (EPPO)—www.eppo.go.th

Ministry of Energy (MoEN)—www.energy.go.th

Prime Minister's Office—www.opm.go.th

UNITED STATES

INTRODUCTION

The United States (US) is the world's second-largest economy, with a gross domestic product (GDP) of USD 17.3 trillion (2011 USD purchasing power parity [PPP]) in 2016) (World Bank, 2018). The US spans 9.9 million square kilometres (km^2) and has a population of 323 million. The economy's population growth rate has declined from 1.1% in 2000 to 0.7% in 2016. Per capita GDP in 2016 was USD 53 399, the fourth-highest among the APEC member economies (World Bank, 2018).

The US enjoyed economic expansion from 1990 to 2000, recording an annual growth of 3.4% in real terms, which then slowed to 1.8% from 2000 to 2016. In 2016, economic growth was 1.5% down from 2.9% in 2015 (World Bank, 2018).

The US is the second-largest producer and consumer of energy in APEC. In 2016, the US had 50 billion barrels of proved oil reserves, 8.7 trillion cubic metres (tcm) of natural gas reserves and 252 billion tonnes of coal reserves (BP, 2017; BP, 2018).

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c, d]	
Area (million km^2)	9.9	Oil (billion barrels)	50
Population (million)	323	Gas (trillion cubic metres)	9
GDP (2011 USD billion PPP)	17 270	Coal (billion tonnes)	252
GDP (2011 USD PPP per capita)	53 399	Uranium (kilotonnes U)	47

Sources: [a] Census (2010); [b] World Bank (2018); [c] BP (2017), BP (2018); [d] NEA (2018).

Notes: Oil reserves comprise crude, condensate and natural gas liquids. Coal reserves are defined as known economically recoverable quantities. Uranium reserves are considered to be reasonably assured resources at USD 130/kg U.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

The total primary energy supply in the US in 2016 was 2 167 million tonnes of oil equivalent (Mtoe). In terms of fuel type, 36% of the supply came from crude oil and petroleum products, 30% from natural gas, 16% from coal and the rest from other sources such as nuclear energy, hydropower and geothermal energy. Only 12% of the economy's primary energy requirements in 2016 were from net imports. The share of net energy imports declined from a peak of 32% in 2006 (EGEDA, 2018).

The economy's total primary energy supply in 2016 decreased by 1.0% compared with the 2015 level of 2 188 Mtoe. The decline mainly resulted from a 9% decrease in coal supply in 2016 (EGEDA, 2018).

Primary oil supply in the US was 787 Mtoe in 2016, a decrease of 0.3% from the 2015 level (EGEDA, 2018). In 2016, the US was the world's second-largest crude oil and natural gas liquids and condensate producer, just behind Saudi Arabia. Production averaged 12.4 million barrels per day (bbl/d) (BP, 2018). Oil import dependence, measured as petroleum net imports as a share of products supplied, was 24.4% in 2016, lower than almost every year since 1970 (EIA, 2018g).

US primary natural gas supply was 653 Mtoe in 2016, an increase of 0.9% from the 2015 level. The economy's natural gas supply quickly grew from 2010 to 2016, with an annual growth rate of 2.7% (EGEDA, 2018). In recent years, production of inexpensive unconventional gas reserves from shale formations has resulted in an abundant supply and low wellhead prices. Relatively low natural gas prices and the substitution of gas for coal by power producers have helped reduce emissions from power generation (EIA, 2016a).

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	1 915 689	Industry sector	263 953	Total power generation	4 294 017
Net imports and others	265 046	Transport sector	621 787	Thermal	2 802 566
Total primary energy supply	2 166 629	Other sectors	492 843	Hydro	269 670
Coal	341 572	Non-energy	136 448	Nuclear	839 918
Oil	787 290	Final energy consumption*	1 378 583	Others	381 863
Gas	652 884	Coal	17 502		
Renewables	156 229	Oil	626 621		
Other	228 634	Gas	317 407		
		Renewables	82 325		
		Electricity and others	334 466		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

The US held approximately 4.5% of the world's natural gas reserves in 2016 (BP, 2018). As of 2016, the economy's natural gas pipeline transmission network was more than 483 000 kilometres (km) long (PHMSA, 2018a). In 2016, the Federal Energy Regulatory Commission (FERC) approved 36 major pipeline projects with a distance of 1 796 km (FERC, 2019). In 2016, 389 active underground storage fields in the US had a working gas capacity of 135 billion cubic meters (bcm). On 11 November 2016, gas in storage peaked at a record 115 bcm (EIA, 2018h, 2019a).

Since the mid-2000s, horizontal drilling combined with hydraulic fracturing spurred the economic production of unconventional gas, largely from shale formations. Shale gas production in the US has rapidly increased from approximately 8% of gross withdrawals in 2007 to 55% in 2016 (EIA, 2018i, 2018j). Proved shale gas reserves were estimated to be 5.9 tcm or more than 60% of the total reserves as of year-end 2016 (EIA, 2018a). Thus, further increases in shale gas production are anticipated.

The US exported more natural gas than it imported in 2017 for the first time since 1957 (EIA, 2018k). Lower-48 LNG exports began in February 2016 from Sabine Pass, Louisiana, with capacity expanding to four liquefaction units by the end of 2017. In 2018, Sabine pass added one more unit, and two more plants in Cove Point, Maryland, and Corpus Christi, Texas, began operation. The US Energy Information Administration projects that annual LNG export capacity will reach 92 bcm by the end of 2019 (EIA, 2018l).

The primary energy supply of coal in the US totalled 342 Mtoe in 2016. In 2016, primary coal supply declined by 9% (EGEDA, 2018), as gas took market share from coal in power generation (EIA, 2018g). US coal reserves are concentrated in the east of the Mississippi River in Appalachia and in several western states (EIA, 2018m).

In 2016, the US was the sixth-largest coal exporter in the world, following Australia, Indonesia, Russia, Columbia, and South Africa. In 2016, primary coal exports amounted to 60 Mt, a decrease of 19% from the 2015 level and significantly below the 2012 peak of 126 Mt (EIA, 2017i). More than two-thirds of exported coal was metallurgical, with most of the rest being steam coal. Europe was the largest importer of coal from the US, constituting more than 40% of US net exports. Coal imports have declined from a peak of 36.3 Mt in 2007 to 9.8 Mt in 2016 (EIA, 2018o).

At the beginning of 2017, the US had 47.2 tonnes of uranium reserves recoverable at less than USD 130 per kilogram, the firth-largest reserves in APEC (NEA, 2018). In 2016, US production of uranium concentrate

was 1.0 million kilograms, far below the 1980 peak of 19.8 million kilograms. Uranium concentrate production continues to decline in the face of declining prices, which were USD 44 to 55 per kilogram in 2017 (EIA, 2018q).

In 2016, the US produced 4.3 million gigawatt-hours (GWh) of electricity, 65% of which came from fossil fuel plants, 20% from nuclear energy and 15% from renewable energy and other sources (EGEDA, 2018).

The US generated more nuclear energy than any other economy in 2016 (EIA, 2018n). In 2016, the US had 99 operable commercial nuclear units, down from a peak of 112 units in 1990. The average utilisation rate rose to 92.3% in 2016 (EIA, 2018g7c). Currently, two commercial nuclear reactors are under construction, and two stopped construction during 2017 (EIA, 2017g). Many nuclear plants have applied to the Nuclear Regulatory Commission (NRC) for 20-year extensions of their operating licences, enabling them to operate for 60 years. By late 2018, the NRC had approved active licence extensions for 88 nuclear reactor units and had applications for 2 more extensions under review, while operators of 4 more units had informed the agency regarding their intention to seek extensions between 2021 and 2022 (NRC, 2017a). Operators of 12 reactors have announced plans to retire them by 2025 (EIA, 2018p).

Total renewable energy production in the US in 2016 was 156 Mtoe or 7% of the total primary energy supply. Production increased by 3.7% from the previous year's level, with growth in wind, liquid biofuels, hydro and photovoltaics. The largest types of renewable production were biomass and liquid biofuels (EGEDA, 2018).

FINAL ENERGY CONSUMPTION

In 2016, the total final consumption in the US was 1 515 Mtoe, an increase of 0.5% from the previous year's level, primarily because of economic growth. The transport and other sectors constituted 41% and 33%, respectively, of the total final consumption, with the remaining share consumed by the industrial sector (17%) and non-energy sector (9%). In terms of final energy consumption by fuel (excluding non-energy), petroleum constituted 45% while electricity and natural gas constituted 24% and 23%, respectively. Coal contributed a modest 1.3% (EGEDA, 2018).

ENERGY INTENSITY ANALYSIS

US energy intensity significantly improved in 2016 (Energy intensity is the amount of energy an economy uses or consumes for every dollar of GDP it produces). Primary supply intensity in 2016 improved by 2.4% from 129 tonnes of oil equivalent per million USD (toe/million USD) in 2015. Total final consumption intensity improved by 1.1% compared with that in the previous year. Final energy consumption intensity, excluding non-energy, improved by 1.0% (Table 3).

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%) 2015 vs 2016
	2015	2016	
Total primary energy supply	129	125	–2.4
Total final consumption	81	80	–1.1
Final energy consumption excl. non-energy	89	88	–1.0

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

The share of modern renewables consumed in the US increased to 6.7% in 2016, an increase of 0.5 percentage points from the previous year's level. In 2016, the consumption of modern renewables increased by 7.1%. Production of energy from wind, biofuel, hydro and photovoltaic (PV) sources increased, while that from biogas decreased. The use of modern biomass increased, mainly in the power sector, while that of traditional biomass decreased, mainly in the residential and commercial sectors (Table 4).

Table 4: Renewable energy share analysis, 2015 vs 2016

	2015	2016	2015 vs. 2016
Final energy consumption (ktoe)	1 373 321	1 378 583	0.4
Non-renewables (Fossils and others)	1 248 010	1 247 103	–0.1
Traditional biomass*	12 979	11 176	-14
Modern renewables*	112 332	120 304	7.1
Share of modern renewables to final energy consumption (%)	8.2	8.7	6.7

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

JURISDICTION AND POLICY

Within the US Government, oversight of the production, transformation, transmission and consumption of energy is shared by several agencies in the executive branch. Supervision of the use of natural resources falls under the Department of the Interior (DOI). Energy-related research, development and deployment (RD&D) takes place mainly under the auspices of the Department of Energy (DOE). The FERC oversees the interstate transmission of energy, and the Environmental Protection Agency (EPA) regulates the environmental impact of energy transformations throughout the economy. The Department of Transportation (DOT) also plays an important role as the regulator of vehicle fuel economy. Compared with many Asian economies, the US Government has a more limited role in the energy sector and its involvement is more decentralised.

While all these federal agencies have some voice in energy policy, the US Congress is responsible for creating the laws that govern the activities of these agencies and setting the rules for energy markets. Since the 1970s, several major legislative packages have defined the economy's energy policies.

The Energy Policy Act of 2005 (EPAct) was the first major piece of energy legislation passed since the Energy Policy Act of 1992 (GPO, 2005; US House, 1992). This was shortly followed thereafter by the Energy Independence and Security Act of 2007 (EISA), the last piece of comprehensive energy legislation passed by the US Congress (GPO, 2007). The American Recovery and Reinvestment Act of 2009 (ARRA) also dramatically increased funding for many federal energy programmes (DOE, 2012). Key elements of these acts are described below.

ENERGY SECURITY

According to one ranking of large energy-consuming economies in 2016, the US was the most energy-secure economy in APEC (GEI, 2018). Oil import dependence, measured as net imports as a percentage of product supplied, peaked at 60.3% in 2005. By 2017, US import dependence declined to 17.2% by the same measure (EIA, 2018g).

The US is a member of the International Energy Agency (IEA). In 1975, it established a strategic oil stockpile, called the Strategic Petroleum Reserve (SPR). The SPR comprises 60 storage caverns in underground salt dome formations located at four sites in Texas and the Louisiana Gulf Coast, and it is the largest government-owned stockpile in the world (DOE, 2016a). Some 650 million barrels of crude oil are currently contained in the SPR, the equivalent of 172 days of net crude and product imports, based on the average 2017

levels, almost double the IEA reserve requirement (EIA, 2018g). Unlike most IEA members, the US relies on publicly held reserves to meet its obligations and holds most of its reserves as crude oil (GAO, 2018).

Given the recent rise in crude oil production and the resulting increase in days of coverage of crude and product imports, Congress passed six laws from 2015 to 2018 that would reduce the amount of oil stored in the SPR to approximately 405 million barrels by the start of 2028. Some of the sales are designed to fund the US budget deficit, while others are for an SPR infrastructure modernisation programme (GAO, 2018).

In addition to the SPR, the DOE established a 1 million barrel Northeast Home Heating Oil Reserve in 2000 and a 1 million barrel Northeast Gasoline Supply Reserve in 2014. These would provide consumers with supplemental sources of home heating oil and gasoline in the event of supply shortages (GAO, 2018). The US Government does not hold strategic reserves of natural gas.

In December 2015, growing US crude oil production also prompted Congress to lift a 40-year-old ban on the export of crude oil (BIS, 2016).

FISCAL REGIME AND INVESTMENT

US fiscal policy is quite complex, particularly as it relates to the energy sector. This section provides a limited introduction to the taxation of energy commodities and to the multitude of fiscal incentives that shape energy-related investments. Energy-producing businesses are taxed like other US corporations, at a maximum statutory federal rate of 21%, while state rates range from 0% to 10%. However, tax rules result in different effective tax rates (US Congress, 2017a; CBO, 2005). A detailed discussion of the taxation of energy businesses is beyond the scope of this overview, but some provisions specifically related to energy investments are described here.

Royalty payments on the production of oil, gas and coal are made to the owner of mineral resources, which is sometimes the government. The US Office of Natural Resources Revenue collected USD 6.9 billion in royalty and other payments for extraction on federal lands in 2017. Royalties from crude oil accounted for 57% of the revenue collected from activities related to energy production on federal lands in 2017, while natural gas royalties accounted for 14% and coal for 8%. Federal royalties are disbursed to federal, state and other funds. In 2017, the US Treasury received the most money, USD 2.5 billion (ONRR, 2018). A USD 0.09 cent per barrel tax to assist in oil spill clean-ups was in place through 2018; the tax generates approximately $500 million per year (US Congress, 2018a; CRS, 2017).

Downstream, sales of some important energy commodities such as gasoline and diesel are taxed by state and federal governments. The federal tax on gasoline and diesel is approximately USD 0.05 per litre (18.4 cents per gallon) and USD 0.06 per litre (24.4 cents per gallon), respectively. In addition, on average, state taxes on gasoline are approximately 25% higher than federal taxes, and taxes on diesel are approximately 6% lower than federal taxes, but there is considerable variation among the states. There are also approximately USD 0.03 per litre of other state taxes on gasoline and diesel (API, 2019). Some states have also introduced a 'public goods charge' on retail electric and natural gas sales, the proceeds of which fund energy efficiency programmes.

A variety of tax incentives have been introduced by the federal and state governments to promote investments in energy-related infrastructure. Two key federal instruments are investment tax credits (ITCs) and production tax credits (PTCs). ITCs allow taxpayers investing in certain qualified energy facilities to reduce their tax burden by some fraction of the amount invested. Similarly, PTCs reduce the taxpayers' tax burden in an amount proportional to the energy production of the facility over a defined period. The types of facilities qualifying for ITCs range from coal gasifiers to wind turbines (IRS, 2017). Tax credits for investments in renewable energy or in energy-efficient home improvements are also available to individuals (DSIRE, 2018).

Two tax breaks historically important to the upstream oil and gas industry are depletion allowances and intangible drilling costs. A depletion allowance is a tax deduction allowed to compensate for the depletion or 'using up' of natural resource deposits such as oil or natural gas. Intangible drilling costs include all the necessary expenses made by an operator in the drilling and preparation of wells, such as survey work, ground clearing, drainage, wages, fuel, repairs, supplies and so on, but are not part of the final operating well. Intangible drilling costs can be deducted in the year spent as a current business expense (IRS, 2017b).

RESEARCH AND DEVELOPMENT

The scope of energy-related R&D supported by the US Government has expanded from a focus on nuclear energy and basic science in the 1960s to include fossil fuels, energy efficiency, renewable energy and carbon sequestration. Much of this expansion occurred in the immediate aftermath of the 1973 oil crisis. In the five years following the crisis, spending on energy-related R&D more than tripled. New support for fossil energy, renewable energy and improved efficiency absorbed much of the increase. Although the amount of spending declined sharply during the 1980s, the broader scope was preserved (Dooley, 2008).

The DOE is the lead agency for R&D activities. It funds 17 laboratories as well as the research conducted at 300 universities across the US. Currently supported research ranges from particle physics to pilot projects for carbon capture and storage (CCS) (DOE, 2016d). Total government spending for energy-related R&D peaked in FY2009 at USD 3.8 billion with the passage of the ARRA, a one-time economic stimulus. After FY2009, US federal funding for energy R&D slid to USD 2.3 billion in FY2013 before increasing to USD 3.1 billion in FY2015 and an estimated USD 3.5 billion in FY2016 (NSF, 2018a6). State governments spent an additional USD 307 million on energy R&D in FY2017, more than 60% by the State of California (NSF, 2018b). Some business leaders in the US have argued that to confront the energy challenges that the US faces, the government should more than triple spending on energy R&D (AEIC, 2015).

ENERGY MARKETS

In 2016, American consumers spent an estimated USD 1.0 trillion on energy purchases or 5.6% of GDP (EIA, 2018g). Government plays many roles in this large market, such as those of resource owner, industry regulator and supporter of R&D.

UPSTREAM DEVELOPMENT

The DOI's Bureau of Land Management (BLM) administers more than 2.8 million km^2 of onshore underground mineral estates (BLM, 2017a), of which approximately 104 000 km^2 was leased for oil and gas development in 2017 (BLM, 2018a). The Bureau of Ocean Energy Management (BOEM), another office of the DOI, leases another 57 000 km^2 of offshore oil and gas resources (BOEM, 2018a). The BLM and BOEM also lease more limited onshore lands and offshore areas for the development of above-ground energy resources such as solar and wind.

While the US Government plays a large role in leasing surface and mineral rights, it is not the sole owner of such rights. Unlike most other nations, individuals and state governments also own and lease surface lands and underground mineral rights for energy extraction (DOI, 2017a). In FY2014, only 21% of crude oil and 14% of natural gas were produced from federal lands (EIA, 2015b). State and federal governments share the regulation of upstream development. State oil and gas commissions prevent the waste of resources and protect public safety in state territories (IOGCC, 2004). In the federal offshore territory, the offices of the DOI exercise similar responsibilities.

EPAct promoted the domestic production of oil by removing some regulatory barriers and offering incentives for production from deep-water resources, low-production wells and unconventional sources. The law excluded underground injection of hydraulic fracturing fluids from the Safe Drinking Water Act of 1974, which allowed the exploitation of tight sand and shale hydrocarbon resources. Congress also clearly stated that the development of unconventional oil resources should be encouraged to reduce US dependence on foreign oil imports (GPO, 2005).

After more than 40 years of debate, Congress authorised opening the Coastal Plain of the Arctic National Wildlife Refuge Section 1002 area to leasing, drilling and production as part of its 2017 year-end tax cut legislation (US Congress, 2017a). BLM is proposing to open the 1.5 million acres of the Coastal Plain to oil and gas drilling. BLM estimates that the area could produce 1.5 to 10 billion barrels of oil over the lifetime of the wells (BLM, 2018b). Elsewhere, BOEM approved a conditional permit for the first artificial island for oil and gas production in federal waters offshore Alaska (BOEM, 2018b), and BLM is moving to expand exploratory drilling in the National Petroleum Reserve in Alaska (BLM, 2019)

In 2017, President Trump set a goal of achieving not just energy independence but also energy dominance, by which he meant becoming a net energy exporter (White House, 2017c; GPO, 2017a). As part

of that effort, in 2018, the DOI proposed opening approximately 90% of federal offshore waters to drilling. In contrast, current policy puts 94% of the Outer Continental Shelf off limits. There have been no offshore Atlantic lease sales since 1983 and none off the Pacific coast since 1984 (DOI, 2018). The administration has also taken a variety of actions that make it easier to drill for and produce oil and gas on federal lands, such as reducing the royalty rate to 12.5% for a shallow offshore Gulf of Mexico lease sale (BOEM, 2017); speeding up the onshore drilling permitting process (DOI, 2017b); and proposing to streamline the issuance of oil and gas drilling permits in national forests (USFS, 2018).

The EPA regulates waste from crude oil and natural gas exploration and production under the Resource Conservation and Recovery Act (RCRA), and many states also regulate this waste (EPA, 2016b). In particular, concerns about the impact of hydraulic fracturing on drinking water led the EPA to conduct an extensive study over the past few years. In December 2016, the EPA concluded that hydraulic fracturing can affect drinking water under some circumstances (EPA, 2016c). Nevertheless, in 2017, the BLM withdrew a rule proposed in 2015 to regulate hydraulic fracturing on federal lands, finding that all 32 states with federal oil and gas leases have regulations that address hydraulic fracturing (BLM, 2017c). The state of California challenged this regulation withdrawal in court (CADOJ, 2018).

The federal government plays a larger role in the production of coal than in the production of oil and gas. In FY2014, 41% of US coal was produced from federal lands (EIA, 2015b). President Trump has encouraged 'reviving America's coal industry' (White House, 2017a), and he and his administration have taken actions such as cancelling a rule meant to protect streams from the mountaintop removal of mining waste (US Congress, 2017b), ending a moratorium on leasing federal lands for coal mining (DOI, 2017c), and amending regulations for the disposal of coal ash, saving the utility sector up to $100 million per year (EPA, 2018c).

DOWNSTREAM OIL

The US had almost 127 000 km of crude oil pipelines in 2016 and 100 000 km of oil product pipelines (PHMSA, 2018b). Interstate crude oil pipelines must have the approval of state authorities, but no broad federal approval is required. The Pipeline Safety and Hazardous Materials Administration (PHMSA) within the DOT sets minimum federal safety standards for pipeline facilities and transportation (CRS, 2016). The FERC sets oil pipeline rates and access conditions (FERC, 2016a). The export of crude oil and petroleum products is largely unregulated (BIS, 2016).

President Trump has promoted building oil pipelines. During his first week in office, Trump issued presidential memoranda to advance the construction of Keystone XL and Dakota Access oil pipelines (White House, 2017b; GPO, 2017b). Although it was approved by the President, the Keystone XL Pipeline, a 1 900-km crude oil pipeline to connect oil sands production in Alberta, Canada to refineries on the US Gulf Coast, was temporarily blocked by a federal judge in 2018, citing failure to consider factors such as low oil prices, greenhouse gas emissions and the risk of oil spills (USDMT, 2018). The Dakota Access Pipeline, a slightly longer project from North Dakota to Illinois, began operation in 2017 (ETP, 2017).

NUCLEAR ENERGY

The US Government supports the nuclear industry through various means, including legislative and financial measures. For example, the EPAct included several provisions considered to be important for revitalising the American nuclear power industry. It extended the Price–Anderson Nuclear Industries Indemnity Act of 1957 (the Price–Anderson Act) limiting the legal liability of nuclear operators. It also introduced loans to cover costs incurred by legal or regulatory project delays (GPO, 2005). In 2014 and 2015, the DOE issued USD 8.3 billion in loan guarantees to support the construction of two Westinghouse AP1000 Generation III+ reactors at the Alvin W. Vogtle Electric Generating Site in Waynesboro, Georgia, the last two nuclear power plants under construction in the US (DOE, 2017a). Under the February 2018 Budget Act, the Vogtle project will also qualify for an advanced nuclear facility PTC of 1.8 cents for each KWh of electricity produced and sold once the units come online (US Congress, 2018a). This is consistent with the president's goal to revive and expand the nuclear energy sector (White House, 2017c). In 2018, the president signed the Nuclear Energy Innovation Capabilities Act to encourage partnerships between the DOE and private companies to develop new nuclear technologies (US Congress, 2018b).

The DOE is responsible for the development and promotion of nuclear energy, while the NRC is the regulatory overseer of the industry. The federal government is also required to provide a site for the permanent disposal of high-level radioactive waste, with disposal costs to be paid by nuclear operators (NRC, 2016). In 2017, the NRC revived preliminary work to license a waste depository in Yucca Mountain, Nevada. Work on licensing was suspended in 2011 after the DOE withdrew its application (NRC, 2017b). The DOE has spent approximately USD 15 billion on developing Yucca Mountain, and the cost to continue the licensing process will be approximately USD 330 million (GAO, 2017).

RENEWABLE ENERGY

Incentives to promote renewables have been established at the federal, state and local levels for utilities and homeowners. At the utility level, a federal PTC is available on an inflation-adjusted per-kilowatt-hour basis for electricity generated by wind through 2019. Utilities may elect an ITC in lieu of a PTC. A utility/commercial ITC for solar, fiber-optic solar lighting systems, geothermal heat pumps, small wind energy systems and landfill gas systems (Section 48) phases down from 30% in 2017 to 10% in 2022 and thereafter (EIA, 2016b). A related ITC for small wind energy, geothermal heat pumps, solar electric, and solar water heating (Section 25D) phases down from 30% in 2017 to 22% in 2021 (CRS, 2018). Several federal loan and loan guarantee programmes also encourage the development of renewable energy and other advanced energy facilities (DSIRE, 2018). The DOE Loan Program Office manages a portfolio of approximately USD 13 billion of loan guarantees covering 17 renewable projects (DOE, 2018a). In January 2018, President Trump approved a declining 30% four-year tariff on almost all imported silicon solar cells and modules, in addition to the existing tariffs on PV cells from China and Chinese Taipei (EIA, 2018b).

Many state and local governments have established financial measures that complement federal incentives for renewable investment. In addition to subsidies, state legislation has also provided significant indirect incentives for renewable development through the establishment of policy frameworks such as renewable portfolio standards (RPS), which mandate that a certain share of electricity sales be sourced from renewable energy. As of 2018, 29 states had enacted the RPS legislation with varying degrees of stringency. Hawaii has the most ambitious goal: 100% renewable generation by 2045 (LBNL, 2018). Other measures have also been enacted to support renewable development, such as net metering, generation disclosure rules, mandatory utility green power options, green power purchasing policies and the use of public benefit funds (DSIRE, 2018).

Biofuels have received strong policy support in the transportation sector. In 2007, the EISA mandated a five-fold increase from previous biofuel use targets by 2022, requiring fuel producers to use a minimum of 136 billion litres (36 billion gallons) of biofuel. This included the increase in advanced biofuels usage (other than that derived from corn) to 79 billion litres (21 billion gallons) by 2022 (CRS, 2007). Since this law was passed, US consumption of gasoline has flattened, causing the biofuel blend ratio in gasoline to rise unexpectedly. Many auto manufactures have stated that their warranties will not cover any damage from biofuel blending above a certain ratio. In response, refineries are purchasing renewable credits to waiver their obligations instead of complying with the mandated targets (CRS, 2013). Consequently, biofuel production is already tracking below the current targets. Nearly all of US gasoline contains 10% ethanol. The EPA mandated that almost 20 billion gallons of biofuels overall should be blended into the fuel supply for 2019, still short of the 28 billion gallons envisioned by Congress in 2007 (EPA, 2018g). In 2018, the president directed the EPA to initiate a rulemaking to consider allowing gasoline with 15% ethanol (E15) to be sold year round (White House, 2018a). EPA has restricted E15 sales because of its potential to aggravate summertime smog problems (EPA, 2010).

ELECTRICITY AND GAS

The FERC regulates the interstate transmission of electricity and gas, as well as wholesale sales of electricity. FERC's mandate is to 'ensure supplies of energy at just, reasonable and not unduly discriminatory or preferential rates'. In regulating wholesale electric power markets, the FERC has implemented a policy of fostering competition (FERC, 2008). This has meant granting open access to transmission lines, thereby allowing wholesale customers to meet their needs with purchases from any number of wholesale suppliers connected across a regional grid. Competitive wholesale electricity markets use distinct models in different regions. Regional transmission organisations and independent system operators administer transmission networks and operate wholesale markets across large parts of the US and Canada. In other regions, bilateral

contracting between consumers and suppliers, with separate contracting for transmission, remains the norm (DOJ, et al., 2007).

Retail electricity markets are regulated by the states. Thousands of retail electricity providers operate under a variety of regulations. Furthermore, in 2017, 64% of retail customers are served by regulated, investor-owned utilities, 14% by public power systems and 13% by cooperatives (EIA, 2019b). State regulators ensure that these providers serve their customers at rates that are 'fair, reasonable and non-discriminatory' (NARUC, 2017). In the 1990s, many states began to explore options for restructuring retail electricity markets to create competition among electricity providers while continuing to regulate distribution networks as natural monopolies. In 2017, 21 states allowed some customers to choose their electricity service provider, while 8% of electricity customers were served by energy-only providers (EIA, 2018r; 2019).

Natural gas markets are similar to electricity markets, with competitive wholesale markets supplying federally regulated transmission pipelines and delivering to state-regulated distribution networks. The FERC sets natural gas pipeline rates. The DOE regulates the import and export of natural gas. The DOT's PHMSA regulates gas transmission pipelines to ensure that they are operating safely. The pricing and safety of natural gas distribution networks are regulated by state agencies (FERC, 2016b; EIA, 2009; DOE, 2016b). The Department of Health and Human Services subsidises the natural gas bills of low-income families through the Low Income Home Energy Assistance Program. This subsidy was USD 3.65 billion in 2018–19 (HHS, 2018).

ENERGY EFFICIENCY

Incentives to promote energy efficiency exist at the federal, state and local levels. Federal grants and loans support residential efficiency improvements. The Weatherisation Assistance Program grants funds to states to pay for a wide variety of energy efficiency measures for low-income homes, including improvements to the building envelope, its heating and cooling systems, its electrical system and electricity consuming appliances. Homeowners can also obtain loans from the federal government to finance energy-efficiency measures in new or existing homes (DSIRE, 2018). The US DOE sets minimum energy conservation standards for more than 60 categories of appliances and equipment, including washing machines, dishwashers, refrigerators/freezers, dehumidifiers, ceiling fans, water heaters, lighting, furnaces, boilers, heat pumps, air conditioners and motors (DOE, 2017b). In 2017, the DOE failed to publish final energy conservation rules for portable air conditioners, air compressors, commercial packaged boilers and uninterruptible power supplies in the Federal Register. This action is under review by the 9th US Circuit Court of Appeals (US9th, 2018). In 2019, the DOE proposed rescinding 2017 efficiency standards for certain light bulbs, including reflector, globe-shaped and candelabra (DOE, 2019).

At the state level, utilities are generally required to consider energy efficiency on an equal basis with new generation in their planning; many utilities administer demand-side management programmes that provide incentives and technical assistance to reduce demand for electricity and natural gas (DSIRE, 2017). In 2018, 30 states had efficiency targets that require electric and/or gas utilities to meet energy reduction targets over time (EIA, 2018s). At the local level, cities often use building codes to mandate building efficiency improvements (DSIRE, 2018).

CLIMATE CHANGE

In 2017, US energy-related carbon dioxide (CO_2) emissions were 5.1 billion metric tonnes. Energy-related CO_2 emissions declined in 7 of the 10 years since 2008. Petroleum was the largest source of CO_2 emissions, followed by coal and natural gas. Transportation was the largest emitting sector, followed by electric power, industry and buildings (EIA, 2018g). Emissions from fossil fuels produced on federal lands represented, on average, 24 percent of national CO_2 emissions from 2005 to 2014 (USGS, 2018).

On 1 June 2017, President Trump announced that the US would withdraw from the Paris Agreement on Climate Change (White House, 2017d). As a part of the United Nations Framework Convention on Climate Change (UNFCCC), the US had previously submitted its Intended Nationally Determined Contributions (INDC) to reduce economy-wide emissions by 26–28% below the 2005 levels by 2025 (UNFCCC, 2016). Although Congress has not passed specific legislation to control greenhouse gases, state and local governments have developed their own goals and action plans.

FEDERAL REGULATION

Consistent with President Trump's 2017 Executive Order on 'Promoting Energy Independence and Economic Growth', in 2018, the EPA proposed the Affordable Clean Energy (ACE) Rule to replace the Clean Power Plan (CPP) (EPA, 2018a). Analysis shows that ACE would cut CO_2 emissions at existing power plants by 33-34% from the 2005 levels by 2030, the same as the no-CPP case (EPA, 2018b). In late 2018, EPA proposed to revise greenhouse gas emission standards for future fossil fuel-fired power plants by replacing the 2015 rule, which identified partial CCS as the best option for emission reduction (EPA, 2018d).

Despite efforts to repeal the CPP, Congress enhanced the 45Q coal tax credit to support CCS technology in coal plants and other facilities in the February 2018 Budget Act. Any new fossil fuel power plant that commences construction before 2024 is eligible for tax credits for up to 12 years. Through 2026, tax credits will be raised linearly from $17-28 per tonne to $35-50. Lesser payments are for storage via EOR and other utilisation processes; greater payments are for dedicated geological storage (US Congress, 2018a). The tax credit is expected to benefit ethanol producers and natural gas processors, in addition to oil and gas drillers. The IEA estimates that the tax credits will add 10-30 million tonnes of CO_2 capture capacity (IEA, 2018), while the Energy Futures Initiative, led by former US Energy Secretary Ernest Moniz, estimates that up to 100 million tonnes of CO_2 capture capacity could be added (EFI, 2018).

The EPA sets limits on sulphur dioxide and nitrogen oxide emissions through the Cross State Air Pollution Rule (CSAPR) and on mercury and toxic pollutants through the Mercury Air Toxics Standard (MATS). Under CSAPR, in the summertime power plants in 22 states in the Eastern US must limit sulphur dioxide and nitrogen oxide, which are precursors of fine particulates (soot) and ozone (smog). Implementation of the regulations began in 2015, with further modifications starting in 2017 (EPA, 2017d). The MATS regulates acid gases and mercury from coal-fired plants of 25 MW or greater. Under the MATS, mercury emissions must be 88% below their uncontrolled levels (EPA, 2012b). In 2018, EPA proposed that the costs of the rule outweigh the benefits and that regulation of hazardous air pollutants is no longer 'appropriate and necessary' but did not propose a repeal of the rule (EPA, 2018f).

In 2018, the BLM issued a final rule repealing some of the key requirements of its 2016 Methane Waste Prevention Rule, which aimed to reduce waste of methane from all oil and natural gas production activities on federal and tribal land. The new regulation rescinds requirements for waste minimisation plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels and leak detection and repair. BLM found that the 2016 rule would have imposed costs exceeding its benefits and might conflict with the EPA regulations (BLM, 2018c) (Methane is the key constituent of natural gas and has a global warming potential more than 25 times greater than that of CO_2.). In 2016, the EPA issued a similar final standard to significantly cut methane emissions from new, reconstructed and modified processes and equipment, including hydraulically fractured oil wells. In 2018, EPA proposed to make it easier for drillers to meet the requirements by reducing the frequency of leak inspections and by giving operators more time to make repairs after a leak is detected (EPA, 2018e). In 2016 EPA also issued a final rule that requires new and existing municipal solid waste landfills to reduce methane emissions by one-third from the current requirement (EPA, 2016e).

STATE- AND CITY-LEVEL CLIMATE CHANGE INITIATIVES

In addition to federal actions to reduce greenhouse gas (GHG) emissions, regions, states and cities have undertaken their own initiatives. Nine states in the north-east and mid-Atlantic US are members of the Regional Greenhouse Gas Initiative (RGGI), which focuses on reducing CO_2 emissions from fossil fuel power plants over 25 megawatts by 45% compared with the 2005 levels by 2020. Using a cap-and-trade system, the states sell emission allowances through auctions and spend the proceeds on energy efficiency, renewable energy and other consumer benefit programmes. The RGGI has conducted 42 auctions thus far and plans an additional 30% regional cap reduction between 2020 and 2030 (RGGI, 2019). The six New England states are also party to the New England Governors/Eastern Canadian Premiers Climate Change Action Plan, whose 11 members have resolved to reduce the region's GHG emissions to 10% below the 1990 levels by 2020 and 35–45% below the 1990 levels by 2030 (NEG/ECP, 2017).

In 2018, California Gov. Edmund Brown issued an executive order setting a state-wide goal of achieving carbon neutrality by 2045 and maintaining net negative emissions thereafter (CAGov, 2018). More concretely,

but more narrowly, in 2018, Brown also signed into a law a bill requiring that California end-use customers get all their electricity from renewable and large hydro sources by 2045 and increasing the renewable portfolio standard to 60% by 2030 (CALeg, 2018). In 2017, California extended its five-year old cap-and-trade programme, which applies to both utilities and non-utilities, to 2030 (EIA, 2018f). In 2016, the state legislature passed a bill to set a target of reducing GHG emissions to at least 40% below the 1990 levels by 2030 in legislation (EIA, 2018t). The California Air Resources Board (CARB) has developed an implementation plan to reach the 2030 goal through adding 4.2 million zero-emission vehicles by 2030, a 40% reduction in methane emissions below the 2013 levels by 2030, and so on (CARB, 2017).

California leads a global effort by cities, states and countries to limit GHG emissions to 2 tonnes per capita or 80–95% below the 1990 levels by 2050. The Under 2 Coalition was formed in 2015 by the states of California and Baden-Wurttemberg, Germany. The coalition represents 220 governments with more than 1.3 billion people and 43% of the global GDP (including 11 US states) (Under2, 2019).

In reaction to President Trump's withdrawal from the Paris Agreement, 20 state governors representing 47% of US population and more than half of US GDP have joined the bipartisan United States Climate Alliance. They pledged to implement policies that advance the goals of the Paris Agreement and aimed to reduce GHG emissions by at least 26–28% below the 2005 levels by 2025, as well as tracked and reported progress to the global community in appropriate settings. Among other steps, the alliance announced that it would promote opportunities to use the social cost of carbon, an economic measure abandoned by the Trump Administration, which provides a dollar valuation of the damages caused by carbon pollution (USCA, 2019).

Municipal governments have undertaken other GHG initiatives. Notably, these include the Climate Mayors network formed in 2014 by the mayors of Los Angeles, Houston and Philadelphia. Each of the more than 400 cities in the coalition is pursuing setting GHG reduction targets (MNCAA, 2017). The earlier Climate Protection Agreement, launched in 2005 through the US Conference of Mayors, had 1 060 signatories by 2017. The goal of these mayors is to reduce CO_2 emissions below the 1990 levels (USCM, 2017).

VEHICLE EMISSION STANDARDS

In 2018, EPA and DOT's National Highway Transportation Safety Administration (NHTSA) proposed rolling back Corporate Average Fuel Economy (CAFE) and tailpipe carbon dioxide emissions standards for passenger cars and light trucks for model years 2021 through 2026. Fuel standards for 2025 would be reduced from 23.2 km per litre (54.5 miles per gallon) to 15.7 km per litre (37 miles per gallon). The agencies estimate that the new rule would save approximately USD 500 billion in social costs, but fuel consumption would increase to approximately 500 000 barrels per day (EPA, 2012a; GPO, 2018).

Unlike light-duty vehicles, which have been subject to fuel economy standards since the 1970s, the EPA and NHTSA are completing the first phase (2014–18) of standards for heavy-duty vehicles. These are expected to reduce the fuel consumption of heavy-duty vehicles by 10–20% between 2014 and 2018, save 530 million barrels of oil and reduce carbon emissions by 270 million tonnes (EPA, 2011). The EPA and NHTSA released final standards for Phase 2 (2018–27) in August 2016, which apply to semi-trucks, large pickup trucks and vans and all types of buses and work vehicles. These standards reduce fuel consumption by 8–24% compared with model year 2017 vehicles, reduce GHG emissions by approximately 1 billion tonnes and save approximately 1.8 billion barrels of oil (NHTSA, 2016).

In addition to the EPA vehicle standards, California is the only state with the right to enact its own emission standards for new engines and vehicles, which are often more stringent than the EPA standards. To date, 12 other states, constituting more than a third of the US auto market, have adopted CARB's advanced clean car programme standards, which retain the current 23.2 km per litre federal standard (CARB, 2018). However, EPA and NHTSA have proposed revoking California's authority to set its own pollution standards (GPO, 2018). In 2014, the CARB issued a rule for its zero-emission vehicle (ZEV) programme for model years 2018 and beyond, which subsequently included battery electric and hydrogen fuel cell vehicles. The ZEV sales requirement for large manufacturers was 4.5% in model year 2018 and will increase to 22% by model year 2025 (CARB, 2014b).

The number of electric vehicle charging stations rose to more than 61 000 in 2018, an increase of 21% from 2017. Hybrid vehicle sales increased to approximately 363 000 in 2017, an increase of 4.6% from the

previous year's level, but down from the 2013 peak. Plug-in vehicle sales were approximately 196 000, the highest ever and an increase of 23% from the previous year's level (ORNL, 2019). An ITC of USD 2 500 to 7 500 is available for plug-in electric vehicles depending on the size of the vehicle and its battery capacity. The tax credit is available until 200 000 qualified vehicles have been sold in the US by each manufacturer (DOE, 2017f). Phase out of the Tesla tax credits began in 2019 (FE, 2019).

NOTABLE ENERGY DEVELOPMENTS

ENERGY SECRETARY TOUTS 'NEW ENERGY REALISM'

In March 2018, US Secretary of Energy Rick Perry called for a 'new energy realism' in a policy speech at the annual CERA Week conference. Perry said that by 'embracing innovation over regulation' America can have both a growing economy and a clean environment. He cited innovation as the key in the 'move from perceived energy scarcity (in the 1970s) to unprecedented energy abundance' today. Noting that the world would continue to rely heavily on fossil fuels through 2040, he said 'We would welcome—and help lead—a global alliance of countries willing to help make fossil fuels cleaner, rather than abandoning them'. He said that the world could move toward a zero emissions goal 'without draining the growth out of developed nations...or dooming developing countries to a future of poverty and want' (DOE, 2018b).

US BECOMES WORLD'S LARGEST CRUDE OIL PRODUCER

In June 2018, the US became the world's largest crude oil producer for the first time since 1973. After the US surpassed Russia as the world's largest producer of crude oil and lease condensate with the production of 46.8 Mt, it maintained that position for the rest of the year. In August, the US exceeded production of 49.8 Mt for the first time. US crude oil production has increased rapidly since 2011, mainly driven by production from tight rock formations, including shale and other fine-grained rock, using horizontal drilling and hydraulic fracturing to improve efficiency. The last time the US was the world's number one crude oil producer was in 1973 at 491 Mt. In 1974, the former Union of Soviet Socialist Republics moved into first position (EIA, 2018g; EIA, 1996).

SECRETARY OF STATE ANNOUNCES ASIA EDGE

In July 2017, US Secretary of State Michael Pompeo announced Asia Enhancing Development and Growth through Energy (EDGE) as part of President Trump's 'Indo-Pacific strategy'. The four core priorities for EDGE are 1) Expand energy commerce (and security). This includes integrating regional gas and electricity markets; modernising the energy sector, including advancing smart grids, efficiency and payment apps; fostering business-to-business connections; and public–private partnerships; 2) Promote market-based energy policies and market reforms, including creating open, efficient, rules-based and transparent energy markets; 3) Catalyse private capital for investment projects by partnering with international financial institutions and firms on pooled finance, insurance and risk mitigation; commercial advocacy; and project development; and 4) Expand access to affordable, secure and reliable energy, primarily by promoting US energy exports. The initiative is tiny compared with China's Belt and Road initiative but that is partly because it is business-focused, rather than government-focused. The idea is to leverage public money with private participation and investment (State, 2018; DOE, 2018c).

CHINA IMPOSES TARIFFS ON COAL, OIL PRODUCTS AND LNG

Trade tensions between the US and China rose in 2018, as the US charged China with a variety of unfair trade practices, leading to US trade deficits with China (White House, 2019). Three rounds of tit-for-tat tariffs in July, August and September included 25% Chinese tariffs on coal and petroleum products, including LPGs, jet fuel and naphtha, and a 10% tariff on LNG (MOFCOM, 2018a; MOFCOM, 2018b). Even though crude oil was not included in the tariffs, US exports to China, which had seen strong growth since 2017, dropped to zero in August 2018 (EIA, 2019c). At the end of 2018, the two economies agreed to a pause in the imposition of new tariffs, while they tried to negotiate a settlement (White House, 2018b).

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Database of State Incentives for Renewables and Efficiency—www.dsireusa.org

Department of Energy—www.energy.gov

Department of Interior—www.doi.gov

Energy Information Administration—www.eia.gov

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Nuclear Regulatory Commission—www.nrc.gov

Pipeline and Hazardous Materials Safety Administration--www.phmsa.dot.gov

US Congress--www.congress.gov

The White House--www.whitehouse.gov

VIET NAM

INTRODUCTION

Viet Nam is an S-shaped economy located at the centre of Southeast Asia. It is bordered by China to the north, Laos and Cambodia to the west and the East Sea (Bien Dong) and Pacific Ocean to the east and south, respectively. Viet Nam has a land area of 331 231 square kilometres (km^2), with diverse geography and an exclusive economic zone stretching 365 km from its 3 260-km coastline (excluding islands). As it is in a tropical monsoon zone and profoundly affected by the East Sea, Viet Nam has warm weather, abundant solar radiation, high humidity and generous seasonal rainfall. The economy was part of the final batch of economies to join APEC in 1998.

Viet Nam is a dynamic emerging economy with a population of approximately 95 million (34% lives in cities and 66% in rural areas [GSO, 2017]) and a gross domestic product (GDP) of USD 552 billion (2011 USD at purchasing power parity [PPP]) in 2016 (Table 1). Over the past 30 years, Viet Nam has transformed from a centrally planned economy in 1986 to its current open, socialist-oriented market economy and active international integration. Viet Nam's GDP continuously grew between 1990 and 2008 at an annual rate of over 7%. The GDP decreased to 5.8% during the global financial crisis and recession period of 2008–15. In 2018, the growth reached almost 7.1%, the highest in the last 10 years. Its economic structure has gradually changed through contributions from the industry and service sectors, expanding from 62% of the economy in the early 1990s to 74% in 2016. Major exports have diversified with more manufactured products, such as electronics, machinery and vehicles (41% of total exports in 2016) as well as textiles, garments and footwear (21%), in contrast with traditional fishery products, coffee and rice (nearly 10%) and crude oil (nearly 2%) (Viet Nam Customs, 2017).

As of 2018, Viet Nam ranks 69th in the world and 18th in APEC region for its business environment, among which getting electricity (accessibility to electricity) is the most progressive indicator (27th in the world) (World Bank, 2018). Electrification in rural areas and remote islands is up to 99.9%. The government has promoted 'green growth' since 2012 for Viet Nam's new phase of industrialisation and modernisation.

Table 1: Key data and economic profile, 2016

Key data[a, b]		Energy reserves[c, d]	
Area (km^2)	331 231	Oil (billion barrels)	4.4
Population (million)	95	Gas (billion cubic metres)	646
GDP (2011 USD billion PPP)	552	Coal (million tonnes)	3 360
GDP (2011 USD PPP per capita)	5 838	Uranium (kilotonnes U)	-

Sources: [a] GSO (2018); [b] EGEDA (2018); [c] BP (2018); [d] NEA-IAEA (2019).

Viet Nam is endowed with diverse energy resources, such as oil, gas, coal and renewables. Although thorough resource assessments have yet to be carried out across the entire territory, especially in deep layers and deep-sea areas, as of the end of 2016, Viet Nam's proven fossil energy reserves were 4.4 billion barrels of oil, 617 billion cubic metres (bcm) of gas and 3 360 million tonnes (Mt) of coal (Table 1). OECD estimates the identified recoverable resources of uranium at approximately 3 900 tonnes, which are yet to be produced (NEA-IAEA, 2019). Surveys on and assessment of renewable energy's potential have been conducted to some extent (APERC, 2016), especially for large hydropower. The economic and technical potential of large hydro is estimated at 95–100 terawatt-hours (TWh)/year or 25 gigawatts (GW), of which the technical potential of small hydropower (less than 30 megawatts [MW]) is approximately 7 GW (MOIT, 2015e). Other renewable sources under the government's consideration for deployment over the next 15 years include wind, solar, biomass and municipal solid wastes (MSW). Potential capacity for wind power development is 6 GW, for solar is 12 GW (PMVN, 2016b), for biomass is 2 GW and for municipal solid waste (MSW) is 320 MW (MOIT,

2015e). The energy sector has been important in attracting significant foreign investments and boosting industry growth, export earnings and science and technology development.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Viet Nam's total primary energy supply (TPES) in 2016 was 69 317 kilotonnes of oil equivalent (ktoe), an increase of 5.4% from the 2015 level (Table 2). By energy source, 40% of the supply came from coal, 28% from oil, 12% from natural gas and 19% from renewables and other sources (mostly biomass).

COAL

Viet Nam had about 49 billion tonnes of potential coal resources as of 2010 (PMVN, 2016a). Although accounting for 81% of the resources, development of the sub-bituminous-rich Red River Delta coal basin is still at its preliminary stages. Given the complex geological conditions and its sensitive environmental and economic area, the exploitation of coal resources in this basin is predicted to take place only after 2020. Domestic coal has been produced and supplied mainly by opencast and underground mines in the Quang Ninh province.

Viet Nam's decreasing coal production reflects changes in government's policy to prioritise coal conservation for long-term domestic uses rather than boosting exports for generating foreign currencies. In 2016, Viet Nam produced about 21 515 ktoe of anthracite and semi-anthracite coals (93% of 2015 volume). With increasing domestic demand for coal, coal exports rapidly declined to 696 ktoe in 2016, about only 3% of the economy's production (EGEGA, 2017). Coal imports are predicted to significantly increase beyond 2017 to meet fuel requirements for over 41 GW of new coal-fired power capacity that the government has planned to build during 2016–30 in central and southern parts of Viet Nam (PMVN, 2016b).

OIL

Oil reserves are mainly offshore and in the southern part of Viet Nam. Active and successful offshore exploration has continuously increased the number of oil reserves in recent years. Crude oil production decreased by 10% to 15.5 Mt despite the CAGR of 4.2% during 2000–15, 56% of which was exported. Based on current proven reserves, oil production will continue to decline to as low as 5 Mt/year by 2035 (MOIT and DEA, 2017) since major fields in the Cuu Long Basin will have matured.

Viet Nam is a net crude oil exporter but a net importer of petroleum products. There were 12.4 Mt of net imported petroleum products in 2016, which continue to account for the majority (63%) of Viet Nam's total primary oil supply. Petroleum product imports have shown a slight downward trend since 2009 as the first refinery in Viet Nam, the 140 000-barrels per day Dung Quat refinery, began operation during that period but then rose again from 2013 in pace with economic growth. With the second refinery on stream since late 2018, Nghi Son, petroleum products for domestic consumption is expected to increase in the next few years.

NATURAL GAS

Viet Nam is self-sufficient in terms of natural gas supply. There are four offshore gas pipeline systems built to deliver gas from Viet Nam's oil and gas fields in the petroleum basins of Cuu Long, Nam Con Son, Malay-Tho Chu and Red River Delta to shores in the south-east and south-west regions of Viet Nam.

Viet Nam's natural gas supply in 2017 was approximately 9.6 bcm (PVGas, 2018a). Growth in the electricity, fertiliser and petrochemical industries has driven demand for natural gas. Under the government's orientation, PVN and PVGas are preparing for the development of two major gas projects to have additional gas supplies of about 7–10 bcm per year from Block B, Ca Voi Xanh field and adjacent sources to southern and central markets beyond 2020 (PMVN, 2016b, PVN, 2014). Viet Nam has also begun to develop new infrastructure for importing LNG, first in the south, to diversify gas supply sources and ensure national energy supply security beyond 2021 (PMVN, 2017a; MOIT, 2015b).

POWER GENERATION

Vietnam Electricity (or EVN) is a state-owned company that has significant control over the national power transmission and distribution, owning approximately 61% of the total 42 GW capacity of electricity in Viet Nam (EVN, 2018). Total power generation in 2016 was 180 356 GWh[1], an increase of 11% from its 2015 level. Of this total electricity output, approximately 35% came from hydro and almost 64% from thermal energy (Table 2). Only a very small insignificant portion is made up of other renewable sources such as wind and biomass, but its share increase sharply (41%) from 2015.

To optimise the electricity supply and cost-effectiveness in all regions in the economy, since 2004, Viet Nam has also relied on power sources from biomass and electricity imports from neighbouring economies such as China and Laos. However, these sources were still marginal in its economy's power system during 2008–16.

Table 2: Energy supply and consumption, 2016

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	59 947	Industry sector	28 121	Total power generation	180 356
Net imports and others	10 608	Transport sector	8 923	Thermal	116 176
Total primary energy supply	69 317	Other sectors	14 384	Hydro	63 911
Coal	27 892	Non-energy	0	Nuclear	0
Oil	19 493	Final energy consumption*	51 427	Others	269
Gas	8 271	Coal	11 748		
Renewables	13 488	Oil	18 319		
Others	172	Gas	684		
		Renewables	6 905		
		Electricity and others	13 770		

Source: EGEDA (2018) (data collected in September 2018).

** Final energy consumption and the corresponding breakdown by fuel types do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to be comprising renewables.*

FINAL ENERGY CONSUMPTION

In 2016, Viet Nam's final energy consumption (excluding non-energy uses) was 51 427 ktoe, an increase of 5.7% from 2015 (Table 2). By fuel source, oil consumption contributed to the largest share (36%), followed by electricity (27%), coal (23%) and renewable energy (13%).

Industry is an important sector in GDP growth and represents the largest segment of the total final consumption at 55%. This sector consumed coal (almost half) and electricity as the main fuel. The transport sector is also a large energy-consuming sector, accounting for 17% of the total final consumption. It remained the main consumer of petroleum products at two-thirds of the economy's total requirement. In the other sectors (residential, agricultural and commercial as a whole), energy consumption represented 28% of the total final consumption. In this sector, biomass accounted for the largest amount and was followed by electricity. All of the biomass and most of the coal volumes were consumed by the residential sector. Demand for electricity grew rapidly in the residential and service sectors, reflecting improvements in household income and creating an increase in electric appliance use and power supply quality.

[1] The 2018 total generation was reported at 219 912 GWh and thermal energy still accounts for 60%.

ENERGY INTENSITY ANALYSIS

In 2016, Viet Nam's energy intensity in terms of primary energy supply was approximately 126 tonnes of oil equivalent per million USD of GDP (toe/million USD), which does not show significant improvement from 2015 level (0.7% reduction). Energy intensity in terms of total final consumption also indicated a little change, from 94 toe/million USD to 93 toe/million USD (Table 3). Energy efficiency measures did not seem to be strongly effective against rapid growth in all sectors, especially transport and industry.

Table 3: Energy intensity analysis, 2016

Energy	Energy intensity (toe/million USD)		Change (%)
	2015	2016	2016 vs 2015
Total primary energy supply	126	126	-0.7
Total final consumption	94	93	-0.5
Total final energy consumption excl. non-energy	95	94	-0.6

Source: EGEDA (2018).

RENEWABLE ENERGY SHARE ANALYSIS

Table 4 shows how the share of modern renewable energy in final energy consumption changed in two years: from 16.5% to 17.3% in 2016. Final consumption of modern renewables increased by 10.7%, while energy consumption from traditional biomass declined by 18%.

For electricity specifically, the installed hydropower capacity has quadrupled from 4.2 GW to almost 17 GW since 2005, reflecting a CAGR of 13%. As a result, total renewables' share increased from 38% in 2005 to 43% in 2016. However, the share includes large hydropower, which is soon to saturate, and hence, this share may decrease in the near future.

Viet Nam is a tropical economy that is rich in natural resources and has abundant potential for solar, wind, and biomass energy, not to mention small and medium hydropower. The economy can significantly contribute to the APEC renewable doubling goal if the potentials are utilised effectively.

Table 4: Renewable energy share analysis, 2015 vs 2016

Energy	2015	2016	Change (%) 2015 vs 2016
Final energy consumption (ktoe)	48 660	51 427	5.7
Non-renewables (Fossils and others)	37 071	39 622	6.9
Traditional biomass*	3 560	2 920	−18
Modern renewables*	8 029	8 886	10.7
Share of modern renewables to final energy consumption (%)	16.5%	17.3%	4.7%

Source: EGEDA (2018).

** Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on.) including biogas and wood pellets are considered modern renewables, although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Ministry of Industry and Trade (MOIT) oversees all industries, including energy. Within the MOIT, two departments (Department of Energy Efficiency and Sustainable Development and Department of Oil, Gas

and Coal) and two agencies (Electricity Regulatory Authority of Viet Nam, ERAV and Electricity and Renewable Energy Authority, EREA) are the key advisory and executive units assisting the MOIT's Minister with the management of the energy sectors. Most of the energy research and projection activities are carried out under the Institute of Energy.

Petro Vietnam (PVN), the Viet Nam National Petroleum Group (Petrolimex), Vietnam Electricity (EVN) and The Vietnam National Coal - Mineral Industries Group (Vinacomin) are the leading state-owned enterprises (SOEs) in the energy industries in Viet Nam. They actively contribute to formulating and implementing development strategies, master plans and annual plans issued by the government in energy sectors.

The latest umbrella policy document is the 'National Energy Development Strategy to 2020, with a Vision to 2050' (PMVN, 2007a), which addresses the Vietnamese Government's energy development viewpoints, key objectives, major policies and measures to be realised towards 2050 in the energy industries. In addition, detailed sectoral targets and policies for each five-year planning period correspondingly adjust to updated assessments. During 2015–18, the prime minister approved several new or revised strategies and master plans for the development of oil and gas, renewable energy, coal and electricity sectors. They include oil and gas strategy to 2025/2035[2] (PMVN, 2015b); renewable energy strategy to 2030/2050 (PMVN, 2015c); revised coal plan to 2020/2030 (PMVN, 2016a); revised power plan for 2010–20/2030, also known as PDP7 revised (PMVN, 2016b), and gas plan 2025/2035 (PMVN, 2017a).

Below is the summary of some of the main targets for energy development in Viet Nam up to 2020/2030:

- To ensure a sufficient and high-quality supply of energy to meet the demands of socio-economic development, with average GDP growth rates expected to be 7%–7.5% per year during 2011–20 and 6%–6.5% during 2021–30 (PMVN, 2015c);
- To strive to increase petroleum reserves at 25–30 Mtoe per year during 2016–20 and 20–28 Mtoe per year during 2021–30 and to produce 11–14 million tons of crude oil and 11–14 bcm of gas annually during 2016–20 and 5-12 million tons of crude oil and 15–21 bcm for 2021–30 (MOIT, 2015d);
- To expand oil refining and petrochemical capacities, aiming to satisfy demands of domestic markets and export of oil and petrochemical products. To ensure domestic production to meet 60%–70% of Viet Nam's demand for petroleum products and 50% of the economy's demand for petrochemical products over the period 2020–30 (MOIT, 2015d);
- To ensure total oil stockpiling (including crude oil and petroleum products) adequate for 90 net-import days until 2020 (PMVN, 2017d);
- To strive to reach coal production of 47–50 million tons by 2020 and 55–57 million tons by 2030. To start exploitation in the Red River Delta coal basin during 2021–30, with a targeted commercial coal yield of 0.5–1.0 million ton per year by 2030 (PMVN, 2016a);
- To achieve a share of renewable energy (including large hydropower) in the total primary energy supply of 31% (or 37 Mtoe) in 2020, 32% (62 Mtoe) in 2030 and 44% (138 Mtoe) in 2050. To develop renewable power (including large hydro and pumped-storage hydropower) of about 24 GW in 2020 and 49 GW in 2030 (PMVN, 2015c) and
- To complete the rural electrification programme for rural, mountainous and remote island areas, increasing the proportion of rural households with access to electricity to 100% in 2020 (PMVN, 2007a).

MOIT is now working on the proposal of National Energy Master Plan through 2050 with updated energy supply and demand projection, and on the PDP8 that reflects improved contemporary electricity demand and supply.

[2] Not open to public

ENERGY MARKETS

ELECTRICITY MARKET

Viet Nam's electricity market is characterised by the active participation of several SOEs and various private players involved in power generation and distribution on a build-operate-transfer (BOT) and independent power producer (IPP) basis. As the leading SOE in Viet Nam's power sector, EVN is entrusted to manage the development and operation of the national power transmission system. In 2018, the 42 GW electricity capacity was owned by EVN (61.4%), PVN (10.5%), Vinacomin (4.2%) and BOT and others (23.9%) (EVN, 2018).

Since 2004, the Government of Viet Nam has established a vision for a competitive power market as part of a long-term development strategy for the electricity sector through the Electricity Law of December (amended 2012), detailed in the Road Map (PMVN, 2013a, b). Accordingly, competitive market development comprises of three phases of pilot and full operation:

- Phase 1 (up to 2014): Competitive Generation Power Market;
- Phase 2 (2015–21): Competitive Wholesale Electricity Market, VWEM (the first two years are pilot) and
- Phase 3 (2021 forward): Competitive Retail Electricity Market, VREM (with a pilot period from 2021–23).

Viet Nam's competitive generation power market (VCGM) launched its pilot operation on 1 July 2011 and commenced full operation on 1 July 2012. By the end of 2016, there were 76 power plants with a total capacity of 20.7 GW directly participating in selling electricity in the spot market. Those 55 power plants constitute 49% of the total capacity of the power system.

The first actual pilot year of the competitive wholesale power market started in January 2016 under simulation, yet with real payments (MOIT, 2014b, c and 2015a, c). Under this pace, VWEM is expected to be implemented in 2019 after year 2017–2018 pilot and VREM will be in full operation from 2023 (EVN, 2018).

TARIFFS

Electricity prices are in accordance with the market and under the regulation of the government (Provision 29 of Electricity Law 2004 and amendments in 2012). The calculation of average retail electricity tariff is defined in Decision 24 (PMVN, 2017c) and is based on the audited costs; the generation, transmission and distribution sector investors' reasonable profits; and the costs of regulating, managing and supporting services in the electricity system. EVN calculates the tariff annually and may increase from 3% to under 5%. For higher increase rates, prompt report to the governmental agencies and approval is required. Current application of retail electricity tariffs by user categories and wholesale prices for electricity retailers follows MOIT's regulations (MOIT, 2014a and 2018) of purchasing and selling prices of electricity from the national electricity system. The average retail tariff (exclusive of value-added tax [VAT]) is VND 1 720.65/kWh, a 6% increase compared to that in the previous period (MOIT, 2017b).

CRUDE OIL MARKET

Players in the upstream oil sector in Viet Nam include PVN and its subsidiary PVEP, various international oil companies and other foreign enterprises. According to the Petroleum Law 1993 and amendments in 2000 and 2008, the government reserves the right to be a priority buyer of oil production from contractors, and in such cases, foreign contractors have the right to sell their profit oil at international prices.

The first refinery, namely Dung Quat in Quang Ngai province with 6.5 Mt capacity of crude oil per year (or 148 000 barrels per day) has been operated by the Binh Son Refining and Petrochemical Company Limited (BSR) since 2009. BSR as well as PVOil and PVPower were PVN subsidiaries but fully equitised in 2018. The sweet crude oil supply to Dung Quat refinery has mainly come from domestic sources, including approximately 60% from Bach Ho field and 40% from others offshore Viet Nam; imports remain a negligent contribution.

Viet Nam's crude oil market and imports are anticipated to further increase together with existing expansion plans of refining capacity towards 2030. A 10-Mt refinery and petrochemical complex—PVN's Nghi Son project (at Thanh Hoa province, central Viet Nam)—has just begun commercial operation in late 2018

after five years of construction. It is expected to meet approximately 40% of domestic petrol demand. Another 16-Mt project, Long Son, is also under construction from 2018 to approximately 2022.

OIL PRODUCT MARKET

In Viet Nam, products of the crude oil refining process, which are used as fuel, including gasoline, diesel, jet fuel, kerosene, fuel oil, biofuels (E5 and E10) and other engine fuels, excluding liquefied petroleum gas (LPG) and natural gas products are often referred to as one group.

The government regulates wholesale prices of fuel oil and others based on the approval of a baseline selling price for the suppliers. The base price of those (excluding E5 and E10) is composed of several price elements, including cost, insurance, freight (CIF) price of importers; government taxes and levies (import tax, excise tax, VAT, environment tax); business expense norms; deductions for the Petroleum Price Stabilisation Fund; and profit norms. Exchange rates also affect the base price. In regard to the E5, E10 base price, the calculation takes into account not only the above-mentioned price elements but also the monthly average price of fuel ethanol (E100) domestically produced and imported to Viet Nam and the blending percentage of fuel ethanol (5% for E5 and 10% for E10) by its volume with unleaded gasoline RON 92. The Ministry of Finance takes the leading role in the calculation of each price element in the regulated base price. Starting from January 2018, E5 has been officially sold economy-wide to replace RON 92 after five years of pilot compulsory sales in several cities/provinces.

NATURAL GAS AND LPG MARKET

The government reserves the right to be the first priority buyer of all natural gases exploited and produced in Viet Nam. PVN and PVGas are the authorised buyers of natural gas from oil and gas contractors and the sellers to consumers in the Vietnamese market. According to the price law, natural gas prices are not subject to government regulation; all upstream sellers and downstream buyers are free to negotiate the price and other terms in the Gas Purchase and Supply Agreement (GPSA) with PVN and PVGas. The natural gas prices and levels are set considering the competitive position of natural gas against that of alternative fuels. This ensures a reasonable profit margin for investors in related upstream and midstream natural gas projects.

PVN submits the GPSA, including a price formula and level, to authorised organisations and the prime minister for approval before the GPSA goes into effect. PVGas is responsible for planning, developing and operating infrastructure projects to ensure a safe and reliable natural gas supply and support natural gas exploration and production in Viet Nam.

Business activities, especially trading and distribution of LPG, and natural gas products are, however, open for competition among all domestic and foreign investors, currently regulated under the government's decree No. 87 (GOV, 2018). LPG market is partly supplied from Dung Quat and Dinh Co Gas processing plant, and the rest is imported from China, Qatar, Saudi Arabia and other countries (PVGas, 2018). By the end of 2016, there were seven LPG import–export trading companies and 23 LPG distribution companies operating in Viet Nam. LNG is also a promising business in Viet Nam backed up by the government's plan on importing LNG for power (PMVN, 2017a). PVGas (51%), Bitexco (39%) and TG Asia (10%) have jointly invested and created the first LNG company in Viet Nam, the LNG Viet Nam, operating since August 2016.

COAL MARKET

Vinacomin's production and sales account for 85% of the total coal market in Viet Nam (Hung and Son, 2018). Apart from that, the North-East Coal Corporation (originally owned by Vinacomin, now under the Ministry of Defence) is the only company could aim at the domestic market, while Vietmindo (Indonesian-owned company) can only exploit for export. PV Power Coal (owned by PVN) oversees coal imports, trading and ensuring coal supply for their five new coal power plants, namely Vung Ang 1, Thai Binh 2, Long Phu 1, Song Hau 1 and Quang Trach 1. The forecast for total coal demand for these power plants is approximately 16 Mt in 2020 and 20 Mt in 2030. Importer of Viet Nam coal include Japan, Korea, India and other ASEAN countries, while the sources of coal import are mostly (84%) from Indonesia, Australia and Russia.

Since July 2009, Vinacomin has set the price for local customers at the market price, except for power generators. Recently, the government has been preparing a strategy to deregulate the price of coal used for power generation, which has been enjoying only 60%–70% of market price. In 2012, the government allowed

the coal price for power production to rise according to the latest electricity price adjustment. Any adjustment would be no less than the coal production cost to ensure funding for the renovation, expansion and improvement of the capacity of the existing mines and the building of new mines to meet coal demand and contribute to improvements in energy efficiency.

ENERGY EFFICIENCY

National energy efficiency and conservation programmes, often referred to as VNEEP (Viet Nam National Energy Efficiency Programme), are conducted under three main periods approved by the Prime Minister (2006–2010, 2011–2015 and 2019–2030) (PMVN, 2006, 2012b, 2019).

The 2006-2015 programme's overall objectives cover community stimulation, motivation and advocacy, science and technology and mandatory management measures for carrying out coordinated activities related to the economical and efficient use of energy in society as a whole. Phase one of VNEEP for 2006–10 was successfully implemented, saving approximately 4 900 ktoe in total energy consumption in the period, equivalent to 4.3% of the total energy consumption. Key legal documents on EE&C were created and issued, including the Law (NAVN, 2010) and its regulations and guidelines by sector. By the end of 2014, the regulation and guidelines of concrete measures for enhancing energy savings and efficiency covered transport (2011), agricultural (2013) and industrial sectors (2014). In 2013, the National Technical Regulation on Energy Efficiency Buildings was revised in line with the updated international trends of minimum standards for energy-efficient building exteriors and interior equipment.

Phase two's results for 2011–15 were discussed at a series of conferences on the five-year implementation of the National Target Programme on Energy Efficiency of 2011–15, held in the fourth quarter of 2015 by MOIT in cooperation with the Vietnam Union of Science and Technology Associations (VUSTA) in Energy Saving and Efficiency (VNEEP, 2015). MOIT reported the level of energy savings at 5.65% of Viet Nam's total energy consumption during 2011–15. More information can be found at the Compendium of Energy Efficiency Policies of APEC Economies 2017 (APERC, 2017).

Under VNEEP in 2012–17, a GEF/World Bank-funded project, Cleaner Production and Energy Efficiency (CPEE), also resulted in significant outcomes related to legal frameworks for action plan and energy consumption in some industries. Another USD 158 million project from 2018, mostly funded by the World Bank, is intended to further support industry with energy efficiency technology and practices.

Phase three has just been approved, targeting energy intensive industries that harm the environment, transport and construction sectors. Phase three is similar to the previous ones regarding reduction target (5%–7% for 2019–25 and 8%–10% for 2019–30 of total national energy consumption) but under a bigger budget (VND 4 400 billion from the state fund and other credit funds) and with more comprehensive goals. Establishing a national energy data centre and training centres for energy efficiency by 2025 is among the outstanding objectives of this phase.

RENEWABLE ENERGY

In November 2015, the government first issued the national strategy of renewable energy for the period through 2030, with a vision towards 2050 (PMVN, 2015c). Renewable energy development in Viet Nam continues to integrate with the implementation of broader objectives of general socio-economic development and industrial and sectoral deployment. In particular, it contributes to modernisation and new rural development, fuel diversification and implementation of Viet Nam's pledge to mitigate the increase in GHG emissions.

The ambitious targets set include commercial renewable energy to reach 37 Mtoe (31% of TPES) by 2020 and 62 Mtoe (over 32%) by 2030; renewable power (including large hydropower) to account for 38% of the total generation by 2020 and 32% by 2030 and biofuels to increase to approximately 5% of total transport fuel demand in 2020 (approximately 800 ktoe) and 13% (3.7 Mtoe) in 2030. The government expects that accelerated renewable energy growth will contribute to a mitigation of GHG emissions in energy activities of around 5% by 2020 and 25% by 2030 compared with the business as usual (BAU) plan. Additionally, a reduction in fossil fuel imports for energy purposes of approximately 40 million tonnes of coal (compared to the case established in the PDP7 in 2011) and 3.7 million tonnes of oil products by 2030 is expected. In March 2016, the prime minister approved the revised PDP7 to update and detail these new targets and policy measures

for renewable power developments in Viet Nam to 2030. Renewable energy needs to take an even more important role because of the absence of the halted nuclear power plant project in late 2016.

Support mechanisms and policies for renewable energy development include various fiscal incentives within import tax, corporate income tax and land taxes and fees, as well as credit incentives, as specified in legislation; approved electricity prices (avoided-cost tariffs, feed-in tariff [FiT]) for on-grid renewable energy; standardised power purchase and sale contracts (20 years) within an obligation for EVN/its regional electricity utilities to prioritise renewable energy in grid connection and dispatch and purchase electricity at approved tariffs; a renewable portfolio standard (RPS) obligation for major electricity generators and traders; and net metering for electricity consumers with simplified connection arrangements and environmental fees for organisations utilising fossil fuels for energy production. More information on Viet Nam's renewable policies can be found at the most recent APEC's Peer Review on Low-Carbon Energy Policies (APERC, 2016). In 2017, the prime minister promulgated the Decision on mechanism on encouragement of solar power development (PMVN, 2017b), and accordingly, MOIT issued a circular on project development and model power purchase agreements applied to solar power projects (MOIT, 2017a). FiT for wind was also updated to attract more investors (PMVN, 2018).

Table 5: FiT for some renewable energies in Viet Nam

Renewable Energy	Tariff level	
	VND/kWh	US cents/kWh*
Wind onshore	1 928	8.5
Wind offshore	2 223	9.8
Biomass power	1 220	5.8
Solid-waste power	2 114	10.05
Solar energy	2 086	9.35

Source: PMVN (2014a, b, 2017b, 2018)*

Roughly estimated at the issuance time of the decision and subjected to change with exchange currency.

This FiT for solar is only applicable to projects coming into commercial operation before 30 June 2019 but the revised regulation for wind, with additional separation for offshore power, offers a longer time (three years). The contract shall remain for 20 years from the commercial operation date.

NUCLEAR

After the decision of halting the Ninh Thuan nuclear power plant project in late 2016[3], the Government of Viet Nam has not mentioned any future restart possibility.

CLIMATE CHANGE

Viet Nam submitted its new climate action plan Intended Nationally Determined Contributions (INDC) in 2015, including a mitigation and an adaptation component. It was then converted into First Nationally Determined Contributions in the next year. In the early stages of industrialisation, and only recently recognised as a lower middle-income developing economy, Viet Nam contributes only 0.5% of global CO_2 emissions (GOV, 2015). In the past 50 years, however, extreme climate events such as storms, floods, droughts and saline water intrusion have increased in both frequency and intensity. Viet Nam is one of the economies that may suffer the most severe impacts of climate change and rising sea levels, according to national and international analyses of climate change scenarios for 2100.

Viet Nam signed the UNFCCC in 1992 and ratified it in 1994 and signed the Kyoto Protocol (KP) in 1998 and ratified it in 2002. Viet Nam has fulfilled all requirements to be an Annex II economy for developing clean development mechanisms (CDMs) under the protocol. A National Strategy on Climate Change (Decision

[3] http://news.chinhphu.vn/Home/Govt-states-reasons-to-cancel-nuclear-power-project/201611/29076.vgp

2139/QD-TTg) was also issued in 2011. It involves a century-long vision and is the foundation for all other ministerial, sectoral and local strategies, plans and programmes.

Viet Nam has set a target to reduce 8%–10% of its GHG emission intensity from 2010 levels by 2020, and after 2020, to reduce GHG emission intensity by 1.5%–2% per year on average (or 20% by 2030). These targets are Viet Nam's voluntary reduction. Additional international support is required for higher targets of 20% by 2020 and 30% by 2030 (PMVN, 2012a; GOV, 2015). Viet Nam's BAU scenario for GHG emissions was developed based on the assumption of economic growth in the absence of climate change policies. BAU began from 2010 (the latest year of the national GHG inventory). It includes the energy, agriculture, waste, and land use, land-use change and forestry (LULUCF) sectors.

- GHG emissions in 2010: 246.8 million tons carbon dioxide equivalent (tCO_2-e);
- Projections for 2020 and 2030 (not including industrial processes):

  2020: 474.1 million tCO_2-e

  2030: 787.4 million tCO_2-e

NDC is now being updated by the Ministry of Natural Resources and Environment (MONRE) with changes regard the base year (2010 to 2014), reduction percentage (9%) and 2030 emission level (888.8 $MtCO_2$ instead of 787.4) to better reflect industry processes. Sectoral NDC is also being developed by MOIT.

NOTABLE ENERGY DEVELOPMENTS

Index of Industrial Products (IIP) of 2018 is reported by the General Statistic Office to grow at 10.2%, of which 0.9 percentage point is contributed by the power sector. Coal and oil production has grown rapidly (65.5%) among the sub-industries, while crude oil and natural gas production has reduced (-5.4%).

Energy production plays an important role in local economy. Highest provincial IIP was recorded at Ha Tinh (89%) and Thanh Hoa (35%), all attributed to energy related activities, such as those of Formosa Cooperation and Nghi Son refinery.

Total installed capacity of the national power system (by the end of 2018) is about 49 GW (generating approximately 219 912 GWh, increasing 11% from its 2017 level), with a dominant 52% share of fossil fuel and 41% of hydropower (EVN, 2018).

RISK OF POWER SHORTAGE AND THE ROLE OF THERMAL POWER

According to the General Statistics Office (GSO), electricity production and distribution sector stably grows at 10% in 2018 (9.4% in 2017 and 11.5% in 2016), being able to meet the demand in production and buildings. However, Viet Nam could face the risk of power shortage, especially in the warmer South, due to increasing demand for the economy when domestic GDP forecast sees continuously high economic growth at about 6.5-7% per year until 2030. In addition, reservoir storage at the Central and the South were at low levels (one third of 2017's level) due to slowly declining rainfall in 2018 (EVN, 2018), forecasting a decrease in hydropower generation for 2019.

One important measure to strengthen energy security is to improve energy efficiency, reduce energy losses and implement extensive measures for the conservation of energy. Viet Nam is assumed to accelerate the energy efficiency programmes, which have gained certain fame and impact in the society since it is regarded as 'the first fuel' (MOIT and DEA, 2017).

Coal is the cheapest source of supply for a developing economy like Viet Nam. While Viet Nam has been a net coal exporter for more than 25 years, increased domestic consumption in 2016 led to a net import of coal for the economy. In the Energy Outlook 2017, the economy is projected to be a net energy importer soon, implying that Viet Nam would have to rely on imported fuel (37.5% in 2025), particularly coal.

Regarding natural gas, Viet Nam has been constructing infrastructure to import about one bcm of LNG per year starting from 2021. Two new gas-fired power plants, Nhon Trach Nos. 3 and 4, are to be added into the PDP. According to PVGas, in 2017, the company invested about a billion USD for the second phase of Nam Con Son 2 pipeline project so that it could receive natural gas from Su Tu Trang (White Lion) field in

conjunction with the first phase of Nam Con son 2. Commencement of the activity is scheduled for 2019 onwards.

RENEWABLE ENERGY DEVELOPMENT

The decision of halting the construction of the nuclear power plant in late 2016 interrupted the projection of energy supply in the long term. Besides promoting gas power, the Government of Viet Nam has also been actively supporting the growth of renewable energy. A few months right after the prime minister's approval for the decision of encouraging solar power development projects, MOIT issued detailed supporting measures for these projects (MOIT, 2017a). The decision has enabled solar power projects to be realised, such as those of EVN in southern areas of Viet Nam (EVN, 2018), where there is a huge potential of variable renewable energy, and many others are to be proposed. In considering a more favourable tariff for wind power, the government raised the tariff to VND 1.928 per kWh (USD cents 8.5) for onshore and VND 2.223 per kWh (USD cents 9.8) for offshore wind power, being effective from November 2018 (PMVN, 2018). Wind power, in combination with solar power, has exhibited the fastest growth in 20 years ahead. Renewable energy is quite costly compared with other sources; therefore, intensifying regional and international energy cooperation to call for more investment is necessary in this context.

In transport, biofuels have been encouraged in Viet Nam as an alternative to partially replace conventional fossil fuels, contributing to enhanced energy security and environmental protection. The intention to promote biofuel originated in 2007 when the government launched a roadmap for biofuels. By 2025, the economy aims to build an advanced biofuel industry, applying a biofuel production technology in Viet Nam that will eventually reach the world's most advanced level (PMVN, 2007b, 2012c, 2015a). In late 2017, gasoline A92 fuel was completely replaced with E5 biofuel (a mixture of gasoline A92 with 5% bio-fuel ethanol by volume) economy-wide from January 2018, a move that followed the biofuel development scheme (PMVN, 2007b). With that change, only two types of petrol for motor vehicles are allowed in the market: the biofuel E5 (some USD 0.71 per litre) and high-octane traditional gasoline A95 (USD 0.77 per litre)[4]. Also from January 2018, cars with up to 9 seats must be qualified under energy labelling programme under the Decision No. 04/2017/QD-TTg.

[4] Price at VND from http://www.petrolimex.com.vn/, retrieved February 27, 2019 and exchange rate at http://www.vietcombank.com.vn/ExchangeRates/default.aspx?bank=VIETCOM&lang=vi.

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Ministry of Industry and Trade—www.moit.gov.vn

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Electricity Regulatory Authority of Vietnam (ERAV)—www.erav.vn

National Load Dispatch Centre (NLDC)—www.nldc.evn.vn/

Vietnam Electricity (EVN)—www.evn.com.vn

Energy savings—tietkiemnangluong.vn

Vietnam Energy—nangluongvietnam.vn

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