



APEC ENERGY OVERVIEW

2017

Prepared by

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FOREWORD

The *APEC Energy Overview* is an annual publication that seeks to outline 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 to deepen the understanding of energy issues among APEC economies, promote the use of EGEDA data and provide useful insights to policy makers in the region.



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EXECUTIVE SUMMARY

APEC population—which had remained constant for the last five years—grew 0.7% in 2015 to reach 2.85 billion. Its GDP, on the other hand, continued to increase significantly, reaching USD 59 014 billion (PPP constant 2011 USD) in 2015, up by 3.7% compared with the 2014 levels (USD 56 908 PPP constant 2011 USD). Total primary energy supply in 2015 posted a negative growth (-0.3%) after continuously slowing since 2012 to reach 7 885 million tonnes of oil equivalent (Mtoe) compared with the 2014 supply level of 7 912 Mtoe. This decline can be attributed to the slide in coal supply posted at -2.5% in 2015. Total final energy consumption in APEC reached 4 728 Mtoe in 2015, an almost negligible increase from the 2014 levels of 4 728 Mtoe. If consumption for non-energy use is added, total final consumption was 5 250 Mtoe.

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

Energy intensity in the APEC region has been improving continuously. In 2015, the final energy intensity was reduced 3.5% to 80 tonnes of oil equivalent (toe) per million USD (PPP constant 2011 USD) as compared with 2014 final energy intensity level of 83 toe/million USD (PPP constant 2011 USD). With 2005 as base year, the final energy intensity has improved significantly by 17.9%. If the current trend continues, final energy consumption intensity (ex. non-energy) reduction would fall just short of the APEC goal, reaching 44.6% in 2035—the APEC goal would be reached the following year.

APERC in cooperation with EGEDA, developed the definition of modern biomass to be used in 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). 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.

In 2015, consumption of modern renewables in APEC grew 1.8% to reach 327 Mtoe compared with 2014 (321 Mtoe). Its share of total final energy consumption in 2015 was 6.9%, which is 1.7% more than the 2014 levels. In 2010, the share of modern renewables to total final energy consumption was 5.8% (253 Mtoe). Since then it has surged at a compounded annual growth rate of 3.5% through 2015. Assuming continuation of a straight line trend from 2010 to 2015, it was estimated that the share of modern renewables to the total final energy consumption will reach 10.2% by 2030. If the current annual growth rate continues, the share of renewables in total final consumption will likely fall short of APEC's renewables doubling goal by 2030 compared with 2010.

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ABBREVIATIONS AND SYMBOLS

Abbreviation	Term
B/D	barrels per day
Bcf	billion cubic feet
bcm	billion cubic metres
Btu	British thermal units
GW	gigawatt
GWh	gigawatt-hour
kL	kilolitre
km	kilometre
km/L	kilometres per litre
ktoe	kilotonne of oil equivalent
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
Mbbl/D	thousand barrels per day
ML	million litres (megalitre)
Mloe	Million litres of oil equivalent
MMbbl	million barrels
MMbbl/D	million barrels per day
MMBFOE	million barrels of fuel oil equivalent
MMBtu	million British thermal units
MMcf/D	million cubic feet per day
MMscf/D	million standard cubic feet per day
mpg	miles per gallon
Mt	million tonnes
Mtce	million tonnes of coal equivalent
Mtoe	million tonnes of oil equivalent
MW	megawatt
PJ	petajoules
Tbbl/D	trillion barrels per day

tce	tonnes of coal equivalent
Tcf	trillion cubic feet
toe	tonnes of oil equivalent
tU	tonnes of uranium metal
TWh	terawatt-hours
W	watt

ACRONYMS

APEC	Asia–Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
APP	Asia–Pacific Partnership on Clean Development and Climate
ASEAN	Association of Southeast Asian Nations
CBM	coal-bed methane
CCS	carbon capture and storage
CCT	clean coal technology
CDM	clean development mechanism
CFL	compact fluorescent lamp
CME	coconut methyl ester
COP 15	15th Conference of the Parties to the United Nations Framework Convention on Climate Change
CSM	coal-seam methane
DUHF	depleted uranium hexafluoride
EAS	East Asia Summit
EGEDA	Expert Group on Energy Data and Analysis
ESTO	Energy Statistics and Training Office
EEZ	exclusive economic zone
FEC	final energy consumption
GDP	gross domestic product
GHG	greenhouse gas
HEU	highly enriched uranium
IAEA	International Atomic Energy Agency
IEA	International Energy Agency

IEEJ	The Institute of Energy Economics, Japan
IPP	independent power producer
JOA	joint operating agreement
JOB	joint operating body
LCD	liquid crystal display
LED	light-emitting diode
LEU	low-enriched uranium
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MDKB	measured depth below kelly
MOPS	Mean of Platts Singapore
NGL	natural gas liquids
NGO	non-governmental organisation
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PES	primary energy supply
PPP	purchasing power parity
PSA	production sharing agreement
PSC	production sharing contract
PV	photovoltaic
RE	renewable energy
TFEC	total final energy consumption
TPES	total primary energy supply
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
VAT	value added tax

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 seaboard. The economy has maintained robust economic growth, with an average annual growth rate (AAGR) of 3.1% from 1990 to 2015 (EGEDA, 2017). In 2015, gross domestic product (GDP) reached USD 987 billion (2010 USD purchasing power parity [PPP]), a 2.4% increase from 2014 (EGEDA, 2017). 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 average annual rate of 3.3% from 2000 to 2015 and 4.3% from 2014 to 2015 (reaching 381 327 kilotonne oil equivalent [ktoe]) supported by growth in coal and gas production (EGEDA, 2017). Australia produces energy for both domestic consumption and export; however, it is becoming increasingly export-oriented. Net energy exports grew by 6% and constituted 65% of domestic energy production in 2015 (EGEDA, 2017).

In 2015–16, coal constituted 74% of Australia's primary energy production in energy content terms, followed by gas (20%), oil (4%) and renewables (2%) (Environment, 2017a). Coal was even more dominant in the energy export mix, constituting 81% of the total, followed by gas (15%) and oil (4%). The Australian energy industry constituted 5% (AUD 87.5 billion) of the economy in 2016–17 (ABS, 2017) and, along with other bulk resource commodities, 55% of exports (OCE, 2017).

Australia constitutes approximately 9% of the world's black coal production and is the fourth-largest producer after China, India and the United States (OCE, 2017). Australian coking and steaming coals are high in energy content and relatively low in sulphur, ash and other contaminants. Coal is Australia's second-largest commodity export, earning AUD 54.3 billion in 2016–17 followed by LNG (AUD 22.3 billion) and crude oil (AUD 5.5 billion) (OCE, 2017).

Australia constitutes approximately 2.4% of the world's energy production and is the world's largest exporter of metallurgical coal, the second-largest exporter of thermal coal and a major exporter of raw uranium and LNG (OCE, 2017). 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, 2015

Key data ^a		Energy reserves ^b	
Area (million km ²)	7.7	Oil (billion barrels)	5.4
Population (million)	24	Gas (billion cubic metres)	3 228
GDP (2010 USD billion PPP)	987	Coal (million tonnes)	130 442
GDP (2010 USD PPP per capita)	41 509	Uranium (kilotonnes U308)	1 287

Notes: Oil reserves comprise crude, condensate and LPG. 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.

Sources: ^a EGEDA (2017); ^b GA (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2015, Australia's total energy production was 381 327 ktoe and total primary energy supply (TPES, the energy that is used in the economy) was 125 307 ktoe (EGEDA, 2017). Coal narrowly remains the primary source of domestic energy supply in Australia at 34%, followed by oil (33%), gas (26%) and renewables and others (6%).

Coal's primary role is in the transformation sector, which constitutes 92% of use (Environment, 2017a), 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), occurs mainly in Queensland and has grown rapidly in recent years. Gas production in 2015–16 of 88 billion cubic metres was a 28% increase on the previous year as Queensland CSG expanded to support the start of liquefied natural gas (LNG) exports from three new projects in Gladstone (OCE, 2017). 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, 2017a). 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 4% in 2015–16 relative to 2014–15, 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, 2017a).

Renewable energy primary energy supply has grown by 2.4% a year over the past decade (to reach 8 197 ktoe in 2015) due to significant investments by the electricity sector in utility-scale wind and solar, residential-scale solar photovoltaic (PV) and hot water (EGEDA, 2017). 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 2015, 252 360 gigawatt-hours (GWh) of electricity were generated, mostly from coal-powered thermal sources (EGEDA, 2017). 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. Despite this, the share of renewable energy in the electricity generation mix dropped to 14% in 2014–15 from 15% in the previous year, as lower rainfall decreased hydro generation, particularly in Tasmania (EGEDA, 2017).

FINAL ENERGY CONSUMPTION

Australia's total final consumption rose slightly to 81 292 ktoe in 2015, following two flat years (EGEDA, 2017). The transport sector is the largest end-use sector, constituting 40% of Australia's total final consumption, followed by industry (30%), others (25%), which includes the commercial, residential and agriculture sectors and non-energy (5%) (EGEDA, 2017). By fuel type, oil constituted 51% of final energy consumption in 2015, followed by electricity (24%), gas (16%), renewables (6%) and coal (3%) (EGEDA, 2017). 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. The share of electricity generated by renewables, however, has grown at 10% a year over that period due to large investments in wind and solar capacity.

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	381 327	Industry sector	24 001	Total power generation	252 360
Net imports and others	-249 562	Transport sector	32 515	Thermal	217 871
Total primary energy supply	125 307	Other sectors	20 707	Hydro	13 445
Coal	42 909	Non-energy	4 069	Nuclear	0
Oil	41 888	Final energy consumption*	77 222	Others	21 044
Gas	32 217	Coal	2 330		
Renewables	8 197	Oil	39 308		
Others	96	Gas	12 705		
		Renewables	4 611		
		Electricity and others	18 268		

Source: EGEDA (2017) (data collected in September 2017).

* 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 is contributing to APEC's aspirational goal of a 45% energy intensity reduction by 2035 from the 2005 level. Australia's energy intensity has been declining since at least 1990 (EGEDA, 2017). In 2015, primary energy intensity declined by 2.3% while final energy intensity declined by 1.9% (EGEDA, 2017). Australia's energy intensity improvements are 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).

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	130	127	-2.3
Total final consumption	84	82	-1.9
Final energy consumption excl. non-energy	79	78	-0.7

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

Modern renewable consumption increased by 1.6% from 2014 to 2015. 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 final energy consumption was almost unchanged, however, as the consumption of non-renewables grew at 1.8%. Traditional biomass, which shrunk by 3.7% in 2015, has been in structural decline in Australia for numerous years as gas and electricity replace wood-fired heating.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	75 905	77 222	1.7
Non-renewables (Fossils and others)	68 864	70 133	1.8
Traditional biomass*	1 243	1 197	-3.7
Modern renewables*	5 798	5 892	1.6
Share of modern renewables to final energy consumption (%)	7.6	7.6	-0.11

Source: EGEDA (2017).

* 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 government oversees the approval process for oil and gas exploration for their jurisdiction. However, the Australian Government, in the form of the Australian Department of the Environment and Energy, considers aspects of 'national environmental significance' in accordance with the Environment Protection and Biodiversity Conservation Act 1999. In this process, each state/territory assesses applications from organisations to explore in its area before declining or granting access. Similarly, each state/territory assesses safety requirements and environmental regulations for the coal industry in its respective jurisdiction.

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, 2018a). The Australian Minister for the Environment and Energy 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 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.

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.

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, 2018a).

Since March 2012, Australia has been non-compliant with the International Energy Agency's (IEA's) 90-day oil stockholding obligation, a key requirement of the International Energy Programme Treaty to which Australia is a signatory. The Australian Government presented a plan to return to compliance with the IEA in mid-2016 that introduces a mandatory reporting of Australian petroleum statistics from January 2018, a return to full compliance with the IEA stockholding obligation by 2026, the purchase of 400 ktoe of oil tickets and the establishment of an Energy Security Office (Environment, 2018b).

Australia is an active participant in numerous other international energy security forums, including the APEC Energy Working Group and Energy Security Initiative fora, and it has bilateral engagement on energy security issues with numerous other economies, including Japan, China and Korea (Environment, 2018c).

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 program, currently has eight priority areas (COAG, 2018b):

- Consumer empowerment;
- Energy market transformation;
- Australian gas markets;
- Energy and carbon policy;
- Institutional performance improvement;
- Security, reliability, affordability and sustainability 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, currently under construction, is scheduled to link the eastern and northern markets via Tennant Creek and Mt Isa in the late 2018.

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, 2018) and the Australian Energy Market Commission (AEMC, 2016) into 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 electricity 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, 2018a).

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 prepares and publishes 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, 2018a).

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 that 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.

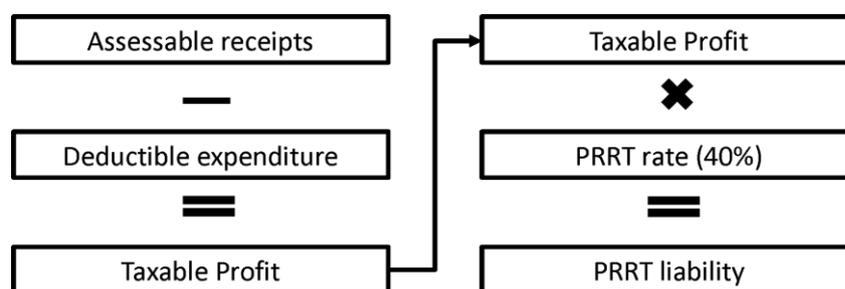
Certain expenditures incurred by energy companies, such as exploration expenditure and royalty payments, are immediately deductible for corporate income tax purposes. Other indirect taxes, such as the payroll tax, fringe benefits tax, fuel excise and land tax may apply.

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, 2018a).

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, 2018a).

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, 2018a).

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, 2018a).

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, 2018b).

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, 2018c).

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, 2018d):

- 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, 2018e).

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 (Industry, 2018b).

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 program, 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, 2017a).

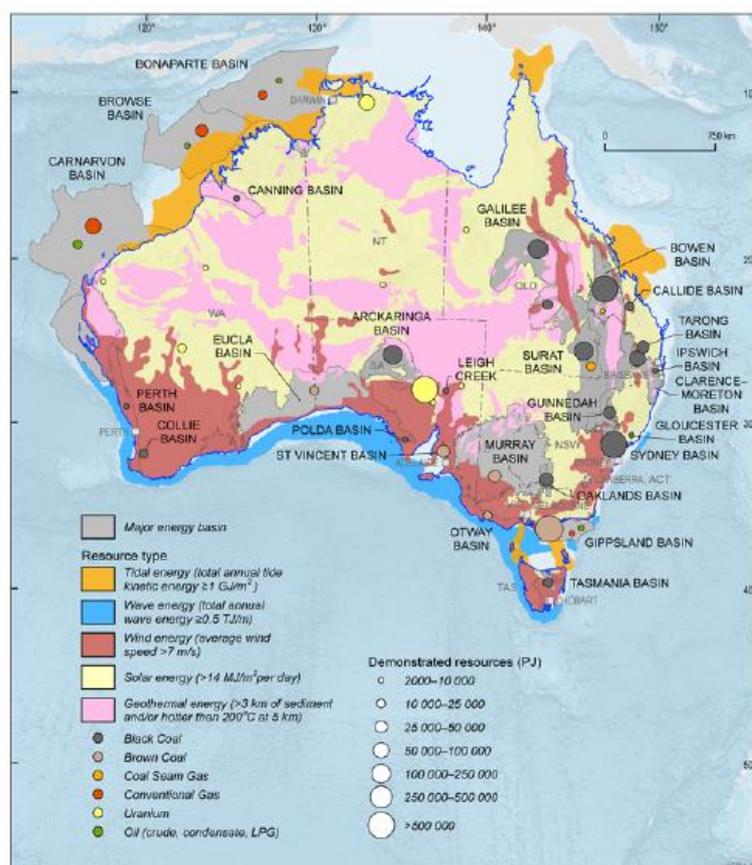
Energy productivity is a measure of the amount of economic output derived from each unit of energy consumed. Over the past decade, Australia's energy productivity has improved; however, it still lags behind many other developed economies such as Japan, Germany and the United Kingdom. The NEPP takes action 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 program, the emissions reduction fund, the Victorian residential efficiency scorecard, Commonwealth Scientific and Industrial Research Organisation's (CSIRO's) energy-use modelling 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 2014–15 to 2015–16, solar PV, hydro and wind-powered electricity generation increased by 24%, 14% and 6%, respectively, due to new capacity (solar and wind) and increased utilisation (hydro, which enjoyed improved water inflows) (Environment, 2017a). In the case of solar and wind, this actually represents a slowdown of 54% and 22%, respectively, on their average annual growth over the past decade (Environment, 2017a).

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, 2018d). 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.

By June 2017, ARENA had committed AUD 1 billion in support of more than 320 projects, studies, fellowships and scholarships, which have a total value of AUD 3.5 billion (ARENA, 2017). ARENA's independent decision-making board comprises up to seven members appointed by the Minister for the Environment and 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 2017, the CEFC has invested AUD 4.3 billion in projects worth AUD 11 billion (CEFC, 2017). 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 ACT. 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, 2018b).

A significant number of wind generation projects such as Coopers Gap (453 MW), Sapphire (270 MW), Silvertown (199 MW), Mt Emerald (181 MW), Mt Gellibrand (132 MW) and Lincoln Gap (126 MW) are also committed or under construction (AEMO, 2018b). 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 will make a final investment decision in 2018.

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. Second, Australia's Nationally Determined Contribution (NDC), submitted to the United Nations Framework Convention on Climate Change (UNFCCC) in 2015, is a 26–28% reduction of the 2005 levels by 2030 (Environment, 2018e). The Emissions Reduction Fund (ERF) is the government's tent-pole program to meet this target. Legislation for the ERF was passed by the 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 sixth auction concluded in December 2017, where 26 abatement contracts were awarded to deliver 7.95 million tonnes (Mt) of abatement at an average price per tonne of \$13.08 for a total of AUD 104 million (Environment, 2018f). Six auction rounds have awarded 404 carbon abatement contracts for 191.7 Mt of abatement since the implementation of the fund in 2014. The average price across all six auctions is now AUD 11.90 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 efficiencies 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, 2018g).

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, 2018g). 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 2017, most recommendations are currently under review or on track, with a small number deemed to be complete or not yet started (COAG, 2017b).

One of the first recommendations implemented by government was the establishment of an Energy Security Board (ESB). The ESB has been instrumental in shaping the government’s response to one of the key recommendations of the review: a national energy guarantee (NEG). The NEG, rather than the clean energy target proposed in the Finkel Review, aims to reduce carbon emissions while maintaining system reliability (Environment, 2017b). It will comprise two parts. The first is a reliability guarantee, which will be set to ensure that retailers and some large users deliver a sufficient amount of dispatchable generation. The second is an emission guarantee that will be set to ensure that Australia achieves its international emission commitments. The government is expected to release further details regarding the implementation and functioning of these guarantees in 2018.

SYSTEM PLANNING

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

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, 2018i).

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, 2018i).

The government has also allocated AUD 90 million 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, 2018j).

COAG's Gas Market Reform Group, established in August 2016, continues to lead the design, development and implementation of a new commercial arbitration framework for pipelines, capacity trading reforms, market transparency reforms and wholesale market reforms, all aimed at promoting the national gas objective¹ (COAG, 2016a).

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 three are still under construction. Wheatstone and Prelude, off the coast of Western Australia, are due online in mid-2018, representing 8.9 and 3.6 million tonnes per annum (Mtpa) of capacity, while first gas at Ichthys, a two-train 8.4 Mtpa project in Darwin, is scheduled for early 2018 (OCE, 2017).

Numerous smaller coal, gas and oil projects, including the Mt Pleasant and Byerwen coal projects, Greater Western Flank gas and Greater Enfield oil, are also under construction and will be completed in 2018. Other new energy projects at the feasibility stage, including the enormous Carmichael coal mine in Queensland, face uncertain prospects as companies wait to see how market conditions unfold (OCE, 2017).

¹The 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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USEFUL LINKS

Australian Bureau of Statistics—www.abs.gov.au

Australian Energy Market Commission—www.aemc.gov.au

Australian Energy Market Operator—www.aemo.com.au

Australian Energy Regulator—www.aer.gov.au

Australian Government Department of Industry, Innovation and Science—www.industry.gov.au

Australian Government Department of the Environment and Energy—www.environment.gov.au

Clean Energy Regulator—www.cleanenergyregulator.gov.au

COAG Energy Council—<http://www.coagenergycouncil.gov.au/>

COAG Gas Market Reform Group—<http://gmrg.coagenergycouncil.gov.au/>

Energy White Paper—www.ewp.industry.gov.au

Energy.gov.au—www.energy.gov.au

Office of the Chief Economist—www.industry.gov.au/industry/Office-of-the-Chief-Economist/Pages/default.aspx

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 districts. Its capital city is Bandar Seri Begawan, located in the Brunei–Muara district. In 2015, the population was 418 000 and the gross domestic product (GDP) growth slowed to 0.6% at USD 31 billion (2010 USD purchasing power parity [PPP]). Brunei Darussalam is prosperous as it enjoys an abundance of oil and natural gas. 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 programs since the discovery of oil in 1929. Crude oil and natural gas have also dominated the economy's foreign trade, constituting approximately 96% of the total exports, whereas imports are dominated by machinery, transport equipment, manufactured goods and food.

The dependency on crude oil and natural gas exports for revenue remains high, which constitutes more than 60% of the economy's GDP. This has generated a high per capita GDP of USD 73 091 (2010 USD PPP per capita) in 2015, 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).

Table 1: Key data and economic profile, 2015

Key data ^{a, b}		Energy reserves ^b	
Area (km ²)	5 765	Oil (billion barrels)	1.1
Population (thousands)	418	Gas (billion cubic metres)	300
GDP (2010 USD billion PPP)	31	Coal (million tonnes)	–
GDP (2010 USD PPP per capita)	73 091	Uranium (kilotonnes U)	–

Sources: ^a EGEDA (2017); ^b BP (2017).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Brunei Darussalam is rich in crude oil and natural gas. In 2015, approximately 84% of the economy's primary energy was met by natural gas, while oil's share remained at 16%. The total primary energy supply declined to 4 034 kilotonnes of oil equivalent (ktoe) in 2015, which represents a decline of 3% from 4 154 ktoe in 2014.

Due to the small size of Brunei Darussalam's population, domestic energy needs are modest; thus, the majority 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 12% of the crude oil produced is refined to produce petroleum products to meet domestic demand, and the rest is exported.

In 2015, Japan was the largest buyer of LNG exports from Brunei Darussalam, at approximately 64%, followed by other economies in the APEC region such as South Korea (20%), Chinese Taipei (12%) and Malaysia (2%); a small percentage was exported to the Middle East (2%). 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 23% of total crude oil exports.

Brunei Darussalam's total installed electricity generation capacity from public utilities and auto producers reached 922 megawatts (MW) in 2015. In the same year, total electricity generated was 4 666 gigawatt-hours (GWh). Almost all of the electricity was generated by natural gas (EGEDA, 2017).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	18 194	Industry sector	153	Total power generation	4 666
Net imports and others	-14 076	Transport sector	456	Thermal	4 665
Total primary energy supply	4 034	Other sectors	319	Hydro	-
Coal	-	Non-energy	432	Nuclear	-
Oil	636	Final energy consumption*	928	Others	1
Gas	3 398	Coal	-		
Renewables	-	Oil	617		
Others	-	Gas	19		
		Renewables	-		
		Electricity and others	292		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2015 declined by 0.1% to 928 ktoe from the previous year. The transport sector constituted a large share of the total energy consumption in 2015 (49%). 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 34% of the economy's energy consumption. The remaining amount was for the industry sector (16%). In terms of the energy source, oil constituted 66% of the final consumption, followed by electricity and others (31%) 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 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 2015, primary intensity dropped to 132 tonnes of oil equivalent per million USD (toe/million USD) and final consumption intensity also declined to 45 toe/million USD, representing a year-on-year decline of 2.3% and 8.2%, respectively. Both measures experienced a significant reduction, indicating a fall in the consumption of natural gas for activities in the non-energy sector compared to that in the previous year. However, if intensity is measured in the absence of non-energy, final energy consumption intensity remains unchanged. 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, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	135	132	-2.3
Total final consumption	49	45	-8.2
Final energy consumption excl. non-energy	30.3	30.4	0.5

Source: EGEDA (2017).

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, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption	929	928	-0.1
Non-renewables (Fossils and others)	929	928	-0.1
Traditional biomass*	0	0	0
Modern renewables*	0	0	0
Share of modern renewables to final energy consumption (%)	0	0	0

Source: EGEDA (2017).

* 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 country. 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. In line with aspirations to grow in a sustainable manner, Brunei Darussalam launched its first Brunei Darussalam Energy White Paper (EWP) in March 2014. The EWP describes a framework for strategic actions, which ensures sustainable energy to augment Brunei Darussalam's prosperity.

ENERGY SECTOR STRUCTURE

The Energy and Industry Department, Prime Minister's Office (EIDPMO), 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. EIDPMO 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 owned solely by the government. PetroleumBRUNEI is given designated areas for which the company has the right to negotiate, conclude and administer petroleum agreements.

On 24 May 2005, the Energy Division at the Prime Minister's Office was established as the body responsible for the formulation and implementation of Brunei Darussalam's energy policies and other energy-related matters. The Petroleum Unit, which oversees the development of the economy's oil and gas sector, and the Department of Electrical Services, which is tasked with managing and developing the economy's electricity sector, come under the purview of the Minister of Energy at the Prime Minister's Office. In 2011, the Energy Division and the Petroleum Unit merged to become the EDPMO.

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 the diversification of supply, 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 DEVELOPMENT

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 and Champion. The Champion field holds approximately 40% of the economy's oil reserves. It is situated within 30 metres of water about 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 372 000 barrels of oil equivalent per day (BOE/d) in 2013 to 430 000 BOE/d by 2017 and 650 000 BOE/d by 2035. This is in accordance with the Brunei Darussalam EWP, where additional reserves totalling 3.5 billion barrels will be targeted by 2035. Brunei Darussalam is committed to maintaining its oil and gas reserve replacement ratio (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 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 km². 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 DEVELOPMENT

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 that have been established for the energy sector. EIDPMO 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 EIDPMO, 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 Brunei Investment Agency 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 that specifies comprehensive EEC action plans that will be implemented for the next 24 years until 2035. Through the rigorous implementation of EEC key initiatives, coupled with the deployment of renewable energy (RE) programs, Brunei Darussalam will be able to reduce the nation's total energy consumption (TEC) by up to 63%. The reduction will primarily come from a reduction of the fossil fuel supply for inland energy use via five major sectors, namely, power, commercial, residential, transportation and industrial. This was announced by His Majesty the Sultan and Yang Di-Pertuan of Brunei Darussalam at the United Nations (UN) Climate Change Summit in September 2014 (RTB News, 2014). 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 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*

EIDPMO, in collaboration with the Brunei National Energy Research Institute (BNERI), is currently in the process of developing the standard and labelling order. The objective of the order is to restrict or perhaps 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.

- *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. With the introduction of these baselines, the energy consumption of new buildings could be reduced up to 30%.

- *Fuel Economy Regulation*

EIDPMO is currently working with the Ministry of Communication for the implementation of fuel economy regulations. To support this policy initiative, the introduction of hybrid cars, fuel-efficient vehicles (FEV) and electric vehicles has already been widely undertaken.

- *Financial Incentives*

EIDPMO 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.

- *Creation of Awareness*

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 program.

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 EIDPMO 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 awareness.

BRUNEI DARUSSALAM DOMESTIC GAS CONSUMPTION SURVEY (2016)

Surveys on the consumption of domestic gas supplies at residences in the Belait District were conducted in late October 2016, initiated by the Public Works Department and EIDPMO. 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 supplied domestic gas directly 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 (EIDPMO, 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 (CO₂) emissions.

The economy recently completed a waste-to-energy assessment study, which estimated that municipal solid waste production could be developed with a capacity of 10 MW. Meanwhile, for other potential alternative energy sources, which include wind power and hydropower, they may still be subject to further R&D collaboration among EIDPMO, 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 recognises the importance of its economic growth for energy security and environmental sustainability. Environmental policy directions are embedded in Vision Brunei 2035. These are as follows:

- Implementing the highest environmental standards for existing and new industries in accordance with the established international standards and practices;
- Strictly enforcing appropriate regulations on the maintenance of environments that affect public health and safety; and
- Supporting global and regional efforts to address trans-border and regional environmental concerns.

Brunei Darussalam acceded to the United Nations Framework Convention on Climate Change (UNFCCC) in 2007 and to its Kyoto Protocol in 2009. It also associated itself with the Copenhagen Accord in 2009. At the twenty-first session of the Conference of the Parties (COP21) to the UNFCCC, Brunei Darussalam identified some key actions directed at reducing greenhouse gas (GHG) emissions by 2035 through the following goals (UNFCCC, 2015):

- To reduce 63% of the economy's energy consumption compared with the business-as-usual (BAU) scenario;
- To derive 10% of the energy mix from the utilisation of renewable energy; and
- To reduce 40% of CO₂ emissions from morning peak-hour vehicle use compared with the BAU scenario.

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.

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, designed specifically 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 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 Zhejiang Hengyi Group Co. Ltd. The project is expected to begin operation in the first half 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 addition, a new 400 MW power plant will be built at PMB to provide power and steam to industries, including Hengyi.

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 will boost the improved efficiency to greater than 30% through the application of combined heat and power integration or cogeneration (EIDPMO, 2014).

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 program 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, former United States 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). The United States has made up to USD 6 billion available for the financing of this venture.

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 (US DOE, 2013).

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USEFUL LINKS

Brunei Department of Economic Planning and Development—<http://www.depd.gov.bn>

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>

Energy and Industry Department, Prime Minister's Office—www.ei.gov.bn

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

PetroleumBRUNEI—www.pb.com.bn

CANADA

INTRODUCTION

Canada is the world's second largest country 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, the Atlantic Ocean to the east and the Arctic Ocean to the north. There are 10 provinces and 3 territories in Canada, with a total population of 35.2 million (StatCan, 2016a). Most Canadians reside near the southern border. In 2015, Canada's gross domestic product (GDP) grew by 0.9% to USD 1 515 billion (2010 USD purchasing power parity [PPP]) and GDP per capita grew by 0.1% to USD 42 273 (EGEDA, 2017).

Canada is the fourth largest energy producer in the APEC region and the fifth largest in the world after China, the US, Russia and Saudi Arabia. The energy sector directly contributed 6.7% to Canada's GDP in 2016 and indirectly contributed (through purchases of goods and services from non-energy industries) an additional 3.2% (NRCan, 2017a). In 2016, Canada exported CAD 86 billion worth of energy products and imported CAD 40 billion (NRCan, 2017a). Canada is one of the world's top four exporters of crude oil, natural gas, uranium and electricity (NRCan, 2016a).

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 172 billion barrels, of which oil sands constituted 97% (166 billion barrels) as of March 2017 (NRCan, 2016a). The bulk of the oil sands reserves are in the province of Alberta; however, the province of Saskatchewan is also rich in bitumen reserves. Conventional oil reserves exist in most Canadian provinces and territories, including Alberta, British Columbia, Saskatchewan, Ontario, Manitoba, Nova Scotia, Newfoundland and Labrador, the Northwest Territories (NWT) and the Yukon. However, Alberta and Saskatchewan have the largest onshore reserves, while Newfoundland and Labrador has the largest offshore reserves (NEB, 2016c).

Canada has substantial proven gas reserves, which are estimated at more than 76.7 trillion cubic feet (Tcf) and equal to 1.2% of global reserves in 2015 (BP, 2017). The largest concentrations of gas reserves are in Alberta and British Columbia. Saskatchewan, Newfoundland and Labrador, New Brunswick, Nova Scotia, the NWT and Yukon also have established reserves, although significantly smaller (NEB, 2016b).

Canada currently holds 8.7 billion tonnes of proven resources of coal-in-place, of which 6.6 billion tonnes are recoverable. 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 2015, Canada's uranium resources were estimated at 509 800 tonnes (WNA, 2017), most of which are located in the Athabasca Basin of northern Saskatchewan. This basin has the world's largest high-grade deposits (NRCan, 2014). These resources are equal to 9% of the world's known resources, which are recoverable at a price of US\$130 per kilogram. If the price of uranium were to increase in the future, additional uranium deposits would become economically recoverable; therefore, Canada's uranium reserves would increase.

Table 1: Key data and economic profile, 2015

Key data ^{a, b}		Energy reserves ^{c, d, e}	
Area (million km ²)	9.9	Oil (billion barrels)	172
Population (million)	36	Gas (trillion cubic feet)	77
GDP (2010 USD billion PPP)	1 515	Coal (million tonnes)	6 600
GDP (2010 USD PPP per capita)	42 273	Uranium (kilotonnes U)	490

Sources: ^a EGEDA (2017); ^b StatCan (2015); ^c BP (2017); ^d CAC (2016); ^e NRCan (2014).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Canada's domestic energy production reached 471 330 kilotonne oil equivalent (ktoe) in 2015. This represented an increase of 0.3% compared with that in 2014 (469 849 ktoe) (EGEDA, 2017). Fossil fuel dominated this production at about 84%, with no major change compared with that in 2014. Oil, including natural gas liquids (NGL), constituted the largest share (226 233 ktoe, 48%), followed by gas (139 112 ktoe, 30%) and coal (30 609 ktoe, 6.0%). The share of nuclear energy production was 5.6% (32 732 ktoe), thereby leaving a share of approximately 10% for renewables. Renewables comprised hydro (32 732 ktoe, 6.9%); other renewables (bioenergy), including biomass, wood and waste (13 647 ktoe, 2.9%); and geothermal, solar, wind and ocean (2 566 ktoe, 0.5%) (EGEDA, 2017). 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, 2016a).

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 2015, energy exports grew at 4.6% per year. Exports accelerated in 2015 as seen in a 6.9% increase over 2014 (EGEDA, 2017). In 2015, Canada exported 284 423 ktoe of energy (excluding uranium exports), which comprised crude oil and NGL (170 858 ktoe), petroleum products (22 686 ktoe), gas (65 988 ktoe), coal and coal products (18 418 ktoe), electricity (5 870 ktoe), and renewables (814 ktoe) (EGEDA, 2017). In 2015, energy exports constituted 18% (CAD 86 billion) of domestic merchandise export revenue (NRCan, 2017a).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	471 330	Industry sector	42 517	Total power generation	665 576
Net imports and others	-199 174	Transport sector	61 384	Thermal	141 306
Total primary energy supply	270 192	Other sectors	68 207	Hydro	380 717
Coal	18 418	Non-energy	21 316	Nuclear	101 423
Oil	94 332	Final energy consumption	172 108	Others	42 130
Gas	87 026	Coal	2 457		
Renewables	48 902	Oil	70 691		
Others	21 514	Gas	44 374		
		Renewables	10 547		
		Electricity and others	44 039		

Source: EGEDA (2017) (data collected in September 2017).

* 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 for the past two decades. In 2016, it was the world's fourth-largest oil producer. In 2015, Canada produced 226 233 ktoe of crude oil, including NGL. This was an increase of 2.9% from 2014 (EGEDA, 2017). Oil sands production, which increased by 146% from 2005 to 2016, first surpassed conventional production levels in 2010 and has long been the main driver of growth in Canadian production (CAPP, 2017a). Production from oil sands, which are mainly located in the Athabasca oilfields in Alberta, has grown consistently since it began in 1967. In 2016, its production reached 2.4 million barrels per day (Mbbbl/D),

an increase of 1.5% over that in 2015 (CAPP, 2017a). Conventional oil production in 2016 was 1.5 Mbbbl/D, a decrease of 2.6% from 2014 (CAPP, 2017a).

Although Canada's crude oil and equivalent production is geographically dispersed, 94% of the production came from Western Canada, of which 66% was from the oil sands in 2016. The bulk of Canadian crude oil and equivalent production occurred in Alberta (74%), followed by Saskatchewan (12%), Manitoba (1.0%), British Columbia (0.6%) and the NWT (0.2%) (CAPP, 2017a). Offshore production in the Atlantic Ocean (Hibernia, Terra Nova and White Rose) constituted 5.5%, except for small-scale production in Ontario (<0.1%) and the Atlantic provinces (<0.1%). Pentanes plus constituted 6.8% of total crude oil and equivalent production (CAPP, 2017a).

In 2015, the economy's oil exports, including NGL, (170 858 ktoe) increased over those in 2014 by 12.7% and with a slight increase of 0.3% in petroleum products (22 686 ktoe) (EGEDA, 2017). The main market was the US.

GAS

Canada holds large proven natural gas reserves. It is the world's fifth-largest producer and fourth-largest exporter of natural gas (NRCan, 2016a). In 2015, Canada's natural gas production reached 139 112 ktoe, an increase of 1.1% from 2014 (EGEDA, 2017). This increase in production extends the growth from 2013, when gas production began to ramp up again after a seven-year period of decline (IEA, 2017b). In terms of exports, the volume of its gas exports was 65 988 ktoe, an increase of 1.0% compared with that in 2014 (EGEDA, 2017).

Western Canada constituted 99% of the economy's gas production in 2016, including Alberta as the largest producer (67%), British Columbia (30%) and Saskatchewan (1.6%) (CAPP, 2017b). Eastern Canada's gas production was mainly offshore in the Atlantic Ocean (1.2%). Gas production in Ontario has been declining, representing 0.1% of the total gas production in 2016 (CAPP, 2017b).

Although conventional natural gas reserves are shrinking, technological advances and rapid investment in the Western Canadian Sedimentary Basin have renewed the growth potential from shale gas, tight gas and coal-bed methane. Shale gas is emerging as the new low-cost source of natural gas in North America, requiring greater investment and research for its development. In Canada, shale gas resources are found in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick and Nova Scotia. In 2015, British Columbia continued to see most of its current drilling and production activities in the northeast in the Montney and Horn River shale basins, with unconventional gas constituting almost 80% of the total gas production (NRCan, 2016b). Although Alberta's production increased by 1.9% in 2016 over that in 2015, it declined in all areas except the Upper Mannville, Duvernay and Montney formations (wet gas) and from shale wells (AER, 2017).

COAL

Annual coal production has experienced minor fluctuations since 2004 (BP, 2017). In 2015, Canada produced 30 609 ktoe of coal, a decrease of 13.5% from its 2014 production (EGEDA, 2017). All of Canada's coal production in 2015 took place in Western Canada, including Alberta (43%), British Columbia (43%) and Saskatchewan (14%) (NRCan, 2016a).

Canada is a mid-size coal producer. Approximately 45% of its annual production of 62 million tonnes (Mt) is metallurgical (coking coal). This is used in steel manufacturing and largely exported, while the other 55% is thermal coal, which is used domestically for electricity generation (CAC, 2017).

Canada exported 59% (18 206 ktoe) of its coal production in 2015, a 12% decline from its 2014 exports (EGEDA, 2017). Coking coal constituted 91% of the exports (EGEDA, 2017). In 2015, Canada exported CAD 3.5 billion of coal, of which 72% went to Asia. The remainder was exported to a number of European countries, the US, Latin America, the Middle East and Australia (ISED, 2017).

URANIUM

Canada is among the three leading producers of uranium, along with Kazakhstan and Australia. Collectively, these three exporters constituted about 72% of total global output in 2016 (WNA, 2017). Canada maintained its position as the world's second-largest uranium producer in 2016. Canada produced 14 039 tonnes of

uranium metal (tU) in 2015 (WNA, 2017), constituting 22% of the global production (WNA, 2017). Canada's 2015 uranium metal production increased by 46% from 2014 (WNA, 2017). Current production is entirely from the Athabasca Basin of northern Saskatchewan (NRCan, 2014).

The mining and milling of uranium is a major industry (CAD 2 billion in 2015) (NRCan, 2016a). The two largest-producing uranium mines in the world are both located in Canada; these are McArthur River (6 928 tU) and Cigar Lake (6 666 tU), producing 22% of the total world output in 2016 (WNA, 2017).

RENEWABLE ENERGY

Canada is a world leader in the production and use of renewable energy. The economy has substantial renewable energy resources, including bioenergy, hydro, solar, wind, geothermal and ocean energy. In 2015, the economy's total renewable production was 48 743 ktoe, consisting of hydro (32 732 ktoe); bioenergy and waste (13 445 ktoe); and solar, geothermal, wind and ocean (2 566 ktoe) (EGEDA, 2017). Production was 2.4% below the 2014 level (EGEDA, 2017). Renewables constituted almost 11% of the total indigenous energy production in 2015 (EGEDA, 2017).

Hydro is the most important source of renewable energy in Canada, supplying 57% of Canada's electricity generation in 2015 (EGEDA, 2017). In 2016, Canada's installed hydraulic capacity was over 80 859 MW (StatCan, 2017). The installed small capacity was approximately 4 131 MW in 2016 (NRCan, 2017b).

Canada has access to large and diversified biomass resources for energy production owing to its large landmass covered with active forests and utilised by agricultural industries. In 2015, bioenergy was the second most important form of renewable energy, with biofuels and renewable waste representing 5.0% of Canada's total primary energy supply (EGEDA, 2017).

Canada had 70 bioenergy power plants, with a total installed capacity of 2 475 MW in 2016 (NRCan, 2017b). Most of this capacity is built around the use of wood biomass, spent pulping liquor and landfill gas. Biofuel is also a growing form of bioenergy in Canada and constituted 2% of the world's biofuel (ethanol and biodiesel) production in 2014, making Canada the fifth-largest producer after the US, Brazil, the European Union and China (NRCan, 2017b). The federal government, alongside the provinces, has introduced regulations on renewable content to increase future production and the use of biofuels.

Wind is also an important renewable energy source whose provincial leaders are Ontario, Québec and Alberta (NRCan, 2016a). However, other provinces with wind potential are increasing the share of wind energy in their power mix. Prince Edward Island (PEI) is a major electricity importer from New Brunswick, which uses coal and nuclear, among others. PEI's indigenous electricity generation is almost entirely wind, but this accounts for only 17% of its consumption (NRCan, 2015b).

Canada has vast areas with significant potential for wind resources to make the expansion of wind-generated power economical. Installed wind power capacity has expanded rapidly in recent years and is estimated to grow at a rapid pace given that the government initiatives are in place and support its growth. In 2016, Canada had nearly 6 100 wind turbines in operation in 283 wind farms, with a total installed capacity of 11 973 MW. In 2017, Canada added 10 projects that increased capacity by 341 MW to reach 12 239 MW of wind energy capacity (CanWEA, 2018).

Solar energy has also experienced continuous growth both in thermal and photovoltaic (PV) power. Cumulative PV power capacity grew to 2 662 MW in 2016 (IEA, 2017a). Ontario was the leading province in terms of solar capacity (99% of total installed capacity) (IEA, 2017a). Offgrid capacities were not reported in 2013 but were estimated at approximately 1% of the total installed capacity (IEA, 2017a). Other Canadian provinces, including British Columbia, Alberta and Saskatchewan, were also expanding their solar capacity in 2016.

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, generating 20 MW of electricity, and an in-tidal technology demonstration project. Roughly, 13 MW of tidal current capacity is expected to be installed in the Bay of Fundy, Nova Scotia in the upcoming years (NRCan, 2017a).

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 under way in Western Canada, with commission planned in the 2020 timeframe. In 2010, there were over 95 000 ground-source heat pumps with an installed capacity of about 1 045 MW of thermal energy (NRCan, 2017b). NRCan has financially supported the demonstration projects in British Columbia, the NWT, the Yukon and Alberta.

FINAL ENERGY CONSUMPTION

Canada's final energy consumption in 2015 reached 172 108 ktoe, a decrease of 1.9% from that in 2014 (EGEDA, 2017). This makes Canada the fifth largest energy consumer in APEC after China; the US; Russia; and Japan (EGEDA, 2017).

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 (68 207 ktoe, 35%), followed by the transport sector (61 384 ktoe, 32%), and the industrial sector (42 517 ktoe, 22%) (EGEDA, 2017). 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 21 316 ktoe in 2015 (EGEDA, 2017).

Fossil fuels constituted the largest share in final energy consumption (68%), comprising petroleum products (70 691 ktoe, 41%), gas (44 374 ktoe, 26%) and coal and coal products (2 457 ktoe, 1.4%) in 2015 (EGEDA, 2017). The remainder was the share of renewables (10 547 ktoe, 6.1%) and electricity and others (44 039 ktoe, 26%), of which the share of renewable electricity and others was 27 564 ktoe (EGEDA, 2017). Factors contributing to Canada's higher consumption of energy relative to that of other industrialised countries include its cold climate, long periods of heating, long distances between major cities, extensive use of private vehicles and the prevalence of energy-intensive industries.

POWER GENERATION

Canada generated 665 576 gigawatt-hours (GWh) of electricity in 2015, a decrease of 0.4% from the previous year (EGEDA, 2017). Renewables constituted the largest share of this generation (63%), with hydro as the major contributor (57%). Other renewables included solar, wind and geothermal. The share of nuclear was 15%, which increased the combined share of non-emitting power generation to 79%. The share of oil, gas and natural gas-fuelled thermal generators was 21% (EGEDA, 2017). Coal constituted the largest share of the latter (46%), followed by coal (45%) and other fossil fuels such as diesel, light fuel oil, heavy fuel, wood and spent pulping liquor (8.9%) (StatCan, 2017).

Canada has been increasing the share of renewables, including hydroelectricity, for electricity generation since 2000. For example, some provinces have introduced policies and programs to promote renewable energy while discouraging the continued use of coal-fired power plants. In 2013 and early 2014, Ontario, Canada's largest energy consumer, shut down its remaining coal-fired power plants (NEB, 2015).

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; the original federal schedule would have allowed the plants to retire according to a pre-determined schedule ranging from 2036 to 2061 based on the end of useful life (approximately 50 years) (Alberta Energy, 2015; Canada Gazette, 2012). The decision was announced along with a comprehensive climate change plan discussed in more detail below under 'Climate Change'.

In 2016, the federal government additionally 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, 2017). 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).

As part of the 2013 Long-Term Energy Plan, Ontario intends for nuclear to continue to be a major source for the province's electricity supply. To this end, the province has announced a CAD 25 billion investment into the refurbishment of 10 nuclear reactors: four at the Darlington Nuclear Generating Station

and six at the Bruce Nuclear Generating Station. These refurbishments will add about 25–30 years to the operational life of each unit. Refurbishment at Darlington began in October 2016 with one reactor, with work on the second reactor beginning in 2017 (PO, 2016a; OPG, 2017). Refurbishment at Bruce is expected to start in 2020. This investment will annually displace 31 to 52 Mt of greenhouse gas (GHG) emissions relative to coal- or gas-fired electricity.

Low natural gas prices, the rapidly decreasing cost of renewable energy and new regulations that limit the use of coal have all made Canada's electricity sector increasingly 'greener' (NEB, 2015). Canada is the APEC region's and the world's second-largest hydroelectricity producer after China (IEA, 2017b). Canada's rich water resources enable many parts of the economy to rely on hydropower.

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 2015, Canada exported 5 870 ktoe of electricity to the US while importing 750 ktoe (EGEDA, 2017). This makes Canada APEC's largest exporter of electricity and the world's second-largest exporter of electricity after Germany (IEA, 2017b).

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, 2017). The Site C Clean Energy Project (C\$10.7 billion) in British Columbia is expected to provide 1 100 MW of clean electricity capacity and producing about 5 100 gigawatt hours of electricity each year. New capacity additions and low domestic electricity demand resulted in record-high Canadian net exports, reaching 73 terawatt-hours (TWh) in 2016 (NEB, 2017). 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 (NEB, 2016b). 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 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 4.0% and 2.8% from 2014, respectively (EGEDA, 2016). This was mainly because of a significant decrease in the energy intensity of the industrial (pulp and paper, mining and quarrying, and construction), transport (road and rail) and residential sectors, which registered the largest sub-sectoral reductions in their energy intensity compared with that in 2014. Canada experienced a decline in GDP in the first half of 2015, contributing to the decline in energy use because of job losses and production curtailments in the natural resource sectors (NEB, 2016a). Increasing energy efficiency and reducing energy intensity have been policy goals for the Canadian Government as a means to mitigate climate change and conserve energy.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	186	178	-4.0
Total final consumption	131	128	-2.4
Final energy consumption excl. non-energy	117	114	-2.8

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

The share of modern renewables in final energy consumption remained flat in 2015 at 20.4% because both modern renewables and final energy consumption declined proportionately year-over-year. Use of traditional biomass also remained flat, while modern biomass declined by 5.4% from 2014 to 2015 (EGEDA, 2017).

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	175 475	172 108	-1.9
Non-renewables (Fossils and others)	136 746	133 997	-2.0
Traditional biomass	3 001	3 001	0
Modern renewables	35 729	35 110	-1.7
Share of modern renewables to final energy consumption (%)	20.36	20.40	0.2

Source: EGEDA (2017).

* 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 government and those of its 10 provinces and 3 territories 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; NEB, 2015).

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; NEB, 2015). 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, 2015).

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 that is 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, 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, forming a larger grid (NEB, 2018). The provinces and territories have jurisdiction over the generation, transmission and distribution of electricity within their boundaries. Such jurisdiction also encompasses restructuring initiatives and electricity prices (NEB, 2018).

The electricity industry in most provinces is highly integrated. The bulk of generation, transmission and distribution services are provided by one or two dominant utility providers. Some of them are privately owned, while many are Crown corporations owned by the provincial governments. 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 Electricity 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, 2018). A capacity market will serve to support the recommendations of the Climate Leadership Plan as the province moves to phase out coal-fired generation by 2030 and increase the penetration of renewable generation in the electricity mix. The AESO will be responsible for designing and implementing the capacity market. This process began with stakeholder engagement and market design in 2017, and will be followed by the first round of procurement in 2019 with contracts awarded by 2020–21 (AESO, 2018).

Retail 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 set by a combination of market spot prices and a dynamic price component (global adjustment) set to cover the costs of guaranteed rates to generators (NRCan, 2016f). Transmission and distribution rates across all 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 have been fully deregulated since the conclusion of the Western Accord and the Agreement on Natural Gas Markets and Prices between the Canadian federal government and the Canadian energy-producing provinces in 1985. The latter 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	11%	12%	12%	15%	16%
Total	26%	27%	27%	30%	31%

Sources: Crisan and Mintz (2016).

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, 2017).

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, 2017). 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 and gas. For oil, the royalty rate is sensitive mainly to productivity; for gas, it is sensitive only to price. For certain high-cost shale gas projects, there is a pre-payout of 2% royalty on gross revenue (refer to next column).	For certain high-cost shale 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.

Province	Royalty	Rent-based tax
Alberta <i>(Updated)</i>	<p>For conventional oil and gas, under the new regime, 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. The new system includes a consolidation of royalty rates for fuel 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.</p>	<p>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.</p>
Saskatchewan	<p>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%.</p>	<p>None.</p>
Newfoundland and Labrador <i>(Updated)</i>	<p>The province introduced a new, generic offshore-oil royalty regime in November 2015 based on the R-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. After costs have been recovered, a net royalty ranging from 10–50% will be applied to net revenue varying by the R-factor, and the basic royalty becomes a credit against net royalties.</p>	<p>A two-tier net royalty (20% and 10%), along with a two-tier return allowance, applies after payout. Tier 1 net royalty applies after all the project costs and the basic gross royalty and the compounded Tier 1 return allowances are exhausted. Tier 2 royalty becomes payable after the payout of both gross royalty and Tier 1 net royalty along with the Tier 2 return allowance. The return allowance is 5% above LTBR for Tier 1 and 15% above LTBR for Tier 2.</p>
Nova Scotia	<p>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.</p>	<p>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.</p>

Sources: Chen & Mintz (2012); Crisan & Mintz (2016).

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

Although Canada does not currently export LNG, an LNG tax was conceptualised and enacted in British Columbia, which went into effect on 1 January 2017. It involves profits from an LNG source applied only to a ring-fenced set of activities from the input of feed gas to a sale from the British Columbia Coast (EY, 2017). The tax is two-tiered: a Tier 1 tax of 1.5% applies to an LNG operator's net operating income, and a Tier 2 tax of 3.5% applies to net income. The Tier 1 tax is creditable against the Tier 2 tax such that the maximum aggregate tax payable is the Tier 2 rate. This tax is not deductible under federal or provincial income tax legislation (EY, 2017). In addition, a natural gas income tax credit, 3% of natural gas purchased for operations, was introduced to reduce the corporate income tax (CIT) in British Columbia (EY, 2017).

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. Together with provincial-level law and regulations, 35 federal acts and regulations relate to the mining industry (CAC, 2016).

Among the many existing guidelines, a regulation adopted in August 2012 places a performance standard on new coal-fired electricity. This should further reduce coal consumption in Canada but not necessarily coal production. The regulation, adopted under the Canadian Environmental Protection Act 1999 (GOC, 1999), is a performance standard that sets an emission intensity level equivalent to natural gas combined cycle (NGCC) technology, a high-efficiency type of natural gas generation, at 420 tonnes per GWh (GOC, 2012). It also contains a caveat to encourage new technology for the reduction of GHG emissions whereby units that incorporate carbon capture and storage (CCS) technology can apply to receive a temporary exemption from the performance standard until 31 December 2024 (GOC, 2012).

Canada—jointly with the United Kingdom—launched the Powering Past Coal Alliance in November 2017 on the margins of the United Nations Climate Change Conference in Bonn, Germany (COP23). The Alliance brings together a range of government, business and non-government partners committed to achieving the sustainable phase out of traditional coal power.

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 by 'leading Canadians to [improve] energy efficiency at home, at work and on the road' (NRCan, 2016c).

Since 2011, the federal government has committed CAD 3 million to support alternative fuels used in the transport sector (NRCan, 2015c). Federally, an additional CAD 1.5 billion of funding was available for the period 2008–17 to support the production of renewable alternatives to gasoline and diesel for the development of a competitive domestic industry (NRCan, 2015c).

Additionally, the Federal Buildings Initiative (FBI) is a Natural Resources Canada initiative. It was implemented in 1991 and aimed at assisting federal departments and agencies to reduce the energy consumption and GHG emissions of their facilities (NRCan, 2015d). This voluntary program provides knowledge, training and expertise that helps custodial departments through the process of undertaking energy efficiency retrofit projects in their buildings and assists them to plan for an energy performance contract that allows major retrofits to be self-financing. No upfront capital funds are required as future energy savings pay for the investment. As of 2015, over 80 retrofit projects attracted hundreds of millions of dollars in private sector investments. These projects have resulted in an impressive 15% to 20% energy savings on average. Annual savings of CAD 44 million have been reinvested into programs for Canadians while reducing the impact of government operations on the environment (NRCan, 2015d).

CLEAN ENERGY RESEARCH AND DEVELOPMENT

The Government of Canada 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.

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 on clean energy technologies is 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 organizations, including the Natural Sciences and Engineering Research Council (NSERC) and Sustainable Development Technology Canada (SDTC) also contribute to advancing clean energy innovation in Canada.

The federal government is also implementing cross-cutting 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, outcomes-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, 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 2015, nuclear energy accounted for 15% of its electricity generation (EGEDA, 2017). 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.

Nuclear energy falls within federal jurisdiction, unlike other energy sources. 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 1985¹ (NRCan, 2017c). They provide the framework for developing nuclear energy in Canada.

The federal government is the central body that regulates nuclear energy. However, the decision to invest in nuclear power plants for electricity generation rests with the provinces (in concert with relevant provincial energy utilities) (NRCan, 2017c). Although there are currently no projects 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. In addition, investments of CAD 26 billion will be made for the refurbishment of 10 nuclear reactors in Ontario: four at the Darlington Nuclear Generating Station and six at the Bruce Nuclear Generating Station. These refurbishments will add about 25–30 years to the operational life of each unit. 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

Canada is fully committed to address climate change in a meaningful manner while ensuring the competitiveness of its economy (GOC, 2018a). 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 also 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.

PAN-CANADIAN FRAMEWORK ON CLEAN GROWTH AND CLIMATE CHANGE

As a first step towards implementing the commitments Canada made under the Paris Agreement, First Ministers released the Vancouver Declaration on Clean Growth and Climate Change on 3 March 2016. Through the Vancouver Declaration, working groups were established to develop options for pricing carbon pollution; complementary actions to reduce emissions; adaptation and climate resilience; and clean technology, innovation and jobs (GOC, 2016).

As a result of these efforts, 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

¹ 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.

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 2018. 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 plans to introduce new legislation and regulations to implement a carbon pollution pricing system—the backstop—to be applied in jurisdictions that do not have carbon pricing systems that align with the benchmark (GOC, 2016).

The Pan-Canadian Framework includes 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 to reduce emissions from fuels used in transportation, buildings and industry.

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 and performance standards for natural gas-fired electricity. 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 energy efficiency of appliances and equipment.

Actions in the transportation sector include continuing to set increasingly stringent standards for light- and heavy-duty vehicles, in addition to taking action to improve efficiency and support fuel switching in the rail, aviation, marine and off-road sectors. Canada will also be developing a zero-emission vehicle strategy by 2018; 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 developing regulations to achieve a reduction in methane emissions from the oil and gas sector, including offshore activities, by 40–45% by 2025. Federal, provincial, and territorial governments will work together to help industries improve their energy efficiency and invest in new technologies to reduce emissions, including in the oil and gas sector. Canada has also committed to finalising regulations to phase down the use of HFCs in line with the Kigali Amendment to the Montreal Protocol (GOC, 2016).

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. For example, the federal government will establish a new Canadian Centre for Climate Services and work with provinces and territories and other partners to build regional adaptation capacity and expertise that will make it easier for governments, communities, and businesses to access and use climate data and information to make adaptation decisions. Measures to build resilience through infrastructure include climate-resilient codes and standards and a fund to build natural, large-scale infrastructure projects that support mitigation of natural disasters, extreme weather events and climate resilience (GOC, 2016).

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. This includes support for Indigenous Peoples to monitor changes in their communities and take action to address climate impacts, including repeated and severe flooding. In addition, targeted funding will be provided to enhance resilience in northern communities by increasing capacity to adapt and improve the design and construction of northern infrastructure (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 revenue-neutral carbon tax in 2008, which is applied to the purchase or use of fossil fuels within the province at a current rate of CAD 30 per tonne of CO₂ equivalent (PBC, 2016a). In 2015, British Columbia formed a Climate Leadership Team that reported 32 considerations for updating the current climate plan. In August 2016, the province announced 21 new measures to reduce net annual emissions by up to 25 Mt by 2050 but did not increase the price of the carbon tax as recommended, citing competition with other jurisdictions. Examples of the measures adopted include a reducing fugitive and vented methane emissions by 45% by 2025 in infrastructure built before 2015, increasing the low-carbon fuel standard and transitioning to 100% clean energy on the integrated electricity grid by 2025 (PBC, 2016b). British Columbia’s Budget Update 2017 indicated it would be ending the revenue neutrality requirement to fund its climate action commitments (PBC, 2017).
- **Alberta:** In November 2015, Alberta announced the results of its Climate Leadership Plan (CLP) panel recommendations, which included a CAD 20/tonne economy-wide carbon price beginning in 2017, which increases to CAD 30/tonne in 2018 (GOC, 2018a). The price will continue to increase thereafter, in real terms, as long as comparable action is taken in competing jurisdictions. The CLP 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 replaced the Specified Gas Emitters Regulation on large facilities. The province also announced a cap on GHG emissions from oil sands production (excluding upgrading 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. In 2018, the results of the first renewable energy program procured 600 MW of electricity at a weighted average bid price of CAD 37 per MWh (AESO, 2018).

- 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 (CO₂) (SaskPower, 2018b). The province is also home to all of Canada's active uranium mines, operating under the province's Mineral Industry Environmental Protection Regulations. 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, 2018a). Saskatchewan has said it will apply a sector-specific output-based performance standard on facilities emitting in excess of 25 Mt of CO₂-e per year (CEC, 2017).
- Manitoba: In October 2017, Manitoba announced its provincial Climate and Green Plan with a carbon price of CAD 25/tonne in 2018 with output-based allowances for large industrial emitters (PM, 2017). The price will be held constant until 2022 when the plan will be reviewed. This price will bring Manitoba in line with the federal carbon price floor in 2018; however, it will fall below the floor in 2019.
- Ontario: Ontario joined the cap-and-trade market operating in Quebec and California in 2018 and its system covers facilities and natural gas distributors with emissions of 25 Mt or more per year, including fuel suppliers that sell more than 200 litres of fuel per year and electricity importers. Emission allowances are distributed to participants that are not a) electricity generators or involved in electricity importation and transmission, b) producing or supplying petroleum, or c) distributing natural gas. Ontario has also announced that it will create a green bank to finance low-carbon energy technologies to reduce pollution from buildings (PO, 2016b).
- Quebec: Quebec has an economy-wide cap-and-trade system that is linked with California. In 2015, Quebec adopted a 37.5% reduction target for emissions below the 1990 levels by 2030 (GOC, 2018a).
- New Brunswick: The province has GHG emission reduction targets that reflect a total output of 10.7 Mt by 2030 and 5 Mt by 2050. New Brunswick also plans to phase out coal-fired generation as soon as possible (PNB, 2016). New Brunswick's environment minister has said that consumers will not pay a new direct carbon tax, but rather the province will repurpose a portion of existing gas and fuel taxes to act as a carbon price in accordance with the federal price floor. 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 in light of the federal intent to accelerate the phase out of coal-fired electricity generation by 2030. In December 2016, Nova Scotia committed to establish 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).
- Newfoundland and Labrador: 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. In November 2017, Newfoundland and Labrador announced that it will release a carbon pricing plan in Spring 2018 (Telegram, 2017).

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.

In 2015, Canada announced it would contribute CAD 2.65 billion over the next five years to help developing countries tackle climate change. The contribution supports the commitment made under the 2009 Copenhagen Accord to work to mobilise climate finance to reach USD 100 billion annually by 2020 (GOC, 2018a). 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.

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, to amend the Navigation Protection Act and to repeal certain Acts and make consequential amendments to other Acts.

The proposed changes aim to address the following issues:

- **Rebuilding public trust:** The proposed legislation aims to rebuild trust by increasing public participation in project reviews so that Canadians can help shape the project design, provide input into the project plan and assess the science used to make decisions. In addition, improved early planning would lead to improved project design, and provide companies more certainty about what's expected of them from the start of the review process.
- **Investor confidence:** The intent of the proposed legislation is to protect Canada's environment while improving investor confidence, strengthening the Canadian economy and creating good middle-class jobs by providing a more efficient and predictable process. With better rules, companies would have more clarity about what is required of them, and project reviews would be more predictable and timely, encouraging investment in Canada's natural resources sectors. Project reviews would benefit from early planning, where the government would clarify how to engage Indigenous peoples effectively, and identify potential issues with project proposals up-front—all leading to more timely decisions.
- **Advancing reconciliation with Indigenous peoples:** Under Bill C-69, there would be early and regular engagement and partnership with Indigenous peoples based on recognition of Indigenous rights and interests from the start. Consideration of Indigenous traditional knowledge would be mandatory and the government would protect the confidentiality of Indigenous traditional knowledge (e.g. sacred site locations) and respect Indigenous laws and protocols for its use.
- **Public participation:** The new early planning and engagement phase would provide clarity on what is required and more certainty about the process ahead. The government would ensure that Canadians' views are heard from the start and improve participant funding programs for Indigenous

peoples and the public. Independent reviews would be done where there is strong public concern or the results of a study are uncertain.

- **Assessing what matters to Canadians:** Project reviews would consider not just impacts on the environment, but also on social and health aspects, Indigenous peoples, jobs and the economy over the long-term. The government would also conduct gender-based plus analyses. Project decisions would be guided by science, evidence, and Indigenous traditional knowledge. The regulator would evaluate regional and strategic issues outside of project reviews (e.g. climate change, biodiversity, species at risk), the cumulative effects of development and provide context for impact assessments. Project reviews would consider how projects are consistent with our environmental obligations and climate change commitments, including the Paris Agreement on Climate Change. The government would also undertake a strategic assessment for climate change to provide guidance on how to consider greenhouse gas emissions in individual project reviews.
- **One project – one review:** The government would streamline the process and coordinate with the provinces and territories to reduce red tape for companies and to avoid duplicating efforts in reviewing proposed projects. The proposed Bill will enhance cooperation with provinces and territories by focusing on enhanced harmonization and collaboration, including early engagement and more flexible timelines; renewing bilateral cooperation agreements to support harmonized processes; and maintaining provisions for substitution. The new Impact Assessment Agency of Canada would be responsible for leading impact assessments of designated projects (on the project list) projects and work collaboratively with life-cycle regulators, like the Canadian Energy Regulator (CER), to draw upon their expertise and ensure that safety and other key regulatory factors are considered as part of a single, integrated review.
- **New Canadian Energy Regulator:** Under the new legislation, the CER would replace the National Energy Board (NEB) to support greater investment certainty; build confidence through open, accessible, inclusive, and transparent public participation processes; provide predictable timelines and clear expectations for energy projects; and advance Indigenous reconciliation objectives. Canadians, investors and companies would have certainty that good projects can move forward, creating jobs and building a stronger economy, while ensuring the environment is protected for future generations.

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.

PIPELINE DEVELOPMENTS

Oil exports through pipelines are a major means for securing new markets for the long-term success of Canada's landlocked oil economy, which is mainly based in Alberta, Saskatchewan and Manitoba. Although the industry is experiencing growth in production from oil sands and new light oil prospects, its location is not ideal. The producing reserves are far from the major refining hub on the US Gulf Coast and ocean ports, which would provide access to the expanding overseas market. The governments and industry are working together to find options to access markets. Consequently, several pipeline proposals are in the regulatory process or have recently received approval.

The federal government granted approval to two pipeline projects in 2016, the expansion of Kinder Morgan's Trans Mountain Pipeline, 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 (greenfield construction) was rejected. Prime Minister Trudeau cited Alberta's recent Climate Leadership Plan as vital to the approval of both pipeline expansions (CP, 2016).

In 2017, TransCanada's Keystone XL Pipeline project received the presidential permit required from the US Trump Administration. The pipeline also cleared a regulatory hurdle in Nebraska in November 2017. However, TransCanada has not yet finished negotiating with landowners along the route, and construction has yet to begin.

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).

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 is an estimated 9.8 billion barrels of recoverable resources (NRCan, 2016d).

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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 joined APEC in November 2004 and is one of the two South American member economies. It is located in the south-west of South America, occupying a long narrow land area between the Andes Mountain to the east and the Pacific Ocean to the west. Chile shares borders with Peru to the north, Bolivia to the northeast and Argentina to the east. Its coastline runs along the Pacific Ocean for 6 435 km, with an average width of 175 kilometres (km) and a land area of 756 102 square kilometres (km²). Administratively, Chile is divided into 54 provinces and 15 regions, headed by regional governors appointed by the president. In 2017, the economy's population was 17.6 million, and 40.5% of the population resided in the Metropolitan Region (INE, 2018).

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 almost tripled its gross domestic product (GDP) per capita from USD 8 175 in 1990 to USD 21 279 in 2015 (2015 USD purchasing power parity [PPP]). It is one of the fastest growing economies in South America, with an average annual growth rate of 3.1% between 2000 and 2015. In 2015, Chile's GDP reached USD 378 billion (2015 USD PPP), which represents an increase of 2.3% from the 2014 levels. Chile's economic activity is highly correlated with final energy consumption, where the industry sector accounted for 42% of final energy consumption in 2015 and represented around 24% of Chile's economic activity (INE, 2017).

Despite the diverse geography and abundant natural resources, the territory is very limited in fossil fuel resources, making Chile a net importer of fossil fuels; thus, one of its mainstay priorities revolves around a steady energy supply. Fossil fuel reserves are limited, so nearly the entire fossil fuel supply is imported (around 64% of total primary energy supply [TPES] in 2015). Chile imports 98% of its oil, 84% of its gas and 79% of its coal, but despite high oil and gas import dependence, hydro and non-conventional¹ renewables contributed about 40.3% of TPES in 2015 (EGEDA, 2017).

Table 1: Key data and economic profile, 2015

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 (2010 USD billion PPP)	378	Coal (million tonnes)	171
GDP (2010 USD PPP per capita)	21 279	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 2017 (EGEDA 2017), Chile's TPES increased by 2.5% from 2014 to 2015 to reach 36 113 kilotonnes of oil equivalent (ktoe). Approximately 42.4% of this energy volume was supplied in the form of crude oil and its by-products, 20% as coal, 11% as natural gas and the remaining 26.8% as other sources, particularly renewables 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 65% of the TPES, having increased by nearly 1.5% from 2010 to 23 988 ktoe in 2015.

¹ Solar, wind, biomass and biogas.

Final energy consumption (excluding non-energy) increased in 2015, reaching 24 923 ktoe, 2.6% higher than 2014. Fossil fuel consumption increased by 2.5% from 2014 to 2015; in fact, 55% (13 774 ktoe) of the final energy consumption (excluding non-energy) is represented by oil, followed by 14.8% by gas (1 384 ktoe) and 1.3% by coal (322 ktoe). The remaining final energy consumption comes from renewable energy (15%) and electricity and others (23%). According to the National Oil Company (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 2015, Chile's final energy consumption was 24 923 ktoe, representing an increase of 2.6% from the previous year.

By sector, total final consumption in the industrial sector accounted for 42%, transport accounted for 34% and others (including the residential, commercial and public sectors) accounted for 23%. The remaining 1% represented non-energy use, including agriculture and other.

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 (1%). Oil consumption increased by 5.4% from 2014 and electricity consumption decreased by 0.1% (EGEDA, 2017).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	12 906	Industry sector	10 601	Total power generation	75 387
Net imports and others	23 988	Transport sector	8 446	Thermal	42 515
Total primary energy supply	36 113	Other sectors	5 876	Hydro	23 881
Coal	7 165	Non-energy	226	Nuclear	-
Oil	15 294	Final energy consumption*	24 923	Others	8 991
Gas	3 980	Coal	322		
Renewables	9 674	Oil	13 774		
Others	0	Gas	1 384		
		Renewables	3 695		
		Electricity and others	5 748		

Source: EGEDA (2017) (data collected in September 2017).

* 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.

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 2015 was 96 tonnes of oil equivalent per million USD (toe/million USD), increasing by 0.2% from 95 toe/million USD in 2014. The energy intensity for total consumption decreased by 1.5%, from 68 toe/million USD in 2014 to 67 toe/million USD in 2015.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	95	96	0.2
Total final consumption	68	67	-1.5
Final energy consumption excl. non-energy	65.7	65.9	0.3

Source: EGEDA (2017)

RENEWABLE ENERGY SHARE ANALYSIS

In 2015, the share of modern renewable energy to final energy consumption was 18%, a decrease of 1 percentage point from the previous year.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	24 291	24 923	2.6
Non-renewables (Fossils and others)	17 800	18 722	5.2
Traditional biomass*	1 835	1 706	-7.0
Modern renewables*	4 655	4 495	-3.5
Share of modern renewables to final energy consumption (%)	19%	18%	-5.9%

Source: EGEDA (2017)

* 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 grown significantly. 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.

Energy 2050, launched in July 2014, was a participatory process to formulate the Energy Policy. The process lasted a year and a half and brought together more than 4 000 people, both energy experts and citizens, to establish a common vision regarding the energy of the future (Ministerio de Energía, 2018a). By December 2015, which was at the end of the process, the Chilean Ministry of Energy presented ‘Chile’s Energy Policy’ to guide energy policy in the economy for the long term. The policy is an effort to establish a long-term vision on energy policy. Note that this long-term policy was approved by Supreme Decree N°148, which emanated from the Presidency of the Republic and was endorsed by all ministries involved, making it a state policy. The main goal of Energy 2050 is to document Chile’s long-term energy policy, which has been validated in an open participative process with Chilean citizens. The policy addresses the citizens’ concerns, and aims to work towards improving energy security and reliability. The creation of this document is envisaged across the following stages and goals:

1. **Energy Road Map:** This road map, completed in September 2015, was oriented to create agreements and build a shared long-term vision for the sector under the concepts of sustainability and inclusion. It originated as a proposal from an Advisory Committee convened by the Ministry of Energy and was used as input to formulate Chile’s Energy Policy. According to the Energy Road Map, the economy’s future energy policy needs to consider the following features:
 - Compatibility with the environment and communities;
 - Universal and equitable access;
 - Essential conditions for development;
 - Opportunity for innovation;
 - Efficient production and consumption and
 - Energy security.

2. **Energy 2050–Chile’s Energy Policy:** Released in December 2015, this policy describes the four pillars of Chile’s energy policy that will help to achieve a vision of Chile’s energy sector by 2050 that is reliable, inclusive, competitive and sustainable:
 - Quality and security of supply;
 - Energy as a driving force for development;
 - Environmentally friendly energy and
 - Energy efficiency and energy education.

The main goals of Energy 2050 are summarised in the following table.

Table 5: Main goals of Energy 2050 by 2035 and 2050

By 2035	By 2050	Current Status ^a
Interconnection with other Andean Region Electric Interconnection System members (Chile, Peru, Ecuador and Colombia are member countries, and Bolivia is an observer country) and with other South American economies, particularly Mercosur economies (Brazil, Paraguay, Uruguay, Argentina, Bolivia [in the accession process] and Venezuela).	Energy sector GHG emissions below limits established in the economy-wide goals.	In 2016, Chile sent natural gas to Argentina via national pipelines located in the north and central areas of the country. In February 2016, the economy began to export electricity with Argentina. This exchange follows the authorization of the Company AES Gener S.A. to export electric power to Argentina as stipulated in Supreme Decree N° 7 (July 2015).

By 2035	By 2050	Current Status ^a
		In December 2017, Chile and Argentina signed a protocol agreement to exchange electricity and gas between the countries.
Energy disruption reduced to less than four hours per year in any locality in Chile, except in cases of force majeure.	Energy disruption reduced to less than one hour per year in any locality in Chile, except in cases of force majeure.	In 2016, disruptions totalled 6.5 hours, which was a decrease of 8.5 hours from 2015.
Continuous and reliable access to energy services for all vulnerable dwellings.	Universal and equitable access to reliable and modern energy services.	No information
All developed projects have association mechanisms between project developers and communities to foster local development and better performance.	Territorial, regional and local planning and management tools conforming to the energy policy are in place.	No information
Be among the five OECD economies having the lowest average electricity prices at the residential and industrial levels.	Be among the three OECD economies having the lowest average electricity prices at the residential and industrial levels.	No information
At least 60% of electricity generation from renewable sources.	At least 70% of electricity generation from renewable sources.	Overall, in 2016, 35% of electricity generation in Chile came from renewable resources
A 30% GHG emissions intensity reduction in comparison with 2007.	Energy consumption decoupled from GDP growth.	Energy consumption in 2015 decoupled from GDP growth in a 30% approximately.
All large energy consumers (industry, mining and transport) to apply energy efficiency measures.	All new buildings will be constructed as per the Organisation for Economic Co-operation and Development (OECD) standards of efficient construction and smart systems of energy management.	No information
All municipalities to adopt regulations declaring traditional biomass as solid fuel.	100% of the main categories of appliances sold in the Chilean market are energy efficient.	No information
All new auctioned vehicles for public passenger transportation to be evaluated under energy efficiency standards.	Energy conservation measures are implemented in all sectors.	No information

Sources: ^a Ministerio de Energía (2018b); La Tercera (2017)

Nuclear energy is not a short-term option under Energy 2050, but further research has been proposed to be considered in the next policy review. A complete revision of the Energy Policy will start in 2019 and the final document will be ready by 2020.

MARKET DESIGN

PETROLEUM-BASED FUELS REGULATORY FRAMEWORK

The Gas Services Law (D.F.L N° 323 of 1931), amended by Law 20 999, establishes a regime of tariff freedom regulated by concessionary gas distribution companies with eventual tariffs. A concessionaire company will be charged when it exceeds the maximum limit of profitability set by the law equivalent to the Cost of Capital Rate, whose minimum floor is 6%, plus an additional margin of three percentage points. Said maximum profitability will be controlled by the National Energy Commission (Comisión Nacional de Energía or CNE), through an annual profitability check process. For Magellan and Chilean Antarctica, the law contemplates a permanent pricing regime that must be carried out by the CNE four times a year.

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).

On the other hand, 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 privatises the electricity industry, introduces competition into the generation sector and separates 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 country 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.

1. 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.
2. 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.
3. Law NCRE (Ley ERNC): It introduces modifications to the LGSE, establishing short- and long-term policy targets for the share of renewable energy in 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 in

order 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.

4. 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 and 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. In the remuneration of the transmission system, tolls are borne completely by the consumers and defined 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:

1. Spot market: generators buy and sell electricity.
2. 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 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 very 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, node price based on the marginal cost of energy of the respective tender, capacity charge and transmission charge.
- Non-regulated customers: These customers are free to negotiate directly 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 26 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. 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.

TENDERS FOR LONG-TERM ELECTRICITY SUPPLY

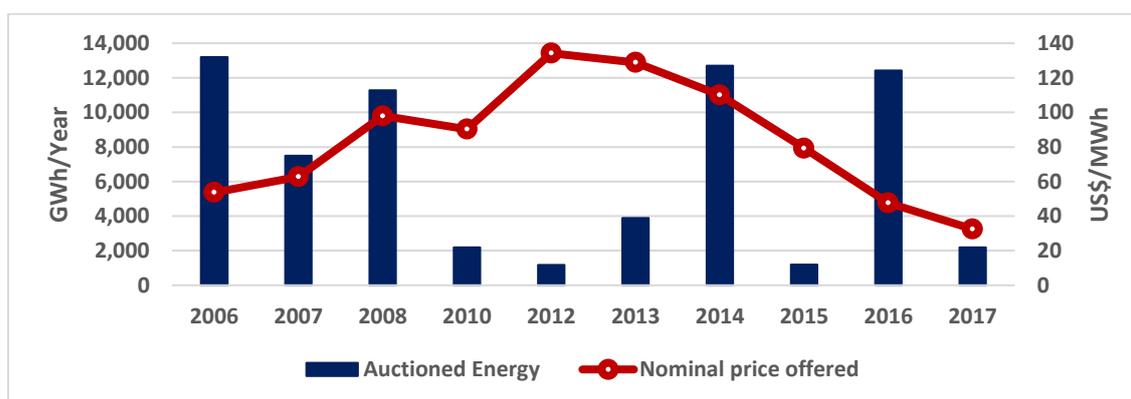
The New Electricity Act on Energy Auctions (Law 20 805) establishes the process of open energy auctions, encouraging the entrance of new players and electricity generation technologies. This improves competitiveness and promotes better price mechanisms in favour of end users in the electricity market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

Following are the main features of these tenders:

- The energy tenders provide the opportunity to acquire 20-year 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;
- 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

In 2015, Chile's total net installed electricity capacity was 19 874 MW, representing an increase of 5% from 2014, with thermal power plants representing 58% of the total capacity. The remainder was accounted mainly by hydropower and others (33% and 9%). Note that, in 2005, solar photovoltaic (PV) and onshore wind technologies made no contribution to the total electricity capacity. Therefore, 10 years later in 2015, solar and wind generation started appearing, with low contributions of 3% and 5%, respectively.

In 2017, Chile's overall net installed electricity capacity was 23 232 MW, with thermal power plants representing 54% of the total capacity, hydropower 29%, onshore wind 6% and PV 9% (the missing 2% is from contributions by other technologies).

Chile had two main electricity systems—the Greater Northern Interconnected System (SING) and the Central Interconnected System (SIC), nowadays the interconnection between these two systems created a new national electricity system (SEN). In addition, Chile has medium-sized electricity systems—the Aysén System,

which covers the consumption of Region XI, and the Magallanes System, which supplies Region XII, as well as two medium-sized electricity in Los Lagos Region (X) and in the Eastern Island (Region V).

All the above-mentioned systems provide a total of 33 097 km of transmission lines, where 220 kV lines account for 51%, followed by 110 kV lines at 18% and 500 kV lines at 8% of the total.

OIL

Oil is the most dominant fuel in Chile, accounting for 42% of TPES and 55% of total final consumption (excluding non-energy). Domestic production accounted for less than 2% of the supply (234 million cubic metres) and the rest was imported.

Considering the low domestic production, nearly all of Chile's crude oil supply (15 294 ktoe) in 2015 came from imports, which also included by-products such as diesel, gasoline and liquefied petroleum gas (LPG) (EGEDA, 2017). In fact, Chile heavily relies on imports to satisfy its oil demand; 47% of the imported crude oil comes from Brazil, followed by 28% from the US and the rest from other countries.

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 42% in 2015 due to the increase in renewable energy and coal.

The transport sector is the largest oil consumer, accounting for 58% in 2015 (Ministerio de Energia, 2017). Road transport consumes 84% of the total oil products, followed by air transportation at 12%.

Industry is the second-largest oil consumer, accounting for 27% in 2015, and its consumption has increased by 76% 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). Domestic gas production accounts for 23% of the primary energy supply.

Considering the low domestic production, nearly all of Chile's natural gas supply (3 980 ktoe) in 2015 came from imports (EGEDA, 2017). In fact, Chile heavily relies on imports to satisfy its gas demand, where 72% of the imported natural gas comes from Trinidad and Tobago, followed by the US at 17% and the rest from other countries.

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 so-called 'gas crisis' had started and Argentina began restricting the supply of natural gas. After this crisis, a group of private and public Chilean companies worked together to build LNG terminals to avoid dependence on its neighbour country. 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 m³ (one tank) with a regasification capacity of 5.5 million m³/d, and Quintero LNG has a storage capacity of 334 000 m³ (two tanks) with a regasification capacity of 15 million m³/d (Ministerio de Energia 2018 c).

Industry is the largest gas consumer, accounting for 19% in 2015 (Ministerio de Energia 2017), followed by the service and residential sectors, which consume 16%.

Between May and August 2016, 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 m³ between June and August through the GasAndes gas pipeline (Ministerio de Energia, 2018c).

COAL

Coal is the third dominant fuel in Chile, accounting for 20% of the TPES and 1.3% of total final consumption (excluding non-energy). Domestic coal production accounts for 29% of the primary energy supply.

Considering the low domestic production, nearly all of Chile's coal supply of 7 165 ktoe in 2015 came from imports (EGEDA, 2017). In fact, Chile heavily relies on imports to satisfy its coal demand; 42% of the imported coal comes from Colombia, followed by Australia (29%) and the US (22%).

By 2004, the coal supply was 2 704 ktoe, increasing to 4 403 ktoe in 2008. In fact, after the ‘gas crisis’, the increasing coal use for power generation 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 165% (7 165 ktoe).

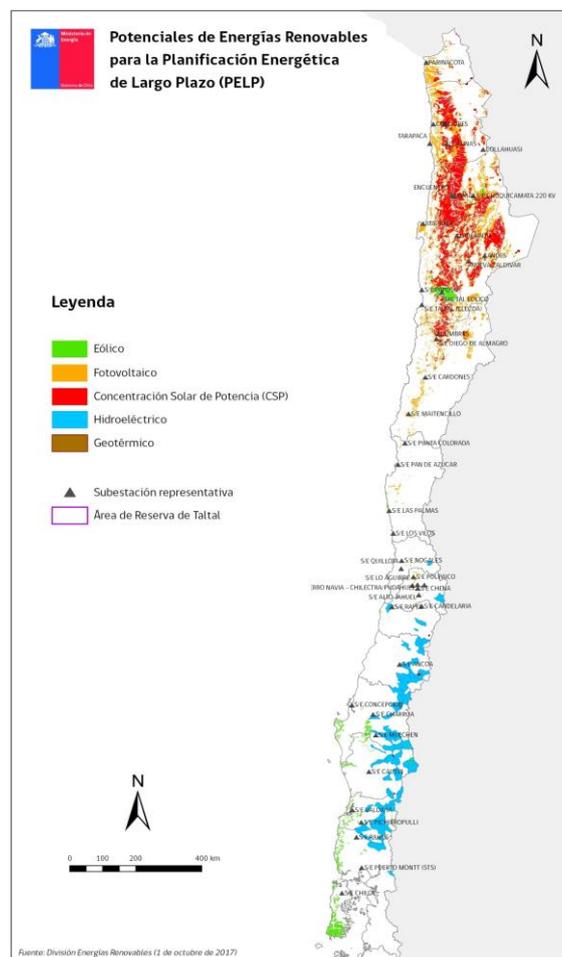
The industry sector is the largest coal consumer, accounting for 3.5% in 2015. In 2015, domestic production accounted for 29% of the total supply (Ministerio de Energía, 2017).

RENEWABLES

Chile has abundant renewable resources, being the second dominant fuel contributing economy to the TPES, with a total of 9 674 ktoe (27%) in 2015 and accounting for 15% of total final consumption (excluding non-energy) (EGEDA, 2017). Chile’s primary supply of non-fossil energy in 2015 mainly consisted of biomass, solar, wind and hydropower. From 2005 to 2015, the renewable energy supply in the TPES grew by 36% (2 554 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 Energía, 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 Energía (2018d)

At the end of December 2017, Chile had an installed capacity of 4 110 MW of NCRE, with solar and wind representing 8% and 6%, respectively, and a total of 1 455 MW is under construction. The installed capacity of NCRE represents 19% of the total (SING and SIC) installed capacity and 19% of the total system generation (CNE, 2018b).

Table 6: NCRE units in operation and under construction

Energy Source	Operation (MW) ^a	Construction (MW) ^b
Biogas	56	
Biomass	410	
CSP		110
Geothermal	24	
Hydro (<= 20 MW)	485	107
Solar PV	1 825	746
Wind	1 310	492
Total	4 110	1 455

Sources: ^a CNE (2018b); ^b Ministerio de Energía (2018d)

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 and transmission companies participate and with a contract market in which all of the demand should be covered and in which generation companies, transmission 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 sell their production to distribution companies, unregulated clients or other generation companies, having the option to sell their surpluses to the spot energy market. 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 used to have four main separated electricity systems (CNE, 2018b):

SIC and SING had their own system operators, which were originally controlled by the largest generators and transmission companies in each system. Nowadays both systems are interconnected, conforming the National Electricity System (SEN).

1. Greater Northern Interconnected System (SING – Sistema Interconectado del Norte Grande):
 - a. Serves the desert mining regions in the north and covers an area equivalent to 25% of Chile's continental territory, in which about 6% of the population of Chile lives;
 - b. Total installed capacity of 5 0288 MW, 84% thermal (45% coal, 35% natural gas and 5% oil and diesel), 15% renewables (11% PV, 4% onshore wind) and one geothermal plant.
2. Central Interconnected System (SIC–Sistema Interconectado Central):
 - a. Serves the central part of the country and reaches about 92% of the population, with more than 70% of customers under a regulated tariff;
 - b. Total installed capacity of 17 603 MW, 45% thermal (13% coal, 17% natural gas and 15% diesel), 38% hydro, 8% PV, 7% onshore wind and 2% biomass.

Table 7: Units in operation, under construction and tender projects, 2017

Energy Source	Operation (MW) ^a	Construction (MW) ^b	Tender Projects (MW) ^c	Total (MW)
Biogas	56			56
Biomass	410			410
Coal	4 746	375		5 121
Diesel	2 854	16		2 870
Fuel Oil	142			142
Geothermal	24			24
Hydro	6 645	1,094		7 739
LNG	4 961	284		5 245
Other	95			95
PV	1 825	746	579	3 150
CSP		110		110
Onshore Wind	1 310	492	2,405	4 207
Total	23 068	3 117	2 984	29 169

Sources: ^a CNE (2018b) –unit in test are not considered in operation, ^b and ^c Ministerio de Energía (2018d)

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

3. Aysén: Total installed capacity of 62 MW; 57% diesel, 37% hydro and 6% onshore wind;

4. Magallanes: Total installed capacity of 104 MW; 98% thermal (82% natural gas and 15% oil) and 2% onshore wind.

The construction of the interconnection between the two main systems of Chile (SING and SIC) was started in August 2015, with an investment of USD 7 000 million. The new electric system would have a length of 3 100 km from Arica to Chiloe, supplying electricity to more than 97% of the national population. This milestone came true on 21 November 2017, and will provide security to the system and lower the prices of the electricity tariff. As a result, SEN was created with an independent system coordinator (CEN).

NUCLEAR ENERGY

In 1965, Chile created the Chilean Nuclear Energy Commission (Comisión Chilena de Energía Nuclear or 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 protect 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 2010, the study ‘Nuclear Electricity: Possibilities and Challenges’ (MINREL, 2007) stated that the development of nuclear energy in Chile should aim to close identified gaps: ‘... technological, institutional and fundamental knowledge such as complete geological information of the economy, modify the current legal and regulatory institutions, implement a plan to meet the human resources necessities and finalise other complementary studies’. The study also concludes that public approval is not only a fundamental requirement but also the biggest challenge faced before considering nuclear power as an energy alternative. If these problems are solved by the mid-2010s, the study estimates that nuclear power plants can be included as part of Chile’s energy matrix by 2024.

The Presidential Advisory Commission for Electricity Development was established in 2011. One of the main conclusions of a study undertaken by it is that nuclear power would be a ‘strategic insurance that would ensure sustainable energy supply in the long term’. The study predicted that nuclear energy could become part of Chile’s energy matrix as early as 2030. In the National Energy Strategy 2012–30, the Chilean government enacted a moratorium on nuclear energy to generate electricity (MMA, 2012).

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 Agenda in 2014, 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 Efficiency Agency, which is responsible for implementing many of these policies by promoting, disseminating and implementing dedicated programs, 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 Energía, 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	<ul style="list-style-type: none"> • Promote energy management systems • Promote energy cogeneration • Encourage efficient technologies • Technical assistance in industry and mining projects
Transport	<ul style="list-style-type: none"> • Improve EE standards for light- and heavy-duty vehicles • Use new transport technologies in heavy-duty vehicles

	<ul style="list-style-type: none"> • Promote public transportation • Promote electric vehicles • Technical assistance in transport projects
Buildings	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • Extend appliance labelling • Establish minimum energy performance standard (MEPS) • Promote minimum lighting efficiency standards through specific programs focused in low income households
Heating	<ul style="list-style-type: none"> • 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 Energía (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 Energía, 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.

The agenda also considers the implementation of programs 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.

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 CO₂ 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 Sector².

The government's National Determined Contribution (NDC) is to reduce greenhouse gas (GHG) intensity by 30% by 2030, based on the 2007 levels. The NDC goals are established on intensity-based targets in tonnes of CO₂ emissions per unit of GDP. 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 country's capacity to adapt to climate change, improving the knowledge of its impacts and the vulnerability of the country 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 country'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 2013, GHG emissions were 109 MtCO₂-e, increasing by around 114% from 1990 levels and 19% since 2010. The main GHG emitted was CO₂ (79%), followed by CH₄ (11%). The energy sector is the main emitter (77%), 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 to 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'.

² This plan is currently being revised and edited.

The Energy Sector Mitigation Action Plan (committed under the Energy Policy 2050), by the Ministry of Energy in collaboration with 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 pricing is important here, since, in combination with energy reform, it can provide important incentives for clean technology investments, and therefore, for a transition to decarbonise the economy. In this regard, the National Energy Policy states the analysis of other carbon pricing instruments to internalise the environmental externalities associated with existing and future energy infrastructure. In this context, the policy explicitly notes that 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 CO₂ 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 CO₂ emitted, thus affecting thermal plants with an installed capacity equal to or greater than 50 MW. The increase in the relative price of electricity will promote the use of less contaminant energy sources, encouraging energy consumers to implement energy efficiency measures and low-carbon technologies.

NOTABLE ENERGY DEVELOPMENTS

In February 2016, it began to trade electricity with Argentina. As stipulated in Supreme Decree N° 7, July 2015, the Ministry of Energy authorised the company, AES Gener S.A., to export electric power to Argentina. Chile has a transmission line from Andes through Salta in 345 kV, of 390 kilometres with a capacity of 350 MW. In 2016 Chile had exported approximately a total of 100 825 MWh (CDEC SING, 2016) and 36 MWh in 2017 (Coordinador Eléctrico Nacional [CEN], 2017).

Chile also exported gas to Argentina in 2017. The agreement between both governments establishes the export of 5.5 million m³ of natural gas per day to Argentina between May and September and the export of electricity from the Chilean north to Argentina, from Mejillones, Chile to Salta, Argentina. This interconnection will supply about 200 MW to the National Interconnected System in Argentina. The new law approved by the Chilean Congress maintains current gas tariff freedom but sets a cap rate equivalent to the capital cost rate plus a spread of 3%. The National Energy Commission shall review the capital cost rate every four years. When a distribution company exceeds the cap rate, tariff regulations and direct discounts to consumers will be applied. The Gas Service Act was established in 1931 and has remained in force through 2016 with some modifications. According to the Ministry of Energy, the current regulation is not adequate under the new gas scenario because it does not consider

- The pricing methodology and procedure;
- The method and procedure to assess companies' rentability;
- The method for calculating the fair capital cost rate (CCR); and
- A mechanism to settle disputes between the regulatory agency and gas distribution companies.

The interconnection between the two main systems of Chile (SING and SIC), with an investment of USD 7 000 million, was completed on 21 November 2017. The new electric system will have a length of 3 100 km from Arica to Chiloe, supplying electricity to more than 97% of the national population. This milestone will enhance security to the system and lower the prices of the electricity tariff. As a result, a national electricity system (SEN) and an independent system coordinator (CEN) were created.

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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 north-east Asia and is bordered by the East China Sea, Yellow Sea, and 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 (km²) with diverse landscapes, which comprise mountains, plateaus, plains, deserts and river basins. Its total maritime area is 4.7 million km², and the length of its coastline is 32 400 km (NBS, 2017).

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 twenty-first century. In 2004, China overtook Japan as the leading Asian exporter. In 2009, China surpassed Germany to become the world's leading exporter. By 2016, China's merchandise exports constituted 13.6% of the world's merchandise exports (WTO, 2017). In 2015, China's GDP was USD 18 230.91 billion (2010 prices and 2010 purchasing power parity [PPP]), with the primary, secondary and tertiary industries constituting 9%, 40%, and 51%, respectively (EGEDA, 2017; NBS, 2017).

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 1.3% in 2016. This was less than one-third of the 10-year average growth rate of 5.3% and the slowest annual rate of growth since 1998 (BP, 2017). 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 2016 (BP, 2017). Its per capita primary energy consumption, at 1.23 tonnes of oil equivalent (toe) in 2015, is far lower than that of most developed economies and below APEC's average of 1.66 toe (EGEDA, 2017).

China is relatively rich in energy resources, particularly coal. According to BP statistics published in June 2017, China had total proven coal reserves of approximately 244 010 million tonnes (Mt), total proven oil reserves of 25.7 billion barrels and proven natural gas reserves of 5.4 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 worldwide average levels. The limitations of its energy reserves per capita force China to conserve its resources. From 2000 to 2015, the compound annual growth rate (CAGR) of final energy consumption was 7.9% and the CAGR of GDP was 9.6% (EGEDA, 2017).

Table 1: Key data and economic profile, 2015

Key data ^{a, b}		Energy reserves ^c	
Area (million km ²)	9.6	Oil (billion barrels)	25.7
Population (million)	1 371	Gas (trillion cubic metres)	4.8
GDP (2010 USD billion PPP)	18 231	Coal (million tonnes)	244 010
GDP (2010 USD PPP per capita)	13 295	Uranium (kilotonnes U)	272.5 ^d

Sources: ^a EGEDA (2017); ^b NBS (2016); ^c BP (2017); ^d Recoverable resources, WNA (2017)

Note: Data for coal reserves is as of end 2016

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

China's primary energy supply has expanded sharply since 2001. This expansion was mainly driven by rapid economic growth, especially in energy consumption by heavy industry. In 2015, the total primary energy supply

increased by 0.4% compared with that in 2014, reaching 2 898 million tonnes of oil equivalent (Mtoe), including net imports and others. Most of the growth came from oil, natural gas, renewables and others, while the indigenous production decreased slightly compared with that in 2014. Coal was the dominant source, constituting 68%, followed by oil (19%), renewables (6.4%), gas (5.9%) and others (1.5%) (EGEDA, 2017).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	2 424 581	Industry sector	1 018 791	Total power generation	5 814 573
Net imports and others	485 141	Transport sector	252 625	Thermal	4 284 188
Total primary energy supply	2 897 571	Other sectors	420 573	Hydro	1 130 270
Coal	1 963 150	Non-energy	167 974	Nuclear	170 789
Oil	535 193	Final energy consumption*	1 691 989	Others	229 326
Gas	171 190	Coal	652 230		
Renewables	184 602	Oil	403 682		
Others	43 437	Gas	109 575		
		Renewables	27 653		
		Electricity and others	498 849		

Source: EGEDA (2017) (data collected in September 2017).

* 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. From 2000–15, electricity generation output increased quickly from 1 356 terawatt-hours (TWh) to 5 815 TWh, of which thermal power generation constituted 73.7% of the total power generation. In 2016, installed generation capacity reached 1 650 GW (NBS, 2017).

The power supply structure has diversified, with wind power and nuclear energy generation increasing rapidly. In 2016, total power generation in China was 6 142 TWh. Thermal power constituted 72.2% (4 434 TWh of the total generation); conventional hydropower constituted 19.4% (1 191 TWh); nuclear energy constituted 3.5% (215 TWh); wind power constituted 3.9% (239 TWh); and photovoltaic (PV) constituted 1.0% (61 TWh) (NBS, 2017).

FINAL ENERGY CONSUMPTION

Total final consumption in China reached 1 860 Mtoe in 2015, 0.8% higher than that in 2014. The industrial sector was the largest consumer, constituting 55% 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, 2017). By energy source, coal constituted 39% of the final energy consumption (excluding non-energy), followed by electricity and others (30%), oil (24%), gas (6.5%) and renewables (1.5%).

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 billion tonnes of oil equivalent by 2020.

ENERGY INTENSITY ANALYSIS

China has reduced its energy intensity in the last two decades. Compared to 1990, the intensities of primary energy supply and total final consumption in 2015 reduced by 59% and 64% 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, 2017).

In 2015, China eliminated more than 5.27 GW of backward thermal power plants, 49.7 million tonnes (Mt) of backward cement production capacity and 101.7 Mt of out-dated coal mining production capacity (MITT, 2017). With these efforts, the intensity of total final consumption decreased by 5.7% from 2014 to 2015. The government also introduced policies on energy structural optimization 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, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	169	159	-6.1
Total final consumption	108	102	-5.7
Final energy consumption excl. non-energy	99	93	-6.0

Source: EGEDA (2017).

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 5.0% from 2014 to 2015, the largest increase among APEC economies. China's traditional biomass consumption increased 5.5% 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 out-dated steel and cement production lines, China's non-renewable energy consumption only increased by 0.13%. This is mainly due to declining coal consumption, despite the rapid increase in the consumption of oil and natural gas between 2014 and 2015.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	1 683 868	1 691 989	0.48
Non-renewables (fossil fuels and others)	1 565 083	1 567 181	0.13
Traditional biomass*	18 044	19 032	5.5
Modern renewables*	100 740	105 776	5.0
Share of modern renewables to final energy consumption (%)	6.0	6.3	4.5

Source: EGEDA (2017).

* 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 168.0 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 Energy Thirteenth Five-Year Plan 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 fewer 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% in the coming 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 13 departments and has an authorised staffing complement of 250 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 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.

LAW

The laws relating to energy in China include the Coal Law (issued in 1996 and revised in 2013), Electricity Law (issued in 1995 and revised in 2015), 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 (Qiu and 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 price and supply disruptions. Chinese policy focuses on diversification to reduce oil imports, which rely almost exclusively 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; promote technological, industrial and business model innovation; vigorously promote high-tech fields; and cultivate 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 (SEOs) 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 (CO₂) 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.

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 (Mbbbl/D) in April. This is approximately 7.7% of the world's oil consumption per day and exceeds United States' imports of 7.2 Mbbbl/D. Larger shipments from Iran, Oman, and 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 Unipecc 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).

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).

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 upgrade 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 programs 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.

China's power sector has faced a severe overcapacity problem. Slowing demand for electricity due to the economic downturn and the slashing of energy-intensive industries have caused widespread under-utilisation of existing power generation capacities, which are seeing their lowest utilisation hours since 1978. The situation has prompted regulators to consider putting a two-year 'freeze period' in the Energy Thirteenth Five-Year Plan for the approval of any new coal-fired power projects. The NEA promised to keep coal-based power capacity below 1 100 GW by 2020, setting an upper limit for new coal capacity.

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). China is now preparing to roll out carbon markets on an economy-wide basis. 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 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.

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.

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. 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 farms-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, 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).

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 332.1 GW, including 26.7 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 developed significantly 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, 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 27.73 GW and 30.95 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, Shandong 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 reactors, molten-salt reactors, gas-cooled fast reactors, sodium-cooled fast reactors and lead-cooled fast reactors) which have 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 2017.

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 emissions 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 greenhouse gases 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.

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 for 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 photovoltaic 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 program. 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 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 about 1 700 coal-fired and gas-fired power generation enterprises, which emit over 26 000 tonnes of CO₂ per year and have emitted over 3 billion tonnes of CO₂ (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 about 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 carbon 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).

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USEFUL LINKS

Central People's Government of PRC—www.gov.cn

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

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

Ministry of Environmental Protection (MEP)—www.zhb.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 2015, the per capita gross domestic product (GDP) of Hong Kong, China was USD 52 408 (2010 USD purchasing power parity [PPP]), the highest among the APEC economies. The GDP increased by 16% in real terms to USD 383 billion after 2010 (2010 USD PPP). The service sector remained the dominant driving force of the overall economic growth, constituting 89% of the GDP in 2015 (EGEDA, 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 actively liaise with Guangdong to identify favourable treatment and implement opportunities for the people and enterprises of Hong Kong, China in the planning and development of Nansha, Qianhai and Hengqiu. Furthermore, it will increase the number of economic and trade offices in Asia to help business and investors tap Asian markets. Moreover, the government has invited the submission of proposals to complement the National 13th Five-Year Plan (Policy Address, 2015).

Table 1: Key data and economic profile, 2015

Key data		Energy reserves	
Area (km ²)	1 104	Oil (million barrels)	–
Population (million)	7.3	Gas (billion cubic metres)	–
GDP (2010 USD billion PPP)	383	Coal (million tonnes)	–
GDP (2010 USD PPP per capita)	52 408	Uranium (kilotonnes U)	–

Source: EGEDA (2017).

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 2015, 0.315 Mtoe lower than that in the previous year. Coal maintained the highest share in the total primary energy supply (48%), followed by oil (24%), gas (21%) and other sources (7%) (EGEDA, 2017).

In 2015, the total installed electricity generating capacity in Hong Kong, China was 12 645 MW (EGEDA, 2017). All locally generated power is thermal-fired. Electricity is supplied by CLP Power Hong Kong Limited (CLP Power) and the Hongkong 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 3 757 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, which is locally manufactured using naphtha and natural gas as feedstock, is being distributed by the Hong Kong and China Gas Company Limited (Towngas, 2016).

FINAL ENERGY CONSUMPTION

In 2015, the final energy consumption in Hong Kong, China was 6 760 kilotonnes of oil equivalent (ktoe), a decrease of 1.6% from the previous year. The residential and commercial sectors constituted the largest share of energy used (64%), followed by the transport sector (31%) and the industry sector (5%). By energy source, electricity and 'others' constituted 56% of end-use consumption, followed by petroleum products (35%) (EGEDA, 2017).

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, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	65	Industry sector	351	Total power generation	37 971
Net imports and others	30 331	Transport sector	2 100	Thermal	37 921
Total primary energy supply	14 059	Other sectors	4 309	Hydro	2
Coal	6 694	Non-energy	0	Nuclear	–
Oil	3 433	Final energy consumption*	6 760	Others	48
Gas	2 953	Coal	0		
Renewables	71	Oil	2 334		
Others	908	Gas	601		
		Renewables	44		
		Electricity and others	3 781		

Source: EGEDA (2017) (data collected in September 2017).

*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 2015 was only 37 tonnes of oil equivalent per million USD (toe/million USD) compared with the median value of 138 toe/million USD for APEC economies, while the final energy consumption was only 18 toe/million USD compared with the median value of 83 toe/million USD (EGEDA, 2017).

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 and the Scheme on Fresh Water Cooling Towers (GHK, 2015a).

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	38	37	-4.5
Total final consumption	18.4	17.7	-3.9
Final energy consumption excl. non-energy	18.4	17.7	-3.9

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

Despite geographical constraints in developing renewable energy, 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 renewable energy (RE) have already been taken to address the issue. In 2015, 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, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	6 867	6 760	-1.6
Non-renewables (Fossils and others)	6 807	6 711	-1.4
Traditional biomass*	5	3	-29
Modern renewables*	55	45	-18
Share of modern renewables to final energy consumption (%)	0.82	0.68	-17

Source: EGEDA (2017).

* 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 emissions 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, 2015a).

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 programs 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:

- 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).

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, 2012a):

- 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 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. It is estimated that up to 2025, energy savings from

all new buildings in Hong Kong, China will be approximately 5 billion kilowatt-hours of electricity, equivalent to a reduction in carbon dioxide (CO₂) emissions of approximately 3.5 million tonnes (Mt).

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% 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% 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).

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 2022 (EMSD, 2015c).

ENERGY CONSUMPTION INDICATORS

Since 2001, the government has commissioned the development of energy utilisation indexes and benchmarking tools for the residential (six groups), commercial (32 groups) and transport (30 groups) sectors. The tools assist stakeholders to compare the energy consumption performances of sectors and provide applicable advice regarding energy conservation (EMSD, 2017b).

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 (refrigerators, washing machines, non-integrated type 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 instantaneous gas water heaters and gas cookers). The scheme was extended to cover passenger cars running on petrol (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 five types of

products: room air conditioners, refrigerating appliances, CFLs, washing machines and dehumidifiers. Under the MEELS, energy labels must be displayed on the products supplied to Hong Kong, China to inform consumers regarding their energy efficiency performance (EMSD, 2012b).

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, 2015).

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.

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 about 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), one solar air-conditioning system and four electric inverter air-conditioning systems. Additionally, a ferry was retrofitted with a diesel-electric propulsion system and a seawater scrubber.

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. In 2010, it introduced regulatory controls for motor vehicle biodiesel to help safeguard its quality and encourage drivers to use it.

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 CO₂ 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 and 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 naphtha used as 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 carbon emissions per year, equivalent to planting 2.4 million trees (Towngas, 2016).

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, 2017c).

The government 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 CO₂ emissions. Data gathered will be used as 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 to reduce GHG emissions, the government has been planning and constructing several waste management facilities.

- (a) 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 about 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).
- (b) The government is planning to construct an integrated waste management facility (IWWMF). IWWMF Phase 1 can incinerate 3 000 tonnes of mixed municipal solid waste per day and is capable of exporting about 480 million kWh of electricity (about 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 about 440 000 tonnes of GHG per year (EPD 2017c).
- (c) 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, 2016a, 2016b).

CLIMATE CHANGE

Hong Kong, China is committed to working closely with the international community to combat climate change. The government is pursuing measures established in Hong Kong, China's Climate Change Strategy and Action Agenda (EPD, 2010) to reduce the territory's carbon intensity 50–60% by 2020 compared with the 2005 level. The government also published the 'Hong Kong Climate Change Report 2015' in November 2015, which outlines the work and joint efforts of the government and key private sector stakeholders in responding to climate change. It also provides an account of the economy's climate change actions so that the public can have a more complete picture of Hong Kong, China's contributions to concerted global action.

The major contributors of GHGs in Hong Kong, China are the power generation and land transport sectors, constituting approximately two-thirds and one-fifth of the territory's GHG emissions, respectively. In addition, energy consumption in buildings contributes approximately 90% of the total electricity consumption. Therefore, the government is focussing on decarbonising the future fuel mix for power generation, enhancing building energy efficiency and greening road transport to reduce carbon emissions.

The GHG emission reduction measures are classified in the following sections.

REVAMPING THE FUEL MIX FOR ELECTRICITY GENERATION

The government aims to increase the use of non-fossil, clean and low-carbon fuels for future electricity generation. In 2015, the government proclaimed the fuel mix for 2020: to increase the proportion of natural gas for power generation from around 20% in 2014 to around 50% in 2020, aiming at reducing the territory's carbon intensity by 50–60% by 2020, using 2005 as the base level.

MAXIMISING ENERGY EFFICIENCY

In particular, measures to improve energy efficiency in buildings include reducing the energy consumption of air conditioning and other major electrical equipment. Specific measures include the following:

- Expanding the scope and tightening the requirements of the BEC so that major electrical equipment in all new commercial buildings will be up to 50% more energy efficient by 2020 compared with buildings in 2005;
- Expanding the use of district cooling or water-cooled air conditioning so that up to 20% of all commercial buildings will have up to 50% better refrigeration performance by 2020 compared with buildings using regular air conditioners;
- Reducing energy consumption in new buildings by various means such as tightening overall thermal transfer value standards and promoting the wider adoption of green roofing so that all new commercial buildings will reduce their energy consumption by up to 50% by 2020 compared with new buildings in 2005;
- Improving energy efficiency in commercial buildings through good housekeeping, information technology products and intelligent building environmental management systems so that up to 25% of

existing commercial buildings will be 15% more energy efficient by 2020 compared with those in 2005; and

- Expanding the scope and tightening the energy efficiency of electrical appliance standards for domestic use so that all major domestic appliances sold in the market will be 25% more energy efficient by 2020 compared with those sold in 2005.

GREENING ROAD TRANSPORT

These initiatives include measures to promote the use of electric vehicles and implement energy efficiency standards for vehicles. Specific measures include the following:

- Expanding access to public transportation, establishing pedestrian areas and covered walkways, and so on, to reduce transport needs;
- Promoting wider use of alternative fuelled vehicles such as hybrids and EVs;
- Expanding railway networks and controlling the number of vehicles;
- Waiving the first registration tax on EVs until 31 March 2017;
- Allowing enterprises to have 100% profit tax deductions for capital expenditures in the first year of EV procurement;
- Implementing importers' average fleet efficiency standards so that new vehicles will be 20% more energy efficient than the 2005 market average; and
- Promoting the use of clean fuels (biofuels) for motor vehicles.

TURNING WASTE INTO ENERGY

These initiatives comprise measures to explore the potential of RE. Specific measures include the following:

- Developing and operating one IWMF, one organic waste treatment facility and one STF; and
- Utilising landfill gas and gas generated from wastewater treatment.

LONG-TERM CLIMATE STRATEGY

With the positive outcome of the twenty-first session of the Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC), the government recognised the need to step-up climate actions and draw up long-term policies. The Chief Executive announced in the 2016 Policy Address the establishment of an inter-departmental committee (namely, the Steering Committee on Climate Change) under the leadership of the Chief Secretary for Administration. The Steering Committee comprises members from 10 policy bureaux and 2 departments. It seeks, among other things, to steer the overall direction of the government in combating climate change, including the setting of post-2020 carbon reduction targets as well as long-term climate strategies with regard to the UNFCCC and Paris Agreement.

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. 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.
- Devising the future regulatory framework and delineating 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.

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USEFUL LINKS

Electrical and Mechanical Services Department—www.emsd.gov.hk

Environment Bureau—www.enb.gov.hk

Environmental Protection Department—www.epd.gov.hk

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

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 (km²). This constitutes Indonesia's exclusive economic zone. The economy's total land area (25% of its territory) is about 1.9 million km². The population was around 258 million in 2015.

Indonesia had a gross domestic product (GDP) of around USD 2 622 billion and a per capita GDP of USD 10 158 in 2015 (2010 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 seventy-second place, a significant increase of 19 places from ninety-first place in the previous year (World Bank, 2017).

Indonesia has substantial and diverse energy resources from oil, natural gas, coal and renewable sources. In 2016, Indonesia's proven fossil energy reserves consisted of 3.3 billion barrels of oil, 101 trillion cubic metres of natural gas and 29 billion tonnes of coal. Indonesia is one of the largest coal producers in the world. Coal production reached 456 million tonnes in 2016, where 73% of the production was exported (ESDM, 2017d). Renewable energy sources include 29-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.

Domestic oil, gas and coal reserves have played an important role in Indonesia's economy as sources of energy, industrial raw materials and foreign exchange. In 2014, oil and gas exports contributed 11% and coal exports contributed 5% of Indonesia's total exports. Overall, tax and non-tax revenue from oil, gas and minerals, including coal accounted for 19% of the Indonesian Government's budget in 2014 (ESDM, 2015a).

Table 1: Key data and economic profile, 2015

Key data ^a		Energy reserves ^{b, c}	
Area (million km ²)	1.9	Oil (billion barrels)	3.3
Population (million)	258	Gas (trillion cubic metres)	101
GDP (2010 USD billion PPP)	2 622	Coal (billion tonnes)	29
GDP (2010 USD PPP per capita)	10 158	Uranium (kilotonnes U)	6.3

Sources: ^a EGEDA (2017); ^b ESDM (2015b); ^c NEA (2014).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2015, Indonesia's total primary energy supply (IPES) was 231 757 kilotonnes of oil equivalent (ktoe) of commercial energy, consisting of oil (36%), coal (22%), natural gas (16%) and other energy (mainly hydropower, geothermal and biomass) (27%). Indonesia is a net exporter of energy; overall energy exports of crude oil, condensates, natural gas, liquefied natural gas (LNG), petroleum products and coal totalled 212 604 ktoe in 2015. Total energy exports in 2015 slightly decreased by 3.4% from 2014 (219 585 ktoe), a decrease driven primarily by a decrease in the price of exported coal.

OIL

In 2015, Indonesia produced 88 754 ktoe of crude oil and condensates. Of this, 17 584 ktoe (20%) was exported, an increase of 2% compared to 2014. Because oil production has declined significantly over the past decade (in 1997, Indonesia produced 72 474 ktoe of crude oil and condensates), the economy imported 20 893 ktoe of crude oil and 28 534 ktoe of petroleum products in 2015 to meet its domestic oil requirements (EGEDA, 2017; ESDM, 2015b).

Most crude oil is produced onshore from two of Indonesia's largest oil fields: the Minas and Duri oil fields in the province of Riau on the eastern coast of central Sumatra. Because these fields are considered mature, the Duri oil field in particular has been subject to one of the world's largest enhanced oil recovery efforts.

NATURAL GAS

Indonesia produced 67 294 ktoe of natural gas in 2015, a slight decrease of 0.5% from the 67 627 ktoe produced in 2014 (EGEDA, 2017). Of the total natural gas production, 34% was converted to LNG for export. The economy produced 23 045 ktoe of LNG in 2015, an increase of 4.6% from 21 976 ktoe in 2014. In 2015, Indonesia also exported 9 billion cubic metres of natural gas through pipelines to Singapore and Malaysia. Overall, 46% of Indonesia's natural gas production was exported in 2015. The balance is made available for domestic requirements (ESDM, 2015b).

Indonesia's large natural gas reserves are located near Arun in Aceh, around Badak in East Kalimantan, South Sumatra, the Natuna Sea, the Makassar Strait, the Masela Block in Maluku and Papua, with smaller gas reserves offshore in West and East Java. LNG exports from Tangguh, 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 2015, Indonesia produced 271 401 ktoe of coal, an increase of 1% from 269 361 ktoe in 2014. Most of Indonesia's coal production in 2015 (215 120 ktoe, or 79%) was exported. For domestic consumption (41 215 ktoe in 2015), the source is from power generation (56%) and industrial uses 30 898 ktoe (44%) (EGEDA, 2017; ESDM, 2015b).

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) and independent power producers (IPPs). In 2015, 249 terawatt-hours of electricity was generated, of which 23% was supplied by IPPs and 1.5% was imported from Malaysia. 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, solar and wind) (10%), and oil power plants (diesel power plants and oil-powered thermal plants) (12%) (ESDM, 2017d).

FINAL ENERGY CONSUMPTION

Total final consumption was 171 724 ktoe in 2015, a slight increase of 1.4% from 169 269 ktoe in 2014. The share of total final consumption by sector in 2015 was 26% for industry, 31% for transport, 43% for other sectors and 13% for non-energy consumption. By fuel source, oil consumption had the largest proportion in final energy consumption (excluding non-energy consumption) at 41%, whereas renewable energy was the second largest at 33% final energy consumption (EGEDA, 2017).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	445 243	Industry sector	39 098	Total power generation	234 487
Net imports and others	-212 064	Transport sector	47 380	Thermal	210 240
Total primary energy supply	231 757	Other sectors	65 585	Hydro	13 741
Coal	51 047	Non-energy	19 659	Nuclear	0
Oil	82 534	Final energy consumption*	152 064	Others	10 506
Gas	36 533	Coal	9 838		
Renewables	61 642	Oil	61 765		
Others	1	Gas	13 163		
		Renewables	49 853		
		Electricity and others	17 445		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2015, Indonesia's primary energy intensity was 88 tonnes of oil equivalent per million USD (tonnes of oil equivalent/million USD), a decline of 3.4% from previous year. This indicates 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 total final consumption, energy intensity amounted to 65 tonnes of oil equivalent/million USD, a decrease of 4.6% from 2014. This was mostly driven by decreasing energy consumption in industry and transportation and other sectors.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	91	88	-3.2
Total final consumption	68	65	-3.3
Final energy consumption excl. non-energy	61	58	-4.3

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

In 2015, renewable energy's share in Indonesia's final energy consumption was 51 657 ktoe, a slight decline of 0.2% from previous year. The share of modern renewables was 9 026 ktoe (17.5%) while traditional biomass was 42 631 ktoe (82.5%) in 2015. This indicates 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 General Plan of Energy that includes a policy target for achieving 23% renewable energy sources in the energy mix by 2025. In 2017, the electricity generations from renewable energy was accounted at 12.5% of the total electricity generation mix in 2017.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	151 584	152 064	0.3
Non-renewables (Fossils and others)	99 735	100 407	0.7
Traditional biomass*	42 668	42 631	-0.1
Modern renewables*	9 181	9 026	-1.7
Share of modern renewables to final energy consumption (%)	6.1%	5.9%	-2.0%

Source: EGEDA (2017).

* 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 the utilisation of energy resources and final energy use, the security of supply, energy conservation, the protection of the environment with regard to energy use, the pricing of energy and international cooperation. 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, policy making 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 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:

- Draft the National Energy Policy (KEN);
- Endorse the National Energy Master Plan (Rencana Umum Energi Nasional, RUEN);
- Declare measures to resolve energy crises and energy emergencies; and
- Provide oversight on the implementation of energy policies that are cross-sectoral.

The President chairs the assembly of DEN members. 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. The selection and appointment of members of the DEN was finalised in 2014.

After obtaining approval from the parliament (the DPR) on 17 October 2014, the government issued the new 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.

The RUEN implements 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 input 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 input. On 2 March 2017, the government issued Presidential Regulation No. 22/2017 about RUEN that 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); the Geothermal Energy Law (Law No. 27/2003, which was replaced with Law No. 21/2014); the Mineral and Coal Mining Law (Law No. 4/2009); and the 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 as an alternative to a monopolistic industry, 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. 21/2001). 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 relied mainly 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 industry structure. Until the enactment of this law, an interim working unit for upstream oil and gas business activities (SKSPMIGAS) has been established under the MEMR to assume all BP MIGAS roles and responsibilities. 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.

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, 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.

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

In 2004, the Constitutional Court rejected an advanced reform of the electricity sector, which would have established the possibility of direct competition in power generation through Law No. 20/2002 (currently annulled).

On 23 September 2009, the government enacted Law No. 30/2009 regarding electricity. 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 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 new electricity law, 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 remove the restriction to develop geothermal electricity in 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 because the government has changed the permit scheme from that of a 'geothermal mining permit' to a 'geothermal permit'. This new law states that geothermal energy can be developed in production, protection and conservation forests after obtaining a permit from the Ministry of Forestry under the category of the environmental service use permit.

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).

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.

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 exploitation only. 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, a fifth generation of PSCs have been introduced. The key differences between the PSCs of the later generation and earlier generations are as follows:

- Rather than a fixed production historical after-tax share, there is some flexibility in the production-sharing percentage offered;
- PSC now provides for a domestic market obligation for natural gas;
- BP MIGAS is entitled to FTP of 10% of the petroleum production, which is not shared with the contractor;
- The profit-sharing percentages that appear in the contract are determined on the assumption that the contractor is subject to a dividend tax on after-tax profits under Article 26 (4) of the Indonesian Income Tax Law, which is not reduced by any tax treaty;
- Certain pre-signing costs (for example, seismic purchases) may be cost recoverable;
- BP MIGAS must approve any changes to the direct or indirect control of the entity; and
- The transfer of the PSC participating interest to non-affiliates is only allowable with BP MIGAS's approval and where the contractor retains majority interest and operatorship, or three years after the signing of the PSC (PwC, 2012). Note that BP MIGAS has since been handed over to SKKMIGAS.

Indonesia revised the terms of the domestic market obligation in 2009. Under Government Regulation No. 55/2009, the contractor must allocate 25% of its oil or gas share to the domestic market. In relation to the development of new gas reserves, the government advises the contractor, on request, of the domestic gas supply requirement about a year prior to production. The contractor and prospective domestic buyers negotiate directly on gas price and terms of supply. However, if there is no domestic consumption for gas or if an agreement between the contractor and prospective buyers is not reached, the contractor may sell the entire share to the international market.

THE GROSS SPLIT SCHEME

On 13 January 2017, the government issued Ministerial Regulation No. 8 of 2017 on production sharing contracts. 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 (ESDM, 2017b). The regulation includes the following:

- The ownership of natural resources remains in the hands of the government until the point of delivery;
- Management control operations are at SKKMIGAS;
- Capital and risks are borne by the contractor;
- Gross split for oil is 57% government and 43% PSC;
- Gross split for gas is 52% government and 48% PSC; and
- For gross revenue share split, especially for oil and gas development in the deep sea, which is located in the eastern part of Indonesia where its infrastructure is underdeveloped, a different split will be determined by the government.

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. Government Regulation No. 53/2017 provides fiscal framework for gross split PSCs that will be detailed into implementing regulations that, at the time of this writing, was still being prepared by the MEMR through the revision of Ministerial Regulation No. 8/2017. Key features of Government Regulation No. 53/2017 about Tax Rules for Gross Split PSCs 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;

It is evident that the introduction of regulations on gross split PSCs is accepted by the upstream oil and gas industry. On 31 January 2018, the government announced five winning bidders for upstream oil and gas field development that will adhere to the gross split contract scheme as follows:

- Andaman I—Mubadala Petroleum (SE Asia) Ltd;
- Andaman II—Joint consortium of Premier Oil Far East Ltd, Kriss Energy (Andaman II) BV, Mubadala Petroleum (Andaman II JSA) Ltd;
- Merak-Lampung—PT. Tansri Madjid Energi;
- Pekawai—PT. Saka Energi Sepinggan; and
- West Yamdena—PT. Saka Energi Sepinggan.

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 the economy's oil and gas in new fields through a number of major projects, including the following (SKKMIGAS, 2014):

- Banyu Urip—ExxonMobil Cepu Ltd;
- Indonesia Deepwater Development—Chevron Indonesia Company;
- Abadi—INPEX Masela Ltd;
- Jangkrik dan Jangkrik North East—Eni Muara Bakau B.V.;
- Bukit Tua—PC Ketapang II Ltd;
- Ande-Ande Lumut— (Northwest Natuna) Pte Ltd;
- North Duri Development 13 (NDD-13)—PT Chevron Pacific Indonesia;
- Corridor—ConocoPhillips Grissik Ltd;
- Ruby—Pearl Oil (Sebuku) Ltd;
- Kepodang—PC Muriah Ltd;
- Donggi Senoro—JOB Pertamina-Medco Tomori; and

- Tangguh Train 3—BP Berau Ltd.

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 canisters were distributed by 2010. From 2011 to 2013, some 6.8 million three-kilogram LPG cylinders were distributed. In 2014, the programme expects to distribute 1.629 million cylinders with the same characteristics.

CITY GAS NETWORK DEVELOPMENT PROGRAMME

The MEMR has rolled out a city gas network development programme that aims to connect 3 million households by 2025 and to reach 5 million households by 2030. The city gas network 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 network. The number of households with gas connection has increased from 200 000 in 2014 to 402 583 connections in 2017.

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. The Directorate General of Oil and Gas technically establishes and offers coal-bed methane work areas with due consideration given to the opinion of BP MIGAS (which has now passed on its duties to SKKMIGAS).

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 (ESDM, 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 citizens mining permits (Izin Pertambangan Rakyat [IPRs]). The new law also introduced a contract called the mining business contract (Perjanjian Usaha Pertambangan [PUP]). The IUPs apply to large-scale mining. The PUP is a contract between the government and a private mining company whereby the government is represented by an implementing body, which is yet to be established.

Under the new law, 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.

According to the Geological Agency of the Ministry of Energy and Mineral, proven coal reserves in Indonesia reached 26.2 billion tons in 2017. The coal reserve is distributed in three regions of Kalimantan (14.9

billion tons), Sumatera (11.2 billion tons) and Sulawesi (0.12 billion tons). At a production rate of 461 million tons per annum, existing coal reserves could last for another 56 years.

Domestic coal consumption was recorded at 97 million tons in 2017, equivalent to 21% from the total coal production. The remaining portion of the coal production was exported to 28 countries with the biggest portions to China (51 million tons), India (46 million tons), and Japan (22 million tons). 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.

Government guarantees for the PPP Central Java power plant project are an advanced step in infrastructure development in Indonesia because the approach taken is considered more transparent and accountable. The PPP scheme to be used for the Central Java power plant project is the build-own-operate-transfer (BOOT), which has a concession period of 25 years. Commercial operation is expected to commence at the end of 2019.

GEOHERMAL

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. 27/2003 on geothermal energy, the government issued Government Regulation No. 28/2016 regarding the amount and procedures for geothermal production bonuses (ESDM, 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 formulation of a National Energy Conservation Master Plan (Rencana Induk Konservasi Energi Nasional), which will be updated every five years or annually, as required;
- 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. These incentives include eligibility for energy audit partnerships funded by the government and/or recommendations for priority access to energy supplies by ministers, governors and regents or

mayors within their respective jurisdiction. Disincentives shall be imposed on energy source users and energy users who have not achieved energy conservation through energy management. These disincentives include written notices advising compliance, public announcements of non-compliance, monetary fines (calculated at 5% of the cost of energy used during the one-year reporting period) and/or reduced energy supply (maximum 5% of contract capacity for a period of one month, with a possible extension) for non-compliance.

As part of the government commitment to increase energy efficiency and conservation, the MEMR has developed an energy conservation project as one of its nationally appropriate mitigation actions (NAMAs), namely, the Smart Street Lighting Initiative (SSLI). The SSLI programme aims to implement energy efficiency in street lighting by replacing conventional lighting technology with energy efficient technology, namely, light emitting diodes in urban areas. The SSLI will be implemented in 22 cities in Indonesia to promote transformational changes in this particular sector. This programme will then be implemented throughout the economy. The SSLI has been registered with a NAMA of the United Nations Framework Convention on Climate Change (UNFCCC) since May 2014 to seek international support for implementation. In addition to being proposed to the NAMA facility, the project has been attracting support from several development partners, namely, the Asian Development Bank, the United States Agency for International Development and the French Development Agency.

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 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. 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. The Greenship Programme has the following four criteria:

- Sustainable building materials;
- Water and waste water management;
- Energy efficiency; and
- Waste management.

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

BARRIER REMOVAL

Indonesia is participating in a United Nations Development Programme-Global Environment Facility (UNDP-GEF) project, which involves six developing Asian economies. This project, Barrier Removal to the Cost-Effective Development and Implementation of Energy Efficiency Standards and Labelling (BRESL), comprises five major programmes promoting energy standards and labelling: policy making, capacity building, manufacturing support, regional cooperation and pilot projects. The BRESL project was completed in 2014 but the government has continued its implementation (UNDP, 2014).

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 2016 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 ministry regulation on refrigerator labels were submitted to the DGNREEC and will be the basis for the creation of technical guidelines for labels;
- Drafts of energy performance tests on rice cookers and electric fans were finalised and submitted to the DGNREEC and will be enacted as the Indonesian Standard for Energy Performance;
- A testing protocol for electronic ballast was submitted to DGNREEC to be evaluated and included as a technical guideline under a ministerial regulation; and
- A regional feasibility study on CFL was conducted based on Australian practices and updated for the standard harmonisation of CFL energy performance.

POTONG (CUT) 10% MOVEMENT

Indonesia launched a Potong (cut) 10% Movement in May 2016. The Potong 10% Movement aims to change people's behaviour in using energy more wisely. The main target of this national movement is to reduce energy consumption by 10%. This campaign is intended to promote the rise of a movement such as the Public Lifestyle Change Joint Action (government, business/industry and individual) to encourage energy savings. Nationally, it is easier and less expensive to save 10% than to raise the energy equivalent by the same amount (ESDM, 2016a).

The campaign will continue to illuminate ideas through the labelling of energy efficiency, formation of managerial and energy auditors, the use of energy-saving lamps and optimising the role of energy service companies and the Nation Energy Activator (PETA). The public campaign will hold simultaneous meetings in 20 major cities, namely, Medan, Pekanbaru, Batam, Padang, Palembang, Lampung, Jakarta, Bogor, Depok, Tangerang, Bekasi, Cilegon, Bandung, Yogyakarta, Semarang, Sidoarjo, Surabaya, Denpasar, Makassar and Balikpapan.

Public campaigns have been carried out comprehensively and sustainably through the following four scheme campaigns:

- Direct campaigns in public spaces, such as schools, universities, monuments, shopping centres and city parks;
- A viral campaign through social media;
- Sustained campaigns involving 33 young communities and 35 community service officers (CSO); and
- The campaign with the Report 10% mechanism.

The overall campaign will also be accompanied by information dissemination through various media, such as public service announcements on national TV, branding on the train and commuter-lines, cover seat information on planes, banners on online media and appearances on talk shows on national TV. The activity will continuously post various advertisements on television and distribute print media on trains and planes and in bus terminals.

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 to:

- 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).

BIOFUELS

In 2008, Indonesia passed Ministerial Regulation No. 32/2008, regarding the supply, use and commerce of biofuel as another fuel. This regulation made biofuel consumption mandatory from 2009.

The regulation controls the following:

- the utilisation priority of biofuels;
- biofuel categories;
- standards and specifications of quality;
- price setting;
- biofuel commerce, as another fuel;
- directives and oversight; and
- sanctions.

To reduce fuel imports by accelerating the improvement and expansion of biofuels, the government revised Ministerial Regulation No. 32/2008 through Ministerial Regulation No. 12/2015 on 18 March 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	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: (ESDM, 2015c).

Until the end of 2014, the realisation of biofuel (biodiesel and bioethanol) utilisation was 4.1 million kilolitre (kL), an increase of 47% from 2.8 million kL in 2013.

GEOTHERMAL

In 2017, Indonesia's total geothermal capacity was 1 808 MW, which is 6.25% of the total geothermal potential of 28 910 MW (PLN, 2018). Indonesia has identified 11 705 MW of geothermal power potential from existing geothermal plants, through capacity expansion of productive geothermal resources and from new geothermal projects at 67 sites. Specifically, the latter are anticipated to produce 5 195 MW in Sumatra at 22 sites, 4 096 MW in Java at 26 sites, 1 036 MW in Sulawesi at five sites, 813 MW in the Nusa Tenggara and Bali at eight sites and 565 MW in the Maluku islands at five sites (EBTKE, 2015).

This geothermal power potential will be developed under the 10 000 MW Accelerated Development of Electricity Generation—Phase II programme as well as a 35 000 MW programme. Some of these projects have achieved commercial operation date and other projects will operate between 2018 and 2027. Under PLN's Electricity Power Supply Business Plan 2018–27 (*Rencana Usaha Penyediaan Tenaga Listrik*, or RUPTL), a further increase in geothermal capacity by 4 583 MW is expected between 2018 and 2027. Of the total capacity, 2 170 MW will be developed by IPPs, 425 MW by PLN, and 1 988 MW is currently under business case and has not been allocated to either PLN or IPPs (PLN, 2018).

HYDROPOWER

In 2014, Indonesia's total hydropower capacity was 5 229 MW (including 170 MW of micro- and mini-hydro). This was 7% of the total hydropower potential of 75 GW (DJK, 2015a). Under the 10 000 MW Accelerated Development of Electricity Generation—Phase II programme over 2015–22, Indonesia is committed to developing additional hydropower with a total capacity of approximately 1 803 MW. Of this total capacity, 424 MW will be developed by IPPs and 1 379 MW by PLN.

PLN's RUPTL 2018–27 also includes the potential for an additional 8 283 MW of hydropower capacity during 2018–27 (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 hydropower capacity includes the 88 MW Peusangan hydro-power and 174 MW Asahan III hydro-power in Sumatera that are 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. These pump-storage plants are considered important for the technical performance and stability of the Indonesian electricity grid, particularly the Java-Bali electricity grid.

These hydropower plants would increase Indonesia's total large hydropower capacity to 14 480 MW, or 19% of Indonesia's total hydropower potential. It is worth noting that Indonesia's large hydropower potential is located in the eastern part of Indonesia, 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 large scale wind power in Indonesia.

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

SAVING ENERGY AND WATER

Presidential Instruction No. 13/2011 Regarding Saving Energy and Water instructs Ministers of the Unity Indonesia II Cabinet, the Supreme Justice of the Republic of Indonesia, the Commander of the Armed Forces of Indonesia, the Head of State Police Republic of Indonesia, heads of non-ministerial government agencies, heads of state secretariat institutions, governors and regents or mayors to take measures and innovate in order to save energy and water within their institutional domains and/or in the domains of state-owned businesses and regional government-owned businesses within their jurisdiction.

Presidential Instruction No. 13 assigns an electricity saving target of 20% from the average electricity use over the six months prior to the presidential instruction; fuel saving targets of 10% through regulations to limit the use of subsidised fuels; and water saving targets of 10% from the average water use over the six months prior to the presidential instruction.

The presidential instruction calls for the creation of a national team on saving energy and water. The Coordinating Minister of Economic Affairs is the chair and the Minister of Energy and Mineral Resources is the Executive Chief and both are members of the national team; 11 cabinet ministers are also members of the team. The national team is supported by the executive team, which is headed by the secretary of the national team.

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.

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. A fourth 10-MW pool-type research reactor is planned for development in the near future.

Indonesia currently has two prospective uranium mines. The first is the Eko-Remaja prospect of the Remaja-Hitam Ore Body, a uranium vein in fine-grained metamorphous rock, estimated to contain 5 000–10 000 tonnes of uranium with a grade ranging 0.1–0.3. The second is the Rirang Tanah Merah Ore Body, a uranium vein, which may contain fewer than 5 000 tonnes of uranium of a grade ranging 0.3–1.0. The uranium mines are located in West Kalimantan.

Despite the above developments, the Fukushima Daiichi nuclear accident in 2011 generated negative perceptions, discouraging prospects for building nuclear energy power plants in Indonesia. At the same time, people have resisted development on candidate sites, thereby making development uncertain. Hence, the government has stated that nuclear energy will be the last option used to achieve Indonesia's energy consumption, 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 United States. 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 response to this commitment and the challenges of climate change, the Indonesian Government has established a roadmap for integrating climate change issues into development planning. The climate change roadmap will integrate mitigation and adaptation into policy instruments, regulations, programmes, projects, funding schemes and capacity building in all development sectors. Two initial phases are the integration of

climate change into the Mid-Term Development Plan 2010–14 (Rencana Pembangunan Jangka Menengah 2010–14, RPJM) and the launching of the Indonesia Climate Change Trust Fund (ICCTF) on 14 September 2009.

The ICCTF is a financing mechanism for climate change mitigation and adaptation within Indonesia's policy framework. The ICCTF has two key objectives:

- Achieving Indonesia's goal of a low-carbon economy and greater resilience to climate change through the facilitation and acceleration of investment in renewable energy and energy efficiency; sustainable forest management and forest conservation; and the reduction of vulnerability in key sectors such as coastal zones, agriculture and water resources.
- Enabling the government of Indonesia to increase the effectiveness and impact of its leadership and management in addressing climate change by bridging the financial gap in order to address climate change mitigation and adaptation and increasing the effectiveness and impact of external finance for climate change work in Indonesia.

Through the ICCTF, the government of Indonesia can utilise not only government budgets but also bilateral and multilateral financial agreements, public-private partnerships, mandatory and voluntary international carbon markets and the Global Environmental Fund and other funds in order to implement a policy framework for climate change.

The ICCTF consists of two funds: the Innovation Fund and the Transformation Fund. The Innovation Fund is a grants-based fund to finance demonstration and innovation projects, pilot projects and research and development. The Transformation Fund is used to finance low-emissions programmes, projects and initiatives developed by private parties. The Transformation Fund is not a grants fund but a revolving fund; thus, projects are expected to generate returns on the fund's investments.

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 to 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 INDC 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).

In order 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, including:

- Prioritise electricity supplies from renewable energy sources while ensure cost competitive of electricity
- Fuel switching from oil to gas and biodiesel
- Adopt advanced clean coal technologies such as ultra-supercritical and consider Carbon Capture and Storage (CCS) when the technology has reached mature stage of development.

NOTABLE ENERGY DEVELOPMENTS

ELECTRICITY

ACCELERATED ELECTRICITY GENERATION PHASE I, PHASE II AND 35 GW PROGRAMME

The accelerated power development programme, 10 000 MW Phase I, had completed 9 120 MW of new generation capacity by the end of December 2015. With regard to project constraints, the MEMR had set a new final completion date of 2016 for the 10 GW Phase I of the programme.

In 2010, the government mandated PLN to implement Phase II of the programme. In this second phase, PLN will add 11 GW of capacity based on 68% coal, 19% geothermal, 10% combined cycle gas and 3%

hydropower. The two-phase accelerated power development programme is expected to rapidly increase generating capacity, encourage renewable energy utilisation and simultaneously eliminate oil-based power plants, except in regions where there are no other competitive alternative energy sources.

The composition of the generation capacity mix for Phase II of the 10-GW Accelerated Power Programme is required to be updated to accommodate the current situation's conditions. In 2014, the MEMR established a new final energy mix for the 10-GW Phase II with a total capacity of 17 458 MW, 60% of which will be developed from coal, 28% from geothermal, 10% from hydropower and 2% from gas. The scheduled completion date for the 10-GW Phase II is 2022.

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. Based on the latest project status update in November 2017, 1 GW of power plants are already operating, 16.6 GW are under construction, 12.8 GW has entered into power purchase agreements, 3.2 GW is being tendered by PLN, and 2.2 GW is being planned by PLN (PLN, 2018).

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 underline 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 that are 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 electricity grids. For example, the Batam electricity system has 75.21% of reserve margin while the Java-Bali electricity grid has 35.7% reserve margin in 2017.

ELECTRIFICATION RATIO

The Government of Indonesia has rapidly increased the Indonesia's electrification rate from 84.4% in 2014 to 95.4% in 2017. The rate of electrification will increase to 97.5% in 2018 and is forecasted to reach 99% in 2019. The government has a target to achieve 100% electricity access by 2024n. The electrification program includes the expansion of transmission and distribution network in the Eastern Indonesia to reach remote villages. At the same time, solar home systems program 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.

UPDATE OF THE PLN ELECTRICITY SUPPLY BUSINESS PLAN 2018-2027

The MEMR has 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.

REGULATIONS

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 and it was enacted to replace the previous Ministerial Regulation No. 12/2017 and previous feed-in tariff regulations (Ministerial Regulation No. 22/2012 for geothermal energy, Ministerial Regulation No. 19/2015 for hydro energy, Ministerial Regulation No. 21/2016 for biomass and biogas energy and Ministerial Regulation No. 19/2016 for solar energy).

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. This regulation also stipulates that PLN is obligated to operate renewable energy power plants with a capacity within 10 MW continuously (ESDM, 2017a).

Purchasing electricity from solar and wind power 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 respective local grid. Meanwhile, if generation cost in the local grid equal to or below the average national generation cost, the electricity purchase price is equal to the generation cost in the local grid.

Purchasing electricity from biomass and biogas energy with a maximum capacity of 10 MW using the reference price and with a maximum capacity more than 10 MW using the mechanism of direct selection 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 respective local grid. 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.

Electricity from municipal solid waste power plant can be obtained by the technology of methane gas collection along with anaerobic digestion or similar methods from sanitary landfills or through the heat/thermal technology using thermochemical. The developers can be provided facilities in the form of incentives that will be set in a separate regulation. For areas where the generation cost is above the average national generation cost, the purchase price of electricity is equal to the generation cost on the respective local grid. Meanwhile, if the generation cost in the local grid equals or is below the average national generation cost, the electricity purchase price is determined upon agreement of the parties.

Electricity from geothermal energy can only be purchased by PLN to electric power developers that have GWA in accordance with proven reserves after exploration. For areas where the generation cost is above the average national generation cost, the purchase price of electricity is equal to the generation cost on the respective local grid. Meanwhile, if the generation cost in the local grid equals or is below the average national generation cost, the electricity purchase price is determined upon agreement of the parties.

Electricity from hydro energy power plants is purchased on the basis of the reference price or direct selections. A plant with a maximum capacity of 10 MW must be able to operate with a minimum capacity factor of 65%. With a capacity larger than 10 MW, the capacity factor depends on the needs of the system. 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 the 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 (ESDM, 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-Owned 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

In the early 2018, MEMR has subsequently simplified several regulations, including revoking ninety Ministerial regulations and ninety-six permits from the subsectors of oil, coal, electricity, renewable energy, SKK Migas, and BPH Migas. These policies are aiming at improving investment climates in the energy sector and particularly in the upstream oil and gas development. Detailed information on the list of regulations and permits that have been revoked can be found on the MEMR website.

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USEFUL LINKS

BPH MIGAS—www.bphmigas.go.id

Ministry of Energy and Mineral Resources (KESDM)—www.esdm.go.id

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

JAPAN

INTRODUCTION

Located in East Asia, Japan comprises several thousand islands, the largest of which are Honshu, Hokkaido, Kyushu and Shikoku. Most of its land area, approximately 377 800 square kilometres (km²), is mountainous and thickly forested. Japan is the third-largest economy in the world and among the APEC economies after the United States and China. Its real GDP in 2015 was approximately USD 4 707 billion (2010 USD purchasing power parity [PPP]). In 2015, Japan's population of 127 million people had a per capita income of USD 37 021. The GDP grew by 1.2% in 2015 compared with that in 2014. Since indigenous energy resources are modest, Japan imports nearly all of its fossil fuels to sustain economic activity. The proven energy reserves¹ include approximately 44 million barrels of oil, 21 billion cubic metres (bcm) of natural gas and 350 million tonnes (Mt) of coal.

Table 1: Key data and economic profile, 2015

Key data ^a		Energy reserves	
Area (thousand km ²)	377.8	Oil (million barrels) ^b	44
Population (million)	127	Gas (billion cubic metres) ^b	21
GDP (2010 USD billion PPP)	4 706	Coal (million tonnes) ^c	350
GDP (2010 USD PPP per capita)	37 021	Uranium (kilotonnes U)	–

Sources: ^a EGEDA (2017); ^b Conglin Xu and Laura Bell (2017); ^c BP (2017).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2015, Japan's total primary energy supply was approximately 430 million tonnes of oil equivalent (Mtoe), a decrease of 0.7% from the previous year. By fuel type, oil contributed the largest share (44%), followed by coal (27%) and natural gas (25%). In 2015, the net imports of energy sources constituted 97% of the total primary energy supply.

In 2015, Japan was the fourth-largest oil consumer in the world and the third among the APEC economies (4.3 million barrels per day [Mbbbl/D]), following the United States, China and India (BP, 2017). Almost all of the oil was imported. The bulk of the imports (83% in fiscal year (FY)² 2015) was from economies in the Middle East such as Saudi Arabia, the United Arab Emirates and Qatar (METI, 2017a). In 2015, the primary oil supply was 187 Mtoe, a decrease of 2.9% from the previous year.

Japan is endowed with only limited coal reserves, 350 Mt, while its coal consumption in FY2015 comprised 120 Mt of steam coal and 73 Mt of coking coal (METI, 2017a). It is one of the world's largest importers of coking coal for steel production and steam coal for power generation, in addition to cement production. Japan's main steam coal suppliers are Australia (77% in FY2015); Indonesia (11%); and Russia (10%), while those for coking coal are Australia (50%); Indonesia (29%); and Canada (9%) (METI, 2017a).

Natural gas resources are also scarce in Japan. Domestic reserves stand at 21 bcm, which is less than one-fifth of the annual consumption in 2015, and are located in Niigata, Chiba and Fukushima prefectures. In FY2015, the domestic demand was met almost entirely by imports in the form of liquefied natural gas (LNG mainly from Australia (23%); Malaysia (29%); Qatar (16%) and Russia (9%) (METI, 2017a). LNG imports to Japan comprised 31% of the total global LNG trade in 2016 (BP, 2017). Natural gas is mainly used for

¹ Oil and natural gas are as of January 2017. Coal is as of the end of 2016.

² The fiscal year starts in April in Japan.

electricity generation, followed by reticulation as city gas and as an industrial fuel. The primary natural gas supply was 105 Mtoe in 2015, an increase of 0.7% from the previous year.

Japan has 290 gigawatts (GW) (EGEDA, 2017) of installed generating capacity and generated 1 051 593 gigawatt-hours (GWh) of electricity in 2015. Fossil fuels—coal, gas and oil—constituted 83% of generated electricity. The share of renewables, including hydro, solar, wind and geothermal, was 17%. Nuclear power generation increased to 4.5 terawatt-hours (TWh) (0.4% of the total generation) in 2015 from 0 TWh in 2014 due to the restart of the Sendai nuclear power plants (two units).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	24 405	Industry sector	133 459	Total power generation	1 051 593
Net imports and others	418 386	Transport sector	74 079	Thermal	873 311
Total primary energy supply	430 078	Other sectors	88 336	Hydro	89 012
Coal	117 238	Non-energy	3 366	Nuclear	4 459
Oil	186 876	Final energy consumption*	295 874	Others	84 811
Gas	105 156	Coal	32 557		
Renewables	19 646	Oil	148 331		
Others	1 162	Gas	30 089		
		Renewables	2 159		
		Electricity and others	82 739		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2015, the final energy consumption in Japan was 295.9 Mtoe, a decrease of 0.5% from the previous year. The industrial sector consumed 45% of the total final consumption, followed by the other sectors, including buildings (30%), and the transportation sector (25%). Final energy consumption decreased by 0.2% from the previous year in the industry and transport sectors and by 1.4% in the other sectors. By energy source, petroleum products constituted 50% of the total final consumption, followed by electricity and others (28%), coal (11%) and gas (10%).

ENERGY INTENSITY ANALYSIS

In 2015, Japan's energy intensity declined in terms of primary energy and total final consumption compared with that in the previous year. Primary energy intensity decreased to 91 tonnes of oil equivalent per million USD (toe/million USD), -1.9% from the previous year. Final energy intensity also dropped to 64 toe/million USD, equivalent to -1.8% from 2014. This was mostly driven by the decreasing energy consumption in the other sector, which includes buildings, and the industry sector.

Table 3: Energy intensity analysis, 2014 vs 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	93	91	-1.9
Total final consumption	65	64	-1.8
Final energy consumption excl. non-energy	64	63	-1.7

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

In 2015, the share of modern renewable energy in final energy consumption was 5.4%, an increase of 0.5 percentage point from the previous year. Incremental modern renewables, especially renewable electricity after the introduction of the feed-in tariffs (FIT) system in 2012, combined with declining consumption, contributed to the share growth.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	297 484	295 874	-0.5
Non-renewables (Fossils and others)	282 839	280 019	-1.0
Traditional biomass*	24	22	-8.5
Modern renewables*	14 621	15 833	8.3
Share of modern renewables to final energy consumption (%)	4.9	5.4	8.9

Source: EGEDA (2017).

*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 Economy, Trade and Industry (METI) of Japan is responsible for designing the energy policy of the economy. Within METI, the Agency for Natural Resources and Energy is in charge of the rational development of mineral resources, securing stable supplies of energy, promoting efficient energy use and regulating electricity and other energy industries. Regarding nuclear safety, the Nuclear Regulation Authority (NRA), which is an independent commission affiliated with the Ministry of the Environment (MOE), has been responsible for nuclear safety since September 2012.

Before the Great East Japan Earthquake in March 2011 and the subsequent Fukushima Daiichi nuclear power plant accident, the aim of Japan's energy policy was to achieve the '3E' goals—energy security, economic efficiency and environment (for example, against global warming)—in an integrated manner. After these events, Japan aims to achieve the '3E+S' goals—the original 3E concept plus safety as the foremost condition.

The Basic Act on Energy Policy 2002 presents the core principles of Japan's energy policy—assurance of a stable supply, adaptation to the environment and use of market mechanisms. The Strategic Energy Plan was established in 2003. The plan is required to be reviewed at least every three years and revised as necessary.

Since then, the Strategic Energy Plan was revised three times. The current fourth plan was approved by the Cabinet in April 2014, considering the energy situation after the Great East Japan Earthquake in March 2011 and the subsequent Fukushima Daiichi nuclear power plant accident (METI, 2014). This plan provides a direction to Japan's energy policies for the medium/long-term (about the next 20 years) based on the '3E+S' policy. It reaffirms the importance of renewables as promising low-carbon and domestic sources, coal as a stable and cost-effective base-load power source and natural gas as the main flexible middle-load power source. The latest plan also reaffirms the importance of nuclear energy as a low-carbon and quasi-domestic power source. However, it states that dependency on nuclear generation will be lowered to the greatest extent possible by energy saving and introducing renewable energy, as well as by improving the efficiency of thermal power generation.

In addition to the fourth plan, the government concluded the Long-term Energy Supply and Demand Outlook of Japan in July 2015 (METI, 2015a). The outlook indicates an electricity mix, primary energy demand and supply, and energy-related CO₂ emissions in FY2030, which realise the '3E+S' policy in the Strategic Energy Plan. The outlook has three steps: 1) increase energy self-sufficiency (including nuclear as a quasi-domestic energy) to approximately 25% from approximately 6% in 2012; 2) reduce electricity costs from the current level; and 3) reduce greenhouse gas (GHG) emissions comparable to the targets of Europe and the US. The government's outlook aims for a well-balanced power mix wherein nuclear constitutes 20–22% of the total generated electricity, renewables constitute 22–24%, LNG constitutes 27%, coal constitutes 26% and oil constitutes 3%. Nuclear dependence is lower than that before the earthquake (when it was around 30%). Within renewables, the two largest sources are hydro, constituting 8.8–9.2%, and solar (7%).

In August 2017, the government began discussions for the fifth Strategic Energy Plan at the Strategic Policy Committee of the Advisory Committee for Natural Resources and Energy. According to Mr Hiroshige Seko, the METI minister, the fifth plan is expected to retain the core directions in the fourth plan, while considering the developments in the last few years³. As of January 2018, the fifth plan is under consideration.

ENERGY MARKETS

OIL

Japan aims to decrease its oil dependency, partly because of its experiences during the oil crises in 1973 and 1979. However, oil still dominates the total primary energy supply of the economy. The share of oil was approximately 40% in 2010, and it increased to 47% in 2012 due to the loss of nuclear generation and incremental oil-fired generation after the earthquake. Although the share of oil declined to approximately 44% in 2014, securing its stable supply is one of Japan's major energy policy issues.

The oil supply structure of the economy is vulnerable to the disruption of maritime transport because it imports almost all of its domestic consumption by tankers. In preparation for possible supply disruptions, Japan has created emergency oil stockpiles and independently developed resources as well as promoted cooperation with oil-producing economies to manage emergencies.

The Japan Oil, Gas and Metals National Corporation (JOGMEC) is responsible for the state-owned stockpile. It provides financial and technical assistance to Japanese oil industries for oil and natural gas exploration and development domestically and abroad. The oil stocks of Japan are well in excess of the International Energy Agency's 90-day net import requirements. As of October 2017, Japan held the equivalent of 226 days of net imports, including state-owned stocks, private sector stocks and joint oil storage programs, with oil-producing economies (PAJ, 2017).

To utilise crude oil effectively, the government has been regulating domestic refining capacity in a phased manner through the law that regulates the promotion of the use of non-fossil energy sources and the effective use of fossil energy materials by energy suppliers. First regulation aimed to raise the heavy oil cracking unit capacity in the economy to approximately 13% of the total distillation capacity from FY2010 to FY2013. Second regulation aimed to raise the residues processing capacity⁴ to approximately 50% of the total distillation capacity from FY2014 to FY2016. Oil refining companies achieved the regulation mainly by reducing

³ The METI minister mentioned at the first meeting of the Strategic Policy Committee (METI, 2017b).

⁴ Such as RFCC (Resid Fluid Catalytic Cracking), FCC (Fluid Catalytic Cracking), hydrocracking, and SDA (Solvent Deasphalting).

distillation capacity (METI, 2017c). The number of oil refineries in Japan decreased from 40 in 1996 to 22 in October 2017, and the refining capacity decreased from 5.3 Mbbbl/D to 3.5 Mbbbl/D (PAJ, 2017). Third revision to the law, which was enforced in October 2017, was to encourage the refining companies to set a target for the utilisation rate of residues processing capacity from FY2017 to FY2021. This regulation aims to promote the production of higher-value oil products, such as gasoline and naphtha rather than asphalt, from residues.

Competition continues in the domestic oil product market. For example, the number of service stations in the economy decreased from 59 615 in 1996 to 34 706 in 2013 due to market liberalisation (NPA, 2014). The Specific Petroleum Law (provisional measures law regulating the importation of specific kinds of refined petroleum products) was abolished in March 2012. In this context, the Japanese Government aims to establish a fair and transparent market in terms of quality and prices, where oil product retailers are able to play an important role in the interaction with final consumers.

NATURAL GAS

Over the past two decades, demand for natural gas has increased rapidly at an annual rate of 3.7% between 1990 and 2015 (EGEDA, 2017). Natural gas is supplied almost entirely by imports in the form of LNG. Since Japan prioritises a stable and secure supply of LNG, Japanese LNG buyers have generally paid a higher price than those in Europe or the US under long-term ‘take or pay’ contracts with rigid terms on volume and price. Recently, Japanese gas and electric utilities have sought to reduce their costs because of the deregulation of the gas and electricity markets. The utilities have been striving to secure an LNG supply on flexible terms that enable them to quickly respond to changes in the market situation and supply gas at lower prices. The government holds the LNG Producer–Consumer Conference every year to support the development of flexible LNG markets (METI, 2017d). Japan has also been seeking alternative gas supplies; for example, the economy promoted technological developments in the production and processing of methane hydrate, which is abundant in the ocean areas surrounding Japan and is considered to be a future energy resource.

The Fourth Strategic Energy Plan states that the period from 2014 to 2018–20 will be devoted to reforming the electricity and gas systems to build a more liberalised and competitive energy market. Accordingly, amendments to the Gas Business Act were enacted in June 2015 to fully liberalise the retail market by approximately 2017 and legally unbundle the gas pipes owned by three city gas utilities—Tokyo Gas, Osaka Gas and Toho Gas—by April 2022 (METI, 2015b).

COAL

In 2015, coal constituted 27% of the total primary energy supply. Coal will continue to play an important role in Japan’s energy sector, mainly for power generation and iron, steel, cement, and pulp and paper production. Japan is the third-largest coal importer in the world after China and India. Japan’s imports constituted approximately 14% of the total global coal imports in 2015 (IEA, 2017).

ELECTRICITY

After oil, electricity was the second-largest contributor to the total final energy consumption in 2015. The increased use of electrical appliances in homes, widespread use of personal computers and related information technology in offices, in addition to a shift in the industry structure to more services-based sectors, have steadily increased electricity consumption in recent years.

Since 1995, Japan has been partially liberalised to ensure fair competition and transparency: for example, introduction of independent power producers in 1995; introduction of power producers and suppliers (PPS) and partial retail competition (over 2 000 kW) in 2000; and expansion of retail competition in 2004 (over 500 kW) and 2005 (over 50 kW) (METI, 2002). As of FY2013, approximately 60% of the market was already liberalised in terms of electricity consumption. However, after the earthquake and the subsequent Fukushima Daiichi nuclear power accident, Japan’s electricity sector faced mounting pressure to further deregulate the market for a more competitive and transparent electricity supply. The Electricity Business Act was amended in 2013, 2014 and 2015 to reform the market (METI, 2015b). This reform mainly focuses on three stages: 1) establishing the Organisation for Cross-regional Coordination of Transmission Operators (OCCTO) in April 2015; 2) ensuring full retail competition from April 2016; and 3) legal unbundling of the transmission/distribution sector from 2020 and transition to overall liberalisation of retail prices after the

unbundling. To avoid a monopoly situation after retail liberalisation in 2016, retail tariffs of designated utilities will be regulated as a transitional measure and gradually deregulated at the same time or after the legal unbundling.

Japan's electricity market faces technical and institutional challenges due to the growing penetration of variable renewable power, especially solar photovoltaic (PV), after the introduction of the FiT system in 2012. To ensure secure and reliable electricity supply while realising active market, the government will open the following markets, in addition to the current wholesale market and reserve tender system: a non-fossil fuel market in FY2018 for FiT electricity; a base-load market in 2019; and real-time and capacity markets in FY2020 (METI, 2017e). To encourage a cost-effective electricity supply, the government will implement new operation rules for inter-regional transmission lines in FY2018 on a 'first-come, first-served' basis to an implicit auction system.

HYDROGEN

In the Strategic Energy Plan in 2014 (METI, 2014) and the Basic Strategy for Hydrogen in 2017 (METI, 2017f), Japan has reaffirmed the potential of hydrogen, which can be produced from diverse energy sources, to construct a secure and lower-carbon energy system. To realise a 'hydrogen society', METI compiled the Strategic Road Map for Hydrogen and Fuel Cells in 2014 and revised it in 2016 (METI, 2016a). This road map summarises the steps needed to be taken to make use of hydrogen, from production to transport and storage, with clear time frames. The revised road map set short-term targets as follows:

- Installation cost target for polymer electrolyte fuel cells (800 000 JPY/kW by 2019) and solid oxide fuel cells (1 million JPY/kW by 2021);
- Vehicle stock target for fuel cell vehicles (4 million by 2020, 20 million by 2025 and 80 million by 2030); and
- Target for the number of hydrogen stations (160 stations by FY2020 and 320 stations by FY2025).

According to the revised road map, in the mid- to long-term, Japan aims to utilise hydrogen for power generation in the late 2020s and establish a 'CO₂-free' hydrogen supply system by around 2040.

FISCAL REGIME AND INVESTMENTS

The Japanese Government recognises the need for encouraging domestic petroleum companies to obtain upstream oil and gas equities overseas. JOGMEC offers technical support to domestic petroleum companies in areas such as geological structure studies and mining technologies. In addition, both JOGMEC and the Japan Bank for International Cooperation (JBIC) offer financial support to companies.

In the short-term, the government intends to concentrate on financial support for existing upstream projects to assist with start-up and continuation. In the mid-term, the government will continue to appropriately support domestic petroleum companies by borrowing money from the market with government guarantees and building a flexible and effective finance system through JOGMEC, aiming at reducing geopolitical and technical risks for future projects.

ENERGY EFFICIENCY

The 1979 Energy Conservation Law, established after the oil crises, is the basis of all energy conservation policies in Japan. It requires improving the energy efficiency of the industrial, building (commercial and household), and transport sectors (METI, 2017g). Based on the law, the government has been implementing energy efficiency policies through regulation and economic incentives, and the economy achieved a 40% improvement in terms of energy intensity (final consumption basis) from 1980 to 2014. Regulations include 1) regular reports on energy efficiency and efforts for energy intensity improvements of 1%/year for factories and business establishments with energy consumption of 1 500 kl/year; 2) the Top-Runner Programme, which was introduced in 1998 to establish energy efficiency standards to curb consumption in the residential, commercial and transport sectors; and 3) regular reports on energy efficiency implementation for specified-scale cargo owners and carriers. The law also requires factories and business establishments with energy consumption of 3 000 kl/year to appoint qualified energy managers. Economic incentives include subsidies,

accelerated depreciation and tax reductions for installing efficient equipment or facilities, in addition to R&D subsidies for high-efficient technologies such as high-performance heat pumps and insulation materials.

Following the earthquake in 2011 and electricity shortage situation, the 1979 Energy Conservation Law was partially amended in May 2013 to strengthen energy efficiency activities and promote activities for levelling electricity load. Key amendments included the development of new indicators and guidelines to evaluate 'peak-shift' activities and the expansion of the Top-Runner Programme. The Top-Runner Programme initially covered 11 items, including cars and air conditioners, and expanded to 31 items in 2013. In the 2013 amendments, in addition to energy-consuming items, items that do not consume energy but rather contribute to high efficiency or energy conservation, such as building insulation materials, were added to this program.

In 2014, the revised Strategic Energy Plan established the following initiatives (METI, 2014):

- Enhancing Japan's energy efficiency (already at the highest level in the world) by introducing the most advanced technologies for replacing equipment in the industrial sector;
- Enhancing support and regulatory measures (including the Top-Runner Programme) to increase the adoption of highly efficient equipment in each sector. Expanding the coverage of the program, which now includes industrial refrigerators, printers, heat pumps, LED lamps and building insulation materials;
- Replacing 100% of the lighting with high-efficiency lamps (including LED and organic electroluminescence [EL] lighting) on a flow basis by 2020 and stock basis by 2030;
- Achieving net zero energy with regard to newly constructed public buildings by 2020 and all newly constructed buildings on average by 2030;
- Raising next-generation vehicles' share of new vehicle sales to between 50% and 70% by 2030 while promoting comprehensive measures, including improving traffic flow such as introducing intelligent transportation systems (ITS); and
- Facilitating the introduction of the energy management system, such as building energy management system (BEMS), and encouraging the acquisition of the certification of the ISO 50001 standard.

RENEWABLE ENERGY

As mentioned, Japan has a system of FiT. In August 2011, the Act on Purchase of Renewable Energy-Sourced Electricity by Electric Utilities was passed by the Diet (the Japanese Parliament). This act took effect on 1 July 2012. It requires electric utilities to purchase electricity generated from renewable energy sources (solar PV, wind power, small- and medium-sized hydropower, geothermal and biomass) based on fixed-period contracts with fixed prices. Table 5 shows the prices for the FiT in FY2017.

Beginning in April 2017, the government enforced a partial revision to the act to facilitate the installation of authorised capacity, revise the FiT pricing system and obligate the general transmission companies to purchase FiT electricity instead of retail companies under current rules. Regarding the pricing system, the revision will allow the government to determine the purchase prices for the next several years. This new system is expected to promote renewable energy with longer lead times, such as geothermal, wind, medium hydro and biomass, by improving the predictability of the projects. To promote renewable energy in a cost-effective manner, the revision also allows the government to use auctions for determining the FiT prices. The government began to use the auction system for utility-scale solar PV (METI, 2016b). For other technologies, METI determined purchase prices for the next three years (METI, 2017h).

Table 5: Prices for feed-in tariffs from FY2017 to FY2019 unless otherwise specified

Renewable Energy		Prices (JPY/ kWh)	Years
Solar	Over 2 000 kW	Determined through auctions	20
	From 10 kW to 2 000 kW (for FY2017)	21 + tax ^a	20
	Less than 10 kW		
	- FY2017	28.0/30.0 ^b	10
	- FY2018	26.0/28.0	10
	- FY2019	24.0/26.0	10
	Less than 10 kW (Double generation)		
	- FY2017 and FY2018	25.0/27.0 ^b	10
	- FY2019	24.0/26.0	10
Onshore wind	Over 20 kW	22 + tax	20
	- from October 2017 to March 2018	21 + tax	20
	- FY2018	20 + tax	20
	- FY2019	19 + tax	20
	Over 20 kW (replacement)		
	- FY2017	18 + tax	20
	- FY2018	17 + tax	20
	- FY2019	16 + tax	20
	Less than 20 kW (FY2017)	55 + tax	20
Offshore wind		36 + tax	20
Hydro	From 5 000 kW to 30 000 kW (from October 2017 to FY2019)	20 + tax	20
	Facilities that utilise existing headrace (from FY2017 to FY2019)	12 + tax	20
	From 1 000 kW to 5 000 kW (from FY2017 to FY2019)	27 + tax	20
	Facilities that utilise existing headrace (from FY2017 to FY2019)	15 + tax	20
	From 200 kW to 1 000 kW	29 + tax	20
	Facilities that utilise existing headrace	21 + tax	20
	Less than 200 kW	34 + tax	20
	Facilities that utilise existing headrace	25 + tax	20

Renewable Energy		Prices (JPY/ kWh)	Years
Geothermal	Over 15 000 kW		
	- New facility	26 + tax	15
	- Replacement	20 + tax	15
	- Replacement but reusing utilising underground equipment	12 + tax	15
	Less than 15 000 kW		
	- New facility	40 + tax	15
- Replacement	30 + tax	15	
- Replacement but reusing utilising underground equipment	19 + tax	15	
Biomass	Methane fermentation gasification	39 + tax	20
	Unused woods (less than 2 000 kW)	40 + tax	20
	Unused woods (over 2 000 kW)	32 + tax	20
	General woods (from October 2017 to FY 2019)	21 + tax	20
	Waste (excluding woods)	17 + tax	20
	Recycled woods	13 + tax	20

Source: METI (2017h)

Note: a. consumption tax (8%); b. Solar PV, approved for grid connection in Hokkaido, Tohoku, Hokuriku, Chugoku, Shikoku, Kyusyu and Okinawa areas is obliged to be installed with a suppression control system. Higher purchase prices are applied to this case.

Costs incurred by the utilities in purchasing renewable energy-sourced electricity shall be transferred to all electricity customers, who will pay a surcharge for renewable energy at a rate proportional to their electricity usage. The surcharge for renewable energy has been calculated from May 2017 to March 2018 as follows (METI, 2017h):

$$\text{Surcharge for renewable energy} = \text{Monthly electricity consumption (kWh)} \times 2.64 \text{ JPY/kWh}$$

FiT rates and contract periods are to be determined according to factors such as the type of renewable power, form of installation and scale of renewable energy sources. Contract rates and periods shall be reviewed by METI and are based on the recommendations of an independent committee in the ministry.

Table 6 indicates the installed generation capacity for each renewable source of energy after the introduction of FiT (METI, 2013; METI, 2017h). Almost five years after the introduction of FiT, 105 136 MW of renewable capacity were authorised compared with the accumulated renewable capacity at the end of June 2012, that is, before the introduction of FiT of 20 600 MW. This indicates that if all the authorised capacity is installed, the generation capacity based on renewable energy is more than six times since the introduction of FiT. Non-residential solar PV has flourished in Japan. Its installed capacity and authorised capacity under the system amounts to 28 753 MW and 79 047 MW, respectively, constituting 80% of the total newly installed capacity and 75% of the authorised capacity. Biomass follows in terms of authorised capacity. The start-up renewable capacity is 35 392 MW, approximately one-third of the authorised capacity.

Table 6: Installed generation capacity by renewable energy after the introduction of FiT (MW)

	Installed capacity		Authorised capacity under FiT
	By the end of June 2012	Newly installed under FiT (July 2012–March 2017)	July 2012–March 2017
Solar (Residence)	4 700	4 745	5 492
Solar (Non-residence. More than 10 kW)	900	28 753	79 047
Wind	2 600	2 852	6 972
Medium hydro	9 600	239	1 118
Biomass	2 300	851	12 416
Geothermal	500	15	88
Total	20 600	35 392	105 136

Source: METI (2013, 2017h).

NUCLEAR ENERGY

There were 54 commercial nuclear reactors in Japan in 2010, the last year before the Fukushima Daiichi nuclear power plant accident. As of December 2017, the number of commercial reactors decreased to 40 due to the decommissioning of the Fukushima Daiichi nuclear power station⁵ and eight other reactors:⁶ Tsuruga Unit 1, Mihama Unit 1 and Unit 2, Shimane Unit 1, Genkai Unit 1, Ikata Unit 1 and Oi Unit 1 and Unit 2. Owners of the eight reactors decided on the retirements due to the aging of the facilities and the large amount of additional costs to meet the new safety regulations enforced in June 2013.

As mentioned above, 2014 was the first year without nuclear generation since its introduction. After the Oi Unit 3 and Unit 4 ceased operations for periodic inspections in September 2013, no nuclear reactors were restarted until August 2015. The Sendai nuclear power plant became the first reactor to restart under the new regulatory scheme. In October 2016, the NRA gave the final safety approval to Ikata Unit 3, Mihama Unit 3, Sendai Unit 1 and Unit 2 and Takahama Units 1 to 4. The Nuclear Regulation Authority (NRA) approved a 20-year license extension for Takahama Units 1 and 2; this was the first lifetime extension under the current regulatory scheme. However, several nuclear reactors in Japan face challenges due to the decisions made by local district courts. For example, in March 2016, the Otsu district court suspended the operation of Takahama Unit 3 and Unit 4, which were restarted in January and February 2016, respectively. In 2017, the suspension was overturned by the Osaka high court and these reactors were restarted.

Regarding the nuclear fuel cycle, Japan promotes the reprocessing process and the effective utilisation of the plutonium retrieved. Although Japan continues to maintain its nuclear fuel cycle policy, the government decided to decommission Monju, the prototype fast breeder reactor, in December 2016 due to repeated troubles. For future R&D of nuclear fuel cycle, the government is discussing alternative approaches, including cooperation with France in the ASTRID project (CAS, 2016). Despite its prolonged efforts, Japan has not yet decided the site for final disposal. To further economy-wide and regional comprehension about the final disposal site, the government published an economy-wide map of scientific features for geological disposal of high-level radioactive waste in July 2017 (METI, 2017i).

⁵ A total of six reactors. The reactor owner (Tokyo Electric Power Company) decided to decommission units 1-4 in April 2012 and units 5 and 6 in January 2014.

⁶ Except for Oi Unit 1 and Unit 2, reactor owners announced their decisions in March 2015. Decommission of the Oi Unit 1 and Unit 2 was decided by the plant owner in December 2017.

CLIMATE CHANGE

According to the Kyoto Protocol, Japan was obliged to reduce GHG emissions by 6% on average between 2008 and 2012 from the 1990 level, and the economy has exceeded this commitment by reducing emissions by 8.4%. In fact, average GHG emissions in Japan during the commitment period increased by 1.4%, from 1 261 million tonnes of CO₂ equivalent to 1 278 million tonnes of CO₂ equivalent, partly due to additional fossil fuel consumption after the earthquake and the subsequent nuclear plant shutdowns. However, the carbon sink by forest ecosystems (equivalent to a 3.9% reduction) and the Kyoto Mechanism Credit (equivalent to a 5.9% reduction) contributed to achieving the commitment level (MOE, 2014).

To generate further emission reductions, Japan introduced the Tax for Climate Change Mitigation in October 2012 (MOE, 2012). This tax is levied on crude oil/oil products, gas and coal. The tax was raised in phases in April 2014 and 2016 (Table 7); the tax value is JPY 289 per tonne CO₂ for each kind of product since April 2016. Revenue from this tax is used for implementing various measures to promote energy efficiency and renewable energy, in addition to the use of clean fossil fuels.

Table 7: Tax for the promotion of global warming countermeasures

	October 2012	April 2014	April 2016
Crude Oil/Oil Product (JPY/kL)	250	500	760
Gas (JPY/tonne)	260	520	780
Coal (JPY/tonne)	220	440	670

Source: MOE (2012).

Japan also has prefectural-level emission policies, such as emission trading schemes in Tokyo, Kyoto and Saitama. Sectoral coverage and the level of regulation vary by prefecture; Tokyo focuses on the industry and commercial sectors, while Kyoto includes transport as well. For example, the level of regulation in Tokyo is as follows: 8% and 17% reductions in commercial buildings and 6% and 15% reductions in factories in FY2010–14 and FY2015–19, respectively, from the average emissions in three consecutive years in FY2002–07.

The private sector has been working towards a low-carbon society. KEIDANREN (Japan Business Federation), which is a comprehensive economic organisation, published a voluntary action plan (KEIDANREN, 2017). The action plan comprises two phases: Phase I was published in 2013, with a focus on 2020 targets, and Phase II was published in 2015, with a focus on 2030 targets. Voluntary targets, such as CO₂ reduction, were individually formulated by 62 industries/companies in the industrial, commercial, transport and transformation sectors.

In July 2015, Japan submitted its Intended Nationally Determined Contribution (INDC) to the United Nations Framework Convention on Climate Change (UNFCCC, 2015). The economy determined its emission reduction level based on the government's Long-term Energy Supply and Demand Outlook. Japan's INDC towards its post-2020 GHG is a reduction of 26% by FY2030 compared with FY2013 (25.4% reduction compared with FY2005), equivalent to 1 042 Mt of CO₂ in 2030.

In the same month of Japan's INDC submission, a voluntary action plan was decided by 10 former general electric power companies, Japan Atomic Power Company (J-POWER) and 23 PPS. This action plan targets an emission intensity of 0.37 kgCO₂/kWh in 2030, which is consistent with Japan's Long-term Energy Supply and Demand Outlook and INDC. To support the voluntary action plan, the government amended several laws, in particular, the Energy Conservation Law (conversion efficiency standards on new fossil fuel plants: 42% for coal-fired and 50.5% for LNG-fired on a higher heating value basis) and the Act on Sophisticated Methods of Energy Supply Structure (non-fossil's share standards for retail companies: 44% in 2030) (METI, 2017a).

NOTABLE ENERGY DEVELOPMENTS

THE NEXT STRATEGIC ENERGY PLAN

In August 2017, the government began discussions for the Fifth Strategic Energy Plan at the Strategic Policy Committee of the Advisory Committee for Natural Resources and Energy (METI, 2017b). According to the METI Minister Mr Hiroshige Seko, the fifth plan is expected to retain the core directions in the fourth plan, while considering the developments in the last few years. As of January 2018, the fifth plan is under consideration.

ELECTRICITY MARKET REFORM

To ensure secure and reliable electricity supply while realising active markets, the government will open the following new markets in addition to the current wholesale market: non-fossil fuel market in FY2018 for FIT electricity, base-load market in 2019 and real-time and capacity markets in FY2020 (METI, 2017e). To encourage cost-effective electricity supply, the government will implement new operation rules for inter-regional transmission lines in FY2018 on a ‘first-come, first-served’ basis to an implicit auction system.

FINAL DISPOSAL SITE FOR HIGH-LEVEL RADIOACTIVE WASTE

As mentioned in the Nuclear Energy section, the government published an economy-wide map of scientific features for geological disposal of high-level radioactive waste in July 2017 to deepen the general public’s comprehension about the final disposal site (METI, 2017i).

THE 6TH LNG PRODUCER–CONSUMER CONFERENCE

Japan has been holding an annual LNG Producer–Consumer Conference since 2012 as a platform to exchange ideas and enhance cooperation among producers, consumers and all the key stakeholders (METI, 2017d). The 6th Conference held in October 2017 focused on the following key themes: 1) producer–consumer cooperation towards LNG markets in Asia; 2) new LNG opportunities driven by innovation; 3) LNG as a transport fuel; and 4) flexible LNG markets and spot pricing. Mr Hiroshige Seko, the METI minister, announced that Japan will contribute to expanding the LNG market in Asia through financing and human resource development. The 7th Conference will be held in Nagoya in 2018.

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USEFUL LINKS

- Agency for Natural Resources and Energy—www.enecho.meti.go.jp/en/
- Institute of Energy Economics, Japan—eneken.ieej.or.jp
- Ministry of Economy, Trade and Industry—www.meti.go.jp/english/index.html
- Ministry of the Environment—www.env.go.jp/en/index.html

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 2015. Korea's population density is very high, with an average of more than 520 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) has increased at 5.1% every year from 1990 to 2015, reaching USD 1.8 trillion (2010 USD purchasing power parity [PPP]) in 2015. GDP per capita (2010 USD PPP) income in 2015 was USD 34 206, about three times higher than 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 315 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 about 87% of its primary energy supply in 2015. 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.

Table 1: Key data and economic profile, 2015

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (km ²)	100 284	Oil (million barrels)	–
Population (million)	51	Gas (billion cubic metres)	5.7
GDP (2010 USD billion PPP)	1 745	Coal (million tonnes)	315
GDP (2010 USD PPP per capita)	34 206	Uranium (kilotonnes U)	–

Sources: ^a UN (2017); ^b EGEDA (2017); ^c EIA (2017); ^d KEEI (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Korea's total primary energy supply almost tripled between 1990 and 2015 from 93 million tonnes of oil equivalent (Mtoe) in 1990 to 273 Mtoe in 2015. In particular, from 1990 to 2000, energy supply increased at an annual average rate of 7.3%, far exceeding the economic growth rate of 6.5% for the same period. Likewise, per capita primary energy supply grew from 2.2 tonnes of oil equivalent in 1990 to 5.3 tonnes of oil equivalent in 2015. This increase was similar to that in Japan and most European economies.

In 2015, Korea's total primary energy supply was 273 Mtoe, a 1.6% increase from the supply in the previous year. In terms of energy source, oil represented the largest share (38%), followed by coal (30%) and gas (14%). The remaining 18% of the primary energy supply came from nuclear and renewable energy sources. Energy imports accounted for about a quarter of Korea's total import value in 2015.

The oil supply in 2015 was 103 Mtoe, a 6.6% increase over the previous year. In 2015, the economy imported 82% of its crude oil from the Middle East. With regard to coal, the supply in 2015 totalled 81 Mtoe, a 1.1% decrease from the previous year. 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 39 Mtoe in 2015. Its share of the primary energy supply was 14% 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 2015 was 548 terawatt-hours (TWh), a 0.4% increase from 2014. Generation by thermal sources, including coal, oil and natural gas, accounted for 68% of the total electricity generated, followed by nuclear energy source at 30% and hydropower source and others at 2%.

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	51 292	Industry sector	49 129	Total power generation	551 370
Net imports and others	237 007	Transport sector	33 410	Thermal	371 960
Total primary energy supply	272 559	Other sectors	44 331	Hydro	5 796
Coal	80 836	Non-energy	47 328	Nuclear	164 762
Oil	102 682	Final energy consumption*	126 579	Others	8 852
Gas	39 335	Coal	11 243		
Renewables	4 003	Oil	43 521		
Others	45 703	Gas	20 498		
		Renewables	2 429		
		Electricity and others	48 888		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2015 was 127 Mtoe, which was a 2.2% increase from the previous year. The industrial sector accounted for the largest share at 39%, while the transport sector accounted for 26%. The remainder (35%) 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 have increased.

By energy source, electricity and others accounted for 39% of final energy consumption, followed by oil (34%), natural gas (16%) and coal (8.9%). Natural gas consumption has increased significantly because of the economy's policy measures.

ENERGY INTENSITY ANALYSIS

The 2.8% growth of Korean GDP in 2015 resulted in a 1.2% decrease in the energy intensity of the economy's total primary energy supply. This was an economy-wide energy intensity level decrease of 1.9 tonnes of oil equivalent/million USD. With regard to final energy consumption, the energy intensity level decreased by 0.7%, from the 2014 level of 73.1 tonnes of oil equivalent/million USD to 72.5 tonnes of oil equivalent/million USD in 2015. This was mostly driven by the decreasing energy consumption in the industry sector, which had decreased 0.2% from the previous year.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	158.1	156.2	-1.2
Total final consumption	100.3	99.8	-0.5
Final energy consumption excluding non-energy	73.1	72.5	-0.7

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

In 2015, the share of modern renewable energy in final energy consumption was 1.3%, a decrease of 0.3% from the previous year. Increased use of fossil fuels and others, especially coal, combined with the expansion of traditional biomass contributed to the decrease in the share of modern renewable energy by 18% over the previous year.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	124 014	126 579	2.1
Non-renewables (fossils and others)	120 880	123 428	2.1
Traditional biomass*	1 144	1 554	36
Modern renewables*	1 990	1 597	-20
Share of modern renewables in final energy consumption (%)	1.6%	1.3%	-18%

Source: EGEDA (2017).

* 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 to 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 financed directly 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. 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 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, the privatisation of import and wholesale businesses, the stabilisation of prices and the balance of supply and consumption and the 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 to 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 was conducting 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 nine 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, the Asia-Pacific Economic Cooperation (APEC) forum, the Association of South-East Asian Nations (ASEAN)+3, the International Energy Forum and the 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. Not only is KOGAS the world's second-largest LNG buyer, 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 2015, installed capacity increased almost five-fold, from 21 gigawatts (GW) in 1990 to 103 GW in 2015.

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, 2017). If decommissioning is taken into account, this translates to about 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 that is 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 while 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 to 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 2012 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.

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 CO₂ 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:

1. A consumption management service, which collects electricity saved from buildings and factories using electricity-saving devices and sells it to the electricity trading market.
2. An integrated energy management service, which connects finance, insurance and an energy management system (EMS) and provides systems maintenance for companies.
3. An independent micro-grid, which replaces diesel generators with NRE generators and an electricity storage system (ESS).
4. Photovoltaic equipment rental, which lends photovoltaic equipment to households and receives payment through electricity gains.
5. A recharging service for electric vehicles, which provides paid recharging.
6. 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 MtCO₂ 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 basic roadmap to national GHG reduction in 2030 (Government of Korea, 2016). It provides comprehensive policy directions for expanding 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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USEFUL LINKS

Korea Electric Power Corporation—www.kepco.co.kr/eng/

Korea Energy Economics Institute—www.keei.re.kr

Korea Energy Agency—www.energy.or.kr

Korea Gas Corporation—www.kogas.or.kr

Korea National Oil Corporation—www.knoc.co.kr

Ministry of Trade, Industry and Energy—<http://english.motie.go.kr>

Ministry of Strategy and Finance—<http://english.mosf.go.kr>

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 (km²), covering 11 states and two federal territories in Peninsular Malaysia as well as two states and one federal territory on the Borneo Island (EPU, 2017). In 2015, Malaysia's population stood at 30.7 million, an increase of 1.6% over the 2014 level of 30.2 million (EGEDA, 2017).

Malaysia's gross domestic product (GDP) reached USD 752 billion (2010 USD purchasing power parity [PPP]) in 2015, an increase of 5% from USD 717 billion in 2014. The GDP increase contributed to a 3.3% improvement in GDP per capita from USD 23 706 in 2014 to USD 24 483 (EGEDA, 2017). The largest contributions to GDP were from services (54%), manufacturing (23%), agriculture (9.0%), mining and quarrying (9.1%) and construction (4.4%) (EPU, 2017). In 2015, the main export products were electrical and electronic (E&E) products (approximately 36% of the total exports), chemicals and chemical products (7.1%), petroleum products (7%) and LNG (6%) (MATRADE, 2016).

Compared with other large economies in the APEC, Malaysia's energy resources can be considered to be moderate in absolute terms. A 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 5.9 billion barrels, 37% of which is found in Peninsular Malaysia (the Malay Basin). The natural gas reserves of the economy are estimated at approximately 2.8 trillion cubic metres (tcm) or 100 trillion cubic feet (Tcf) in 2015. More than half of the reserves are found in the Sarawak Basin. The coal reserves, assessed at 1.9 billion tonnes, are located mostly in Sarawak and Sabah (EC, 2017a).

Malaysia being an equatorial economy enjoys a high irradiance level throughout the year and is well suited for harnessing solar power. Although Malaysia has a huge 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) installation 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 8,000 MW by 2050 (SEDA, 2011).

The economy also has vast 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, 2014

Key data ^{a, b}		Energy reserves ^c	
Area (km ²)	330 323	Oil (billion barrels)	5.9
Population (million)	31	Gas (trillion cubic metres)	2.8
GDP (2010 USD billion PPP)	752	Coal (million tonnes)	1 938
GDP (2010 USD PPP per capita)	24 483	Uranium (kilotonnes U)	—

Sources: ^a EPU (2017); ^b EGEDA (2017); ^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).

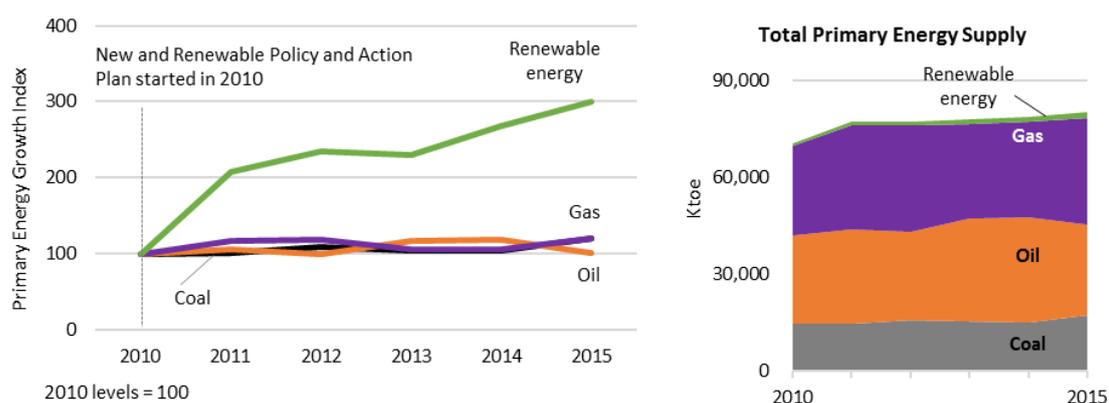
ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Malaysia's total primary energy supply was 80 104 kilotonnes of oil equivalent (ktoe) in 2015, an increase of 1.9% from the 2014 level of 78 626 ktoe. This increase is higher than 2013-14 level, which recorded only 0.8%. Gas contributed the largest share at approximately 41% (32 993 ktoe), followed by oil with 35% share (27 788 ktoe) and coal with a 22% share (17 506 ktoe). Other resources include hydro, which in 2014 provided a minimal share of 2.3% (1 816 ktoe) to the primary energy supply (EGEDA, 2017). Compared with the previous year, the 2015 primary energy supply saw major changes in Malaysia's energy mix, with natural gas overtaking oil as the largest share of primary energy. Among the primary energy sources, consumption of gas, coal and renewables increased by 15%, 13% and 12%, respectively, over the 2014–15 levels, while oil consumption decreased by 15%.

In the past six years, growth rate for renewables has shown tremendous improvement, tripling from 606 ktoe in 2010 to 1 816 ktoe in 2015. This huge increase is partly due to the New and Renewable Energy Policy and Action Plan introduced by the government in 2009, under which the Feed-in Tariff (FiT) for renewable energy was introduced (Figure 1).

Figure 1: Primary energy growth index and total primary energy supply, 2010–15



Source: EGEDA (2017) 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 exports² of 46 035 ktoe in 2015, an increase of 11% from the 2014 level of 41 414 ktoe. Most of the growth in energy exports came from the sudden increase of crude oil exports from 2 051 ktoe in 2014 to 7 696 ktoe in 2015, a level that was last seen in 2007. During the same period, total energy imports decreased by 0.4% from 38 080 ktoe to 37 927 ktoe, which happened in two consecutive years. Most of the decrease occurred in the petroleum product sector, which saw imports decrease from 16 009 ktoe in 2014 to 14 218 ktoe in 2017 (EC, 2017a).

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, 2017a). 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 662 thousand barrels per day in 2015, approximately 85% of which were crude oil while the rest were condensates. In 2014, Peninsular Malaysia yielded 40% of the total oil production, followed by Sabah (37%) and Sarawak (approximately 23%) (EC, 2017a).

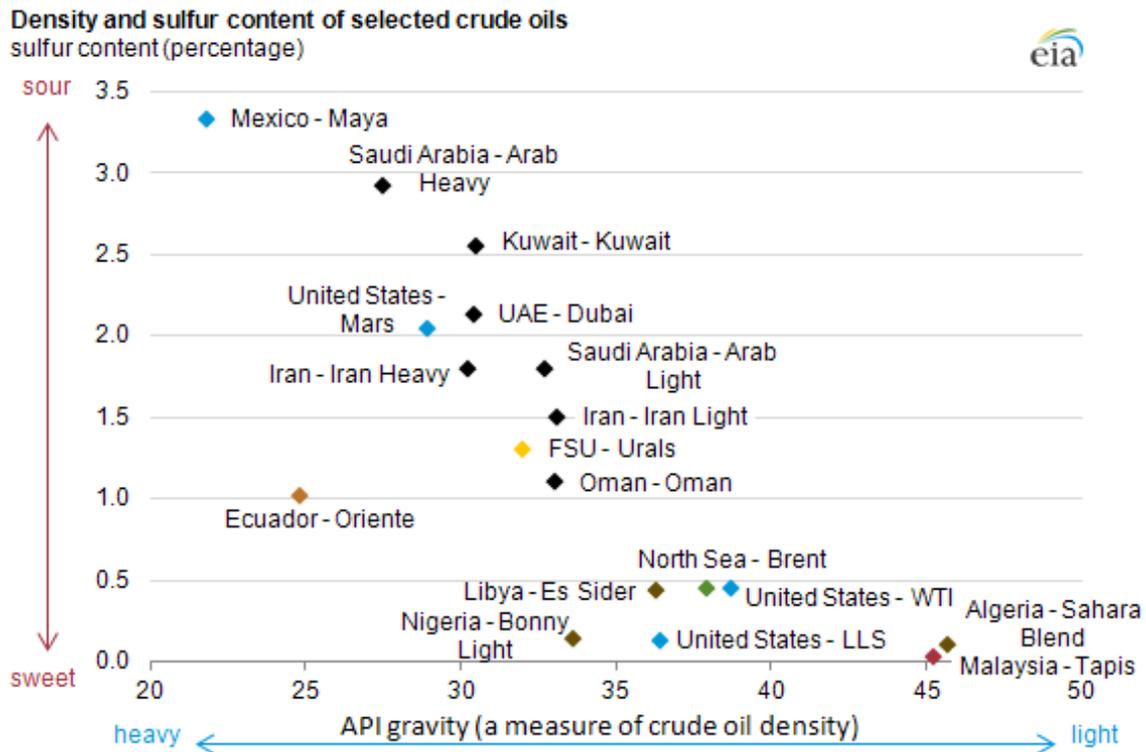
² Total energy exports/imports is equivalent to the sum of LNG and piped gas exports/imports, crude oil exports/imports, petroleum products exports/imports and coal exports/imports.

Malaysia has five oil refineries with a combined capacity of 566 thousand barrels per day (kbbbl/d) (including condensate splitter capacity). Petrolim 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 78% of total domestic sales of petroleum products in 2014 (EC, 2017a).

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 the 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).

About 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 (Figure 2) (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 Gravity³ of 42.7 and sulphur level of 0.04% (ExxonMobil, 2018).

Figure 2: Density and sulphur content of selected crude oils

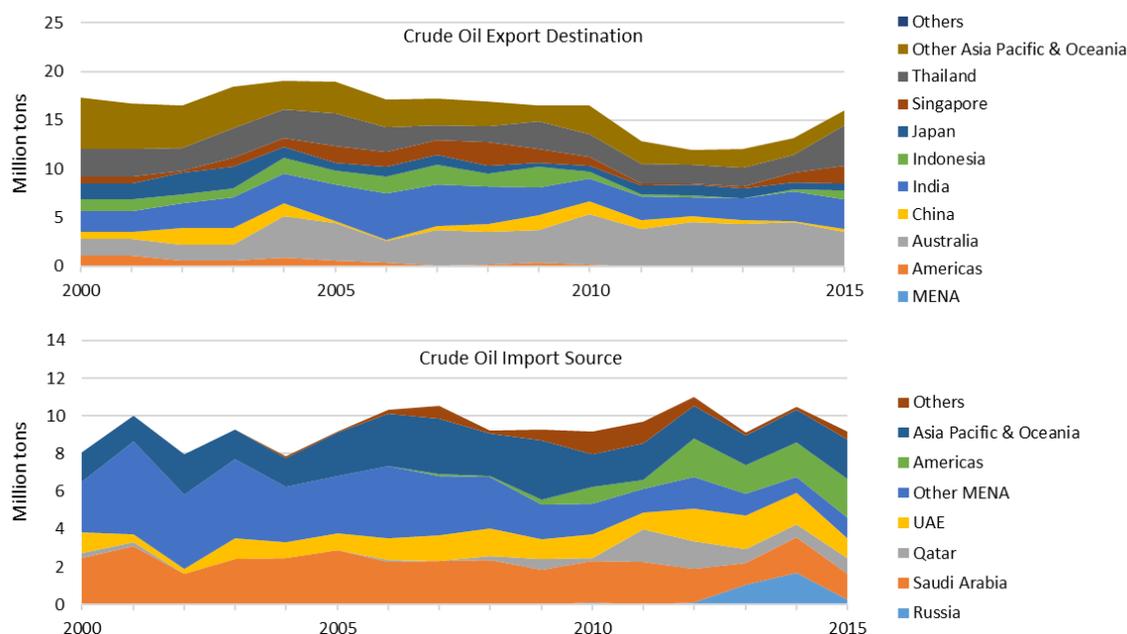


Source: EIA (2012)

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).

Based on UN Comtrade data, Malaysia's crude oil was exported mainly to Asia-Pacific economies, particularly Australia, India, China and Thailand (UN Comtrade, 2018). At the same time, Malaysia imported slightly under half of its total crude oil in 2015 from the Middle East and North Africa (MENA)⁴ region. Imports from the Americas region has been increasing since 2010, accounting for 22% of total imports in 2015, an increase from 10% of total imports in 2010 (Figure 3).

Figure 3: Crude oil export and import, 2000–15



Source: UN Comtrade (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 (86%), while the remaining reserves are associated with oil basins (14%). Sarawak hosts slightly more than half the total reserves, followed by Peninsular Malaysia (32%) and Sabah (15%). In 2015, the average daily natural gas production was 6 472 million standard cubic feet per day (MMscf/D), a decrease of 1.8% from the 2014 level of 6 593 MMscf/D (EC, 2017a). 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.

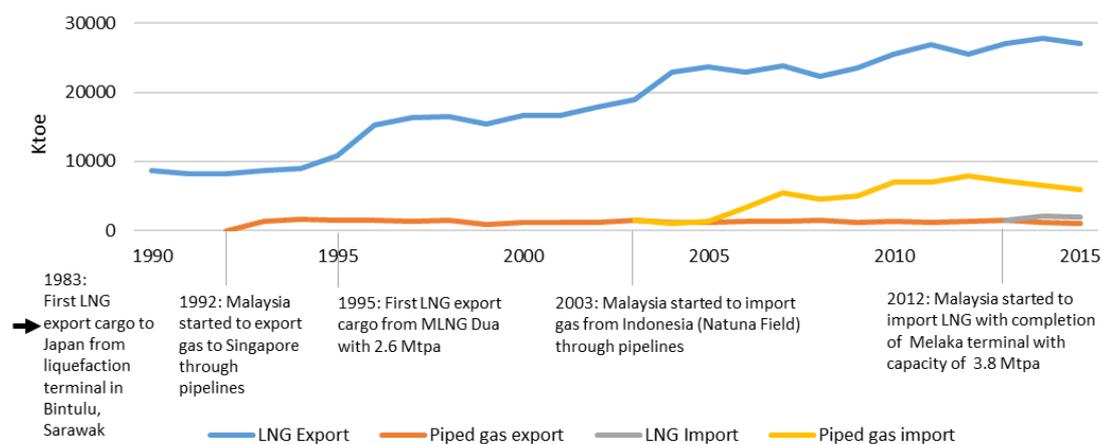
Although Malaysia is one of the world's largest LNG exporters, a geographical mismatch between where the gas is produced (Sabah and Sarawak) and the regions of highest consumption (Peninsular Malaysia) prompted Malaysia to build a LNG regasification terminal (RGT) to facilitate LNG imports. In 2015, Malaysia imported approximately 1 873 ktoe of LNG, a decrease of 7.2% from 2 019 ktoe in 2014 (EC, 2017a) (Figure 4).

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

⁴ Based on the World Bank's definition, the MENA region covers Algeria, Bahrain, Djibouti, Egypt, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Libya, Malta, Morocco, Oman, Qatar, Saudi Arabia, Syria, Tunisia, United Arab Emirates, West Bank and Gaza, and Yemen.

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).

Figure 4: Natural gas import into and exports from Malaysia, 1990–2015



Source: EC (2017a) and APERC analysis.

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. 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 1.8 million metric tonnes of production in 2015, Kapit with 0.7 million metric tonnes and Sri Aman with 25 842 metric tonnes (EC, 2017a).

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, 2017a).

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 to 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 in 2014 was recorded at 32 005 MW, an increase of 6.2% from the 2014 level of 29 953 MW. This increase in installed capacity was attributed to the additional capacity of 700 MW of the hydro project in Sarawak and an additional 1 000 MW of coal power plants in Peninsular Malaysia. Approximately 60% 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, 2016).

In the same year, total electricity generation was 150 123 gigawatt-hours (GWh), an increase of 1.8% from the 2014 level. Thermal generation, mostly from natural gas and coal, constituted 90% of total power generation, while hydropower and other fuels accounted for the remainder (EGEDA, 2017).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	94 219	Industry sector	13 728	Total power generation	150 123
Net imports and others	-11 611	Transport sector	20 900	Thermal	135 175
Total primary energy supply	80 104	Other sectors	8 448	Hydro	13 924
Coal	17 506	Non-energy	5 652	Nuclear	-
Oil	27 788	Final energy consumption*	43 076	Others	1 024
Gas	32 993	Coal	1 777		
Renewables	1 816	Oil	25 106		
Others	1	Gas	4 823		
		Renewables	0		
		Electricity and others	11 369		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2015, Malaysia's total final consumption reached 48 727 ktoe, an increase of 0.5% from the 2014 level. This marked the second consecutive year for total final energy consumption growth to be below 1%, where the growth in 2013–14 was 0.2%, although the economy grew at 6% in 2014 and 5% in 2015. The transport sector was the largest energy consumer, constituting 43% of the total final consumption, equivalent to 20 900 ktoe. It was followed by the industry sector with a 28% share or 13 728 ktoe, the non-energy sector with a 12% share or 5 652 ktoe and other sectors (residential, commercial and agriculture sectors combined) with a share of 17% or 8 448 ktoe (EGEDA, 2017).

In terms of fuel type, oil was still the most consumed fuel, particularly in the transport sector, constituting 52% of final energy consumption (excluding non-energy uses). This was followed by electricity with a 23% share, gas with a 10% share and coal with a 4% share. Oil consumption decreased by 0.7% to 25 106 ktoe in 2015 from 25 271 ktoe in 2014. However, natural gas and coal consumption increased by 3% and 4.1%, respectively (EGEDA, 2017).

ENERGY INTENSITY ANALYSIS

Malaysia's primary energy intensity decreased from 110 tonnes of oil equivalent per million USD (toe/million USD) in 2014 to 106 toe/million USD in 2015, representing a 2.9% reduction. The reduction in 2015 marked the fifth consecutive year of primary energy intensity reduction for Malaysia. Final consumption intensity also decreased at the same rate of 4.3% from 68 toe/million USD in 2014 to 65 toe/million USD in 2015. Excluding the non-energy sector, the final energy consumption intensity reduction would stand at 3.9% (EGEDA, 2017). However, based on Malaysia's National Energy Balance 2015, final energy consumption in 2015 reached 51 806 ktoe, a decrease of 0.8% from 2014 (52 210 ktoe) (EC, 2017a).

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	110	106	-2.9
Total final consumption	68	65	-4.3
Final energy consumption excl. non-energy	60	57	-3.9

Source: EGEDA (2017).

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 final energy consumption increased from 2.5% in 2014 to 2.6% in 2015. Based on year-on-year growth, modern renewables registered a 5.7% increase in final consumption.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%)
			2014 vs 2015
Final energy consumption (ktoe)	42 697	43 076	0.9
Non-renewables (Fossils and others)	41 626	41 944	0.8
Traditional biomass	0	0	0
Modern renewables	1 071	1 132	5.7
Share of modern renewables to final energy consumption (%)	2.5	2.6	4.8

Source: EGEDA (2017).

* 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 (KeTTHA, 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, 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 (KeTTHA, 2015).

In support of the Five-Fuel Diversification Policy, Malaysia launched the National Biofuel Policy in 2006 and introduced the NREPAP in 2010 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 (EPU, 2015).

The National Green Technology Policy (NGTP) was launched in 2009 as an initial step towards embracing sustainable development of the economy. The policy has four pillars, namely 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, Green Technology and Water (KeTTHA, 2017), Malaysia has introduced various programs and incentives to advocate the use of green technology in key economic sectors. The NGTP aims to facilitate the growth of the green technology industry and enhance its contribution to the national economy to 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 generation (KeTTHA, 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 (EPU, 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, KeTTHA 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 (KeTTHA, 2017).

ENERGY SECTOR STRUCTURE

The key ministries and government agencies for the Malaysian energy sector are as follows (APEREC, 2014):

- The Economic Planning Unit (EPU) 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.
- The Ministry of Energy, Green Technology and Water (KeTTHA) oversees programs and projects in strengthening energy resources to ensure electricity supply is of good quality, reliable and cost effective. It also drives the development of RE and the promotion of energy efficiency, among others. Part of the ministry's role is also to assist the EPU in formulating the energy policy.
- 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, regular supply of electricity and piped gas and reasonable prices.

Besides the key agencies listed above, other authorities involved in energy development in Malaysia are as follows:

- The Ministry of Natural Resources and Environment that oversees the overall Malaysian environmental targets as well as natural resources other than oil and gas;
- The Ministry of Plantation Industry and Commodity that oversees the biofuel development in Malaysia; and
- The Ministry of International Trade and Industry 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, namely, 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, launched in 2016, outlines the strategic approaches designed to improve energy supply security. Demand-side management (DSM), a major paradigm shift, 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. A 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).

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 power and natural gas. 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 programs;
- 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, related particularly to biofuels and public road transport (KeTTHA, 2011).

Among the policy's long-term goals is the infusion of green technology and a significant reduction of energy consumption into Malaysian culture. Malaysia has joined the global endeavour by earmarking the promotion of green technology through the establishment of the Ministry of Energy, Green Technology and Water in April 2009, which replaced the Ministry of Energy, Water and Communication. In addition, the Malaysian Energy Centre was restructured as 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)⁵ 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).

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:

- (i) SIRIM Eco Labelling by SIRIM Berhad for certifying the environmental attributes of green products and services;
- (ii) Energy Efficiency Labelling by the EC for energy-efficiency labelling of electrical appliances; and
- (iii) 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

⁵ The exchange rate is based on average daily conversion data from Bank Negara Malaysia in 2017 (BNM, 2018).

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, programs and projects for the Eleventh and Twelfth plans. Under this master plan, six areas have been identified as target areas: energy, manufacturing, transport, building, waste and water. Derived from NGTP, the GTMP lists five major strategic thrusts to foster a 'green culture' in Malaysia.

Table 5: GTMP strategic thrust

Strategic Thrust	Key Areas	Outcomes
Promotion and awareness	<ul style="list-style-type: none"> Tailored communication strategy Industry and business promotion via International Greentech and Eco Products Exhibition and other platforms. Collaboration with primary and secondary educational institutions 	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> Government Green Procurement (GGP) Green incentives Innovative financing Green cities International collaborations 	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> Capability building in the public sector Capability building in the private sector Collaboration with higher education institutions 	<ul style="list-style-type: none"> 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)	<ul style="list-style-type: none"> R&D&C funding Public-private partnership 	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> Governance (policy leadership) Policy planning Policy implementation 	<ul style="list-style-type: none"> Strengthened governance to facilitate cross-sectoral cooperation among Government bodies to improve the ease of doing business

Source: KeTTHA (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

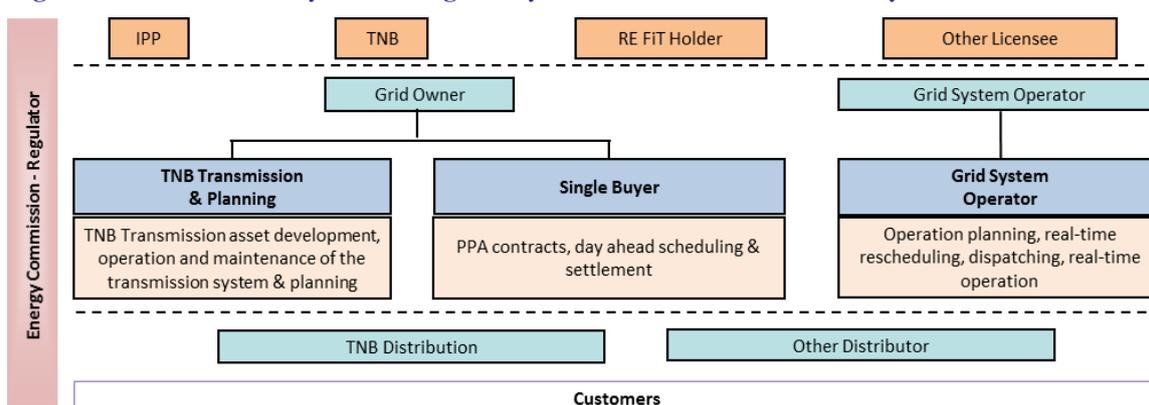
market-based prices. The intention of this approach is to unbundle energy bills to itemise subsidy values. This will eventually delink subsidies from energy use.

As part of the market reform initiative and to move towards better regulation, 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 in turn, benefit end consumers (EPU, 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 infrastructure, which is the PGU pipeline and the RGT, 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, the PGU pipeline and the 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 (EPU, 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, 2017b).

Figure 5: 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 as an oligopoly. It is vertically integrated whereby each 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 (EPU, KeTTHA 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 should encourage industry to be more energy efficient in the future. Similar electricity subsidy rationalisation is also expected to occur during 2016–20 (EPU, 2015).

The gradual reduction of the gas subsidy will eventually enable the adoption of a market price level 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, 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 (EPU, 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 EPU will initiate a study on DSM, which covers the whole spectrum of the energy sector (EPU, 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 ⁶
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

⁶ ISO 50001 is a voluntary international standard to provide organisations with a recognised framework to manage and improve their energy performance.

Households	Encourage additional appliances with minimum energy performance standards (MEPSs) and extend existing labelling programme
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Source: EPU (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 (EPU, 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 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) program, which is based on a bidding process. The total quota allocated for the LSS from 2017 to 2020 is 1 250 MW_{ac}⁷. Of this, 250 MW_{ac} was granted direct award under the fast track program 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, 2017c).

CLIMATE CHANGE

Malaysia is a signatory to the United Nations Framework Convention on Climate Change (UNFCCC) and 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 adaptation.

⁷ Unless specified, all PV capacities in this report are dc-rated.

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 programs to strengthen resilience to the potential impact of climate change. Third, to strengthen institutional and implementation capacity to harness opportunities to reduce the negative impact of climate change more effectively (NRE, 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 (EPU, 2015).

NOTABLE ENERGY DEVELOPMENTS

GREEN TECHNOLOGY MASTER PLAN LAUNCHED

Malaysia launched the GTMP in October 2017 after launching the Eighth International Greentech & Eco Products Exhibition and Conference Malaysia (IGEM, 2017). The ministry will be seeking MYR5 billion from federal funding over the next five years to develop and implement this plan. The GTMP will help the sector achieve a revenue of MYR80 billion and create more than 200 000 green jobs by 2030 (The Sun Daily, 2017).

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).

MALAYSIA ENERGY STATISTICS MOBILE APPLICATION

As a step towards a more transparent energy sector and realising the importance of energy data especially in policymaking, the EC, as the hub for energy data in Malaysia, has developed a mobile application on energy statistics. Known as 'MyEnergyStats', the application, which is the first mobile application on energy statistics in the ASEAN region, displays information on energy reserves, energy supply, energy transformation, energy consumption, energy prices, energy indicators, electricity supply performance as well as gas distribution statistics.

The application, which can be downloaded for free from the Apple Appstore and Google Playstore, was developed in 2016 and became fully operational in July 2017. Users can select their desired parameter, and the application will display the data in a tabular or graphical form (EC, 2017d).

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USEFUL LINKS

Prime Minister's Office—www.pmo.gov.my
Economic Planning Unit, Prime Minister's Department—www.epu.gov.my
Energy Commission—www.st.gov.my
Green Technology Financing Scheme—www.gtfs.my
Grid System Operator—www.gso.org.my
Malaysia Green Technology Corporation—www.greentechmalaysia.my
Malaysian Palm Oil Board—www.mpob.gov.my
Ministry of Energy, Green Technology and Water—www.kettha.gov.my
Ministry of Finance—www.treasury.gov.my
Ministry of National Resources and Environment—www.nre.gov.my
PETRONAS—www.petronas.com.my
Sabah Electricity Sdn.Bhd.—www.sesb.com.my
Sarawak Energy Berhad—www.sarawakenergy.com.my
Single Buyer Department—www.singlebuyer.com.my
Sustainable Energy Development Authority—www.seda.gov.my
Tenaga Nasional Berhad—www.tnb.com.my

MEXICO

INTRODUCTION

Mexico, officially known as the United Mexican States (*Estados Unidos Mexicanos* in Spanish), is a federal republic bordered by the United States 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 (km²). 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 125 million, the 10th most populated economy in the world. Mexico City is the capital and is one of the largest urban centres in the world. Mexico City's metropolitan area is home to more than 20 million people, with 9 million living in Mexico City proper and more than 11 million in the 60 surrounding municipalities in the states of Mexico and Hidalgo (INEGI, 2013). 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.

Several major reforms and free trade agreements introduced since the 1990s have resulted in macroeconomic stability and increased flows of foreign direct investment and the creation of a robust manufacturing industry, making it the 15th largest economy of the world with a similar size to that of Spain or Australia. Despite these milestones, the growth of the Mexican economy between 2000 and 2015 has been modest, rising little more than 2.3% annually, with real gross domestic product (GDP) in 2014 reaching USD 1 994 billion (2010 USD purchasing power parity [PPP]) (EGEDA, 2017).

The accomplishment of significant political, economic and energy reforms was expected to underpin a more robust economy, but GDP only increased by 2.6% from 2014 to 2015. Despite this growth and the implementation of social programmes to improve standards of living, the growth of Mexico's GDP on a per capita basis has been small, with an annual rate of 0.7% from 2000 to 2015 (EGEDA, 2017). In addition, by the end of 2016, around 44% of the Mexican population was deemed to be living under poverty conditions, with this share being roughly the same as in 2010 (CONEVAL, 2016).

Energy, particularly oil, is a significant component of the Mexican economy. In 2016, the value of crude oil exports represented only about 5% of Mexico's total exports, in contrast to around 11% in 2014. However, in that same year, crude oil revenue provided 36% of the government's total revenue; that share decreased to 24% in 2016. (Banxico, 2018). This reduction is mainly explained by the low oil prices and a decrease in oil production, highlighting the risks of relying on oil revenue. Moreover, Mexico has the lowest tax revenue rate as a share of GDP among the Organisation for Economic Cooperation and Development (OECD) members (OECD, 2018).

Table 1: Key data and economic profile, 2015

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (million km ²)	2	Oil (billion barrels)	8
Population (million)	125	Gas (billion cubic metres)	200
GDP (2010 USD billion PPP)	1 994	Coal (billion tonnes)	1.2
GDP (2010 USD PPP per capita)	15 842	Uranium (kilotonnes U)	6.3

Sources: ^a World Bank (2018); ^b EGEDA (2017); ^c BP (2017); ^d NEA (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2015, the total primary energy supply in Mexico was 187 366 kilotonnes of oil equivalent (ktoe), a decrease of 0.4% from 2014 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 10% (EGEDA, 2017). With an economy endowed with abundant fossil and renewable energy resources, Mexico's oil reserves stood at 8 billion barrels of crude oil (eighteenth-largest in the world) by the end of 2015, whereas gas reserves were around 200 billion cubic meters (bcm) and coal stood at 1.2 billion tonnes of coal (BP, 2017).

Mexico is a major oil producer, producing around 1.9 million barrels per day (Mbbbl/D) of crude oil in 2017, mostly the heavy type (SIE, 2018). This volume was almost 10% lower than that in 2016, mostly because of the decline in several major fields. 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 Mbbbl/D, constituting more than 60% of the total crude oil production in Mexico. However, its productivity has been decreasing steadily since then. By 2017, Cantarell produced less than 0.2 million barrels, representing only 9% of the economy-wide production (SIE, 2018).

Petróleos Mexicanos (PEMEX), the state-owned oil company, has focused its strategy on the discovery and development of new oil fields that can offset the natural decline of its major assets. Mexico is a net crude oil exporter with around half of its total indigenous crude oil production being exported, especially to the United States (SIE, 2018). Historically, Mexico has been one of the largest crude suppliers to the US, after Canada and Saudi Arabia; however, Mexican crude exports have been decreasing sharply since 2011 (EIA, 2018).

Despite Mexico's robust production of crude oil and a domestic distillation capacity of 16 Mbbbl/D in six refineries located across its territory, Mexico is a net importer of oil-based products, especially gasoline. With the increase in internal consumption and decrease in production, net exports have decreased at an average rate of 4%/ year in the last decade (PEMEX, 2017).

Mexico's significant proven natural gas reserves are under-exploited with production in 2016 reaching only 37 bcm, of which more than three-quarters were associated with the production of crude oil (SENER, 2017g). This is enough to cover around half of Mexico's growing gas consumption. As a net natural gas importer, Mexico is looking to boost domestic gas resources, including the development of its unconventional resources, such as shale gas. However, the challenges in early shale gas development and the ready availability of cost-competitive natural gas from the United States have favoured a rising volume of imports and have prevented a more accelerated domestic gas production.

By the end of 2016, the contribution of domestic gas production to the natural gas supply in Mexico amounted to 47%, much lower than the 2007 level of 81% (SENER, 2017g). Of the 53% of the natural gas imported in 2016, approximately 13% was from Liquefied Natural Gas (LNG) and 87% was from pipeline imports, all of the latter one coming from the United States. From 1999 to 2004, the US gas exports to Mexico grew from 1.7 to 11 bcm. The US exports to Mexico remained stable until 2010, when Mexico's gas production peaked and started decreasing. With domestic production plummeting and with inexpensive and competitive shale gas flowing from the US, imports to Mexico started growing almost exponentially, from around 11 bcm in that year to 43 bcm in 2016, reaching a new historical record each year. With increasing import needs and reliance on the United States, Mexico built three regasification terminals: Altamira, on the Gulf Coast and Ensenada and Manzanillo in the Pacific Coast. LNG imports have averaged 6 bcm since 2012.

COAL

In comparison to most other economies in the APEC region, coal is not as widely used in the primary energy supply of the economy representing less than 7% of the total supply in 2015, 13 654 (EGEDA, 2017). Most of Mexico's recoverable coal reserves of 1.2 billion tonnes are in the state of Coahuila in the north-eastern part of the territory, with some significant additional resources in the states of Chihuahua and Sonora in the northwest, and Oaxaca in the south.

Table 2: Energy supply and consumption, 2015

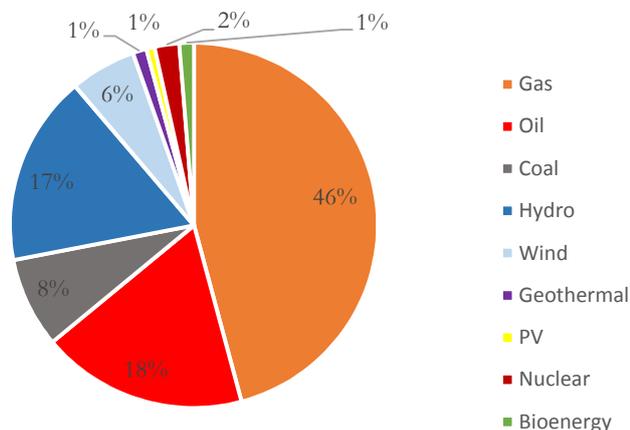
Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	191 785	Industry sector	35 352	Total power generation	311 138
Net imports and others	-1 570	Transport sector	51 096	Thermal	251 636
Total primary energy supply	187 366	Other sectors	28 035	Hydro	30 815
Coal	13 654	Non-energy	5 321	Nuclear	11 577
Oil	90 632	Final energy consumption*	114 483	Others	17 110
Gas	64 644	Coal	3 769		
Renewables	15 467	Oil	67 985		
Others	2 969	Gas	13 446		
		Renewables	7 142		
		Electricity and others	22 141		

Source: EGEDA (2017) (data collected in September 2017).

*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 311 terawatt-hours in 2015, mostly derived from thermal power plants (EGEDA, 2017) largely fuelled by natural gas. In 2015, the total installed power capacity was around 68 gigawatts (GW). This installed capacity represented an increase of almost 3 GW over the previous year level. Natural gas is the dominant fuel in power generation with 46% of the total share, followed by oil with 18%, hydropower with 17%, coal with 8%, wind with 6%, nuclear energy with 2% and other renewables with 3%.

Figure 1: Mexico's power generation capacity, 2016

Comisión Federal de Electricidad (CFE), Mexico's state-owned and largest power utility, developed the bulk of the electricity generation infrastructure and currently owns 60% of Mexico's capacity. (SENER, 2017c). However, the number of private generators has grown fast over the last two decades since reforms in the sector.

Although CFE and private generators predominantly rely on combined cycle technologies fuelled by gas, the use of renewable energy, particularly wind energy, has grown robustly, with additions of approximately 4 GW in the past 6 years. This growth is aligned with the government goals of electricity generation based on clean sources of 25% by 2018, 30% by 2021 and 35% by 2024.

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)

FINAL ENERGY CONSUMPTION

In 2015, total final consumption in Mexico reached 119 804 ktoe, an increase of 0.9% from 2014, despite a decrease in energy consumption in the most energy-intensive transport sector. By end-use, the transport sector was the largest consumer of energy (43%), followed by the industry sector (30%) and the residential, commercial and agriculture sectors combined (23%). The remaining 4% comes from feedstock for non-energy purposes. By energy source, oil-based products accounted for 59% of final energy consumption (excluding non-energy consumption); electricity and others for 19%; natural gas for 12%, renewables for 6.2% and coal for 3.3% (EGEDA, 2017). This structure has remained with the same trend since 2010.

ENERGY INTENSITY ANALYSIS

In the last 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, from 2014 to 2015, primary energy supply intensity improved more than 3%. Following the same trend, total final energy consumption intensity decreased by 1.7% compared to 2014, whereas it was only 0.7% when excluding non-energy consumption such as petro-chemistry, plastics and others.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	97	94	-3.0
Total final consumption	61	60	-1.7
Final energy consumption excl. non-energy	58	57	-0.7

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

Modern renewables consumption decreased by 7.9% from 2014 to 2015. The share of final energy consumption decreased even further as consumption of non-renewables increased by 2.5%. Traditional biomass, which decreased by 0.5% in 2015, has been in decline in Mexico; however, it retains a share of about 37% on the residential sector.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	112 381	114 483	1.9
Non-renewables (Fossils and others)	101 414	103 933	2.5
Traditional biomass*	6 068	6 038	-0.5
Modern renewables*	4 899	4 512	-7.9
Share of modern renewables to final energy consumption (%)	4.4%	3.9%	-9.6%

Source: EGEDA (2017).

* 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. The current programme, in force until 2018, aims to remove hurdles for ensuring a more vigorous energy supply and infrastructure development, foster regulatory institutions and state-owned companies. The milestone reform passed in 2013 profoundly changed the sector dynamics, introducing a new structure and institutional arrangement.

In the oil and gas industry, the Ministry of Finance determines the fiscal terms for oil and gas exploration and production contracts, whereas the National Hydrocarbons Commission (CNH) awards these contracts and authorises the working plans originating from them. Regarding exploration and production activities, SENER selects the areas to tender and designs the technical guidelines to observe. SENER is also responsible for granting permits related to oil and natural gas processing.

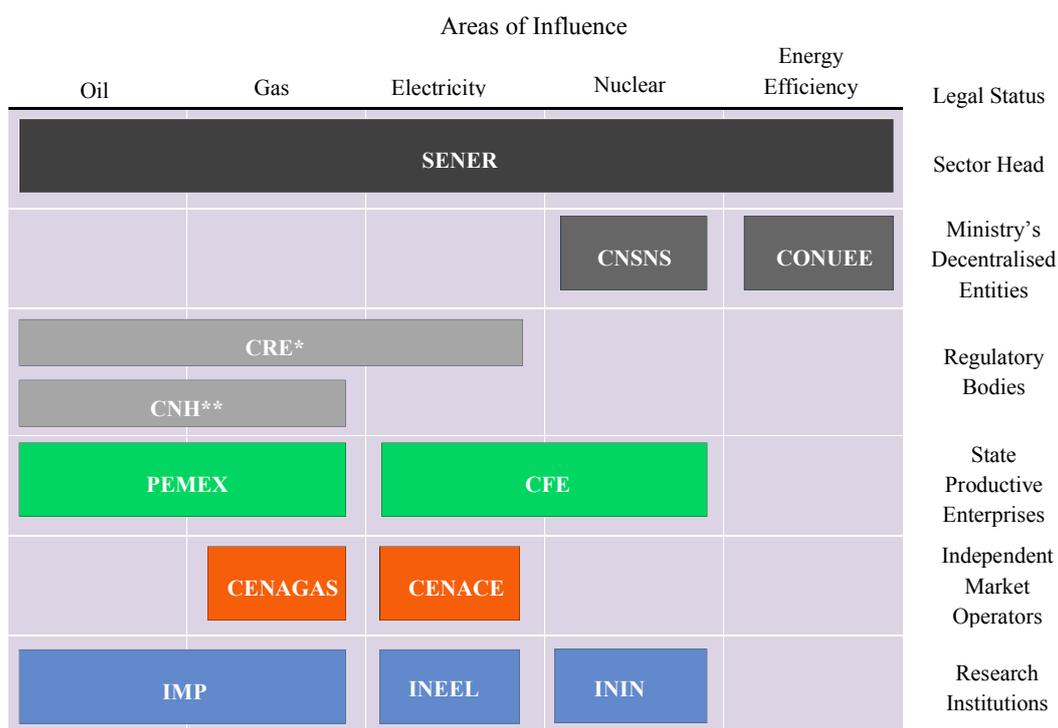
The reform reaffirmed state ownership of all hydrocarbons in the subsoil while introducing more competition in the energy sector. These changes seek to foster investment in the sector by allowing private companies to participate across the entire value chain of the oil, gas and power industries. Before the reform, most of the value chain of these industries were monopolised by the two state-owned companies: Pemex in the oil and gas sector and CFE in the power industry. With the new electricity industry framework, the private sector can participate in electricity generation and marketing activities under state regulation, except for nuclear energy. Concerning transmission and distribution, private parties may participate under contract with CFE.

As part of this transformation and with the participation of new players as well as with increasing competition in the sector, regulators had their mandates expanded and capacities strengthened. Responsibilities that used to be in the hands of the state-owned monopolies were transferred to regulatory bodies. The existing CNH and the Energy Regulatory Commission (CRE) became coordinated regulatory organisations with technical and management autonomy and budgetary self-sufficiency. The CNH is responsible for regulation in the oil and gas upstream industry and for conducting bids and administering contracts. The CRE is the regulator for hydrocarbons midstream and downstream operations and the whole electricity value chain.

Moreover, in addition to enhancing regulators, the reform created institutions such as Independent System Operators and other agencies. The National Centre for Natural Gas Control (CENAGAS) was created as the independent transmission gas pipelines 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 on 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

With the reform enacted in Mexico, international and domestic companies other than Pemex are already conducting hydrocarbon exploration and extraction activities. These contracts awarded by the CNH have been the result of eight bidding processes conducted since July 2015. In fact, some of these companies have established partnerships with Pemex for specific contracts and projects. The reform established four types of

contracts for hydrocarbons: services, profit sharing, production sharing and licenses. The last three allow the transfer of the geological and financial risks involved in the exploration and extraction activities to contractors.

The state-owned oil and gas company, Pemex, was provided with a new tax regime and a corporate management board. Pemex and CFE were re-labelled as ‘state productive enterprises’, a way to show that they now aim for maximising productivity and value creation. In 2014, a ‘Round Zero’, whereby PEMEX requested to retain certain strategic oil and gas assets prior to any public tenders for private competitors, handed over to Pemex 83% of Mexico’s 2P reserves and 21% of prospective resources.

Apart from its role of hydrocarbon upstream regulator, the CNH is also responsible for the quantification of Mexico’s oil and gas potential and geological records and for overseeing the technical issues related to upstream permits. Conversely, the CRE is responsible for hydrocarbon regulation on midstream and downstream, such as oil products transportation, distribution and commercialisation. Therefore, these institutions oversee passing from a monopolistic oil and gas regime to a competitive, market-oriented oil and gas sector.

ELECTRICITY

Since 1992, the private sector has participated in electricity generation in Mexico owing to the industry’s partial liberalisation, which allowed private companies to generate electricity. However, it had to be either sold to the state-owned power utility, CFE, or used for their own purposes. The 2013 Energy Reform also meant a deep transformation in the electricity sector, sometimes overshadowed by oil and gas industry changes.

The reform opened the generation segment to companies other than CFE and mandated its unbundling along the value chain. 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 on the expansion of the transmission and distribution grids.

The CRE’s duties span the electricity industry, including the generation, transmission, distribution, supply and rates to final consumers. The newly independent CENACE, the power grid operator, operates the wholesale power market to ensure open and non-discriminatory access to the public transmission and distribution grids. CENACE does not receive funding from the government but income from its operations.

Mexico also enacted the Energy Transition Law in 2015, which further opens the market to the private sector to improve the sustainability of the electricity system through the increased use of clean energy. The law establishes the goals for electricity clean generation: 25% by 2018, 35% by 2024 and 50% by 2050. In the law’s definition of clean generation, apart from all non-fossil fuel generation, natural gas ‘efficient cogeneration’ is included.

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).

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 drafted jointly 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, 2017f).

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. A maximum share of fossil energy in Mexico's total electricity generation was mandated at 65% by 2024, 60% by 2035 and 50% by 2050.

The 2015 Energy Transition Law overrode this law, but preserved the goals passed on December 2015. Nevertheless, the goals were largely preserved, mandating the minimum share of economy-wide electricity generation, based on clean energy (renewables, nuclear energy and others), and divided them into the following sub-goals: 25% by 2018, 30% by 2021 and 35% by 2024.

SENER calculates Mexico's renewable energy potential to be approximately about 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 an average 4.3%, solar PV increased by 34% and wind by 110%. SENER expects, from 2017 and 2031, renewable energies will grow at an annual average rate of 7.4%, reaching 41 GW of installed capacity, of which wind is expected to lead with 17 GW by 2031 (SENER, 2017d).

ENVIRONMENTAL SUSTAINABILITY

Mexico's Greenhouse gas (GHG) emissions represent 1.4% of the worldwide total (UNFCCC, 2015). Mexico issued its first specific strategy in 2000. It was the first developing economy to have a law dedicated exclusively 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; plugging and abandonment of wells and facilities; and control of polluting emissions and waste.

RESEARCH AND DEVELOPMENT

SENER, through its Vice-Ministry for Planning and Energy Transition, is responsible for fostering research and development (R&D) policies. 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 on electricity and clean energies and the National Institute for Nuclear Research (ININ) supports research and development 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, managed jointly 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 about 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

OIL AND GAS

As previously noted, 'Round Zero' resulted in PEMEX retaining 83% of the proven and probable reserves in Mexico and 21% of the prospective oil and gas resources.

During 2015 and 2016, a subsequent 'Round One' offered oil and gas resources in four consecutive tenders, in which 38 contracts were awarded for exploration and extraction in deposits located in shallow and deep waters of the Gulf of Mexico and onshore. In total, the awarded contracts represent an estimated investment of USD 41 billion (CNH, 2018). For the first time, Pemex made an association for exploration and production in deep water via farm-out with BHP Billiton for the Trion Block.

'Round Two' consisted of additional four consecutive tenders. In June 2017, the 12 winning bidders of the 10 contracts for exploration and extraction of hydrocarbons of the first tender were declared. Pemex was among the winning bidders. The assigned contracts have an associated investment of approximately USD 8.2 billion over the next 30–40 years. In July, 21 license contracts for the second and third tenders were awarded with an investment of up to USD 2 050 million expected during the life of the contracts. Finally, in January 2018, 19 contracts to 18 different companies were awarded for exploration and production of deep-water hydrocarbons in the fourth tender of 'Round Two.'

In summary, the first two 'Rounds' have concluded with promising results for the Mexican oil and gas industry. Out of the eight tenders concluded by CNH, 89 contracts for the exploration and extraction of hydrocarbons were awarded to more than 70 companies from 21 countries. As of September 2017, Mexico's net revenue from these contracts was more than USD 145 million (CNH, 2018). Moreover, some companies have already started production. Finally, the CNH already announced the first tender of 'Round Three' for shallow water scheduled for April, whereas the second tender, including for first-time unconventional resources, was scheduled for July.

In 2017, the CRE granted more permits for importing oil products as a part of the market liberalisation policy. For instance, in June 2017, private imports of diesel represented 7% of total imports of this product. However, midstream and downstream infrastructure development remains a challenge because most of it is still owned by Pemex. Consequently, Pemex still dominates the oil products market.

In September 2016, the CRE conducted the first open season for gas transport capacity in the gas network operated by the CENAGAS. In June 2017, the CRE abolished the 'first-hand fee' (*Venta de Primera Mano* or VPM) for natural gas. VPM was a price control on the first sale of natural gas that Pemex made to a third party for delivery in Mexican territory. The elimination of VPM allows suppliers other than PEMEX to offer gas volumes on a free-market basis, while creating incentives to increase domestic production.

Similarly, the CRE also started the Contract Assignment Programme, an asymmetric regulation instrument applicable to Pemex that seeks to facilitate the entry of new participants in the gas industry by gradually offering 70% of its gas supply contracts to other companies.

From 2012 to 2017, 11 new gas pipelines and around 2 400 km have been added to the national gas pipeline network, which is an increase of 21%. The expansion of the network has increased the number of stated access to natural gas. Currently, nine pipelines are still under construction; however, at least six of them face delays in their construction processes. It is estimated that by 2019 the total increase will be up to 7 444 km (SENER, 2017a).

Finally, SENER published the Second Review of the CENAGAS Five-Year Plan, in which it assessed the challenges on optimising existing gas transport infrastructure through physical interconnections between pipelines under construction and the CENAGAS managed gas pipeline network. This is particularly relevant in regards to the increasing gas imports coming from the United States, highlighting the following gas pipelines under construction, which could alleviate these requirements if they are effectively connected to the CENAGAS grid: (i) South of Texas–Tuxpan (ii) New Era and (iii) Ojinaga–El Encino (SENER, 2017e).

ELECTRICITY

The electricity sector in Mexico continues under transformation from monopoly to competitive market. As part of this changed, in March 2016, the vertical unbundling process of CFE, the state-owned electricity utility, officially started. CFE was divided into 13 subsidiaries and affiliate companies: six generation subsidiary companies, CFE Transmisión, CFE Distribución, CFE Suministro Básico, CFE Generador de Intermediación, CFE Calificados, CFENERGÍA and CFE Internacional. In 2017, all 13 CFE companies operated for the first time fully independently from each other (SENER, 2017a).

Since January 2016, the Wholesale Electricity Market operated with the start of operations of the short-term energy market. In February 2017, the balance of power market began its operations. In the Wholesale Electricity Market, 48 different participants have signed contracts with the CENACE under different figures, including 24 generators and 17 qualified suppliers. The opening of the electricity sector has meant that 83% of the 48 Wholesale Electricity Market participants are companies other than CFE (SENER, 2017a).

In addition, since March 2016, three long-term auctions have been carried out to purchase energy, capacity and clean energy certificates. Because of the first two auctions, more than 7.55 GW new clean generation capacity will be added by around 35 companies carrying out an investment of USD 9 billion. Wind and Solar PV are 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: USD 20.57 per megawatt-hour in the last auction held in November 2017 (CENACE, 2018).

Finally, as of June 2017, non-fossil fuel power generation capacity increased by almost 1 GW, around 6%, whereas clean power generation increased by 9% compared to the previous year's levels. The biggest growth was in wind capacity, which increased by 800 MW compared to that in the previous year (SENER, 2017b).

ENERGY EFFICIENCY

Mexico saved more than 3 200 GWh of energy during the first half of 2017 owing to several efficiency programmes, many of which had been implemented for a long time. Some of the programmes 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, 2017a).

In 2017, the revision and update of PRONASE 2014–2018 was published. CONUEE has developed 30 energy efficiency standards (NOMs) and a compliance evaluation system, which includes eight certification bodies, 71 testing laboratories and 205 verification units. The National Programme for Energy Management Systems (PRONASGEN), through the integration of five learning networks, is designed to strengthen managerial and technical capacities to implement Energy Management Systems in large energy consumer's facilities such as factories, office buildings and governments' headquarters (SENER, 2017a).

RENEWABLE ENERGY

As mentioned above, the Energy Transition Law, the operations of the Wholesale Market, the clean energy certificates and the transformation of the electricity sector in Mexico has brought an impressive growth on renewable energy in the past years. As of June 2017, renewable power generation capacity increased by almost 1 GW compared to that in 2016, representing around 6% of Mexico's total generation capacity. The fastest-growing renewable energy as a share of total generation capacity was solar PV with a 71% rate, whereas wind increased at 23%. (SENER, 2017b). As mentioned, the three long-term auctions will play a key role on renewable energy growth with a further increase of 7 GW already underway.

In additionally, SENER granted 21 exploration permits for geothermal resources; 13 of them were awarded to CFE in July 2015, and the remaining eight will be assigned to four private companies. It is expected that these permits will allow a 50% increase to the current installed capacity of geothermal energy in the economy (SENER, 2017a).

ENVIRONMENTAL SUSTAINABILITY

SENER issued the requirements for acquiring clean energy certificates, which fundamentally mandate users with an intensive use of electric power to prove that at least 5% of their consumption comes from clean energy sources starting in 2018. 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 (UNFCCC, 2015). Non-fossil fuel power generation and energy intensity goals mandated in the Energy Transition Law, if achieved, will impact positively on emission reduction by phasing out fossil fuels.

An oil-to-gas switch is already underway in power generation. In 2002, oil-fuelled power generation led the total share with 47%, whereas gas was only 25%. Conversely, in 2016, oil represented 16% of total power generation, whereas gas grew to 54%. Moreover, SENER expects to completely phase-out oil-fuelled power generation by 2025. Although natural gas still produces emissions, oil-fuelled power plants produce around 70% of the pollutant emissions (SENER, 2017c).

INTERNATIONAL COOPERATION

The most relevant international cooperation event in the Mexico's energy sector was its accession as the 30th member of the International Energy Agency (IEA), becoming its first member from Latin America. Mexico expressed its initial willingness to join the organisation in November 2015. In the last IEA Ministerial Meeting, held in Paris in November 2017, ministers representing the IEA's members unanimously endorsed Mexico's accession and recognised that Mexico had taken all necessary steps in record time. The Mexican Senate ratified in December 2017 the accession agreement and Mexico became an official member on 17 February 2018.

SENER promoted bilateral strategic cooperation initiatives with several economies across diverse energy topics. These economies were Canada, Cuba, the Dominican Republic, Guatemala, the United States and Venezuela in the Americas; Austria, Denmark, Finland, Germany, Italy, the Netherlands, Norway and the United Kingdom in Europe; China, India, Japan, Saudi Arabia and the United Arab Emirates in Asia.

On a multilateral level, Mexico participated in and led several dialogues, mainly through SENER. This collaboration included several multilateral organisations such as the United Nations, the IEA, the International Atomic Energy Agency (IAEA), the Nuclear Energy Agency (NEA), the International Renewable Energy Agency (IRENA), the International Energy Forum (IEF), the Organisation of the Petroleum Exporting Countries (OPEC), the Latin-American Organisation (OLADE), the Clean Energy Ministerial, the G20 and Asia Pacific Economic Cooperation Forum (APEC) (SENER, 2017a).

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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.iiie.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 between that of Japan and the United Kingdom, its low population of about 4.6 million is comparable to that of a medium-sized Asian city. Due to its remote location, New Zealand has no electricity or pipeline connections to other economies. The economy has a mature economy with a per capita gross domestic product (GDP) of about USD 33 584 (2010 USD purchasing power parity [PPP]) in 2015.

New Zealand is self-sufficient in all energy forms except oil. It has a vast renewable energy potential, which in 2015 accounted for 80% of electricity generation, largely from hydro, but with increasing support from geothermal and wind. Fossil energy proven and probable (2P) reserves are more modest, including 510 petajoules (PJ) of oil and liquefied petroleum gas (LPG), 50 billion cubic meters (bcm) of natural gas, and the BP Statistical Review (2017) estimated coal reserves at 7.6 billion tonnes at the end of 2016 (BP, 2017; MBIE, 2017a).

Table 1: Key data and economic profile, 2015

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (km ²)	269 652	Oil (PJ)	510
Population (million)	4.6	Gas (billion cubic metres)	50
GDP (2010 USD billion PPP)	154	Coal (billion tonnes)	7.6
GDP (2010 USD PPP per capita)	33 584	Uranium (kilotonnes U)	–

Sources: ^a World Bank (2017); ^b EGEDA (2017); ^c MBIE (2017); ^d BP (2017).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2015, New Zealand's total primary energy supply (TPES) was 20 589 kilotonnes of oil equivalent (ktoe), a 0.7% increase from the previous year. Renewable energy (geothermal, wind, solar and others) was the major contributor to TPES (41%), followed by oil (33%), gas (20%) and coal (7%). The slow growth is the result of the increase in oil and renewables (3.9% and 2.6%) being balanced by decreases in gas and coal (6.9% and 2.1%). As geothermal electricity generation only has an efficiency of 13% in New Zealand (MBIE, 2016), the geothermal share of total final energy consumption is significantly smaller than TPES share. New Zealand's energy self-sufficiency (indigenous production/primary energy supply) in 2015 was 80%, 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, 2017).

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 2015, coal production dropped by 17% after the 15% decrease in 2014 on an energy-equivalent basis compared to 2013 as domestic producers struggle to compete with low coal prices (MBIE, 2017a).

Oil is sourced from 19 fields in the Taranaki region in the North Island (MBIE, 2016). The production of crude oil, natural gas liquids and condensate increased by 3.8% on an energy-equivalent basis in 2015 compared to 2014 as the Maari field redevelopment increased production. However, the longer-term trend is for a continuous decrease characteristic of the depleting fields, and will continue unless new fields are discovered and brought on stream (MBIE, 2017). 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, 2015). 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 around 32% of the domestic oil consumption in 2015.

Natural gas is sourced from 17 fields currently in production, although 86% of production comes from just four (MBIE, 2016). In 2015, natural gas production decreased by 8%, compared to 2014, as improved recovery techniques were applied to the ageing Maui gas field and a major expansion of the Mangahewa field (MBIE, 2015). The largest uses for gas are industrial heat, electricity generation and in 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 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, but geothermal heat is used directly 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 2015, New Zealand generated 44 148 GWh of electricity, a 1.5% increase from 2014 (EGEDA, 2017). Hydro is the major source of electricity generation, accounting for 56% of total generation in 2015. Geothermal generation accounted for 18% (EGEDA, 2017). 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, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	16 503	Industry sector	4 341	Total power generation	44 148
Net imports and others	4 872	Transport sector	4 815	Thermal	8 748
Total primary energy supply	20 589	Other sectors	3 511	Hydro	24 535
Coal	1 367	Non-energy	1 415	Nuclear	0
Oil	6 767	Final energy consumption*	12 666	Others	10 865
Gas	4 088	Coal	607		
Renewables	8 366	Oil	5 876		
Others	1	Gas	1 614		
		Renewables	1 204		
		Electricity and others	3 365		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2015, New Zealand's total final consumption was 14 082 ktoe, a 0.8% reduction from 2014. This decrease is due to a reduction in gas demand (both for energy and non-energy uses) from the methanol manufacturing industry due to an increased number of shutdowns during 2015 (MBIE, 2016). This reduction in the industry sector, however, masks a significant increase in the transport sector (4.1%) and a modest increase from other sectors (1.1%) (including residential, commercial and agricultural). The largest consumption sector was transport with 34% of total demand, while the industry sector decreased to 31% and the other sector remained stable at 25%; the remaining 10% was used for non-energy purposes. Oil was the largest component of final energy consumption with 5 876 ktoe (46%), followed by electricity and others at 3 365 ktoe (27%), gas at 1 614 ktoe (13%) and coal at 607 ktoe (5%) (EGEDA, 2017).

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, one cement plant, several pulp and paper mills and a very 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 4% in 2015. This is a significant development following several years of a relatively flat trend. 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 82% of domestic oil consumption in 2015. Consumption of oil products in the other sectors was shared among the residential, commercial and agricultural sectors (11%) and the industrial sector (7%). 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 2015 was 133 tonnes of oil equivalent per million USD (toe/million USD), a decrease of 1.7% from 136 toe/million USD in 2014. This is largely due to the reduction in gas for non-energy use discussed earlier and offsets the intensity growth posed by the increase in the transport sector. Similarly, the final energy consumption intensity decreased by 3.1% to 91 toe/million USD.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	136	133	-1.7
Total final consumption	94	91	-3.1
Final energy consumption excl. non-energy	83	82	-1.6

Source: EGEDA (2017).

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 2015, the total share of renewable energy increased to 29.6%, an increase of 1.6% over the 2014 share (29.1%). This is largely due to an increase in renewable electricity generation and all other modern renewables of 2.4% in 2015 from 2014.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	12 566	12 666	0.8
Non-renewables (Fossils and others)	8 751	8 764	0.1
Traditional biomass*	153	153	0.0
Modern renewables*	3 662	3 749	2.4
Share of modern renewables to final energy consumption (%)	29	30	1.6

Source: EGEDA (2017).

* 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 Business, Innovation and Employment (MBIE) was established in July 2012 through the merger of four government ministries: the Ministry of Science and Innovation, the Ministry of Economic Development (formerly responsible for energy policy), the Department of Labour and the Department of Building and Housing. The merger was part of a broader effort to simplify government departments, enhance performance and reduce government spending. MBIE is responsible for developing New Zealand's energy policies and strategies with assistance from several agencies, and reports to the Minister of Energy and Resources.

New Zealand's oil and gas exploration and production activities are privately owned and open to competition. In April 2018, the Government announced that there would be no new offshore oil and gas exploration permits issued, but that the 31 oil and gas exploration permits that are currently active (22 of which are offshore) would be honoured. Oil and gas development shows a mixed international ownership, including New Zealand companies, major international oil companies and Japanese industrial/energy concerns.

Electricity generation and retailing are also open to competition and there are over 30 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 generator-retail companies have some state-ownership, which 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, 2018). 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 and its assets sold to pay creditors. The assets were sold to private sector interests, effectively ending the direct involvement of government in the industry (Otago Daily Times, 2017).

The New Zealand Energy Efficiency and Conservation Strategy 2017–22 (NZEECS) 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, titled “Unlocking our energy productivity and renewable potential” has the goal of New Zealand having an energy productive and low emissions 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-emissions transport, and innovative and efficient use of electricity.

In October 2017, following the surprising general election result, a new government came into power with more ambitious climate change policies, such as setting a target of net zero carbon emissions by 2050, establishing an independent Climate Commission to recommend targets and actions and strengthening the emissions trading scheme. This will have some impact on energy markets policy.

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 corporatized or privatised and the electricity market was deregulated.

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 (MED, 2009) 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 these agencies, 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, and to make improvements in security of supply, a fund to encourage customers to switch electricity providers and 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 the requirement 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 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, or an accounting profits royalty of 15% on the first NZD 750 million for offshore projects, or 15% on the first ANZD 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 has good oil and gas resource potential but the economy is considered underexplored (Ralph Samuelson, 2008). Responding to this challenge, the government has developed an action plan for realising the potential of New Zealand's petroleum resources. The Action Plan for the Development of Petroleum Resources, released in November 2009 and updated periodically, aims to ensure that New Zealand is considered an attractive destination for investment in petroleum exploration and production. The plan has several work streams, including

- Reviewing the fiscal and royalty framework to ensure that the government receives a fair return from petroleum resources while providing sufficient incentives for investors;
- Investing in data acquisition to improve resource knowledge and foster more investment, particularly in frontier resources and
- Developing a fit-for-purpose legislative framework for the petroleum sector (MBIE, 2012; NZG, 2010b).

In August 2011, the government announced a new approach for allocating petroleum exploration rights. Previously, New Zealand primarily used a 'first-in, first-served' priority-in-time allocation scheme. Under the new scheme, the government will announce 'block offers' for specific acreage and invite competitive bids to develop them. The goal of this change is to attract significant additional investment to New Zealand while providing the government with more control over where, when and to whom exploration rights are granted (NZP&M, 2014).

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 includes essentially all energy development projects. Resource consents are generally obtained from regional, district or city councils, depending on the nature of the resources affected. 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 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 RMA was completed. This phase of RMA has taken over 5 years to complete as it was looking comprehensively 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 local government level to follow the established 'national direction' handed down by 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 Energy Efficiency and Conservation Authority (EECA) to spearhead the strategy's implementation (EECA, 2012a).

In August 2017, the government released the latest New Zealand Energy Efficiency and Conservation Strategy 2017–22 (NZE ECS) 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. NZE ECS 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:

1. 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.
2. Area 2: Efficient and low carbon transport. Target 2: Electric vehicles make up 2% of the vehicle fleet by the end of 2021.
3. Area 3: Innovative and efficient use of electricity. Target 3: 90% of the electricity will come from renewable sources by 2025 (MBIE, 2017b).

Some of New Zealand's major policies for promoting energy efficiency are as follows:

- In May 2016, an electric vehicle support program was announced, which involved road user tax exemptions, government/private bulk purchasing programs 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 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 program called Warm Up New Zealand has delivered insulation retrofits for more than 300,000 homes since 2009. As per the Labour Party's election manifesto, the Government intends to introduce a new grant scheme for subsidised insulation and heating retrofits. 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 program. This initiative is coordinated with Australia to have a robust mechanism for both economies (EECA, 2017).

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 the 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. The New Zealand Government is also in the process of setting up the independent Climate Change Commission, whose work will include how we transition towards 100 per cent 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).

Hydro power 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 for 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, EECA has been promoting the conversion of medium-scale industrial or commercial boilers to biomass through the use of denser, and 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, not just as a form of demand but also as a source of electricity storage from intermittent renewable electricity generation, enabling further integration of wind and solar to the electricity grid.

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. It has announced plans to introduce a new Zero Carbon Bill later in 2018 which will seek to set a new emissions reduction target by 2050 and establish an independent Climate Change Commission. In the meantime, an Interim Climate Change Committee will be set up early in 2018 to progress key issues for climate change policy 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 law.

The Government has stated that its goal is for New Zealand to be a net zero emissions economy by 2050. Under the Paris Agreement, New Zealand has an existing target to reduce greenhouse gas emissions by 11 percent below 1990 levels by 2030.

The key climate change intervention is the Climate Change Response (Emissions Trading) Amendment Act of 2008, which established New Zealand's emissions 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 (MFE, 2017b):

- 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

In 2014, the New Zealand Government completed the partial privatisation of the three large state-owned energy utilities by selling 49% of each company. This raised NZD 4.7 billion, lower than expected by government. The funds raised from this were promised to be reinvested in education and infrastructure but so far this promised has yet to be realized (RadioNZ, 2015)

The electricity sector is grappling with uncertainty on both the demand side from large industrial electric consumers and supply side through the possible closure of Huntly power station (the only coal plant) and the recent unexpected closure of gas generation. New Zealand's second-largest electricity consumer, a paper mill, reduced the output by half and there are concerns about the profitability of the Tiwai Point Aluminium Smelter (TPAS), which accounted for 12% of New Zealand's total electricity demand in 2014 (MBIE, 2015). The New Zealand Government supplied a short-term NZD 30 million one-off subsidy to ensure that the plant continues to operate for the next few years (NZAS, 2013). However, its long-term future is uncertain as is the capacity at which TPAS will be able to operate over the medium term.

On the supply side, the 2015 closure of nearly 600 MW of natural gas generation due to a stagnant market and the slated retirement of 500 MW of coal generation by 2018 are 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 completion of the Te Mihi geothermal plant of 166 MW and the Mill Creek wind farm of 60 MW, which were both completed in 2014.

Another development includes the deployment of smart metering devices throughout the market. By the end of 2015, over 70% of all households had smart meters installed (EA, 2016). The key driver resides in operational savings for electricity retailers in terms of not having to employ meter readers and control of 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, etc. (MBIE, 2014).

NEW PROJECTS

Since the 2014 project mentioned above, no new generation projects have undergone construction. There are, however, several large-scale wind, geothermal and hydro projects that have regulatory and environmental consent to proceed, but utility companies have stated that they are unlikely to develop any new large-scale project for the next several years owing to the current market's oversupply of capacity and tepid electricity demand growth. With continued improvement in the energy intensity demand, growth may be much slower in the medium to long term than seen historically.

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); the North Island grid upgrade project (completed in 2012); the 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 that 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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USEFUL LINKS

Climate Change Information, Ministry for the Environment—www.climatechange.govt.nz

Electricity Authority—www.ea.govt.nz/

Energy Efficiency and Conservation Authority (EECA)—www.eeca.govt.nz

Environmental Protection Authority—www.epa.govt.nz/Pages/default.aspx

Ministry of Business Innovation and Employment (MBIE)—<http://www.mbie.govt.nz/info-services/sectors-industries/energy>
New Zealand Government (portal for access to New Zealand government agencies and government-funded websites)—www.newzealand.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/cms

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 (km²) 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' that frequently faces earthquakes, volcanic eruptions and even tsunamis. In fact, on 5 January 2018, a volcano on the remote island of Kadovar, located about 24 kilometres (km) north of the Papuan mainland, began erupting. Amidst the mountainous terrains, tropical rainforests and scattered small islands lie the economy's rich natural resources dominated by gold, copper, oil, gas, and also 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 7.92 million-strong population in 2015 (EGEDA, 2017), almost 40% was below 15. PNG is one of the most culturally diverse countries in the world with a representation of 'thousands of different tribes, dances, adventures, and traditions and over 800 indigenous languages spoken, more than anywhere else in the world'. PNG's population lives mostly in the rural areas; only about 18% of the population lives in urban centres. The population density is also low, at about 18 people per km² (World Bank, 2017a).

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 2015, posting an annual average gross domestic product (GDP) growth rate of 7.8% (at 2010 prices and 2010 purchasing power parity [PPP]) (EGEDA, 2017). This was because of a significant resources 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 2015, PNG's real GDP was estimated at USD 21.18 billion (2010 USD PPP), an increase of 6.3% from 2014. 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 2015 was the lowest among the Asia-Pacific Economic Cooperation (APEC) member economies, at USD 2 674 (2010 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, the Non-Aligned Movement, the Pacific Community, the Pacific Islands Forum, the United Nations and the World Trade Organization (The Commonwealth, 2017).

Table 1: Key data and economic profile, 2015

Key data ^a		Energy reserves (end 2015) ^b	
Area (km ²)	462 840	Oil (million barrels)	159.4 (2017 est)
Population (million)	7.9	Gas (billion cubic metres)	141.5 (2017 est)
GDP (2010 USD billion [PPP])	21.2	Coal (million tonnes)	—
GDP (2010 USD PPP per capita)	2 674	Uranium (kilotonnes U)	—

Sources: ^a EGEDA (2017); ^b CIA (2016)

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

2015 saw a remarkable increase in PNG's primary energy supply. From the 2014 levels of 2 615 million tonnes of oil equivalent (Mtoe), primary energy supply surged by almost 50% to reach 3 833 Mtoe in 2015. This was mainly because of the more than fivefold increase in the gas supply of 283 Mtoe in 2014. Of the total supply, crude oil and petroleum products maintained the largest share in 2015 (49%), although this was more than a 30% reduction from the 2014 level (72%). Gas was the second-largest fuel source and its share increased to 39% in 2015 from just 10% in 2014. The remaining share (12%) was attributed to other energy sources such as hydro and renewables (EGEDA, 2017). Information on coal and uranium reserves have not been recorded as the economy is not rich in nor has it touched upon these resources. There are investigations though indicating 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 programs 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 estimated at 55 990 bbl/d (CIA, 2016). As there no reports of new oil discoveries, the existing oil reserves are depleting rapidly and are expected to dry up in the 2020s (APEREC, 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 (m³) 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 4 million tonnes per annum (MTPA) LNG trains. In addition, subject to 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 nine Tcf of gas is expected to be produced (PNG LNG, 2014).

In 2015, PNG generated 4 324 gigawatt-hours (GWh) of electricity, a 3.6% increase from 2014, which is also the compounded annual growth rate (CAGR) since 2010. Thermal generation, sourced mainly from diesel, contributed the largest share (67%), followed by hydro (23%) and others (10%) (Table 2, EGEDA, 2017). Power generation from renewables, sourced mainly from hydro and geothermal, accounted for 33% of total power generation in 2015. 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 the 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 (APEREC, 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, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	10 098	Industry sector	711	Total power generation	4 324
Net imports and others	-6 249	Transport sector	637	Thermal	2 890
Total primary energy supply	3 833	Other sectors	239	Hydro	1 012
Coal	0	Non-energy	0	Nuclear	—
Oil	1 894	Final energy consumption*	1 587	Others	422
Gas	1 489	Coal	0		
Renewables	450	Oil	1 253		
Others	0	Gas	0		
		Renewables	0		
		Electricity and others	334		

Source: EGEDA (2017) (data collected in September 2017).

* 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 to 2014, total final energy consumption in PNG in 2015 increased by 5.2% to reach 1 587 kilotonnes of oil equivalent (ktoe). The industrial sector remained the largest energy user, accounting for 45% of the total, followed by the transport sector with 40%. In terms of growth, however, transport consumption (8.4%) surged faster than industry consumption (7.2%) in 2015. The other sectors, including agriculture and residential/commercial, constituted 15% of the total and posted a negative change of 7.6% from the previous year's consumption levels. 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 remained roughly the same for the past four years (EGEDA, 2017).

As electrification remains limited to the main urban areas, 85% of the population that lives in rural areas relies largely 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 USA, prepared the National Electrification Rollout Plan whose target is 70% household electrification access by 2030 (APEREC, 2017). Electricity consumption will increase significantly as these projects develop.

The transport sector faces a similar infrastructure challenge with road services generally limited to the main centres while intercity roads are 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 2015, transport consumption grew by 8.4% from the 2014 level to reach 637 ktoe.

Petroleum products such as diesel, petrol and heavy fuel oil are used in the transport and electricity generation sectors. 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 may be mainly 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 affected significantly by individual events or trends and can be volatile. Primary energy intensity in 2015 posted a huge increase of 37.8% over the previous year's intensity level of 131 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.

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 2015 was estimated at 75 toe/million USD. This translated to a 1.1% improvement over the 2014 energy intensity level of 76 toe/million USD (see Table 3).

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	131	181	37.8
Total final consumption	76	75	-1.1
Final energy consumption excl. non-energy uses	76	75	-1.1

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

There are no data available on renewable consumption in PNG. However, the economy relies largely on biomass for cooking and lighting in the residential sector as 87% of its population lacks access to electricity. Nevertheless, a total of 111 ktoe of modern renewables were estimated to be consumed in 2015, which was about 7% of the total final energy consumption. This share was 3.2% lower than the modern renewables consumption in 2014, but in terms of absolute values, it had increased 1.8%.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	1 509	1 587	5.2
Non-renewables (Fossils and others)	1 400	1 476	5.4
Traditional biomass*	0	0	0
Modern renewables*	109	111	1.8
Share of modern renewables in final energy consumption (%)	7.2%	7.0%	-3.2%

Source: EGEDA (2017)

* 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 a 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 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 programs 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 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

Re-elected Prime Minister Peter O'Neill will lead the reorganisation of the DPE. Simultaneously, the government will review the Mining and Petroleum Act in full consultation with PNG's stakeholders, such as the Foreign Investors and Resource Owners. This is to ensure that the benefits prescribed in Project Agreements with regard to royalties and infrastructure grants are fully realised.

As mentioned above, the DPE structure will follow that of the Mineral Resources Authority. 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. With regard to energy, the government will fund and implement the Rural Electrification Policy. This will entail the promotion of green energy systems, including solar, wind, hydro, bio-fuel and geothermal energy. In this regard, the government will introduce a zero-tax policy for these items (Government of PNG, 2018a)

The government's long-term vision is outlined in the national development framework called Vision 2050. While this vision aims to create institutions that will equitably distribute resources and opportunities by 2050, it will be less reliant on the mining and energy sectors but will 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:

- 100% electricity generation from renewable and sustainable sources by 2050
- Reducing greenhouse gas (GHG) emissions by 90% from the 1990 levels

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 the National Energy Policy

(NEP), 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. However, significantly, the NEP with its accompanying plan launched in 2015 was the first governmental document to properly coordinate all energy development issues, in alignment with Vision 2050.

The NEP has been reviewed by all stakeholders and is being revised for submission to the National Executive Council (NEC, the cabinet). This will be deliberated by the NEC and Parliament, before being passed by the end of 2017. The NEP focuses on four aspects of sustainable development—social, economic, environment and energy security—and incorporates the following nine principles:

- Strengthening institutional capacity and recruiting the right human capital to manage the energy sector;
- 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.

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 USA, prepared the National Electrification Rollout Plan (NEROP) which targets 70% household electrification access (). It details the program to achieve this target (75% by grid and 25% off-grid) by 2030 (APEREC, 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 Independent Consumer and Competition Commission (ICCC): (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 (APEREC, 2017).

The Act also authorised ICCC as the technical regulator of the electricity and petroleum sector and put it in charge of determining standards, conducting inspections and controlling applications for all matters relating to the operations of electricity supply. The ICCC was established in 2002 to oversee and regulate price and service-standard issues relating to utilities, such as PPL and selected corporatised government statutory entities. This made it responsible for setting prices or tariffs for electricity and petroleum products. PPL was also corporatised under the Electricity Commission (Privatisation) Act 2002.

Lacking the technical capacity to perform this regulatory role, the ICCC outsourced this role to PPL on a contractual basis for an initial period of two years, ending in 2005. 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 Papua New Guinea, 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 IPBC) was formed by the Government of Papua New Guinea 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), the Karimui Hydro Dam Study (1 800 MW) completed in January 2016, the POM IPP Project, the Port Moresby Transmission Upgrade Project and the 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 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 (APEREC, 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 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 (EE).

The NEP mentioned above, meanwhile, indicates some principles relating to the promotion of EE, among others (APEREC, 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 EE and conservation measures and wise use of energy.

- (a) Draft and enforce an EE Policy within one year of National Energy Authority's creation
- (b) Promote EE 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 programs in all sectors of the economy.

There have also been efforts made by other international agencies to gather information on EE indicators. For example, in 2014, the Asian Development Bank (ADB) funded the Promoting Energy Efficiency in the Pacific (phase 2) project conducted by International Institute for Energy Conservation. Through this project, several activities were conducted in the Pacific to improve EE, including lighting, solar power generation, EE 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 EE performance of the appliances surveyed in the project were indicative of the manufacturer, as these were imported mostly 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 programs relating to renewable energy (RE) 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 National Electrification Roll Out Plan) (APEREC, 2017).

The StaRS seeks to increase the RE-based power capacity of the economy to 100% by 2050. It indicates several plans to achieve this target, including the following pointers (StaRS, 2014):

- Inclusive Green Growth Policy Instruments to tap specific opportunities within spatial and resources systems;
- Green Energy Investment Frameworks and Incentives, requiring 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 RE-based capacity for power generation. Specifically, it intends to deliver the following pointers (APEREC, 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 biomass power to the Ramu grid by 2030 and another 34 MW by 2050;
- To add 30 MW wind power capacity to the POM and Ramu grids by 2030 and another 20 MW by 2050;
- To have new 65 MW solar power capacities by 2030 and pursue the achievement of another 35 MW by 2050; and
- To develop the first 5 MW 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 hydropower and 4 000 MW 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.

In 2016, PPL and the International Financing Corporation started to pursue rooftop solar projects to produce electricity (PNGfacts, 2016), which was expected to reduce dependency on fossil fuels in the long term.

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 Convention 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 reduce GHG emissions significantly 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 demonstrated the determination of the PNG government to reduce GHG emissions (APEREC, 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). A 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).

ENERGY WORKING GROUP (EWG) MATTERS

There was no PNG representative in the EWG 54 Meeting held in November 2017, but Ms Kiage from the Department of Public Enterprises reported via phone patch the following current developments in PNG:

- PNG wishes to include energy access as one of the priority agendas of APEC EWG;
- Preparations are underway for PNG to host the APEC Ministerial Meeting in November 2018; and
- PNG acknowledges the recommendations made by the peer review team during the conduct of PRLCE) in August 2017.

RENEWABLE ENERGY DEVELOPMENT AND RURAL ELECTRIFICATION

PNG Power Ltd is the main agency responsible for rural electrification in PNG. The O'Neill Government will fund and implement the Rural Electrification Policy that entails promoting the use of green energy systems including solar, wind, hydro, biofuel and geothermal energy. Accordingly, the Government will introduce a zero-tax policy for these items.

As mentioned above, 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):

- 75% of the population will be electrified by grid, while the remaining 25% will be electrified via off-grid electrification by 2030;
- USD 150 million will be required to electrify 70% of the households by 2030; the cost of grid connection will vary from USD 40 million to USD 115 million;
- Funding for this program 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 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 NEROP, a total of 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

PNG will be hosting the Asia Pacific Forum for the first time in November 2018. PNG stands to benefit from being in the global spotlight when it hosts this forum, with an anticipated boost in investment, tourism and trade.

In preparation for this, the Australian High Commission and the Papua New Guinea APEC Secretariat hosted a forum through the Pacific Leadership and Governance Precinct. This forum aims to raise awareness of the opportunities that APEC would present in 2018, following the APEC Policy Development Dialogue between PNG, Australia and senior APEC officials from across the region.

Australia is supporting PNG in its policy preparations for APEC by providing training for officials to develop, advocate and implement policies and establishing the APEC Study Centre at the National Research Institute (Australian High Commission, 2018), among other things.

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 Sindann 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, 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

Papua New Guinea, Development Strategic Plan 2010–30—

www.treasury.gov.pg/html/publications/files/pub_files/2011/png-development-strategic-plan.2010-2030.pdf/

Papua New Guinea, Medium Term Development Plan 2016-2017—

<http://www.planning.gov.pg/images/dnpm/pdf/MTDP2.pdf>

Papua New Guinea Mineral Resources Authority. *Government Links and Other Links*—

www.mra.gov.pg/Help/UsefulLinks.aspx/

Papua New Guinea Chamber of Mines and Petroleum—<http://pngchamberminpet.com.pg/>

Peter O'Neill: Prime Minister 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 (Selva). Peru is divided into 25 political departments (administrative regions).

In 2015, Peru had a total population of about 31 million, an increase of 1.3% from the previous year (EGEDA, 2017). In 2015, approximately 22% of Peru's population was considered poor and 4.1% 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).

Between 2000 and 2015, Peruvian economy grew fast with an average annual rate of 5.3%. This rate was higher than the level reached in 2015 (3.3%), 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 2015, Peru's gross domestic product (GDP) was USD 362 billion (2010 USD purchasing power parity [PPP]), whereas its GDP per capita grew by 2%, reaching USD 11 529 (EGEDA, 2017). 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).

Figure 1-Map of Peru

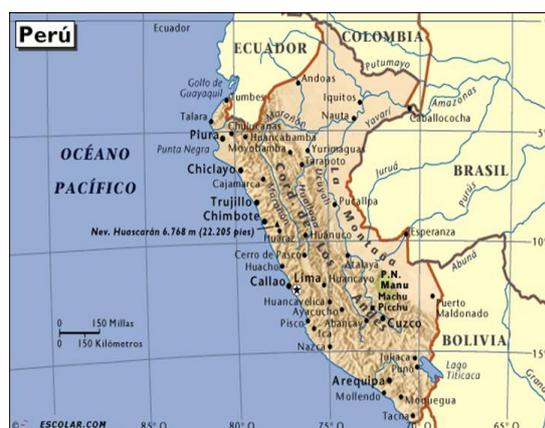


Table 1: Key data and economic profile, 2015

Key data ^a		Energy reserves ^{b, c, d}	
Area (million km ²)	1.3	Oil (billion barrels)	1.2
Population (million)	31	Gas (trillion cubic metres)	0.4
GDP (2010 USD billion PPP)	362	Coal (million tonnes)	9
GDP (2010 USD PPP per capita)	11 530	Uranium (kilotonnes U)	42

Sources: ^a EGEDA (2017); ^b BP (2017); ^c MEM (2014); ^d NEA (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Peru's total primary energy supply (TPES) in 2015 was 22 614 kilotonnes of oil equivalent (ktoe), increasing 5.6% from 2014. This was because of an increase in oil supply, driven by an increase in the import of both crude and oil products, which was more than proportional to decreases in oil, coal and natural gas domestic production. Per energy source, in 2015, around 47% (11 341 ktoe) of the TPES was from oil, 30% from natural gas (7 100 ktoe) and 3% from coal (810 ktoe). Other energy sources, including hydro, wood, bioenergy, wind and others constituted the remaining 20% (4 823 ktoe) (EGEDA, 2017).

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 0.4 trillion cubic metres (tcm) in 2016 and are expected to increase to 0.8 tcm by 2025, based on the information from the Ministry of Energy and Mines (MEM) (MEM, 2014). The Camisea gas field, the largest in Peru, is located 500 km from Lima, in the region of Cusco. Production at the field has allowed Peru not only to meet growing domestic consumption but also to become a liquefied natural gas (LNG) exporter. Since 2012, more than 95% of Peru's total gas production comes from the Camisea field.

The Camisea field was initially aimed at satisfying the domestic consumption for natural gas. However, because production levels have increased at an average annual rate of 63% since 2004, excess supply was directed to exports with the construction of the Peru LNG Melchorita liquefaction plant. Peru's LNG exports amounted to 8.1 billion cubic metres (bcm) (BCRP, 2015).

Peru's proven coal reserves are around 9.9 million tonnes (Mt) with about 95% consisting of anthracite and the remainder of bituminous coal. Most 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).

The other energy sources category, which represents 20% of Peru's TPES, includes different types of biomass, such as firewood, vegetable coal, dung and yareta (a moss-type plant dried and then burned) and are used mostly 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 2015, Peru's electricity generation totalled 48 066 gigawatt-hours (GWh), a 5.6% increase from 2014. Hydropower and thermal generation contributed almost by halves, with 48.9% and 48.5%, respectively. The remainder 2.6% power generation share came from solar PV, biomass and wind (EGEDA, 2017).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	22 614	Industry sector	5 217	Total power generation	48 066
Net imports and others	368	Transport sector	7 942	Thermal	23 524
Total primary energy supply	24 069	Other sectors	5 176	Hydro	23 301
Coal	810	Non-energy	305	Nuclear	0
Oil	11 341	Final energy consumption*	18 335	Others	1 242
Gas	7 100	Coal	726		
Renewables	4 823	Oil	10 058		
Others	-5	Gas	1 730		
		Renewables	2 183		
		Electricity and others	3,638		

Source: EGEDA (2017) (data collected in September 2017).

* 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

Peru's total final consumption increased by 6% in 2015, reaching 18 640 ktoe. Transportation represented 43% of the total final consumption in 2015, increasing rapidly by 5.9% on an average from 2000 to 2015, reaching 7 942 ktoe. The industrial sector share was 28%, whereas the 'other' sector, including residential, commercial and agricultural energy consumption was also 28%. The remaining 1.6% share was attributed to non-energy consumption. Final energy consumption, excluding non-energy consumption, was 18 335. Oil products dominated the final energy consumption in 2015 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 final energy consumption, whereas gas and coal accounted for the remaining 9.4% and 4.0%, respectively (EGEDA, 2017).

ENERGY INTENSITY ANALYSIS

Peru's energy intensity had been decreasing since 2011. However, this trend was reversed in 2015. From 2014 to 2015, primary energy supply intensity increased by 2.3%. Following the same trend, total final consumption intensity increased even faster, by 2.8% compared to that in 2014. Final energy intensity (excluding non-energy consumption) increased by 2.6% compared to that in 2014. Peru's energy intensity increase could be explained by the very rapid growth on oil consumption in the transportation sector.

Table 3: Energy intensity analysis, 2014

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	65	67	2.3
Total final consumption	50	52	2.8
Final energy consumption excl. non-energy	49	51	2.6

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

Modern renewables consumption increased by 13% from 2014 to 2015, driven predominantly by hydropower generation. Its share to final energy also increased at a slower pace, by 6.3%. Traditional biomass consumption decreased by 1.6% in 2015. However, it remains an important fuel for the residential sector.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	2014 vs 2015
Final energy consumption (ktoe)	17 279	18 335	6.1
Non-renewables (Fossils and others)	13 433	14 295	6.4
Traditional biomass*	2 063	2 031	-1.6
Modern renewables*	1 782	2 010	13
Share of modern renewables to final energy consumption (%)	10%	11%	6.3%

Source: EGEDA (2017).

* 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 (MEM) is responsible for the formulation and evaluation of energy and mining policy as well as for environmental issues concerning energy and mining activities. The MEM is divided into two parts: the Vice-Ministry of Energy and the Vice-Ministry of Mines. Through its general directorates (i.e. electricity, rural electrification, hydrocarbons, energy efficiency, mining, energy-environmental issues and mining-environmental issues), the Vice-ministry of Energy covers the major areas of influence in the sector, overseeing activities and promoting investments to achieve sustainable development.

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 energy policy of the economy. According to the plan, Peru's overarching goal is to have a reliable, continuous and sufficient energy system that can support sustainable development, in part by promoting investments in infrastructure (e.g. transport, refinery and production) and exploration. The National Energy Plan's main goals (MEM, 2014) are to provide energy security and universal access to energy supply and to develop energy resources under a social and environmental perspective. 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, electric engines and boilers;
- Promoting an energy efficiency culture;
- Establishing an exclusive means for 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.

Simultaneously, the Energy Plan considers the expansion of gas pipelines to cover the entire coastal region. By 2025, this is expected to increase natural gas consumption up to the goal of 35% of final energy consumption.

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. The programme intends to increase electricity coverage for 2.2 million people living in isolated regions by expanding the grid and providing access to non-conventional energy sources (Table 1). Furthermore, the Social Energy Inclusion Fund aims to provide 1.2 million low-income families access to LPG through discount coupons. Finally, 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 CO₂ emissions and respiratory diseases (APEREC, 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).

Peru is seeking to become an energy hub in the South American region by encouraging energy integration projects with Ecuador, Colombia and Chile in electricity, Brazil in hydropower and Bolivia in gas. Peru has electricity interconnections with Ecuador via two transmission lines (500 kilovolts [kV] and 220 kV). Agreements with Bolivia intend to support transportation of its gas to the LNG terminal in Peru. In addition, Peru and Bolivia are undertaking studies in electricity to assess the potential of interconnecting their power systems to jointly supply electricity to Chile.

ENERGY MARKETS

The Peruvian economy became more market-oriented following structural reforms in the 1990s, resulting in the privatisation of the mining, electricity, hydrocarbons and telecommunications industries. Several laws established a regime under which domestic and foreign investments were subject to equal terms. This has encouraged foreign companies to participate in almost all economic sectors. In 1999, Peru passed the Law for Promotion of Natural Gas Industry Development (Law 27133), establishing specific conditions to promote the development of the natural gas industry (El Peruano, 1999).

In recent years, Peru has expanded and streamlined the available investment schemes with a focus on areas involving exports, infrastructure and services to the population. Thus, investments in oil and gas upstream activities are conducted under licences or service contracts granted by the government through the MEM. Some of the conditions in upstream and downstream activities are summarised in Table 5.

Table 6: Investments required according to the Energy Plan 2014–25

Upstream Activities	
Exploration	Authorisation up to seven years.
	The Ministry of Energy and Mines can extend it up to three additional years.
Exploitation	Maximum 30 years for crude oil.
	Maximum 40 years for non-associated natural gas and condensates.
Downstream Activities	
Transportation	Conducted by ships or pipelines.

	Concession up to 60 years.
Refinery	Authorised by the General Directorate of Hydrocarbons (Ministry of Energy and Mines).
Distribution	Liquid hydrocarbon and similar hydrocarbon by-products require authorisation from the Ministry of Energy and Mines.

Source: E&Y (2014).

The increasing energy consumption and the abundance of natural gas will challenge the economy to increase energy investments to meet future energy infrastructure requirements. Peru's Energy Plan forecasts that USD 50 billion investments will be required in the energy sector, given the expected rapid GDP growth rates.

Table 7: Investments required according to the Energy Plan, 2014–25

		GDP 4.5%	GDP 6.5%
Electricity	Generation	6 700	7 300
	Transmission	1 700	1 700
Gas	Upstream	5 200	6 000
	Gas pipelines	11 550	11 680
	Petrochemicals	5 000	5 000
Oil	Upstream	16 000	18 000
	Downstream refineries	3 500	3 500
Total *USD million		49 650	53 180

Source: MEM (2014).

ENERGY SECURITY

In 2012, the Peruvian Government published the Law to Ensure Energy Security and Promote the Development of the Petrochemical Industry (Law 29970). It states that energy security becomes a matter of national interest and mandates the diversification of energy sources, the reduction of external dependence and an increase in the energy supply chain reliability. The law also mandates the construction of specific infrastructure projects, such as parallel pipelines to the Camisea gas pipeline and the Camisea products pipeline and an LNG imports regasification terminal.

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 aims to reduce energy consumption by 15% from the 2007 levels by 2018 through energy efficiency measures. The plan includes an analysis of energy efficiency in Peru and identifies 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 Energy, 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.

RENEWABLE ENERGY

Peru has established goals to increase renewable energy use and has developed a legislative and policy programme to support their development. Around half of the power generation in Peru comes from renewable sources, of which almost entirely from hydropower.

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 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 total power generation.
- A firm price guaranteed for bidders who are awarded energy supply contracts for up to 20 years; and
- Priority in dispatch and access to networks.
- The drafting of a Peruvian Renewable Energy Plan.

To achieve these goals, the MEM established open auctions for renewable energy suppliers to ensure competitive conditions for the electricity generators and their customers. By 2015, the total generation capacity and average cost by technology were as follows:

- Wind: 232 MW at USD 78 per megawatt-hours (MWh).
- Mini Hydro: 496 MW at USD 56 per MWh.

- Photovoltaic: 96 MW at USD 173 per MWh.

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	Potential (MW)	Installed capacity (MW)
Photovoltaic ^a	540	96
Wind ^b	22 000	232
Hydropower ^b	69 000	391
Biomass ^b	177	27
Geothermal ^b	3 000	-

Sources: a. IFC (2011) b. MEM (2014).

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 the establishment of the Peruvian Institute of Nuclear Energy. Peru has been a member of the International Atomic Energy Agency since its creation in 1957.

CLIMATE CHANGE

As part of its environmental strategy policy, in October 2003, the Peruvian Government approved the National Strategy on Climate Change (NSCC) for the mitigation of an adaptation to climate change (El Peruano, 2003). The main objectives of the NSCC are to reduce climate change impacts through integrated studies on vulnerability and adaptation and to control both pollution and greenhouse gas (GHG) emissions by using renewable energies and energy efficiency programmes in the production sectors.

Table 10: GHG emissions by activity

Activity	GHG emissions (%) by 2012
Industrial processes	51%
Energy	26%
Agriculture	15%
Waste	5%
Land use, land use change and forestry (LULUCF)	3%

Source: MINAM (2016)

Peru accounts for 0.1% of the world's GHG emissions (CAIT, 2012). Based on the Intended Nationally Determined Contribution (INDC), Peru aims to reduce GHG emissions by 30% by 2030 compared with the baseline. The absolute reduction is estimated at 90 million tonnes of CO₂ equivalent, with 50% of this reduction being in the forestry sector, including land use, land use change and forestry (LULUCF) (UNFCCC, 2015).

Table 11: INDC for reduction of GHG emissions

	Emissions Mt CO ₂ eq including LULUCF	Emissions Mt CO ₂ eq 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 to foster sustainable development.

- Energy Sector: The National Energy Plan 2014–25 projects providing natural gas access to residential sector across Peru, because it is currently concentrated in Lima and a handful of other cities. Thus, LPG consumption is expected to diminish in urban areas while promoting it as a substitute of traditional biomass in rural regions.
- 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 around one-third of national production is using natural gas in their industrial process because 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.
- 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 as part of the National Strategy for Climate Change.

NOTABLE ENERGY DEVELOPMENTS

OIL AND GAS

The government announced a plan to reorganise state-owned oil company Petroperú. The changes include structural management changes and the involvement of independent professionals. The reorganisation also allows Petroperú to participate in exploration and production contracts, celebrate associations or joint-ventures with private companies.

Peru is expected to become more dependent on both crude oil and oil products 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 (Mbbbl/D).

The government is also encouraging state-owned companies to become more active in hydrocarbon exploration and production projects. The government is 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. 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. The construction started in 2015. However, by January 2017, 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.

The construction of the pipeline had, at that moment, a general progress of around 40%. Companies, such as Semptra, showed initial interest in acquiring the gas pipeline and continuing its construction, but withdrew from negotiations, based on the argument that the government is unable 'to provide necessary assurances that the concession would not be cancelled due to alleged legal violations by the seller'. The Peruvian government will start a new bidding process and expects the contract to be awarded to a new consortium in early 2019 and only after that will the construction works restart.

Finally, the reactivation of the electrification project in rural areas with photovoltaic energy in charge of the company Ergon Peru has completed 6 000 photovoltaic installations in the regions of Amazonas, Huancavelica, Huánuco, Puno and San Martín, of the total of 150 000 committed. The project will supply electric power to 15 000 rural isolated locations which are not connected to the main electricity grid.

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USEFUL LINKS

Agencia de Promoción de la Inversión Privada—www.proinversion.gob.pe

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

Ministerio del Ambiente—www.minam.gob.pe

Ministerio de Economía y Finanzas—www.mef.gob.pe

Ministerio de Energía y Minas—www.minem.gob.pe

Organismo Supervisor de la Inversión de la Energía y Minería—www2.osinerg.gob.pe

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Presidencia de la República del Perú—www.peru.gob.pe

Programa de Adaptación de Cambio Climático—www.paccperu.org.pe

Proyecto Camisea—www.pluspetrol.net/camisea.html

THE PHILIPPINES

INTRODUCTION

Owing to recent discoveries, the Philippines archipelago now comprises 7 641 islands (Primer, 2017), covers a total land area of 343 448 square kilometres (km²) (Government of the Philippines, 2018) and has a coastline of about 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 2015, the total population of the economy reached 101 million, an increase of 1.6% from the 2014 level (EGEDA, 2017). As per the 2016 World Population ranking, it is the twelfth-most populated economy in the world (WB, 2016).

The Philippines maintained the 6.1% growth rate in its gross domestic product (GDP) from USD 646 billion in 2014 to USD 685 billion in 2015 (2010 USD purchasing power parity [PPP]) (EGEDA, 2017). The service sector continued to drive the economy's growth, followed by industry. While the economy's growth for the last two years was slower than 2012 and 2013, the 2015 rate was still faster in comparison to its middle-income ASEAN neighbours, such as Indonesia and Thailand. The current growth is accompanied by an improved rate of capital formation. 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 4.4% growth, from USD 6 453 in 2014 to USD 6 736 in 2015 (EGEDA, 2017).

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 76 million barrels of oil (includes condensate), 24 billion cubic metres (834 billion cubic feet) of natural gas and 440 million tonnes (Mt) of coal (DOE, 2015a).

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 to 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 to 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, 2015

Key data ^{a, b}		Energy reserves ^c	
Area (thousand km ²)	343	Oil (million barrels)	76
Population (million)	101	Gas (billion cubic metres)	24
GDP (2010 USD billion PPP)	685	Coal (million tonnes)	470
GDP (2010 USD PPP per capita)	6 736	Uranium (kilotonnes U)	–

Sources: ^a Government of the Philippines (2018); ^b EGEDA (2017); ^c DOE (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

The economy's total primary energy supply (TPES) in 2015 increased significantly by 9.3% in comparison to the 2014 level, from 48 460 ktoe to 52 962 kilotonnes of oil equivalent (ktoe). Approximately 53% of the

energy requirement was produced locally, largely from RE (39%) and oil (34%). The economy's self-sufficiency level decreased slightly from 57% in 2014 to 53% in 2015 (EGEDA, 2017).

Renewables—comprising hydro, geothermal, biomass and others—formed the bulk of TPES of the economy in 2015. The 2015 growth was 1.5% percentage point more than the compounded annual growth rate (CAGR) for the last five years of 2.6%. This increase can be attributed to the remarkable upsurges in solar (seven times) and wind (four times) primary supplies (EGEDA, 2017).

Oil remained the second dominant energy source, accounting for 33% of the TPES. The economy's oil supply requirement grew significantly by 19.1% in 2015, reaching 17 933 ktoe from 15 060 ktoe in 2014.

Coal provided the third-largest share to the TPES at 22%, which was an increase of 9.3% from the 2014 level to reach 11 634 in 2015. The recent upswing development in the coal industry, which spurred interest even from the small-scale mining operators in the economy, may have contributed to the increase in coal sources in 2015 (DOE, 2016).

FOSSIL ENERGY

The economy relies heavily on fossil fuels imports, specifically oil and coal, to meet its energy consumption requirement. The net imports in 2015 significantly grew (by 23.8%) from 21 094 ktoe in 2014 to reach 26 118 ktoe in 2015. Oil constituted nearly 70% of the total energy imports, whereas coal represented 31% and bioethanol 1%. The rise in energy imports was caused by a 3% increase in oil consumption for power generation, resulting in an 18% increase in oil imports.

Coal exportation declined by 46% from the 2014 level, resulting in an equivalent net importation of 51% in 2015. Relatedly, local coal production saw a decline of 2% in 2015 from the 2014 coal production level of 4 012 ktoe (EGEDA, 2016). Indonesia remained to be the primary source of coal imports in the Philippines, which also increased by 10% from the 2014 coal import levels (DOE, 2015b).

RENEWABLE ENERGY

RE has long been a significant contributor to the economy's energy supply requirement, providing 39% to the TPES in 2015. Among the renewables, biomass was the largest contributor with 35%, followed by geothermal, which, despite an increase in absolute terms, had supplied 34% of the total indigenous primary energy supply. The residential sector is the primary user of biomass, specifically for cooking. The industry and power sectors also utilised a portion of the biomass supply. Energy production from hydro continued to pose a decline from 786 ktoe in 2014 to 745 in 2015, owing to the El Niño phenomenon from March 2015 (DOE, 2015c).

Solar and wind were smallest contributors, contributing less than 1% to the total indigenous primary supply. The growth of solar and wind however was remarkable, increasing more than five times the 2014 supply levels to reach 76.3 ktoe in 2015 (EGEDA, 2017). The shares from these RE resources are expected to expand soon with the growing number of awarded contracts issued to RE developers by the government. As of the end of 2015, there were 55 and 124 new wind and solar projects awarded, respectively. Commercialisation will bring an additional 571 Mw capacity (Wind: 427 Mw and Solar: 144 Mw) (DOE, 2015d).

ELECTRICITY GENERATION

In 2015, the economy's total electricity generation was up 6.7% from 77 261 GWh in 2014 to 82 413 GWh. Coal is still the dominant fuel for the economy's baseload requirement, accounting for about 45% of the total power supply in 2015. Natural gas also continued to provide a substantial share: 23%. Almost all the natural gas power-generation capacities are located in Luzon Island, supplying around 31% of the Luzon grid requirement (DOE, 2015c). Meanwhile, oil-based power plants had a modest share of 7% during the same period.

Despite the commercial operation of additional capacities from solar, wind and even biomass, the aggregate share from renewables (including hydro and geothermal) in 2015 reduced by 1% from the last two years' share of 26%. Electricity output from hydro went down by 5.2% in 2015, from 9 137 GWh in 2014, owing to El Niño (EGEDA, 2017). 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, 2015c)

Table 2: Energy supply and consumption, 2015

Primary Energy Supply (ktoe)		Total Final Consumption (ktoe)		Power Generation (GWh)	
Indigenous production	27 966	Industry sector	6 718	Total power generation	82 413
Net imports and others	26 118	Transport sector	10 194	Thermal	61 450
Total primary energy supply	52 962	Other sectors	12 743	Hydro	8 665
Coal	11 634	Non-energy	1 179	Nuclear	0
Oil	17 933	Final energy consumption*	29 655	Others	12 298
Gas	2 877	Coal	2 218		
Renewables	20 518	Oil	14 025		
Others	0	Gas	50		
		Renewables	7 530		
		Electricity and others	5 831		

Source: EGEDA (2017) (data collected in September 2017).

* 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 6.1% growth of the Philippines economy in 2015 translated to an 8.5% increase in the total final consumption (including non-energy), reaching 30 834 ktoe in 2015 from 28 430 ktoe in 2014 (EGEDA, 2017). All economic sectors posted an increase in their fuel consumption during the same period. The non-energy sector, although providing the least share of the total final consumption (TFC), displayed the largest growth at 95%, followed by the transport sector at nearly 16%. The other sectors, comprising the commercial, residential and agricultural sectors, exhibited 2% growth. Energy consumption in the commercial sector, which showed increases for the last five years, slightly contracted by 1.1% in 2015 from the 2014 demand level. Consumption in the residential sector increased by 2.8% compared to the 2014 level, whereas the agriculture sector rebounded with a 12% increase in 2015 (EGEDA, 2017).

The transport sector's energy use accounted for 33% of the TFC in 2015. More than 50% of this 33% was diesel oil, the primary fuel used for public transport. Industry consumed 22% of the TFC with coal being the largest share (35%) of the sector's fuel consumption (EGEDA, 2017). About 80% of the coal used in the sector was for cement production (DOE, 2015b).

The other sectors' aggregate energy consumption was 41% of the TFC in 2015 (EGEDA, 2017). The residential sector required more than two-thirds of the other sectors' consumption, representing 30% of the TFC. The bulk of the energy consumption of the sector was biomass. The commercial sector demanded 26% of the other sectors' consumption, and the remaining was shared by agriculture and non-energy use (EGEDA, 2017).

In terms of fuel sources, oil products continued to be the major fuel for the economy, representing 47% of final energy consumption, excluding non-energy. Oil consumption likewise grew the fastest among the fuels at 12% to reach 14 025 ktoe in 2015. Electricity and other fuels expanded by 7%, contributing to an aggregate share of 20% to the final energy consumption (EGEDA, 2017).

ENERGY INTENSITY ANALYSIS

Given that GDP in the Philippines in 2015 grew by 6.1%, the energy requirements in both primary and final consumption increased accordingly. This has also resulted in positive energy intensities between 2014 and 2015, after posting energy intensity reductions for the last five years.

Specifically, primary energy intensity grew by 3% and final intensity (non-energy included) grew by 2.3%. These increases can be attributed to the >10% increase in oil requirement in 2015. Change in energy intensity between 2014 and 2015 in the final energy consumption (non-energy excluded), although minimal, was positive at 0.5%. This may be attributed to the >15% expansion in the transport sector. As in most developing economies in APEC, the increase in the Philippines' purchasing power may have boosted the purchase of private vehicles and consequently the consumption in the transport sector, thereby contributing to the 43 toe/million USD (in 2010 USD PPP) energy intensity in 2015 (EGEDA, 2017).

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	75	77	3.0
Total final consumption	44	45	2.3
Final energy consumption excl. non-energy	43	43	0.5

Source: EGEDA (2017).

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 to the 2010 level, renewables use in the economy has significantly accelerated. Between 2010 and 2015, modern renewables posted an upward trend of 3% compounded annual growth rate. This has further increased by 0.9 percentage point in 2015 to reach 2 616 ktoe. Considering the share of the total final energy consumption, however, it contracted to 8.8% from the 2014 level of 9%. The upswing in the share of fossil fuels to the final energy consumption may have offset the minimal expansion in the renewables share in 2015 (EGEDA, 2017).

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	27 825	29 655	6.6
Non-renewables (Fossils and others)	18 875	20 641	9.4
Traditional biomass*	6 429	6 397	-0.5
Modern renewables*	2 521	2 616	3.9
Share of modern renewables to final energy consumption (%)	9.1	8.8	-2.5

Source: EGEDA (2017)

* 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 programs 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. The Philippine Energy Plan 2012–2030 still serves as the guidepost for the economy, outlining several measures and targets that the government and the energy stakeholders must jointly undertake to bring reliable and affordable energy services to the populace and create a sustainable future with less carbon footprints. The energy plan espouses the government policy thrusts and goals and includes the following pointers:

- a. Ensuring energy security by expanding the share of renewables in the total power generation capacity mix, promoting exploration and development of indigenous fossil fuels and providing reliable and efficient power supply;
- b. Expanding energy access by increasing household electrification levels;
- c. Promoting a low-carbon future by achieving 10% energy savings and increasing the share of alternative fuels in public utility vehicles; and
- d. Promoting more climate-change-resilient energy infrastructure.

The DOE studied the possible fuel mix policy for power generation to determine a reliable long-term power generation mix model for the economy. Based on the results of the prepared fuel mix models with assistance from the Japan International Cooperation Agency (JICA) in August 2014, the proposed fuel mix should comprise 30% renewables and 30% natural gas (DOE, 2015e). In July 2015, the DOE issued a Department Circular (DC 2015-07-0014) prescribing a policy for maintaining the share of RE in the total power installed at a minimum of 30% through FiT and other mechanisms, as stipulated in the Renewable Energy Act (DOE, 2015f).

ENERGY MARKETS

OIL AND GAS

In order 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 has continuously implemented the PECR. The PECR is a transparent and competitive system of tendering onshore and offshore oil and gas blocks for exploration that are offered to both local and foreign investors. During the fifth PECR in 2014 covering 11 petroleum potential areas, the government received three bids in 2015 and recommended awarding service contracts to add to the existing 25 petroleum service contracts already being monitored by the government (DOE, 2016).

The economy's existing oil and gas fields produced 3.07 million barrels (Mbbbl) in 2014, 63% higher than the 2013 output, owing to production from new wells in the Galoc field. In the same year, gas production grew by 5.2%, reaching 130 351 million standard cubic feet, almost all (99%) coming from the Malampaya gas field. 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. Likewise, Malampaya produced 4.2 Mbbbl of associated condensate (DOE, 2015e).

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 exported, mostly to China.

Like oil and gas, the government is also promoting PECR to encourage investors to explore the coal resource potential of the economy. During the fifth PECR, the government awarded seven coal exploration contracts (COCs) to explore potential coal areas in Mindanao Island (DOE, 2016). These additional COCs could boost the coal reserves of the economy. In terms of coal production from existing COCs, a total of 7.6 Mmt (at 10 000 BTU/lb) was produced in 2014. Of the total coal production, 97% came from Semirara, Antique. The small-scale coal mines in Negros, Surigao del Sur, Zamboanga del Sur, Bicol and in Cebu province contributed about 0.23 Mmt or 3% of the total domestic production.

MARKET REFORMS

ELECTRICITY

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). In accordance with Section 31 of the EPIRA, the government successfully commenced the full commercial operation of Retail Competition and Open Access (RCOA) in June 2013, with 275 participating competitive customers duly registered by the Central Registration Body (DOE, 2015f). In 2015, the number of participants increased to 434 (DOE, 2016). Under RCOA, the customers having an average load requirement of 1.0 MW over the last 12 months can source their electricity supply from retail electricity suppliers by allowing the use of transmission and distribution systems and from associated facilities subject to the payments of transmission and distribution wheeling charges duly approved by the Energy Regulatory Commission (ERC).

The DOE has been supervising the operation of the Wholesale Electricity Spot Market (WESM) of the Philippine Electricity Market Corporation (PEMC). As of 2014, the integrated Luzon–Visayas WESM registered 229 participants comprising 54 generating companies and 175 customers (13 private distribution utilities, 71 electric cooperatives (ECs), 79 bulk users, five contestable customers and seven wholesale aggregators). To include ancillary service requirements of the power grid in WESM operation, the DOE issued, in December 2013, a Department Circular (DC 2013-02-0027), ‘Declaring the Commercial Launch for the Trading of Ancillary Services (through the Establishment of a Reserve Market) in Luzon and Visayas under the Philippine Wholesale Spot Market’.

DC 2013-02-0027 set the commercial operation of the reserve market in March 2014 after launching of the trial operation plan (TOP). The PEMC commenced the TOP in February 2014 in two phases. The first phase covered testing of protocols, procedures and interfaces for the Market Operator-System Operation and Reserve Market Working Group, including addressing other operational issues. The second phase involved demonstration of operations of the reserve market and familiarisation of trading participants in all processes (DOE, 2015e).

However, the DOE issued another Department Circular (DC 2014-03-0009) in March 2014, ‘Declaring a New Commercial Launch Date for the WESM Reserve Market and Directing PEMC to Develop a Protocol for Central Scheduling and Dispatch of Energy and Contracted Reserves’, which subsequently reset the commercial operation to May 2014. To have a detailed evaluation, the PEMC conducted a reserve market forum to deliberate the results of the TOP, conducted from February to April 2016. Until June 2016, the PEMC continued to undertake activities for the reserve market, such as market participants’ registration and training and testing of enhancement on market operator and system operator procedures (DOE, 2015f).

The reserve market will benefit the power market with co-optimisation of energy and reserves, as well as promotion of greater competition among energy and reserve providers, leading to more transparent and competitive energy prices. Furthermore, the reserve market will facilitate the entry of RE in accordance with the RE Act of 2008.

As part of the sustainable solutions for the Mindanao Island requiring additional power generation capacities, an Interim Mindanao Electricity Market (IMEM) was established, which commenced full operation in November 2013. The IMEM is intended to encourage participation of the existing power-generating

capacities and interruptible loads,¹ and entry of new generating capacities in Mindanao. The IMEM rules were amended in May 2014 to include ‘demand-side bidding and transitory arrangement’ (DOE, 2015e). In 2014, IMEM market intervention was still in effect because of the continuing power-supply deficiency in the Mindanao grid. The DOE held several discussions with stakeholders to resolve some issues on IMEM operations and make amendments to the market rules. Once the IMEM rules are ready for implementation, the government will lift the IMEM market intervention (DOE, 2015f).

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 to 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, 2015g). The circular mandates all distribution utilities to undergo CSP, through a third party duly recognised by the DOE and ERC. In ECs, the National Electrification Administration (NEA) should recognise the third party (DOE, 2016).

OIL

As part of its mandate, the DOE ensures an adequate and stable oil supply in the economy by continuously monitoring activities in the downstream oil industry, such as crude and product imports/exports and costs, local production, industry consumption, inventory levels, distribution and marketing facilities, and oil price movements. The DOE still implements the minimum inventory requirement to have a steady oil supply, specifically during emergencies such as natural disasters. The minimum inventory requirement covers oil companies, bulk suppliers and liquefied petroleum gas (LPG) players operating in the economy. Refineries are required to have in-country stocks equivalent to 30 days, whereas bulk marketers and LPG players must maintain 15 days and 7 days’ stock, respectively. As of December 2014, the average inventory was equivalent to a 46-day supply (DOE, 2015h).

The DOE entered a memorandum of agreement (MOA) in October 2014 to develop a framework that will enable a sustainable supply of petroleum products in the event of natural disasters or emergencies. Parties to the MOA are the Metro Manila Development Authority, Office of the Civil Defense, Natural Risk Reduction and Management Council, and the members of the Philippine Institute of Petroleum (DOE, 2015e). Likewise, the Mutual Product Sharing Accommodation (MPSA), established through a Department Circular (DC 2011-03-003) issued by the DOE in 2011, is part of the emergency response measures of the economy. The DOE implemented the MPSA when the economy was hit by super typhoon Haiyan in 2013. The MPSA intends to provide and stabilise oil supplies in calamity-affected areas, as it permits oil companies to supply petroleum products to the facilities of other oil companies to ensure a steady supply of petroleum products in the affected areas.

DOWNSTREAM NATURAL GAS

With depleting domestic natural gas resources, the government is now looking at the possibility of importing liquefied natural gas (LNG). The Energy World Corporation (an Australian company based in Hong Kong, China) is building an LNG terminal and a merchant gas-fired power in Pagbilao, Quezon province. The LNG facility constitutes two storage tank units with a capacity of 130 000 cubic meters (Cm) each, a regasification plant, and an on-site 600 MW merchant gas-fired power plant to serve as an anchor load for the project (DOE, 2015e). In 2015, the DOE granted the Energy World Corporation a 12-month extension upon expiration of their five-year provisional permit for the completion of their LNG hub terminal facilities (DOE, 2016).

¹ The interruptible load program (ILP) is another measure implemented in Mindanao where customers of a distribution utility (DU) are compensated for voluntarily de-loading from the grid by using the generation facility for their own use during peak demand hours. The DU will then charge and collect from the customers within its franchise area the corresponding energy ‘freed up’ (in kilowatt-hours) by the ILP customers. This money will be used to pay these customers based on the Energy Regulatory Commission-approved ILP rates.

The Philippine National Oil Company (PNOC) commissioned the Public–Private Partnership Center (PPPC) for the detailed feasibility study of the 105 km Batangas–Manila pipeline (BatMan 1) to supplement the JICA study completed in June 2014 (DOE, 2015e). 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)² 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, 2015e).

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 Houses of Congress.

ALTERNATIVE FUELS

The DOE drafted a MOA with the Development Academy of the Philippines to formulate the Alternative Fuels Roadmap to serve as a blueprint for the government during the program’s implementation. The DOE has been implementing policies and programs on alternative fuels as ways to diversify fuel and reduce dependence on imported fuels and to promote a preference for cleaner fuels.

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 program Natural Gas Vehicle Programme for Public Transport (NGVPPT), the DOE is working closely 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 program, the DOE signed a MOA 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 concerned national government agencies for the promotion and mainstreaming of auto-LPG in the transport sector to diversify the economy’s utilized fuel sources.

ENERGY EFFICIENCY

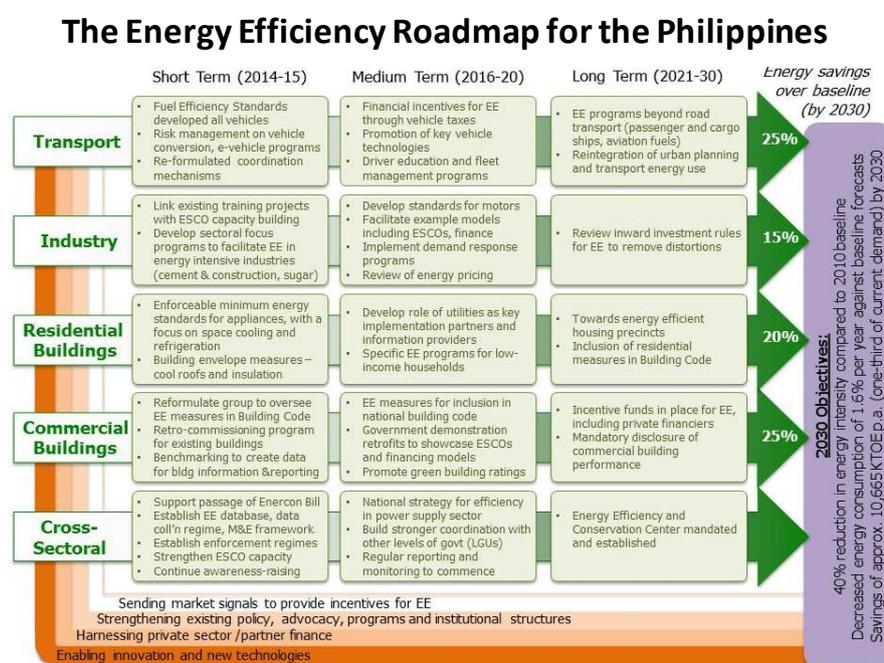
The government has continuously implemented the National Energy Efficiency and Conservation Programme, launched in 2004, as the banner program on the various initiatives on energy efficiency and conservation. This program includes the following projects:

² 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 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 approved the implementation of the Energy Efficiency and Conservation Roadmap in July 2014, which specifies a direction towards an energy-efficient economy by 2030. The roadmap identifies short- to medium-term action plans across key energy consuming sectors with the objective of achieving 40% reduction in energy intensity by 2030 based on the 2010 level. The roadmap will provide more sustainable and long-term policy directions on energy efficiency and conservation.

Fig 1: Energy Efficiency and Conservation Roadmap



Source: DOE (2015c).

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 about 2 million megawatt-hours of energy (DOE, 2015e).

RENEWABLE ENERGY

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 source a portion of electricity supply from RE resources. 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.

In 2014, the DOE awarded 220 service contracts for different RE resources with potential capacity of 3 184 MW (DOE, 2015e), whereas the 133 service contracts awarded in 2015 have an aggregate potential capacity of 5 575 (DOE, 2016).

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 to 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 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 policy-making 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 programs 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 CO₂ 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 CO₂ 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 programs 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 DOE, ERC and NEA in implementing reforms in policies and programs for rural/household electrification, RE development, and promotion of decentralised energy solutions for climate-vulnerable communities, particularly in Visayas and Mindanao.

The 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
- Will try 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

The DOE is 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 base year. The PESLP will cover a wide range of appliances and lighting systems to include even light duty motor vehicles. Currently, 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 Houses of Congress:

- Energy Efficiency and Conservation Act;
- Downstream Natural Gas Industry Development Act;
- Liquefied Petroleum Gas (LPG) Industry Regulation and Safety Act;
- Amendments to the Electric Power Industry Reform Act 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 to provide additional fiscal and non-fiscal incentives to encourage private investments.

GOOD GOVERNANCE AND TRANSPARENCY INITIATIVES

In June 2005, the DOE, through technical support from the United States Agency for International Development, established a web-based system called 'Energy Virtual One Shared System', a system for online tracking of RE service contract applications and processing permits, which will eventually extend to other technology/resource applications in the future. The system could help facilitate and streamline business processes, promote efficiency and transparency, and increase private investments.

Other government initiatives being implemented that provide data and information transparency to the public include websites on 'Kuryente', 'Wattmatters' and 'Langis'. The Kuryente website (www.kuryente.org.ph) offers consumers easy access to information on all distribution utilities in their franchise area pertaining to the components of electricity rates charged to customers, such as systems losses. The Wattmatters website provides information on energy conservation and provides data on more efficient appliances available in the market for the residential sector. The Langis website (www.langis.org.ph) gives information on factors affecting pump prices of petroleum products and international price movements.

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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). It is the only economy in the Asia-Pacific Economic Cooperation (APEC) region located in both Europe and Asia, surrounded by the Arctic and the North Pacific oceans. 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-third of the economy is a zone of high-risk agriculture, owing primarily to its continental climate, which is either too cold or too dry.

From 1993 to 2008, the Russian population declined from 148 million to 143 million: however, from 2009 to 2015, the population increased to 144 million (EGEDA, 2017). The shares of urban and rural population remained unchanged since 2009 at 74% and 26%, respectively. Russia's average population density is 8.4 people per km², with most the population living in the European part of the economy (GKS, 2017).

In 2009, the global financial crisis caused Russia's gross domestic product (GDP) to decline by 7.8% from the 2008 level. Since then, Russia's economic growth declined from 4.5% in 2010 to -2.8% in 2015, with an average growth rate of 3.7% for the period 2000–15. The key reasons for this economic slowdown are structural issues with the economic system, sharp decline in the price of crude oil in international markets and unavailable foreign capital owing to international sanctions imposed by the European Union and the USA.

Table 1: Key data and economic profile, 2015

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (thousand km ²)	17.1	Oil (million barrels) ^b	109.5
Population (million)	144	Gas (billion cubic metres) ^b	32.3
GDP (2010 USD billion PPP)	3 133	Coal (million tonnes) ^c	160
GDP (2010 USD PPP per capita)	21 743	Uranium (kilotonnes U)	342

Note: Data from Nuclear Energy Agency (NEA) is used for uranium reserves recoverable at a production cost of less than 260 USD per kg.

Sources: ^a GKS (2017); ^b EGEDA (2017); ^c BP (2017); ^d NEA (2016).

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 27% of the GDP, 63% of the total exports and 27% of the total capital investment.

In terms of proven reserves, as of 2016, Russia holds 17% of the world's gas, 6.4% oil, 14% coal (BP, 2017) and about 5.8% of its reasonably assured resources of uranium (NEA, 2016).

The proven natural gas reserves in Russia, estimated at 32 trillion cubic metres, should be adequate to meet both the domestic market and export demands for another 55 years.

As of 2017, Russia is estimated to have 36 years' worth of oil supply at current production rates, and 57 years' worth 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).

At the current rates of domestic coal consumption, the reserves should be sufficient for over 800 years.

The refining industry in Russia includes about 30 major refineries with a total capacity for primary processing of about 277 Mt of crude oil per year (ME, 2016).

Russia has the world's largest and 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. Due to the obsolescence of this heating infrastructure, 8.9% of heating energy is lost during distribution, and this indicator is growing (ME, 2018b). However, according to expert estimates, a considerable amount of energy can be saved by adopting relatively accessible technologies and cost-effective energy saving practices.

Russia's energy sector is very important to 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, 2017). 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 2016, exports of coal, crude oil, petroleum products and natural gas accounted for 55.9% of the total exports of the economy by value. Russia holds 45% of world's uranium enrichment capacity (NEA, 2015), and actively exports the product. Russia plays a significant role in the world's energy markets. It accounts for 19% of global natural gas trade, 13% of crude oil trade, 9% of petroleum products trade, and 12% of coal trade (BP, 2017).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Russia's total primary energy supply in 2015 was 710 million tonnes of oil equivalent (Mtoe), comprising natural gas (51%), crude oil and petroleum products (22%), coal (16%), and others, including nuclear and hydro (11%) (EGEDA, 2017).

By destination, most of Russia's total energy exports are directed to Western and Eastern Europe, including the Commonwealth of Independent States (CIS). Since 2008, Russia has been actively diversifying its export routes towards the Asia-pacific region, aiming to deliver oil, natural gas and coal to China; Japan; Korea and South-East Asia.

Russia produced 548 Mt of crude oil and gas condensate in 2016 (ME, 2017a). The oil heartland is the Ural Federal district, which accounts for over half of the total oil production. In that year, refineries consumed 281 Mt of crude oil as feedstock, producing 39 Mt of gasoline, 76 Mt of diesel, 75 Mt of fuel oil and 10 Mt of kerosene. Crude oil exports increased from 245 Mt in 2015 to 255 Mt in 2016 and exports of petroleum products reached 156 Mt in 2016 (GKS, 2017).

After three years of decline, natural gas production increased from 634 bcm in 2015 to 640 bcm in 2016 (ME, 2017h). Exports of natural gas steadily increased from 174 bcm in 2014 to 199 bcm in 2016 (GKS, 2017) or 31% of the production, including 11 Mt of liquefied natural gas (LNG) exports (ME, 2017h).

In 2016, Russia produced 385 Mt of coal, an increase of 3.1% from 2015. In 2015, coal exports reached 151 Mt, declining by 0.4% from the 2014 level (ME, 2017i). From 2000 to 2015, the share of coal for export increased from 17% to 39%, despite the fact that the main coal-producing areas (the Kuznetsky and Kanskó–Achinsky basins) are landlocked in the south of Siberia, some 4 000–6 000 km from the nearest coal-shipping terminal for the Atlantic/Pacific markets.

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	1 334 184	Industry sector	124 166	Total power generation	1 065 623
Net imports and others	-601 923	Transport sector	93 863	Thermal	698 401
Total primary energy supply	709 730	Other sectors	159 553	Hydro	167 993
Coal	116 402	Non-energy	79 302	Nuclear	195 470
Oil	156 736	Final energy consumption*	377 582	Others	3 759
Gas	364 149	Coal	12 060		
Renewables	17 414	Oil	88 481		
Others	55 029	Gas	108 291		
		Renewables	2 045		
		Electricity and others	166 705		

Source: EGEDA (2017) (data collected in September 2017).

* 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 production reached 1 066 terawatt-hours in 2015, of which 66% was from thermal power plants, 16% from hydropower and 18% from nuclear energy. Russia has significant renewable energy potential, such as hydro and biomass in Siberia, wind along its Arctic and Pacific shores and geothermal in Kamchatka and the Kuril Islands.

FINAL ENERGY CONSUMPTION

In 2015, the total final consumption in Russia was 457 Mtoe, a decline of 0.4% compared to 2015. By sector, industry, transport and others accounted for 27%, 21% and 35%, respectively. The share of non-energy was 17%. By energy source, coal accounted for 3.2% of the final energy consumption (excluding non-energy), oil and petroleum products at 23%, natural gas at 29%, electricity and others (including heat) at 44% and renewables at 0.5%.

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 40% by 2020 compared to 2007. The government is implementing policies designed to attract investment in energy efficiency and realise Russia's large savings potential.

ENERGY INTENSITY ANALYSIS

The 2.4% growth of Russia's GDP in PPP in 2015 coincided with a 0.8% increase in the economy's primary energy intensity at 227 tonnes of oil equivalent per million USD (toe/million USD). For the total final consumption intensity, the indicator grew by 2.5% from the 2014 level of 142 toe/million USD to 146 toe/million USD in 2015. For final energy intensity excluding non-energy, the indicator grew by 1.7% from 119 toe/million USD to 121 toe/million USD in the same period.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	225	227	0.8
Total final consumption	142	146	2.5
Final energy consumption excl. non-energy	119	121	1.7

Source: EGEDA (2017) (data collected in September 2017).

RENEWABLE ENERGY SHARE ANALYSIS

In 2015, energy consumption of modern renewables in Russia was 12 511 ktoe, or 2.7% of the economy's final energy consumption. This is lower than 2.9% noted in 2014, mainly caused by a decline in energy generated using hydropower. Use of traditional biomass increased by 4.1% compared to 2014, mainly attributed to the residential sector.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	382 049	377 582	-1.2
Non-renewables (Fossils and others)	368 938	365 071	-1.0
Traditional biomass*	2 053	2 137	4.1
Modern renewables*	11 058	10 374	-6.2
Share of modern renewables in final energy consumption (%)	2.9%	2.7%	-5.1%

Source: EGEDA (2017).

* 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 early 2018, the government continued its work on the new 'Energy Strategy 2035', but the strategic objective of Russia's external energy policy is unlikely to change. The objectives will continue to be the use of Russia's energy potential to effectively maximise its integration into the world's energy markets, strengthen Russia's position in these markets and maximise the benefits of energy resources to the economy (ME, 2017f).

To achieve these objectives, the government is planning to implement several measures to improve the security of domestic energy supply and energy export obligations and to make efficiency improvements along the entire energy supply chain. This includes the development of new hydrocarbon provinces in remote areas and offshore. It will also include the rehabilitation, modernisation and development of energy

infrastructure, including the construction of additional trunk oil and gas pipelines, to enhance the economy's energy export capacity. Furthermore, diversification of export delivery markets will be the key to better integrating Russia into the world energy markets.

Russia's nuclear energy industry remains a priority for the economy's development, despite the nuclear accident at Fukushima, Japan in 2011. The share of domestic nuclear-power generation is expected to continue increasing, with many units being constructed abroad. Russia intends to remain a key player in the practical implementation of improved nuclear fuel technology. Despite the existing programmes for renewable energy development outlined in the Energy Strategy 2030, electricity generated from renewable energy is too expensive to compete with traditional sources, i.e. fossil fuels (ME, 2018c).

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 needs to be one of the main objectives of the Russian energy policy in order to improve the competitiveness of the domestic industry in the global market and stimulate Russia's 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 April 2011, a general scheme for development of the oil industry up to 2020 was approved. This provides for the comprehensive development of the oil sector, which includes 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 2007, the federal government approved the East Gas Programme to develop the natural gas fields and build extensive trunk gas pipelines in Eastern Siberia and the Russian Far East up to 2030. The programme also includes building export pipelines to the East Asian economies. Gazprom, the state gas monopoly and the owner of the economy-wide gas pipeline system, is the coordinator for the programme and is responsible for conducting long-term sales contracts for natural gas deliveries.

In 2011, the Ministry of Energy of the Russian Federation forwarded the second phase development plan up to 2030 for the economy's gas and petrochemical industry to the Russian Government. This includes an updated general plan for the development of key oil and gas investment projects; an updated programme for the division of petrochemical capacities into six clusters, including pipeline transportation projects; projects to build new facilities and upgrade existing ones for the primary processing (pyrolysis) and further processing of raw materials; and activities for the scientific and educational support of the industry.

In January 2012, the Government Presidium of Russia approved a long-term programme for developing the coal industry up to 2030. 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 updated annually and serves as a seven-year outlook for generation and transmission line projects (ME, 2017g). 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, respectively.

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 to 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 a global phenomenon. Owing to increasing interdependence between energy exporters, importers and transition economies, improving international relations is considered 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's control over coal pricing was removed 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, and owns 73% of the shares of Russia's biggest gas company, Gazprom.

As of 2015, the oil industry in Russia comprised 10 vertically integrated companies (VICs) constituting 87% of the crude oil output and 182 small-scale independent enterprises, along with operators of three production-sharing agreements. The refining sector comprises 28 large VICs, nine companies not owned by VIC and 34 small refineries with the total refining capacity of 312 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 in 2014 extracted 67% of the natural gas in Russia and is the owner of 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 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, 2017d).

As of the end of 2016, 181 coal enterprises were operational in the Russian coal industry (66 mines and 115 open-pit mines), with a total annual production capacity of 425 Mt per annum. Coal processing is performed by 65 processing plants and mechanical installations (ME, 2017c).

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, 2017e).

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, AtomEnergProm (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 countries. 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 underdevelopment of its transport infrastructure. The current condition of Russian airports and air-transport facilities provides insufficient capacity and slows the performance of air-transportation services. Further modernisation of air and rail transport is underway in connection with Russia hosting the 2018 Football World Cup and the 2020 World Expo.

The total length of Russian public roads in 2015 was 1 480 817 km, 71% of which are paved (Rosstat, 2017). 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 86 251 km, 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 exceeded 100 Mt in 2017 (Morport, 2017),
- Freight rolling stock renovation plans announced by Russian Railways company (RZD, 2018), this includes the construction of an LNG locomotive, specifically for mining operations in non-electrified areas (RZD-expo, 2017),
- Renovation of suburban and regional passenger trains, which includes upgrade 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. The total length of the pipeline system in the economy was 251 764 km in 2015, of which 71% is gas pipeline, 22% 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, the Azov Sea, the Caspian Sea and the 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 2005. 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, about 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 (about 240 Mtoe per year, less than 1% of the total electricity production). In 2010, the installed RE capacity totalled 2 200 MW, of which less than 25 MW was hydro.

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 single RE generators 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 United States, 23% of Western Europe and 16% of the Asia-Pacific region.

In the Global Nuclear Infrastructure Initiative, announced in early 2006, Russia proposed to host several types of international nuclear fuel cycle service centres as joint ventures with other economies. The centres will be strictly controlled by the IAEA. Their most important roles will be uranium enrichment, reprocessing and storage of used nuclear fuel, along with standardisation, uniform safeguard practices, training and certification, and research and development.

In 2007, the International Uranium Enrichment Centre (IUEC) was established in Angarsk, Siberia, as a joint venture between Russia and Kazakhstan, but open to other interested parties. Ukraine joined the

IUEC in 2010. The IUEC's objective is to provide low-enriched uranium (LEU) to those economies interested in nuclear energy development and ready to comply with the IAEA's non-proliferation regulations. The existing enrichment plant in Angarsk will be used to serve the IUEC.

In February 2007, the IUEC was certified by the IAEA for international operations. A programme for the IUEC's expansion at Angarsk by 2015 was developed. The programme includes three phases:

- Use part of the existing capacity in cooperation with Kazatomprom under the IAEA's supervision;
- Expand capacity with funding from new partners; and
- Internationalise fully with the involvement of many customer economies under the IAEA's auspices.

Russia also created a fuel bank with guaranteed reserves of low-enriched uranium hexafluoride—equivalent to two 1 000 MW reactor loads—at the IUEC available under the IAEA's control. As of 2017, the storage capacity is 120 tonnes of uranium metal as UF₆, from precisely 2.00% to precisely 4.95% enrichment (IUEC, 2017).

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. The expired contracts for depleted uranium hexafluoride enrichment/conversion have not been extended since 2007.

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 seven economies.

Russia has chosen three core reactor technologies for nuclear energy development for the next 20 to 25 years:

- Water–water energetic reactors (VVER) and their modification 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 the period 2012–2020¹. 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).

¹The State Environmental Protection Programme does not include the indicators related to GHG emission.

Russia is considered the world's largest potential host for 'joint implementation' projects under the Kyoto Protocol. In May 2007, the economy adopted procedures for the approval and verification of Russia-based joint implementation GHG reduction projects. Responsibilities were assigned for establishing and maintaining the Registry of Carbon Units, which paved way for the implementation of GHG mitigation projects in Russia.

At the Conference of Parties 15 in December 2009, Russia pledged to reduce its GHG emissions by 25% from the 1990 level by 2020, a figure comparable to the targets of the European Union member states and a 50% decrease from the 1990 level by 2050. These emission reductions are contingent on the following conditions: appropriate 1) accounting of the contribution of emissions reductions from Russia's forestry activities will be introduced and 2) all major emitters will undertake legally binding obligations to reduce GHG emissions caused by human activities.

In December 2012, Russia refused to endorse extended pollution limits under UN COP3 at the UN climate change conference in Doha, because the biggest polluters, US; China; and India, have not joined it.

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 is '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).

NOTABLE ENERGY DEVELOPMENTS

ENERGY POLICY

EnergyNET roadmap, adopted in late 2016, is a part of Russia's Technological Initiative (NTI) and it highlights a number of 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).

CLIMATE CHANGE

In accordance with the Decree of the President of the Russian Federation, the year 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

- Structure of the Government of Russia—<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—<http://en.gosnadzor.ru/>
- Ministry of Economic Development of the Russian Federation—<http://economy.gov.ru/en/home/>
- Federal State Statistics Service—
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

- AtomEnergProm—<http://atomenergoprom.ru/en/>
- Federal Grid Company—<http://www.fsk-ees.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/>
- Central Dispatching Department of Fuel Energy Complex—<http://www.cdu.ru/en/>

SINGAPORE

INTRODUCTION

Singapore is 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 719 square kilometres (km²) in 2015, with a population of 5.5 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, biotechnology, and its expanding role in international cargo and fuel shipping.

From 2014 to 2015, the economy's gross domestic product (GDP) grew 1.9% to USD 439 billion. The services industry accounted for the bulk of GDP share at 69%; goods-producing industries (manufacturing and construction) accounted for 26%; and ownership of dwellings¹ accounted for the remaining 4.4%. Manufacturing represented the largest sub-sector by percentage share of GDP (20%), followed by business services (16%) and wholesale and retail trade (15%) (SingStat, 2017).

Table 1: Key data and economic profile, 2015

Key data ^{a; b}		Energy reserves	
Area (km ²)	719	Oil (million barrels)	–
Population (million)	5.54	Gas (billion cubic metres)	–
GDP (2010 USD billion [PPP])	439	Coal (million tonnes)	–
GDP (2010 USD [PPP per capita])	79 256	Uranium (kilotonnes U)	–

Source: ^{a; b} Department of Statistics Singapore (2017); EGEDA (2017).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Singapore has no 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 2015 were 168 320 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 (91 222 ktoe) were exported in the same year (EGEDA, 2017). Other than having a vibrant oil refining scene, Singapore also plays an important role in international shipping and aviation. This is evident from the share of international marine bunkers (26% of imports, or 43 484 ktoe) and aviation bunkers (4.4% of imports, or 7 379 ktoe) in the economy's total energy imports (EGEDA, 2017).

The economy's total primary energy supply (TPES) in 2015 was 25 612 ktoe, 1.7% lower than the preceding year. Oil constituted the largest share of the TPES at about 60% (15 287 ktoe), followed by natural gas at 36% (9 235 ktoe), coal at 1.6% (407 ktoe) and renewables at 1.5% (376 ktoe) (EGEDA, 2017).

In terms of power generation, the economy generated 50 415 gigawatt hours (GWh) of electricity in 2015, an increase of 2.1% from that in 2014 (49 380 GWh) (EGEDA, 2017). Peak demand for electricity stood at 6 960 megawatts (MW), slightly higher than that in 2014 (6 869 MW) (EMA, 2017a). There are six main power

¹ Ownership of dwellings refers to housing services provided by owner-occupiers and individuals who let out their residential properties.

producers in Singapore that contributed to the bulk of the total power generation (94%) in 2015 while auto-producers accounted for the remaining 6% (EMA, 2016a).

Total licensed generation capacity reached 13 349 MW in 2015. 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 78% (10 356 MW) in 2015. Meanwhile, the share of steam turbine plants dropped from 48% (4 640 MW) in 2005 to 19% (2 557 MW) in 2015. Open-cycle gas turbine plants comprised 1.9% (180 MW) of the generation capacity in 2015 while waste-to-energy (WtE) plants accounted for the remaining 1.9% (257 MW) (EMA, 2017a).

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% from 2014. In 2015, petroleum products accounted for 0.7% and coal for 1.2% while other fuels accounted for 2.9% of the fuel mix (EMA, 2017a).

The adoption of solar photovoltaic (PV) systems in Singapore accelerated further in 2015, with installed capacity of grid-connected solar PV systems (59.7 megawatt peak [MW_p]) more than tripling from 2013 (15.3 MW_p). The shares of Singapore's residential and non-residential grid-connected solar PV system installations in 2015 were 4 MW_p and 55.7 MW_p, respectively (EMA, 2017a).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	620	Industry sector	5 586	Total power generation	50 415
Net imports and others	77 098	Transport sector	2 411	Thermal	48 864
Total primary energy supply	25 612	Other sectors	2 502	Hydro	–
Coal	407	Non-energy	6 626	Nuclear	–
Oil	15 287	Final energy consumption*	10 499	Others	1 551
Gas	9 235	Coal	121		
Renewables	376	Oil	5020		
Others	307	Gas	1 241		
		Renewables	0		
		Electricity and others	4 087		

Source: EGEDA (2017) (data collected in September 2017).

* 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 10 499 ktoe in 2015, a 1.6% decrease from that in 2014. Oil remained the bulk of final energy consumption (5 020 ktoe), with a share of about 48%, followed by electricity and others (39%, 4 087 ktoe), natural gas (12%, 1 241 ktoe) and coal (1.4%, 151 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 33% of total final consumption, other sectors (including residential and commercial sectors) accounted for 15% and the transport sector accounted for 14% (EGEDA, 2017).

ENERGY INTENSITY ANALYSIS

Singapore is fully committed to contribute to APEC's objective of a 45% energy intensity reduction by 2035 (2005 as base year) 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).

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) which focuses on a range of interrelated energy issues including improving energy conservation, efficiency and intensity while reducing CO₂ 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 2014, Singapore's energy intensity in 2015 declined both in terms of primary energy as well as final consumption. Primary energy intensity decreased to 58 tonnes of oil equivalent per million USD (toe/million USD) in 2015, 3.6% reduction from that in the previous year. Final energy intensity decreased to 39 toe/million USD, a 3.2% reduction from 2014. These reductions were mostly driven by decreasing energy consumption in the industry and transport sectors.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	61	58	-3.6
Total final consumption	40	39	-3.2
Final energy consumption excl. non-energy uses	25	24	-3.5

Source: EGEDA (2017).

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, which has made great effort in pursuing these options. In 2014, Singapore set a target to increase the adoption of solar power to 350 MWp by 2020, equivalent to 5% of its projected power needs. This has helped accelerate the adoption of solar PV systems in the economy. In 2015, the share of modern renewable energy in final energy consumption increased by 14% compared with 2014.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	10 669	10 499	-1.6
Non-renewables (Fossils and others)	10 603	10 425	-1.7
Traditional biomass*	0	0	0
Modern renewables*	66	74	12
Share of modern renewables in final energy consumption (%)	0.62%	0.71%	14%

Source: EGEDA (2017).

* 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 strategies² 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 end total dependence on piped imports from Malaysia and Indonesia for gas requirements—which accounted for 95% of its power mix in 2015 (EMA, 2015a)—Singapore began operating its first liquefied natural gas (LNG) terminal in May 2013 (SLNG, 2014). This has enabled the economy to diversify its gas supplies by importing LNG from Australia, Equatorial Guinea and Trinidad and Tobago (MTI, 2015) while securing additional gas for its growing gas demand and adding LNG to the energy mix.

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' (MTI, 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' (MTI, 2015).

Singapore is also intensifying its efforts to promote more efficient energy use and decrease CO₂ 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' (MTI, 2015). 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 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 123 out of 142 countries (NCCS, 2015).

More recently, in January 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 a slower growth of the economy's labour force. The CFE was tasked to build on the 2010 Report by the Economic Strategies Committee and 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, 2016):

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 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

² Diversify Energy Supplies; Enhance Infrastructure and Systems; Improve Energy Efficiency; Strengthen the Green Economy; Price Energy Right.

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, the SP Group (formerly known as Singapore Power Ltd) was created. Electricity activities under the PUB (including electricity transmission and the distribution grid, market support services and power-generation companies) were transferred to Temasek Holdings, a state-owned company. The Singapore Electricity Pool was established in 1998 as a day-ahead electricity market to facilitate trading of electricity between generation and retail companies in a competitive environment.

The Government of Singapore introduced additional reforms in 2000, separating the natural monopoly or non-contestable part of the electricity market (the electricity transmission and distribution grid) and the competitive or contestable part (power generation and retail). As a result, three power-generation companies—Senoko Power Ltd, PowerSeraya Ltd and Tuas Power—were divested as private companies in 2008 to compete with each other and other power-generation companies in Singapore. Additionally, the government founded an independent power system operator and liberalised the electricity retail market.

In April 2001, the Energy Market Authority (EMA) was established to regulate the electricity and gas industries and promote competition in these industries, and since then, it has progressively opened up the retail electricity market to enhance competition and allow business consumers more options to manage their energy cost. The National Electricity Market of Singapore (NEMS), established in 2003, allows generation companies to compete to sell electricity at half-hour intervals in the wholesale electricity market. NEMS represented a progression from the Singapore Electricity Pool to fully competitive wholesale and retail electricity markets.

Currently, electricity consumers in Singapore are separated into contestable and non-contestable consumers. Contestable consumers refer to business consumers with an average monthly electricity consumption of at least 2 megawatt-hours (MWh). They can opt to purchase electricity either at the regulated tariffs from SP Group, the market support services company or directly from retailers of their choice at non-regulated prices. Contestable consumers currently represent more than 80% of the total electricity demand in Singapore. Non-contestable consumers, which include the remaining business consumers and all households in Singapore, purchase electricity from SP Group at the regulated tariffs (EMA, 2018).

Moving forward, Singapore plans to fully liberalise the electricity industry. Starting from the second half of 2018, under the Open Electricity Market, all the remaining electricity consumers will also have the option of buying electricity from retailers other than SP Group.

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 works closely 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.

The gas market's restructuring is mainly aimed at supporting the liberalisation of the electricity industry by providing a competitive source of natural gas for electricity generation. The Government of Singapore expects greater competition in the gas and electricity sectors and the benefits of competition, such as lower prices and a wider choice of retailers, to be passed through to consumers.

In 2016, Singapore imported 9.7 Mtoe of Natural Gas, comprising 76.6% Piped Natural Gas (PNG) and 23.4% LNG (EMA 2017b). 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 (The 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, 2014a).

The terminal's capacity will rise to 11 Mtpa in 2018 when the fourth tank and additional regasification facilities become operational (EMA, 2016b). The LNG terminal is also capable of providing ancillary services, such as LNG trucking, cool-down and break-bulks. 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.

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 2017c). To encourage greater gas-on-gas competition, the government will also allow third-party spot LNG imports and new PNG imports on a case-by-case basis (EMA, 2017b).

ENERGY TECHNOLOGY/RESEARCH AND DEVELOPMENT

In 2014, Singapore announced five energy technology roadmaps to guide the formulation of technology master plans and funding initiatives. These roadmaps are for solar photovoltaic, carbon capture and

storage/utilisation, green data centre, building energy efficiency and industry energy efficiency (NRF, 2014a).

Singapore also supports and promotes energy R&D to develop capabilities to support the clean energy sector as a key growth area; to grow a viable industry that will create jobs; to meet Singapore's energy challenges and its sustainable development objectives and so on.

In terms of funding, the National Research Foundation (NRF) allocated SGD 170 million in 2007 and another SGD 195 million in 2011 to the Energy Innovation Programme Office (EIPO) to promote R&D in the energy sector (NRF, 2014b). Under the economy's five-yearly R&D plan covering the period 2011–2015, the Research, Innovation and Enterprise (RIE) 2015 awarded more than SGD 60 million in funding to catalyse R&D of innovative technologies and solutions in the energy sector. Building on the momentum, a further SGD 46 million has been allocated to spur research into energy technologies and build capabilities in smart grids, power utilities and energy storage under the RIE 2020 (EMA, 2016c).

The EIPO has also supported the establishment of research centres for clean energy. For example, the Solar Energy Research Institute of Singapore (SERIS) was established in 2008 to conduct industry-oriented R&D in solar energy technologies and their integration into power systems and buildings. There are currently around 150 researchers employed with SERIS, which closely collaborates with universities, research organisations, government agencies and industries, both locally and globally. The Energy Research Institute at Nanyang Technological University (ERI@N) was also established with the objective of advancing research aimed at improving the efficiency of current energy systems and maximising the use of alternative energy sources. In a related effort, the Agency of Science, Technology and Research (A*STAR) set up the Experimental Power Grid Centre (EPGC), a programme that undertakes R&D activities in areas such as intelligent and decentralised power distribution, control and management of distributed energy resources, and smart and interactive energy utilisation. It features a 1 MW experimental power grid which is designed to create various power network configurations at near grid-like conditions. This facility acts as a platform for researchers, industries and public agencies to develop energy technologies before bringing them to larger-scale test-beds or commercialisation.

The Energy Innovation Research Programme (EIRP) is a competitive R&D grant call initiative under the EIPO that aims to strengthen Singapore's R&D capabilities and address its energy-related challenges. Between 2012 and 2015, the EIRP launched 13 grant calls in areas such as solar, green buildings, power generation, energy storage, smart grids and gas (NUS, 2015).

The EMA also offers various research grants. Recent example includes a competitive grant call launched by EMA in May 2017 to seek R&D proposals to improve the resilience of Singapore's cyber-physical power systems and energy markets, through the use of technologies such as big data, artificial intelligence and machine learning. In October 2017, EMA awarded a SGD 6.2 million grant to a consortium led by the National University of Singapore (NUS) to develop solar forecasting capabilities over a four-year project (EMA, 2017c).

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, 2015a). 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, 2015b).

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 the 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 Act 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 to reduce the energy use of various sectors of its economy.

In 2007, the government established the Energy Efficiency Programme Office (E²PO), a multi-agency committee led by the NEA and the EMA, in order to implement energy efficiency to promote energy efficiency in both public and private sectors through legislation, incentives and information (NEA, 2014). These energy efficiency efforts are targeted at various sectors, such as power generation, industry, transport, buildings and households.

The E²PO promotes and facilitates the adoption of energy efficiency in Singapore under the following five strategic goals (E²PO, 2014):

- Promote energy efficiency through regulation and standards, incentives and open information
- Develop human and institutional capabilities by developing a local knowledge base and expertise in energy management and collaborating with institutes of higher learning (IHLs)
- Promote emerging energy-efficient technologies and innovation through support for research development and demonstration of new energy-efficient technologies, innovation and business process improvements
- Profile and promote energy efficiency internationally through various platforms such as Singapore International Energy Week (SIEW), APEC and East Asia Summits (EAS)
- Benchmark Singapore's energy efficiency initiatives against other countries and international frameworks

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 CO₂ 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 the least 10% (E²PO, 2015c). Expanding the mass rapid transit system has been the major emissions-reduction policy for the transport sector (E²PO, 2015d).

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 from 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).

Among the various government initiatives to improve industry's energy efficiency are the following:

- Energy Efficiency Fund (E2F): this fund supports energy efficiency efforts at industrial facilities, namely, facilitating 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. For companies that would like to replace their existing equipment with more energy-efficient ones, up to 30% of the project costs could be subsidised.
- 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 program 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 2018, 261 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 program 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 about 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 One-Year Accelerated Depreciation Allowance Scheme: this tax incentive scheme allows capital expenditures on qualifying energy-efficient equipment to be written within one year instead of three.
- The Investment Allowance Scheme: this tax incentive scheme encourages companies to replace old energy-consuming equipment with more energy-efficient ones by allowing an additional 30% of investment allowance to be deducted from the companies' taxable income.
- 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.
- The Grant for Energy Efficiency Technologies (GREET): GREET is a co-funding scheme launched in 2008 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).

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. The government has also 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:

- 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.
- Testing new technologies such as the Diesel Particulate Filter, diesel-hybrid 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.
- Vehicle Emissions Scheme (VES): the VES became effective on 1 January 2018, replacing the Carbon Emissions-Based Vehicle Scheme. The scheme is meant to improve the number of green vehicles purchased, with cars enjoying rebates for having low-carbon emissions while those with high carbon emissions must pay a surcharge (LTA, 2017).
- Fuel Economy Labelling Scheme: since 2012, any passenger and light goods vehicles sold in Singapore must show a Fuel Economy Label that provides information on its fuel efficiency to help buyers make better decisions. Fuel economy labels will be redesigned to help potential vehicle buyers make informed decisions in choosing cleaner, more fuel-efficient cars in 2018.
- 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).
- EV test-bed: An inter-agency EV taskforce (EVTF) led by the EMA and the Land Transport Authority (LTA) launched the EV test-bed from June 2011 to December 2013 in order to determine the feasibility of EVs in Singapore (EMA, 2014c). 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, which will focus on vehicle fleets such as EV car sharing and E-taxis (LTA, 2014). As part of this second phase of the EV test-bed, HDT Singapore Taxi Pte. Ltd also launched a fleet of electric taxis in late 2016 (The Straits Times, 2016). Singapore will launch an EV car-sharing program in collaboration with the Bolloré Group by mid-2017. EVs will be deployed in every single Housing & Development Board (HDB) town by 2020, allowing as many residents as possible to enjoy car-sharing facilities (LTA, 2016a).
- 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, 2016b).

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, 2017). 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 CO₂ 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, 2017):

- **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.
- **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.
- **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. As of November 2017, there were 2 056 grid-connected PV installations with a total capacity of 141.3 MWp, comprising 687 residential (7.1 MWp) and 1 369 non-residential (134.2 MWp) installations (EMA, 2017a). The list of solar initiatives by the economy includes the following:

- In support of Singapore’s solar energy plans, HDB has committed to roll out 220 MWp of solar panels at about 5 500 HDB blocks by 2020. As of November 2017, HDB has held three solar leasing

tenders under the SolarNova programme and has committed a total solar capacity of 190 MWp for 3 350 HDB blocks (HDB, 2017).

- 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. 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. As of August 2017, a total of 18 HDB projects have been designed with solar-ready roofs.
- Added to HDB's efforts to expand solar energy, the EDB and PUB also conducted a pilot SGD 11 million 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 (2 MW) as an alternative to rooftop-based installations (NCCS, 2014). 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).
- The EMA has also increased the intermittent generation threshold from 350 MWp to 600 MWp in order to help expand solar energy growth (EMA, 2016d). This threshold covers power generation from renewables that vary for natural reasons (sunshine in the case of solar) and require fossil fuel-fired generators as a backup.
- Finally, the 'Handbook for Photovoltaic (PV) Systems' has been published by the EMA and the BCA to facilitate the implementation of solar PV systems in Singapore. It provides information on licensing, market and technical requirements, and building and structural issues related to solar installations.

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 2017, Neste announced plans to expand its Singapore refinery by another one million tonnes per annum. A final investment decision is expected to be reached at the end of 2018, with production at the new facility to begin in 2022 (Platts, 2017).

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 enhance 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 (NEA, 2013).

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 (MEWR, 2015). 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 (MEWR, 2015). 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 (MEWR, 2015).

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, 2014d).

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 countries, were unsuitable for deployment in Singapore given the economy's small size and high population density (MTI, 2012).

CLIMATE CHANGE

Singapore is a small and completely urbanised city-state whose CO₂ emissions account for less than 0.2% of global emissions. The economy has made major progress in reducing its CO₂ emissions although its options for non-CO₂ 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, 2014d).

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 countries 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 (NEA, 2014). 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% in 2015, Singapore has substantially reduced its emissions growth over the past 10 years (NEA, 2014). Singapore's efforts have resulted in improving its average operating margin grid emission factor from 0.5255 kg CO₂/kWh in 2005 to 0.4244 kg CO₂/kWh in 2016 (EMA, 2017a).

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 (Singapore Budget, 2018):

- The carbon tax will generally be applied upstream, for example, on power stations and other large direct emitters, rather than electricity users. The expected tax rate is between SGD 10 and SGD 20 per tonne of greenhouse gas emissions. Details are pending the results of industry consultation (NCCS, 2017) to be levied 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. 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. This will be used to support companies in improving energy efficiency, such as funding existing green initiatives via the Productivity Grant (Energy Efficiency) and the Energy Efficiency Fund).

OPEN ELECTRICITY MARKET

As Singapore progresses towards a fully liberalised electricity market, a soft launch of the Open Electricity Market will commence in April 2018. A total of 108 000 residential consumer accounts and 9 500 business consumer accounts in the Jurong area will be able to choose to buy electricity from a retailer with a price plan that best meets their needs. EMA will extend this choice and flexibility to consumers in the rest of Singapore in the second half of 2018. This will involve 1.3 million accounts, mainly households (EMA, 2018).

SMART METERING TRIAL FOR UTILITIES CONSUMPTION

A pilot scheme will be conducted in the second half of 2018 to test technical solutions for remote metering for utilities. The trial will leverage the existing automated meter reading system for electricity metres to cover water and town gas meters. It will include the development of a mobile application to provide timely and useful information to help them better manage their utility consumption (EMA, 2017d).

BUILDING SOLAR FORECASTING CAPABILITIES AND TEST-BEDDING ENERGY STORAGE SYSTEMS

In October 2017, EMA and the SP Group awarded two consortiums to implement the economy's first utility-scale Energy Storage System (ESS). CW Group and Red Dot Power will receive about \$17.8 million in grants to build this test-bed with an aggregate capacity of 4.4 MWh. The test-bed is expected to be operational for three years to evaluate the performance of different ESS technologies under Singapore's hot, humid and highly

urbanised environment. ESS could support the deployment of intermittent generation sources (such as solar) in Singapore by reducing peak demand and providing regulation reserves, which will in turn facilitate greater deployment of solar power in Singapore (EMA, 2017e). EMA is also exploring the feasibility of combining energy storage with solar forecasting capabilities. It awarded a SGD 6.2 million research grant to a consortium led by the NUS to look into improving the accuracy of solar PV output forecasts and grid management using techniques in weather prediction, remote sensing, machine learning and grid modelling (EMA, 2017c).

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, 2017f).

DEMAND-SIDE MANAGEMENT

In October 2016, EMA signed a Memorandum of Understanding with 16 partners for a pilot programme to optimise energy consumption by managing demand. This pilot, known as Project OptiWatt, aims 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 IHLs, government agencies, companies, electricity retailers, research institutions and the electricity grid operator (EMA, 2017g).

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 with an exclusive right to import and sell LNG in Singapore up to 1Mtpa each, or for a period of three years, whichever is earlier (EMA, 2016e).

NEW GENERATION CAPACITY

On 26 October 2015, the NEA signed a WtE services agreement (WESA) with TuasOne Pte Ltd to build Singapore's sixth WtE plant scheduled to be operational in 2019 (NEA, 2015c). The plant will be Singapore's largest WtE plant with the capacity to incinerate 3 600 tonnes of waste per day to generate 120 MW of electricity per day. TuasOne Pte Ltd is a company formed by the consortium of Hyflux Ltd and Mitsubishi Heavy Industries Ltd. This is the second WtE plant that the NEA has awarded to a private enterprise to design, build, own and operate under the Public-Private Partnership (PPP) scheme after the Keppel Seghers Tuas WtE plant, which became operational in 2009.

Singapore's major power-generation companies are Senoko Energy, YTL Power Seraya, Tuas Power Generation, SembCorp Cogen, Keppel Merlimu Cogen, PacificLight Power and Tuaspring. PacificLight Power and Tuaspring are the most recent generation plants added to the economy. PacificLight Power started operations in June 2014 as Singapore's first fully LNG-operated power plant. This state-of-the-art 800 MW plant was built at a cost of USD 1.2 billion. The Tuaspring cogeneration plant, which combines power and water desalination facility, commenced operations in August 2015.

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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 south-west coast of Japan. With an area of 36 193 square kilometres (km²) (Department of Statistics, Ministry of the Interior, 2018), 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 2015, Chinese Taipei's gross domestic product (GDP) was USD 1 002 billion and its per capita income was USD 42 684 (2010 USD purchasing power parity [PPP]). Its GDP grew on an average at a rate of 3.6% during 2000–15. 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 (35%) and agriculture (1.7%) in 2015 (BOE, 2017a). 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 23 million grew at a rate of 0.4% during 2000–15 (EGEDA, 2017).

Lacking natural resources, Chinese Taipei is highly dependent on energy imports in order to meet domestic energy demand. According to the U.S. 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, 2015

Key data ^{a, b}		Energy reserves ^c	
Area (km ²)	36 197	Oil (million barrels)	2.4
Population (million)	23	Gas (billion cubic metres)	N/A
GDP (2010 USD billion PPP)	1 003	Coal (million tonnes)	–
GDP (2010 USD PPP per capita)	42 684	Uranium (kilotonnes of U)	–

Sources: ^a Department of Statistics, Ministry of the Interior (2018); ^b EGEDA (2017); ^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, 2017a), 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 unchanged over the past few years, increasing 2.3% from 106 514 kilotonnes of oil equivalent (ktoe) in 2012 to 108 970 ktoe in 2015. Regarding the composition of the TPES, fossil fuels continue to be the dominant fuel consisting of 89% of the total supply. By fuel type, oil contributes the largest share (39%), followed by coal (33%), natural gas (17%), renewable energy (RE) (2.4%) and other fuels (8.7%) (EGEDA, 2017).

In 2015, Chinese Taipei imported nearly 308 million barrels of crude oil, 2.4% lower than the 315 million barrels imported in 2014. The Middle East is the major supplier, accounting for 86% of the total oil imports, followed by Angola (8.1%) (BOE, 2017a). 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.

Regarding coal, Australia and Indonesia are the major suppliers accounting for 47% and 36%, respectively, of the total coal imports totalling up to 54 million tonnes in 2015. Most of this fuel is used for power generation.

Because indigenous natural gas only accounts for 1.7% of the total natural gas supply in Chinese Taipei, almost the entire gas demand is met by liquefied natural gas (LNG) imports. Qatar, Indonesia and Malaysia are the largest suppliers, accounting for 47%, 17% and 16% of the supply, respectively, in 2015. The total LNG import in 2015 was 14.2 million tonnes (Mt), 7.6% higher than the 13.2 Mt imported in 2014 (BOE, 2017a).

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	12 414	Industry sector	22 250	Total power generation	258 020
Net imports and others	101 035	Transport sector	12 161	Thermal	207 861
Total primary energy supply	108 970	Other sectors	12 251	Hydro	7 505
Coal	35 939	Non-energy	22 642	Nuclear	36 471
Oil	42 699	Final energy consumption*	46 681	Others	6 183
Gas	18 221	Coal	6 869		
Renewables	2 606	Oil	16 406		
Others	9 504	Gas	3 142		
		Renewables	291		
		Electricity and others	19 974		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2015, electricity generation in Chinese Taipei reached 258 026 gigawatt-hours (GWh). Of the total electricity production, the hydropower generated by the Taiwan Power Company (TPC) comprised 2.9%, thermal power 51% (23% coal, 4.5% oil and 23% LNG), nuclear power 14%, wind power 0.28%, cogeneration 15% and independent power producers (IPPs) 17%. In terms of the generating capacity, the TPC dominates Chinese Taipei's electric power sector with 65% and IPPs account for 18% of the total capacity. IPPs are required to sign power purchase agreements with the TPC, which distributes power to consumers. To expand foreign participation, in January 2002, the government permitted foreign investors to own up to 100% of an IPP (BOE, 2017a).

FINAL ENERGY CONSUMPTION

The total final consumption in Chinese Taipei was 69 304 ktoe in 2015, 1.6% higher than that in 2014. The non-energy sector is the largest energy consumer with 33%, which is mostly used by chemical and petrochemical industries. The second largest energy consumer is the industrial sector accounting 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 (15%), gas (6.7%) and RE (0.6%) (EGEDA, 2017).

ENERGY INTENSITY ANALYSIS

In terms of energy intensity by the TPES, Chinese Taipei showed an improvement with a reduction of 2.1%, declining from 111 tonnes of oil equivalent per million USD (toe/million USD) in 2014 to 109 toe/million USD in 2015. However, energy intensity in terms of the total final consumption showed a 1% increase from 68 toe/million USD in 2014 to 69 toe/million USD in 2015, which shows the transformation is more efficient now.

Table 3: Energy intensity analysis, 2014 vs 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	111	109	-2.1
Total final consumption	68	69	1.0
Final energy consumption excl. non-energy consumption	46	47	1.5

Source: EGEDA (2017).

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 12% from 1 200 ktoe in 2014 to 1 349 in 2015. The share of modern RE to final energy consumption also showed an increase from 2.6% in 2014 to 2.9% in 2015.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	45 700	46 681	2.2
Non-renewables (fossils and others)	44 500	45 332	1.9
Traditional biomass*	0	0	0
Modern renewables*	1 200	1 349	12
Share of modern renewables to final energy consumption (%)	2.6%	2.9%	10%

Source: EGEDA (2017).

* 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, 2017b).

The main vision of 'New Energy Policy' is to initiate energy transition and reform power market regulation. It has two main objectives:

1. Enlarge clean energy share of power mix: increase RE share to 20% and natural gas share to 50% of the total power mix in 2025. Reduce coal share of total power mix to 30% in 2025.
2. Nuclear-free homeland: decommission the three existing nuclear plants when their authorised 40-year lifespans expire between 2018 and 2025. Achieve nuclear-free homeland in 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 meter
- 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 the 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. To diversify the energy mix and increase the share of self-produced energy as well as expand RE installation to enhance the supply and security of low-carbon energy. To establish smart system integration including the deployment of smart meters and the promotion of 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 costs pricing mechanism through policy tools or market mechanism such as cap and trade and create new green service economy in order 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 grid 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 risks communication as well as to introduce the participatory governance approach to energy policy making. 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 also stockpiles 30 days of oil consumption. The Act mandates that a liquid petroleum gas stockpile lasting more than 25 days be maintained (BOE, 2017c).

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 onshore oil and gas resources might be depleting in 10 years, CPC has made strenuous efforts to develop upstream exploration and conducted acquisitions to secure oil and gas sources. Thus far, CPC has discovered an appraisal well in Chad, which is estimated to contain 1.6 million barrels of crude oil and another four exploration wells with oil and gas in Niger, which are estimated to contain 2.3 million barrels of crude, totalling up to 3.9 million barrels of crude oil for the company. In line with the government's policy of deepening energy supply safety mechanisms and promoting international energy cooperation, the CPC has engaged in international cooperation in exploration and development with the hope of discovering new reserves of oil and natural gas. As of the end of 2016, this cooperation extended to 22 fields spread over eight economies and countries, totalling up to 1 142 producing wells.

Within Chinese Taipei, CPC completed two-dimensional (2D) seismic surveys over 82 km in Pingtung Plain, a precise gravity survey of the Fongshan mud structures and geological surveys of 73 km², in addition to repairing three production wells in 2016. There are currently 33 oil and gas producing wells spreading 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 320 million cubic metres of natural gas and 8 446 kilolitres (kL) of condensate annually.

For offshore exploration, CPC cooperates with Canada's energy company Husky Energy on a deep-water exploration in Tainan Basin. Pre-Stack Depth Migration on 2D seismic surveys was completed in 2016. A three-dimensional seismic survey is scheduled to be conducted during the second quarter of 2017. Additionally, CPC collaborates with National Taiwan University and National Cheng Kung University on a government contract project to evaluate the potential oil and gas resources in the East China Sea and the South China Sea (CPC, 2017).

ENERGY MARKETS

ELECTRICITY MARKETS

The government of Chinese Taipei aims to secure a total electricity supply with a reserve capacity of 15% (BOE, 2017c) 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 2016, the installed capacity of TPC is 42 130 MW, mainly comprising thermal power generation and nuclear power generation as well as pumped hydro power and RE (TPC, 2017). In the end of 1980s, TPC's power plant construction was delayed because of protests, which led to 36 times the restriction on electricity use during 1991 and 1994 (BOE, 2017d).

In January 1995, the MOEA announced an invitation to the private sectors to participate in power generation as IPPs. The electricity produced by IPPs must be sold to TPC through its transmission lines. There are four stages of opening the IPPs from 1995 to 2006. As of end of 2016, there were two coal-fired IPPs, seven gas-fired IPPs, three hydro IPPs, nine solar-photovoltaic (PV) IPPs and 12 wind-power IPPs (BOE, 2017d).

To become a nuclear-free economy and to 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 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, 2017c).

The first stage amendment includes amendment of three enterprises: generating enterprise, transmission and distribution enterprise and retailing enterprise (BOE, 2017c).

- **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 and the scope of its business operation covers the entire economy. These are 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 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’, BOE started drafting an ‘Energy White Paper’ to help facilitating energy transition. In February 2018, BOE released the ‘Energy Saving Target and Roadmap’ implementation plan, aiming to improve energy intensity by 2.4% every year and electricity intensity improved by 2% every year between 2017 and 2025. The roadmap includes implementation plans in four sectors: commercial, industrial, building and transport. It is expected to save 5 Mtoe or 16.5 TWh in 2025 as compared to 2016 (BOE, 2018a). The energy-saving roadmaps of each sector are as follows:

- **Commercial sector**
 - Target: improved energy efficiency in the commercial sector and the setup of a local energy-saving mechanism. They expect to save 6.5 TWh electricity and 33 ktoe in 2025 compared to 2016.
 - Roadmap: promote energy audit and provide energy-saving counselling for the services subsector. Improve energy efficiency management for the commercial sector. Strengthen basic energy-saving measures in local areas and increase public participation (BOE, 2018b).
- **Industrial sector**
 - Target: reduce energy intensity in the industrial sector by 45% in 2025 compared to 2005. Reduce 2.3 Mtoe in during the period 2016–25. Reduce 7 million tonnes of carbon dioxide (CO₂).
 - Roadmap: promote energy-intensive industries transition, such as improving manufacturing processes and retrofitting factories as well as using more low-carbon fuels. Provide energy-saving and carbon-reduction counselling services for manufacturers. Promote regional resources integration and setup an incentive mechanism for energy saving (BOE, 2018c).
- **Building sector**
 - Target: improve energy-savings design index for new buildings by 10%, add 500 green building materials and candidate certificates every year. Strengthen current energy-saving measures of existing buildings. Reduce 636 ktoe or 31 TWh in the building sector in 2025 compared to 2016.

- Roadmap: improve energy-saving-related regulations and measures for buildings. Subsidise local governments with green building random inspection. Promote transparency of building energy information. Develop cloud-energy-saving simulation estimation tools for buildings. Conduct feasibility studies of zero-energy buildings (BOE, 2018d).
- **Transport sector**
 - Target: reduce 850 000 kilolitres of gasoline use, 104 000 kilolitres of diesel use in 2020 compared to that in 2017. Increase electricity by 0.4 TWh in 2020 compared to 2017. Reduce 2 million tonnes of CO₂ in the transport sector in 2020 compared to 2017.
 - Roadmap: eliminate 80 000 Type I (more than 24 years) and Type II (18–24 years) diesel vehicles in 2019 by subsidising their replacement on the basis of vehicle type and years during 2017–19 with an amount of NTD 30 000–400 000. Increase highway public transport by 2% in 2020 compared to that 2015—1.2 billion people. Improve fuel economy standards for motorcycles by 10%, passenger car by 30% and truck by 25% in 2022 compared to those in 2014. Complete the electrification of round-the-island railway in 2022. Complete the electrification of 10 000 buses in Taipei in 2030. Stop selling non-electric motorcycles in 2035 and non-electric cars in 2040 (BOE, 2018e).

RENEWABLE ENERGY

The two main RE sources in Chinese Taipei are 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 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	2.9
Offshore Wind	–	520	3 000	–	1.9	11.1
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	4.8
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).

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, 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 rooftop and 17-GW 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 wind farms in shallow sea area and then develop wind farms in deep sea area to reach the target of 3 000 MW in 2025 (ITRI, 2017).

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 in 2013.

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 life-span 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; Units 1 and 2 of the second plant in 2021 and 2023 and Units 1 and 2 of the third plant in 2024 and 2025.

CLIMATE CHANGE

GREENHOUSE GAS EMISSIONS

Chinese Taipei produces CO₂ emissions that account for about 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 United Nations and is consequently not eligible to sign the Kyoto Protocol. It is also not directly required to adhere to the emissions reduction requirements. Unlike other UN members, Chinese Taipei is unable to conduct carbon emissions 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).

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USEFUL LINKS

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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 Southeast Asia’ as it is surrounded by fast-growing economies such as Myanmar, the Lao People’s Democratic Republic and Cambodia to the north and east, and Malaysia to the south. Thailand has an area of 513 120 square kilometres (km²) and had a population of about 69 million in 2015. Its gross domestic product (GDP) that year reached USD 1025 billion (2010 USD purchasing power parity [PPP]), a 2.9% increase from USD 996 billion in 2014. In the same period, the GDP per capita increased 2.6%, from USD 14 553 (2010 USD PPP) to USD 14 928 (2010 USD PPP). The largest contributors to its GDP were services (55%) and industry (36%) (UN, 2017).

Thailand has limited energy resources. At the end of 2016, Thailand had proven reserves of 405 million barrels of oil (Mbbbl), 220 billion cubic metres (bcm) of natural gas and 1 036 million tonnes (Mt) of coal. Based on its production rate in 2016, it will deplete its domestic supply very soon—oil resources within two years and natural gas in five years (BP, 2017). Most coal in Thailand is lignite, which is a low ranking coal with high emissions. Notwithstanding its resources, Thailand is highly dependent on energy imports, particularly oil, with about 84% of its oil and 25% of its gas supply coming from imports. (EPPO, 2017).

Table 1: Key data and economic profile, 2016

Key data ^{a, b}		Energy reserves ^c	
Area (km ²)	513 120	Oil (million barrels)	405
Population (million)	69	Gas (billion cubic metres)	220
GDP (2010 USD billion PPP)	1025	Coal (million tonnes)	1036
GDP (2010 USD PPP per capita)	14 928	Uranium (kilotonnes U)	–

Sources: ^a UN (2017); ^b EGEDA (2017); ^c BP (2017).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Thailand’s total primary energy supply in 2015 was 130 916 kilotonnes of oil equivalent (ktoe), which represented a decrease of 2.1% from 2014. Oil accounted for 39% of the total primary supply, while gas, coal and others accounted for roughly 32%, 9% and 20%, 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 2015, coal supply was 11 746 ktoe, down 10% from the previous year.

Natural gas supply in 2015 was 41 661 ktoe, a 0.2% decrease from 41 753 ktoe in 2014. Although natural gas is used mostly 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, both in the form of piped gas and liquefied natural gas (LNG).

In 2015, total electricity generation was 184 350 gigawatt-hours (GWh). Thermal generation, mostly from natural gas and coal, accounted for nearly all of its power generation (92%), with hydropower and others accounting for the rest. In addition to its domestic capacity, Thailand purchased power from the Lao People’s Democratic Republic and Malaysia.

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	76 754	Industry sector	28 125	Total power generation	184 350
Net imports and others	63 385	Transport sector	25 595	Thermal	170 073
Total primary energy supply	130 916	Other sectors	21 679	Hydro	3 838
Coal	11 746	Non-energy	10 950	Nuclear	0
Oil	50 530	Final energy consumption*	75 399	Others	10 439
Gas	41 661	Coal	4 403		
Renewables	25 934	Oil	35 225		
Others	1 045	Gas	6 070		
		Renewables	14 103		
		Electricity and others	15 598		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2016 amounted to 6.8 trillion cubic feet (Tcf), consisting of 6.6 Tcf in gas fields in the gulf and 0.23 Tcf in onshore areas. Compared with the previous year, the proven gas reserves fell by 0.47 Tcf (about 6.49%). Although higher production efficiency, new discoveries and new projects in Bongkot and Arthit resulted in additional proven gas reserves, the total proven gas reserves decreased because of higher throughput than discovery (DMF, 2016). In 2016, domestic natural gas production (including Thailand-Malaysia Joint Development Area, JDA) was at 3 767 million standard cubic feet per day (MMscfd), accounting for 75% of Thailand's gas. The remaining 25%, 859 MMscfd was imported from Myanmar, and along with the imported LNG of 390 MMscfd, the total natural gas supply in Thailand stood at 5 015 MMscfd (EPPO, 2017).

CRUDE OIL AND CONDENSATE

At the end of 2016, Thailand's proven reserves of oil and condensate reserves stood at 349.4 Mbbl, with 178.3 Mbbl of crude and 171.1 Mbbl of condensate, respectively, of which 293.4 Mbbl came from the gulf and 56.0 Mbbl from onshore areas. The total proven reserves fell by 47.0 Mbbl (12%) from the previous year. Falling oil prices had caused the concessionaires to defer their capital investment and resulted in a reduction of proven reserves. (DMF, 2016). The accumulated domestic oil production in 2015 was 152 387 barrels per day (bbl/d). The major crude oil fields in Thailand are Sirikit, Benjamas, Bualuang, Jusmin and the Big Oil Project of Unocal (Thailand) Co. Ltd (EPPO, 2017).

COAL/LIGNITE

Thailand has lignite (low-grade coal), which can be used for about 70 years. The total indigenous lignite output in 2016 was 17 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 while lignite from private companies is depleting and is mainly used in the cement, paper, food, and textile industries. In 2016, based on heating value, the proportion of lignite/coal combustion in the power sector was 51.8% and in the industrial sector, 48.2%. Most of the imported coal is sub-bituminous and bituminous. The amount of coal imports have been increasing continuously because domestic lignite concessions have begun to expire and coal is inexpensive compared with other energy sources (EPPO, 2017).

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 40% in 2016, there was a large increase in IPP, SPP and imported electricity. In 2016, the economy's power generating capacity stood at 41 556 megawatts (MW), an increase of 274 MW from 2015, with EGAT contributing 40%; IPP, 36%; SPP and VSPP, 15%; and imported electricity from Lao PDR and exchange with Malaysia, 9% (EPPPO, 2017).

FINAL ENERGY CONSUMPTION

Thailand's total final consumption in 2015 was 86 349 ktoe, an increase of 4.9% from the previous year. The transport sector was the largest energy-consuming sector, accounting for 25 595 ktoe, or 30% of total final consumption. The second-largest energy consumer was the industrial sector, which consumed 28 125 ktoe in 2015, an increase of 4.6% from 2014. Besides the energy-consuming sectors, non-energy products, which are mostly used in the industry sectors, such as feedstock for petrochemicals, account for 13% of total final consumption, or 10 950 ktoe. By fuel type, oil accounted for 47% (35 225 ktoe) of final energy consumption (excluding non-energy uses) in 2015, followed by electricity and others (21%), renewables (19%), gas (8.1%) and coal (5.8%).

Natural gas consumption increased by 9.0%, from 5 566 ktoe in 2014 to 6 070 ktoe in 2015. Oil consumption also increased significantly by 11.7%, from 31 531 ktoe in 2014 to 35 225 ktoe in 2015. In contrast to natural gas and oil, coal consumption decreased by 4.9%, from 4 629 ktoe in 2014 to 4 403 ktoe in 2015. Domestic electricity and other energy consumption in 2015 increased by 7.9%, from 14 461 ktoe in 2014 to 15 598 ktoe in 2015 (EGEDA 2017).

ENERGY INTENSITY ANALYSIS

Thailand's energy intensity (energy consumption/GDP) in terms of primary energy in 2015 was 128 tonnes of oil equivalent per million USD (toe/million USD), which decreased by 4.9% from 134 toe/million USD in 2014. The energy intensity of final energy consumption excluding non-energy increased 3.3%, from 71 toe/million USD in 2014 to 74 toe/million USD in 2015.

Table 3: Energy intensity analysis, 2014

Energy	Energy intensity (tonnes of oil equivalent/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	134	128	-4.9
Total final consumption	83	84	1.9
Total final energy consumption excl. non-energy	71	74	3.3

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

Modern renewables consumption decreased by 7.4% from 2014 to 2015, whereas traditional renewables consumption increased by 4.3% in the same period. The increase of total non-renewables by 9.0% had caused the share of renewables to final energy consumption to decrease significantly by 12.9%. This is because of decreasing crude oil prices in past years which made fossil fuels attractive once again as compared with renewables.

Table 4: Renewable energy share analysis, 2014 vs 2015

	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	70 915	75 399	6.3
Non-renewables (Fossils and others)	55 139	60 088	9.0
Traditional biomass*	6 033	6 291	4.3
Modern renewables*	9 743	9 020	-7.4
Share of modern renewables in final energy consumption (%)	14%	12%	-13%

Source: EGEDA (2017).

* 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 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;

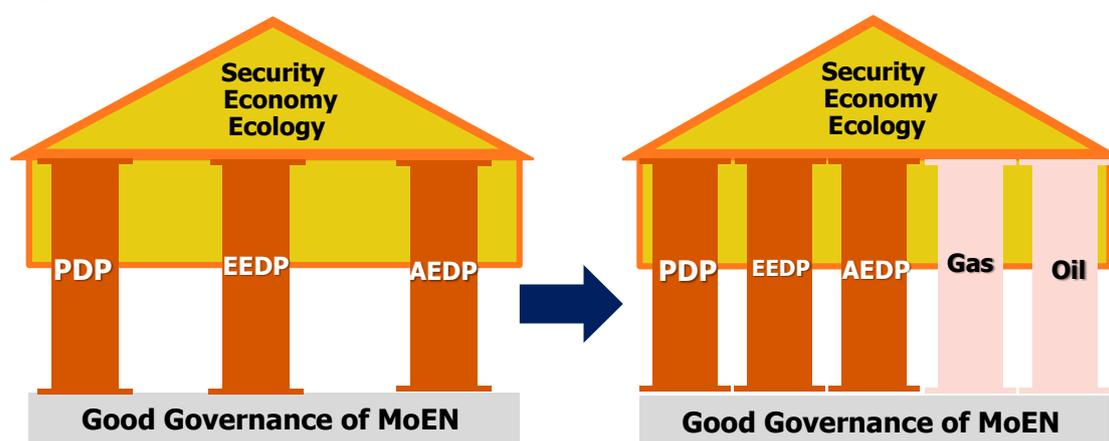
- Electricity Generating Authority of Thailand (EGAT)—the state power generating enterprise;
- PTT Public Company Limited (PTT) and the Bangchak Petroleum Public Company Limited (BCP)—two autonomous public companies;
- The Energy Fund Administration Institute (EFAI)—a public organisation; and
- The Energy Regulatory Commission (ERC) and the Nuclear Energy Study and Coordination Office (NESC) —two independent organisations.

According to the energy policy established under the government of Prime Minister Prayuth Chan-ocha 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 pursued continuously 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) based on the three principles of economy, ecology and security. The blueprint consists of five long-term plans, which are the Power Development Plan (PDP2015) (EPPO, 2016b), the Energy Efficiency Development Plan (EEDP2015) (EPPO, 2016c), the Renewable and Alternative Energy Development Plan (AEDP2015) (EPPO, 2016d), the Gas Plan 2015 (Kaewtathip, S, 2017, DMF, 2016) and the Oil Plan 2015 (EPPO, 2016e). All the proposals have been updated and synchronised to cover the same time period of 2015–36. The PDP2015 includes an energy efficiency target to reduce energy intensity by 30% from 2010 levels, and also includes a target of the AEDP2015 to develop renewable energy generating capacity of about 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 this by:

- 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 EEDP2015, 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 EEDP2015 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 very soon—oil resources within three years and natural gas, in six. To maintain a degree of energy security, the economy must pursue new explorations quickly. 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 various exploration blocks; however, the initiative was halted. The Petroleum Act was to be amended along with the government's energy reform before the twenty-first round of the concession biddings (DMF, 2016). The plan for the government to re-bid needs to be accelerated to catch up with the expiry of the concession blocks Bongkot and Erawan in 2022 and 2023, respectively (S&P Global, 2016).

To secure a natural gas supply for the long term, PTT entered into a contract to buy 2 Mt of LNG per year for the next 20 years from the Qatar Liquefied Gas Company Limited (Qatargas). The first stock of imported LNG was delivered to Thailand in January 2015. Another contract was also secured by PTT with Petronas to deliver up to 1.2 Mt for a period of 15 years. The first cargo was brought into Thailand in July 2017 (Reuters, 2017). In addition, PTT is in negotiations to acquire 1 Mt of LNG per year from Shell Eastern Trading (PTE) Ltd. and another 1 Mt of LNG per year from BP Singapore PTE. Limited. The Ministry of Energy has also entered into an MoU with Lao PDR to import 7 000 MW of electricity. Under the MoU, Thailand has already imported 2 000 MW of electricity from Lao PDR. The latest project is the Hong Sa coal power plant, which expects to connect 1 500 MW to the grid in 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 by:

- 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 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 2010 levels, equivalent to a reduction in 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 five 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 now known as the Energy Efficiency Plan 2015 or EEP2015. The EEP2015 has set a target to reduce energy intensity (EI) 30% by 2036 from 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 EEDP2015 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 high efficiency performance standards (HEPS) and minimum efficiency performance standards (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 ESCO companies 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 EEDP'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 very 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 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 total final energy consumption 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. 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 revised PDP 2010 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 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.

CLIMATE CHANGE

Climate change is an important issue in Thailand, even though in 2012 Thailand contributed to only 0.8% of global GHG emissions. In terms of GHG emissions per capita and per GDP, Thailand's 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 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

THIRD PARTY'S ACCESS

To promote greater competition in the natural gas industry, the Energy Regulatory Commission (ERC) has issued third party access (TPA) codes for state-owned PTT's natural gas transmission pipelines and LNG regasification terminal. This will allow other energy companies to gain access to PTT's pipelines or the LNG terminal facilities in a fair and non-discriminatory manner, which will eventually reduce the market monopoly in the natural gas industry.

THAILAND'S INTEGRATED ENERGY BLUEPRINT

The Ministry of Energy has achieved a significant milestone in accordance with the government's policy to ensure domestic energy security. It has established a comprehensive energy plan, namely the TIEB, based on the three principles of economy, ecology and security. The blueprint consists of five long-term plans including the PDP, the EEDP, the AEDP, the Gas Plan and the Oil Plan. The formulation of these plans has been delicately designed to ensure that public opinion is taken into consideration through a number of public hearings throughout Thailand.

THE APEC FOLLOW-UP PEER REVIEW ON ENERGY EFFICIENCY IN THAILAND— TRANSPORT SECTOR

Thailand conducted the APEC follow-up peer review on energy efficiency focusing on the transportation sector from 3–7 August 2015. The final report was endorsed by the environmental working group (EWG) members in December 2015. It made 48 recommendations to Thailand on energy efficiency in transportation, covering the following six key issues: transport financing and investment; urban land use and transport integration; low carbon transport systems; travel development management; vehicle fuel economy labelling and standards and high efficiency vehicle technologies.

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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 16.6 trillion (2010 USD purchasing power parity [PPP]) in 2015 (EGEDA, 2017). The US spans 9.9 million square kilometres (km²) and has a population of 321 million. The economy's population growth rate has declined from 1.2% in 1997 to 0.7% in 2015. Per capita GDP in 2015 was USD 51 722, the fourth-highest among the APEC member economies (EGEDA, 2017).

The US enjoyed economic expansion from 1990 to 2000, recording a growth of 3.4% in real terms, which then slowed to 1.8% from 2000 to 2015. In 2015, economic growth increased to 2.6% from 2.4% in 2014 (EGEDA, 2017).

The US is the second-largest producer and consumer of energy in APEC. In 2015, the US had 48 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).

Table 1: Key data and economic profile, 2015

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (million km ²)	9.9	Oil (billion barrels)	48
Population (million)	321	Gas (trillion cubic metres)	9
GDP (2010 USD billion PPP)	16 597	Coal (billion tonnes)	252
GDP (2010 USD PPP per capita)	51 722	Uranium (kilotonnes U)	138

Sources: ^a Census (2010); ^b EGEDA (2017); ^c BP (2017); ^d NEA (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

The total primary energy supply in the US in 2015 was 2 188 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, 17% from coal and the rest from other sources such as nuclear energy, hydropower and geothermal energy. Only 13% of the economy's primary energy requirements in 2015 were from net imports. The share of net energy imports declined from a peak of 32% in 2006 (EGEDA, 2017).

The economy's total primary energy supply in 2015 decreased by 1.3% compared with the 2014 level of 2 217 Mtoe. The decline resulted mainly from a 13% decrease in coal supply and a 2% decrease in renewable energy supply. Similarly, a slight reduction in net imports was recorded in 2015 (EGEDA, 2017).

US primary oil supply was 794 Mtoe in 2015, an increase of 1.5% from 2014 (EGEDA, 2017). In 2015, the US was the world's largest crude oil and natural gas liquids and condensate producer, with 6% more production than Saudi Arabia. Production averaged 12.8 million barrels per day (bbl/d), an increase of 8% from the previous year (BP, 2017). Oil import dependence, measured as petroleum net imports as a share of products supplied, was 24.1% in 2015, the lowest since 1970 (EIA, 2017c).

US primary natural gas supply was 646 Mtoe in 2015, an increase of 3.0% from 2014. While the economy's natural gas supply has grown steadily from 1990 to 2015, with an annual growth rate of 1.6%, the primary natural gas supply (including net imports in 2015) grew by 3.0% from the 2014 level (EGEDA, 2017). 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, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	2 018 527	Industry sector	261 574	Total power generation	4 311 641
Net imports and others	257 739	Transport sector	628 990	Thermal	2 882 404
Total primary energy supply	2 188 277	Other sectors	506 274	Hydro	271 129
Coal	374 122	Non-energy	123 300	Nuclear	830 288
Oil	793 952	Final energy consumption	1 396 576	Others	327 820
Gas	646 390	Coal	19 514		
Renewables	147 048	Oil	649 995		
Other	226 765	Gas	317 788		
		Renewables	78 302		
		Electricity and others	331 017		

Source: EGEDA (2017) (data collected in September 2017).

* 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 4.7% of the world's natural gas reserves in 2015 (BP, 2017). As of 2015, the economy's natural gas pipeline transmission network was more than 484 000 kilometres (km) long (PHMSA, 2017). In 2015, the Federal Energy Regulatory Commission (FERC) approved 35 major pipeline projects with a distance of 765 km (FERC, 2017a). In 2015, 392 active underground storage fields in the US had a working gas capacity of 134 billion cubic meters (bcm). On 20 November 2015, gas in storage peaked at 114 bcm; the 2016 peak was on 11 November at a record 115 bcm (EIA, 2017a, 2017b).

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 increased rapidly from approximately 8% of gross withdrawals in 2007 to 48% in 2015 (EIA, 2017d, 2017e). Proved unconventional gas reserves, including shale gas and coalbed methane, are estimated to be 6.2 tcm or more than 60% of the total reserves as of year-end 2015 (EIA, 2018a). Thus, further increases in shale gas production are anticipated.

Abundant supplies and relatively low prices have led to several LNG export projects. On 24 February 2016, the first shipment of LNG produced in the lower 48 states left Sabine Pass, Louisiana (EIA, 2016b). By 2020, exporting capacity is expected to rise to 67 million tonnes (Mt) per year, with the addition of five more LNG plants and another liquefaction unit at Sabine Pass (EIA, 2017f). The newly expanded Panama Canal has considerably reduced voyage times for LNG from the US Gulf Coast to markets in Northeast Asia (EIA, 2016c).

The primary energy supply of coal in the US totalled 374 Mtoe in 2015. In 2015, primary coal supply declined by 13% (EGEDA, 2017), as gas took market share from coal in power generation (EIA, 2017c). US coal reserves are concentrated in the east of the Mississippi River in Appalachia and in several western states (EIA, 2015a).

In 2015, the US was the sixth-largest coal exporter in the world, following Australia, Indonesia, Russia, South Africa, and Colombia. In 2015, coal exports amounted to 74 Mt, a decrease of 24% from 2014 and significantly below the 2012 peak of 126 Mt (EIA, 2017i). More than 60% of exported coal was metallurgical, with the rest being steam coal. Europe was the largest importer of coal from the US, constituting almost 45% of US net exports. Coal imports have declined from a peak of 36.3 Mt in 2007 to 11.3 Mt in 2015 (EIA, 2016f).

In 2015, the US produced 4.3 million gigawatt-hours (GWh) of electricity, 67% of which came from fossil fuel plants, 19% from nuclear energy and 14% from renewable energy and other sources (EGEDA, 2017).

The US generated more nuclear energy than any other economy in 2015 (EIA, 2017i). In 2015, 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 2015 and has continued to rise since then (EIA, 2017c). 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 2017, the NRC had approved licence extensions for 86 operating nuclear reactor units and had applications for another seven extensions under review, while operators of three more units had informed the agency regarding their intention to seek extensions between 2021 and 2022 (NRC, 2017a). Operators of eight reactors have announced plans to retire them by 2025 (EIA, 2017g).

Total renewable energy production in the US in 2015 was 147 Mtoe or 7% of the total primary energy supply. Production declined by 1.7% from the previous year because of decline in biomass, hydro and liquid biofuels. The largest types of renewable production were biomass and liquid biofuels (EGEDA, 2017).

FINAL ENERGY CONSUMPTION

In 2015, the total final consumption in the US was 1 520 Mtoe, a decrease of 0.7% from the previous year (EGEDA, 2017), primarily because the winter weather was not as cold in 2015 as in 2014 (EIA, 2017c). 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 (8%). In terms of final energy consumption by fuel (excluding non-energy), petroleum constituted 47%, while electricity and natural gas constituted 24% and 23%, respectively. Coal contributed a modest 1.4% (EGEDA, 2017).

ENERGY INTENSITY ANALYSIS

US energy intensity improved significantly in 2015. (Energy intensity is the amount of energy an economy uses or consumes for every dollar of GDP it produces.) Primary supply intensity in 2015 improved by 3.8% from 137 tonnes of oil equivalent per million USD (toe/million USD) in 2014. Total final consumption intensity improved by 3.2% compared with that in the previous year. Final energy consumption intensity, excluding non-energy, improved by 3.6% (Table 3).

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	137	132	-3.8
Total final consumption	95	92	-3.2
Final energy consumption excl. non-energy	87	84	-3.6

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

The share of modern renewables consumed in the US increased to 7.6% in 2015, an increase of 0.2 percentage points from the previous year. In 2015, the consumption of modern renewables increased by 2.0%. Production of energy from solar, wind and photovoltaic (PV) sources increased, while that from hydro 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 (ktoe)

	2014	2015	2014 vs. 2015
Final energy consumption (ktoe)	1 411 727	1 396 576	-1.1
Non-renewables (Fossils and others)	1 289 779	1 276 476	-1.0
Traditional biomass*	17 540	13 594	-22
Modern renewables*	104 408	106 506	2.0
Share of modern renewables to final energy consumption (%)	7.4	7.6	3.1

Source: EGEDA (2017).

* 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, jurisdiction over 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 (EP Act) 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 programs (DOE, 2012). Key elements of these acts are described below.

ENERGY SECURITY

Among the APEC economies, the US has the lowest exposure to oil supply disruptions, according to a recent composite index (APERC, 2015). Oil import dependence, measured as net imports as a percentage of product supplied, peaked at 60.3% in 2005. By 2016, US import dependence declined to 24.4% by the same measure (EIA, 2017c).

Nevertheless, 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 this is the largest government-owned stockpile in the world (DOE, 2016a). Some 669 million barrels of crude oil are

currently contained in the SPR, the equivalent of 140 days of net crude and product imports, based on the average 2016 levels (EIA, 2017c).

With the oil in the SPR exceeding the IEA's 90-day coverage requirement, Congress passed the Bipartisan Budget Act of 2015 and the Fixing America's Surface Transportation (FAST) Act in December 2015. In December 2016, Congress passed the 21st Century Cures Act authorising further sales. These laws mandated the sale of an estimated 190 million barrels of crude oil between 2017 and 2025 and approved the funding of an SPR modernisation program through the sale of up to an additional USD 2 billion worth of oil (DOE, 2016a; EIA, 2016d). Congress authorised the sale of an additional 7 million barrels in 2025–27 in its year-end 2017 tax cut legislation (US Congress, 2017a). Under the February 2018 Budget Act, Congress authorised the sale of USD 350 million worth of oil in 2018 for infrastructure modernisation and 100 million additional barrels from 2022 to 2027 (US Congress, 2018).

In addition to the SPR, the DOE established a 2 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 (DOE, 2016a). The US Government does not hold strategic reserves of natural gas.

In December 2015, growing US crude oil production also prompted Congress to pass the Consolidated Appropriations Act of 2016, lifting 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 often the government. The US Office of Natural Resources Revenue collected USD 6.0 billion in royalty and other payments in Fiscal Year (FY) 2016 (ONRR, 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 about 25% higher than federal taxes and taxes on diesel are about 6% lower than federal taxes, but there is considerable variation among the states. There are also about USD 0.03 per litre of other state taxes on gasoline and diesel (API, 2018). Some states have also introduced a 'public goods charge' on retail electric and natural gas sales, the proceeds of which fund energy efficiency programs.

A variety of tax breaks 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, 2016a). Tax credits for investments in renewable energy or in energy-efficient home improvements are also available to individuals (DSIRE, 2017).

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 not part of the final operating well. Intangible drilling costs can be deducted in the year spent as a current business expense (IRS, 2016b).

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, 2016). State governments spent an additional USD 368 million on energy R&D in FY2016, more than 60% by the State of California (NSF, 2017). 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 2015, American consumers spent an estimated USD 1.1 trillion on energy purchases or 6.2% of GDP (EIA, 2017c). Government plays many roles in this large market, such as 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 km² of onshore underground mineral estates (BLM, 2017a), of which about 110 000 km² was leased for oil and gas development in 2016 (BLM, 2017b). The Bureau of Ocean Energy Management (BOEM), another office of the DOI, leases another 62 000 km² of offshore oil and gas resources (BOEM, 2018). 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.

The EP Act 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).

As part of the effort to go beyond energy independence and achieve energy dominance, the DOI proposed opening about 90% of federal offshore waters to drilling in 2018. 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 proposed leasing program is in response to a 2017 executive order by President Trump (GPO, 2017a). 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 identifying 11 offshore protected areas mostly located in the Pacific Ocean for review of opportunities for energy exploration and production (NOAA, 2017).

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) and ending a moratorium on leasing federal lands for coal mining (DOI, 2017c).

DOWNSTREAM OIL

The US had almost 123 000 km of crude oil pipelines in 2016 and 100 000 km of oil product pipelines (PHMSA, 2018). 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). The Keystone XL Pipeline, a 1 100-km crude oil pipeline to connect oil production in Alberta, Canada to refineries in the US, cleared its last major regulatory hurdle in 2017 with the approval of a route by the Nebraska Public Service Commission (NPSC, 2017). However, it continues to face a lawsuit from several environmental groups, alleging that the construction permit was approved without updating the environmental impact statement (NPRC, 2017). 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 EP Act 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, 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, 2018). This is consistent with the president’s goal to revive and expand the nuclear energy sector (White House, 2017c).

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 restarted its endeavour 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 about USD 15 billion on developing Yucca Mountain, and the cost to continue the licensing process will be about 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, the federal renewable electricity PTC is an inflation-adjusted per kWh tax credit for electricity generated by geothermal, wind, biomass, hydroelectric, municipal solid waste, landfill gas, tidal, wave and ocean thermal systems. Wind PTCs extend through 2019, while the others ended in 2017. Utilities may elect an ITC in lieu of the PTC. Related individual ITCs are available for residential solar electric, solar water heating, fuel cell, small wind and geothermal heat pump system expenditures through 2021. Several federal loan and loan guarantee programs also exist to encourage the development of renewable energy and other advanced energy facilities (DSIRE, 2017; US Congress, 2018). The DOE Loan Program Office manages a portfolio of about USD 14 billion of loan guarantees covering more than 20 renewable projects (DOE, 2017b). 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. By mid-2017, 29 states had enacted the RPS legislation with varying degrees of stringency. Hawaii has the most ambitious goal: 100% renewable generation by 2045 (LBNL, 2017). 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, 2017).

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 oil has, in fact, declined in recent years, 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 this 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 more than 19 billion gallons of biofuels overall should be blended into the fuel supply for 2018, still short of the 26 billion gallons envisioned by Congress in 2007 (EPA, 2017a). In addition, the February 2018 Budget Act includes a USD 1 per gallon tax credit for biodiesel blenders and producers for the 2017 tax year (US Congress, 2018).

ELECTRICITY AND GAS

The federal government regulates the interstate transmission of electricity and gas, as well as wholesale sales of electricity under the FERC. The 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, 64% of retail customers are served by regulated, investor-owned utilities, 14% by public power systems and 13% by cooperatives (EIA, 2018c). 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 2016, 21 states allowed some customers to choose their electricity service provider, while 8% of electricity customers were served by energy-only providers (EIA, 2017h; 2018c).

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 more than USD 3 billion in 2017–18 (HHS, 2017).

ENERGY EFFICIENCY

Incentives to promote energy efficiency exist at the federal, state and local levels. Federal grants and loans support residential efficiency improvements. The Weatherization 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, 2017). 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 (EIA, 2016e).

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 programs that provide incentives and technical assistance to reduce demand for electricity and natural gas (DSIRE, 2017). In 2016, 32 states had current or pending efficiency targets that require electric and/or gas utilities to meet energy reduction targets over time (EIA, 2016e). At the local level, cities often use building codes to mandate building efficiency improvements (DSIRE, 2017).

CLIMATE CHANGE

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, the EPA may have authority to regulate them under the existing legislation. State and local governments have developed their own goals and action plans.

FEDERAL REGULATION

Consistent with President Trump's 28 March 2017 Executive Order on 'Promoting Energy Independence and Economic Growth', the EPA proposed to repeal the Clean Power Plan (CPP) in October, which would have limited CO₂ emissions in the power sector. The CPP was originally published in October 2015, but the Supreme Court stayed its implementation pending judicial review (EPA, 2017b).

Despite efforts to repeal the CPP, Congress enacted a new clean 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—USD 50 per tonne for carbon dioxide (CO₂) that is buried and USD 35 per tonne for CO₂ that is reutilised (US Congress, 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, power plants in 27 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, 2016f). The MATS regulates acid gases and

mercury from coal-fired plants of 25 MW or greater. Under the MATS, mercury emissions must be 90% below their uncontrolled levels. The EPA issued its final finding in April 2016 (EPA, 2016a).

On 8 December, the BLM issued a final rule to postpone some of the key requirements of the Methane Waste Prevention Rule, which aimed to reduce waste of methane from oil and natural gas production activities on federal and tribal land, until 17 January 2019 (BLM, 2017d). In 2015, the Obama Administration had set a goal of reducing methane emissions from the oil and gas sector by 40–45% below the 2012 levels by 2025 (UNFCCC, 2016). Methane is a key constituent of natural gas and has a global warming potential more than 25 times greater than that of CO₂. In 2016, the EPA issued a final standard to significantly cut methane emissions from new, reconstructed and modified processes and equipment, including hydraulically fractured oil wells (EPA, 2016d). On 19 December 2017, the states of California and New Mexico sued the administration, challenging the issuance of the final rule issued on 8 December to postpone the implementation of the Methane Waste Prevention Rule (CADOJ, 2017). The EPA also issued a final rule in 2016 that requires new and existing 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 CO₂ emissions from the power sector 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 programs. The RGGI has conducted 38 auctions thus far and is now considering an additional 30% regional cap reduction between 2020 and 2030 (RGGI, 2018). 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 2017, California set a target of reducing GHG emissions to at least 40% below the 1990 levels by 2030 in legislation (EIA, 2018f). This builds on the Global Warming Solutions Act of 2006, which sets a mandatory state-wide GHG emissions cap equal to 1990 levels by 2020 (CARB, 2014a). The California Air Resources Board (CARB) has developed an implementation plan to reach the 2030 goal through a 50% renewable portfolio standard by 2030, 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). The governor also signed legislation in 2016 to spend USD 900 million from an ARB-run emissions cap-and-trade program on public transit, housing, communities and high-speed rail (CAGov, 2016a).

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-Württemberg, Germany. The coalition represents 205 jurisdictions with more than 1.3 billion people and almost 40% of the global GDP, including 11 US states (Under2, 2017).

In reaction to President Trump's withdrawal from the Paris Agreement, 19 state governors have joined the bipartisan United State Climate Alliance, pledging to implement policies that advance the goals of the Paris Agreement and aiming to reduce GHG emissions by at least 26–28% below the 2005 levels by 2025 as well as track and report 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, 2018).

Municipal governments have undertaken other GHG initiatives. Notably, these include the US Mayors' National Climate Action Agenda formed in 2014 by the mayors of Los Angeles, Houston and Philadelphia. Each of the 392 cities in the coalition, comprising more than 69 million people, 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 CO₂ emissions below the 1990 levels (USCM, 2017).

VEHICLE EMISSION STANDARDS

In July 2011, a new US combined car and light truck (CAFE) standard was agreed to by 13 major auto manufacturers in cooperation with the state of California to harmonise economy-wide fuel standards to 23.2 km per litre (54.5 miles per gallon) for cars and light-duty trucks by 2025. The supportive auto manufacturers together account for over 90% of all vehicles sold in the US (NHTSA, 2011). The program is estimated to save 4 billion barrels of oil and reduce GHG emissions by the equivalent of about 2 billion metric tonnes over the lifetimes of the 2017–25 model year vehicles (EPA, 2012). The EPA is reconsidering whether the light-duty vehicle GHG standards established for model years 2022–25 are appropriate and is inviting stakeholders to submit any data and information they believe are relevant to the reconsideration (EPA, 2017c).

Unlike light-duty vehicles, which have been subject to fuel economy standards since the 1970s, the EPA and DOT's National Highway Transportation Safety Administration (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 about 1 billion tonnes and save about 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, nine other states have fully adopted CARB's advanced clean car program standards. In July 2014, the CARB issued a new rule for its zero-emission vehicle (ZEV) program for model year 2018, which subsequently included battery electric and hydrogen fuel cell vehicles. The ZEV sales requirement for large manufacturers is 4.5% in model year 2018 and will increase to 22% by model year 2025 (CARB, 2014b).

In July 2016, the White House announced that up to USD 4.5 billion would be available for new types of electric vehicle charging stations, along with plans for electric vehicle charging corridors, more government electric vehicles and more research (DOE, 2016c). The number of electric vehicle charging stations rose to more than 42 000 in 2016, an increase of 36% from 2015. Hybrid vehicle sales declined to about 347 000 in 2016, a decrease of 10% from the previous year and 2 230% from the 2013 peak. Plug-in vehicle sales were about 160 000, an increase of 38% from the previous year (ORNL, 2017). 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).

NOTABLE ENERGY DEVELOPMENTS

US WITHDRAWS FROM PARIS CLIMATE AGREEMENT

On 1 June 2017, President Trump announced that the US would withdraw from the Paris Climate Accord. He said that the 2015 agreement imposed unfair environmental standards on American businesses and workers and vowed to stand against the 'draconian' deal. By the end of the year, the US became the only economy in the world to oppose the agreement. Trump said he wanted to negotiate a better deal, though no steps have been taken in that direction (White House, 2017d). Under the accord, the US had pledged to cut its GHG emissions by 26–28% by 2025 and send USD 3 billion to poorer countries by 2020. Withdrawal from the agreement requires a formal process that could take up to four years (UNFCCC, 2016).

CARBON CAPTURE AND STORAGE POWER PLANT

In January 2017, the first operating power plant with CCS was opened in the US. The Petra Nova facility, a coal-fired plant near Houston, Texas, is one of only two operating power plants with CCS in the world. The plant's Unit 8 is designed to capture about one-third of total CO₂ emissions, which are then used to enhance oil recovery at nearby oilfields. The plant is a joint venture between NRG Energy and JX Nippon Oil & Gas Exploration (EIA, 2017j). The DOE paid USD 190 million of the USD 1 billion overall cost (DOE, 2017c). In 2018, Congress passed an enhanced tax credit to support the operation of new CCS plants (US Congress, 2018).

SUNSHOT HELPS DRIVE DOWN SOLAR COSTS

The DOE announced in September 2017 that its SunShot Initiative cost target of 6 cents per kWh by 2020 for installed utility-scale PV systems in the US was achieved three years ahead of schedule. Given this success, the SunShot program announced a new target to reduce the cost to 3 cents per kWh by 2030. Since the program was launched in 2011, when costs were about 28 cents per kWh, installed capacity has grown from 3 GW to more than 47 GW in 2017. The DOE projects that combining low-cost storage with low-cost PV could enable solar energy to supply almost half of U.S. electricity by 2050 (DOE, 2017d).

LIQUEFIED NATURAL GAS

The DOE launched the latest edition of its ‘Global LNG Fundamentals’ handbook on 18 October 2017 in Tokyo at the LNG Producer–Consumer Conference 2017, sponsored by the Japan Ministry of Economy, Trade and Industry and the Asia Pacific Energy Research Centre. The handbook attempts to cover a broad spectrum of topics involved with developing and financing LNG projects, with in-depth coverage of the considerations for an LNG export project and the development of a diverse domestic market. The handbook also addresses LNG import projects as an alternative to economy-to-economy pipelines. It seeks to leverage the abundance of US natural gas resources and expand LNG exports to promote jobs and economic growth in the US (DOE, 2017e). In July 2017, the private Potential Gas Committee released its biennial assessment stating that US natural gas resources have reached their highest level in the group’s 52-year history. The report indicated that the US had technically recoverable resources of 2 817 trillion cubic feet (Tcf) (79 800 bcm) as of year-end 2016. The group assessed technically recoverable resources and did not consider a specific price or schedule for the discovery and production of gas; these resources are in addition to the proved gas reserves estimated by the Energy Information Administration (EIA, 2017). In 2016, US LNG exports were 187 billion cubic feet (bcf) (5 bcm), more than double the previous annual record, and 2017 exports were more than triple 2016 exports (EIA, 2018d).

CRUDE OIL PRODUCTION TOPS 10 MILLION BARRELS PER DAY

In November 2017, US monthly crude oil production exceeded 10 million barrels per day, the highest since 1970. At 10.038 million barrels per day, production was just below the November 1970 production value of 10.044 million barrels per day. US crude oil production has increased significantly over the past 10 years, driven mainly by production from tight rock formations, including shale and other fine-grained rock, using horizontal drilling and hydraulic fracturing to improve efficiency. The EIA estimated crude oil production from tight formations in November 2017 to have reached 5.1 million barrels per day, surpassing a previous high of 4.7 million barrels per day in March 2015. These formations also produce considerable volumes of natural gas associated with the crude oil (EIA, 2018e).

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USEFUL LINKS

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

Energy Star—www.energystar.gov

Environmental Protection Agency—www.epa.gov/energy

Federal Energy Regulatory Commission—www.ferc.gov

Fuel economy—www.fueleconomy.gov

Nuclear Regulatory Commission—www.nrc.gov

VIET NAM

INTRODUCTION

Viet Nam is an S-shaped economy located in 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 (km²) with diverse geography and an exclusive economic zone stretching 200 nautical miles 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 about 92 million (34% live in cities and 66% in rural areas) (GSO, 2017) and a gross domestic product (GDP) of USD 509 billion (2010 USD at purchasing power parity [PPP]) in 2015 (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 grew continuously 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 2017, the growth reached 6.8%, 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 to traditional fishery products, coffee and rice (nearly 10%) and crude oil (nearly 2%) (Viet Nam Customs, 2017).

As of 2017, Viet Nam's business environment ranking has risen by 14 levels and is now ranks 68th in the world, in part due to improved possibility of electricity, paying taxes and getting credit change (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, 2015

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (km ²)	331 231	Oil (billion barrels)	4.4
Population (million)	91	Gas (billion cubic metres)	617
GDP (2010 USD billion PPP)	509	Coal (million tonnes)	3 360
GDP (2010 USD PPP per capita)	5 553	Uranium (kilotonnes U)	-

Sources: ^a GSO (2017); ^b EGEDA (2017); ^c BP (2017); ^d NEA-IAEA (2016).

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. OECD estimates the identified recoverable resources of uranium at about 3 900 tonnes, which are yet to be produced. Surveys and assessment for renewable energy's potential have been conducted to some extent (APEREC, 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 about 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 is

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 2015 was 71 052 kilotonnes of oil equivalent (ktoe), which is a considerable increase of 8.9% from the 2014 level (Table 2). By energy source, 35% of the supply came from coal, 28% from oil, 13% from natural gas and 24% 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 2015, Viet Nam produced about 23 231 ktoe of anthracite and semi-anthracite coals. With increasing domestic demand for coal, coal exports have rapidly declined to 979 ktoe in 2015, about only 4% of the economy's production and roughly 5% of its export peak in 2007 (EGEGA, 2017). Coal imports are predicted to increase significantly 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 grew by 7.5% from 18.3 million tonnes (Mt) in 2014 to 19.7 Mt in 2015 (AAGR of 4.2% in 2000-15), 49% of which was exported. According to the Viet Nam Oil and Gas Group (Petrovietnam or PVN) forecast and planning, oil production based on current proven reserves will be about 16–18 Mt/year through 2022, which will then decline to less than 14 Mt/year 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 11.4 Mt of imported petroleum products in 2015, which continue to account for the majority (66%) 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.

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 2015 was about 10.5 bcm (PVGas, 2017). 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 in order 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 for the period beyond 2021 (PMVN, 2017a; MOIT, 2015b).

POWER GENERATION

Vietnam Electricity (or EVN) is a state-owned company that has control over the entire national power transmission and distribution. As of the beginning of 2017, EVN owned approximately 61% of the total 42 GW capacity of electricity in Viet Nam (EVN, 2018). Total power generation in 2015 was 161 923 GWh, an increase of 13% from its 2014 level. Of this total electricity output, about 35% came from hydro and almost 65% from thermal energy (Table 2). Only a very small insignificant portion is made up by other renewable sources such as wind and biomass.

Among thermal power sources which grow as high as 7% in capacity, coal-fired power plants recorded the fastest growth in development. With an installed capacity of 13 GW, coal power's share increased considerably to 33% in 2015 from 4% in 2008. Growing deployment of hydropower and coal power led to relative reductions in the roles of gas and oil power plants in Viet Nam's electricity system. Gas power plants experienced a continuous decline in share, from a record level of 41% in 2008 down to 21% in 2015. The share of oil power plants is not substantial (2.3%) but is supposed to rise.

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 2008–15.

Table 2: Energy supply and consumption, 2015

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	69 081	Industry sector	23 454	Total power generation	161 923
Net imports and others	-3 499	Transport sector	11 826	Thermal	105 609
Total primary energy supply	71 052	Other sectors	17 432	Hydro	56 123
Coal	24 608	Non-energy	1 408	Nuclear	0
Oil	20 168	Final energy consumption*	52 711	Others	191
Gas	9 378	Coal	11 409		
Renewables	16 762	Oil	15 607		
Others	136	Gas	1 491		
		Renewables	11 866		
		Electricity and others	12 338		

Source: EGEDA (2017) (data collected in September 2017).

* 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 2015, Viet Nam's final energy consumption (excluding non-energy uses) was 52 711 ktoe, up 3.3% from 2014 (Table 2). By fuel source, oil consumption contributed to the largest share (30%), followed by electricity, renewable energy and coal of around 22–23% per source. Gas consumption has remained quite flat since 2012 at less than 1.5 Mtoe per year.

Industry is an important sector in GDP growth and represents the largest segment of total final consumption at a constant 43%. This sector consumed coal at 42%, electricity at 28%, biomass at 16%, petroleum products at 7% and natural gas at 6%. The transport sector is also a large energy-consuming sector, accounting for 22% of total final consumption. It remained the main consumer of petroleum products at up to 76% of the economy's total requirement. In the other sectors (residential, agricultural and commercial as a whole), energy consumption represented 32% of total final consumption. In this sector, biomass accounted

for the largest amount at 47%, electricity at 33%, petroleum products at 12% and coal at 9%. 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.

ENERGY INTENSITY ANALYSIS

In 2015, Viet Nam's energy intensity in terms of primary energy supply was about 140 tonnes of oil equivalent per million USD of GDP (toe/million USD), which is an increase of 2.1% from 137 toe/million USD in 2014, while energy intensity in terms of total final consumption reduced by 2.9% in the same period (Table 3). There were improvements in energy efficiency from end-use sectors except transport, the sector with the highest growth rate in 2014–15. The building sector recorded a significant decline in energy intensity at 7.4% as a whole in 2015, while the largest consumer, industry, was at 3% decline.

Table 3: Energy intensity analysis, 2015

Energy	Energy intensity (toe/million USD)		Change (%)
	2014	2015	2014 vs 2015
Total primary energy supply	137	140	2.1
Total final consumption	109	106	-2.9
Final energy consumption excl. non-energy	107	104	-3.2

Source: EGEDA (2017).

RENEWABLE ENERGY SHARE ANALYSIS

Table 4 shows how the share of modern renewable energy in final energy consumption changed in two years: from 16.2% to 15.2% in 2015. Final energy consumption increased by 3.3%, while energy consumption from both traditional biomass and modern renewables experienced declines.

For electricity specifically, the installed hydropower capacity has tripled from 4.4 GW to 14 GW since 2005, reflecting an average annual growth rate (AAGR) of 13%. As a result, total renewables' share increased from 38% in 2005 to 43% in 2015. 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 contribute significantly to the APEC renewable doubling goal if the potentials are utilised effectively.

Table 4: Renewable energy share analysis, 2014 vs 2015

Energy	2014	2015	Change (%) 2014 vs 2015
Final energy consumption (ktoe)	51 024	52 711	3.3
Non-renewables (Fossils and others)	33 701	36 555	8.5
Traditional biomass*	9 034	8 130	-10
Modern renewables*	8 290	8 027	-3.2
Share of modern renewables to final energy consumption (%)	16.2%	15.2%	-6.3%

Source: EGEDA (2017).

* 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) was formed in 2007 and oversees all energy industries. Within the MOIT, the General Directorate of Energy (GDE) and the Electricity Regulatory Authority of Viet Nam (ERAV) are two key advisory and executive units assisting the MOIT's Minister with the management of the energy sectors. GDE (PMVN, 2011a) focuses on formulating law, policy and planning, and generally, managing all energy sectors, while ERAV (PMVN, 2008) specialises in regulatory activities in the electricity sector in order to ensure a safe and high-quality supply of electricity for the economy. However, under the restructure of MOIT in 2017 (GOV, 2017), GDE was disbanded and most of the sub-bodies went to three energy-related divisions: the Authority of Electricity and Renewable Energy, Department of Energy Efficiency and Sustainable Development and Department of Oil, Gas and Coal. 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), Viet Nam 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 up to 2020 in the energy industries. In addition, detailed sectoral targets and policies for each five-year planning period correspondingly adjust to updated assessments. During 2015–17, 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 2025/2035¹ (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 the period 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);

¹ Not open to public

- 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 in the period 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).

As the 2007 National Energy Development Strategy is quite obsolete, MOIT is going to publish National Energy Master Plan through 2035 with updated energy supply and demand projection by mid-2018.

ENERGY MARKETS

ELECTRICITY MARKET

Viet Nam's electricity market is characterised by the active participation of several state-owned enterprises (SOEs) and various private players who are 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 2016, 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. The Electricity Law of December 2004 (effective 2005 and amended 2012) outlines the major principles for establishing the power market in Viet Nam. The scheme and conditions for the power market are detailed in the Road Map (PMVN, 2013a, b), stating the three phases of a competitive market development:

- Phase 1 (up to 2014): Competitive Generation Power Market;
- Phase 2 (2015–21): Competitive Wholesale Power Market (the first two years are pilot) and
- Phase 3 (2021 forward): Competitive Retail Power Market (with a pilot period from 2021–23).

Each phase contains two steps: pilot and full operation. Additional regulations and guidelines are enacted to complement the Road Map, which cover licensing and technical concerns, market rules, tariffs and contract regulations.

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 total capacity of the power system.

The first actual pilot year of the competitive wholesale power market started in January 2016, according to MOIT's conceptual and detailed design of the Viet Nam Wholesale Electricity Market (VWEM) issued during 2014–15 (MOIT, 2014b, c and 2015a, c). This year, the market processed the simulation of wholesale transactions on paper only (or by notes), yet with real payments. Under this pace, the pilot of Vietnam Wholesale Electricity Market (VWEM) is to start from early 2018 and Vietnam Retail Electricity Market (VREM) is expected to 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 2017) 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 the previous period.

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 Dung Quat refinery built in Quang Ngai province has a refining capacity of 6.5 Mt of crude oil per year (or 148 000 barrels per day). It has been operated by the Binh Son Refining and Petrochemical Company Limited (BSR) since 2009 and is the only crude oil consumer in Viet Nam. Currently, BSR as well as PVOil and PVPower are PVN subsidiaries; however, PVN is now inviting domestic and foreign investors for their equitisation. Over the last eight years, BSR has bought crude oil mainly via PVOil. The sweet crude oil supply to Dung Quat refinery has mainly come from domestic sources, including about 60% from Bach Ho field and 40% from others offshore Viet Nam; imports remain a negligible 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)—is under commissioning; commercial operation is scheduled for the first quarter of 2018, a year behind schedule. It is expected to meet about 40% of domestic petrol demand. Another 16 Mt project, Long Son, is also under construction from 2018 to approximately 2022.

PETROLEUM ENGINE FUEL MARKET

'Petroleum engine fuel' (PEF) is a general term used in Viet Nam to refer to 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.

The government regulates wholesale prices of fuel oil and retail prices of other PEFs based on the approval of a baseline selling price for PEF suppliers. The base price for PEFs (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 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. In 2016, the government promulgated regulations (GOV, 2016a, b) on detailed conditions and investment procedures for conducting LPG, CNG and LNG businesses. By the end of 2016, there were seven LPG import-export trading companies and 23 LPG distribution companies operating in Viet Nam. 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 95% of the total coal market in Viet Nam. Recently, the North-East Coal Corporation separated from Vinacomin to become an independent company and operate under the oversight of the Ministry of Defence. In addition, PVN established PV Power Coal, which oversees coal imports, trading and ensuring coal supply for their five new coal power plants, namely VungAng 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 about 16 Mt in 2020 and 20 Mt in 2030.

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 in order 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

In April 2006, the Prime Minister approved the Viet Nam National Energy Efficiency Programme (VNEEP) for 2006–15 (PMVN, 2006, 2012b). The 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. The aim of the programme was to save 3%–5% of the total energy consumption over the 2006–10 period and 5%–8% in the 2011–15 period. The programme is expected to continue under phase three, but this has not yet been decided. Under VNEEP in 2012–2017, 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 2017, mostly funded by the World Bank, is intended to further support industry with energy efficiency technology and practices.

Phase one of VNEEP for the period 2006–11 was successfully implemented, saving about 4 900 ktoe in total energy consumption in the period 2006–10, equivalent to 3.4% of 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 the period 2011–15 were discussed at a series of conferences on the five-year implementation of the National Target Programme on Energy Efficiency—period 2011–15, held in the fourth quarter of 2015 by MOIT in cooperation with the Vietnam Association of Science and Technology in Energy Saving and Efficiency (VNEEP, 2015). MOIT reported the level of energy savings at 5.96% 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 (APEREC, 2017).

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 total generation by 2020 and 32% by 2030 and biofuels to increase to about 5% of total transport fuel demand in 2020 (about 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 to the business as usual (BAU) plan. Additionally, a reduction in fossil fuel imports for energy purposes of about 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) 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; net-metering for electricity consumers with simplified connection arrangements and environmental fees for organisations utilising fossil fuels for energy production. Detailed information on Viet Nam's renewable policies can be found at the most recent APEC's Peer Review on Low-Carbon Energy Policies (APEREC, 2016). In 2017, the Prime Minister promulgated the Decision on mechanism on encouragement of solar power development (PMVN, 2017b), and accordingly, MOIT issued Circular on project development and model Power Purchase Agreements applied to solar power projects (MOIT, 2017), which makes the list of FiT (Table 5) more exhaustive.

Table 5: FiT for some renewable energies in Viet Nam

Renewable Energy	Tariff level	
	VND/kWh	US cents/kWh*
Wind energy	1 614	7.8
Biomass power	1 220	5.8
Solid-waste power	2 114	10.05
Solar energy	2 086	9.35

*Roughly estimated at the issuance time of the decision and subjected to change with exchange currency.

Source: PMVN (2011b, 2014a, b, 2017b)

FiT for wind power is still under review to better reflect the market, so that the tariff can reach as high as 8.7 to 9.9 cents per kWh for onshore and offshore power, respectively.

NUCLEAR

After the decision of halting the Ninh Thuan nuclear power plant project in late 2016², the Government of Viet Nam has not mentioned about 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% global CO₂ 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 to 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.

On 5 December 2011, Prime Minister Nguyen Tan Dung issued the National Strategy on Climate Change (Decision 2139/QD-TTg). This strategy has 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 starts from 2010 (the latest year of the national GHG inventory) and 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 (tCO₂-e);
- Projections for 2020 and 2030 (not including industrial processes):
 - 2020: 474.1 million tCO₂-e
 - 2030: 787.4 million tCO₂-e

NOTABLE ENERGY DEVELOPMENTS

2017 - A DYNAMIC YEAR OF MOIT

In June, the Delegation of the European Union to Viet Nam and the Ministry of Industry and Trade co-hosted the Launching of the Vietnam Energy Partnership Group (VEPG) and Policy Dialogue. VEPG is established to strengthen cooperation between Vietnamese Government and Development Partners to effectively utilise the Official Development Assistance for the energy sector. VEPG aims to be the focal point to establish the Energy Information System, which can lead to a more robust and transparent energy database. In September, the first-ever publication on energy outlook, a co-product of the Embassy of Denmark and MOIT, was published by Danish Energy Agency and Viet Nam Institute of Energy. The report provided a comprehensive update of current energy status with domestic insights, using commonly adopted methodology (Bamorel) based on three scenarios of economic growth. It also set the basis for a possibly biennial publication on energy supply and demand projection in the future. Also, in September, MOIT restructured itself under the Decision 98 of the Government and the disassembly of six-year-old General Directorate of Energy was one among various attempts of MOIT to administrative improvement and simplification. Throughout 2017, the Ministry was busy with APEC preparation: the Ministerial Meeting in May, and finally, the Leaders' week in November, which

² <http://news.chinhphu.vn/Home/Govt-states-reasons-to-cancel-nuclear-power-project/201611/29076.vgp>

made 2017 a dynamic and eventful year. The new national energy plan may be published in the second quarter of 2018.

ENERGY SECURITY: FILLING THE NUCLEAR GAP

The latest revision of Power Development Plan (PDP) was published in early 2016: nuclear projects were included with the contribution of 5.7% power generation in 2030. The decision of halting the construction of the nuclear power plant in late 2016 interrupted the projection of energy supply in the long term. One of the conclusions in the press release then was to replace the gap by thermal power source and actively promote renewable energy.

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.

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, 2017). 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 to be proposed. In an interview with the Minister of Industry and Trade³, 44 approved PV projects with a total of 4 350 MW_p are to be added to the national power plan. The Government is also considering a more favourable tariff for wind power. Currently, 50 projects have been submitted and four with 159 MW are under commercial operation. Wind power, in combination with solar power, has exhibited the fastest growth in 20 years ahead. Renewable energy is quite costly as compared to other sources; therefore, intensifying regional and international energy cooperation to call for more investment is necessary in this context.

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).

TOWARDS A GREENER TRANSPORT: BIO-ETHANOL

In late 2017, Viet Nam's Government made a firm decision to replace all gasoline A92 fuel 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) and reconfirmed the announcement made by the Prime Minister Office in June 2017 (Announcement 255). With that change, only two types of petrol for motor vehicles are allowed in the market: the biofuel E5 (some USD 0.84 per Litre) and high-octane traditional gasoline A95 (USD 0.93 per Litre)⁴. Also from January 2018, all up-to-9 seater cars must be qualified under energy labelling program, under the Decision No. 04/2017/QĐ-TTg.

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).

³ From Vietnam Energy Magazine: <http://nangluongvietnam.vn/news/vn/nhan-dinh-phan-bien-kien-nghi/nhan-dinh-du-bao/nang-luong-viet-nam-trong-lo-trinh-doi-moi-tong-the.html>

⁴ Price at VND from <http://www.petrolimex.com.vn/>, retrieved February 16, 2018.

In 2014, there were five bioethanol plants (E99.5 and above) built in Quang Nam (Dai Tan), Dong Nai (Tung Lam), Quang Ngai (Dung Quat), Binh Phuoc and Phu Tho (Tam Nong), with a total installed capacity of about 500 million litres per year, enough for mixing 10 billion litres of E5 biofuel (MOIT, 2016a). Currently, there are seven plants but only two in Quang Nam and Dong Nai are under commercial operation. Others are expected to restart in 2018–2019 as the economy transits to a full switch to E5 biofuel starting from January 2018. Before this deadline, the switch to E5 biofuel was conducted in Ha Noi and Ho Chi Minh City as a pilot. The economy estimates a total demand of about 5.5 million cubic metres of E5 biofuel in 2018, equivalent to 275 thousand cubic meters of pure ethanol (E100). If domestic production is insufficient, bio-ethanol will be imported from abroad.

However, consumers have expressed concerns about the switch to biofuels. These include doubts that the quality of ethanol might affect a smooth engine start, and that the switch to biofuel might gradually damage the engine. As a result, some consumers may still choose to purchase more expensive A95 gasoline rather than the E5 biofuel.

Despite these challenges, the Government continues to stress on resuming the biofuel development scheme. If according to Decision 53 of the Prime Minister (2012c), two years later, E5 shall be replaced by E10.

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