Power in Indonesia

Investment and Taxation Guide

November 2017 – 5th edition

pwc

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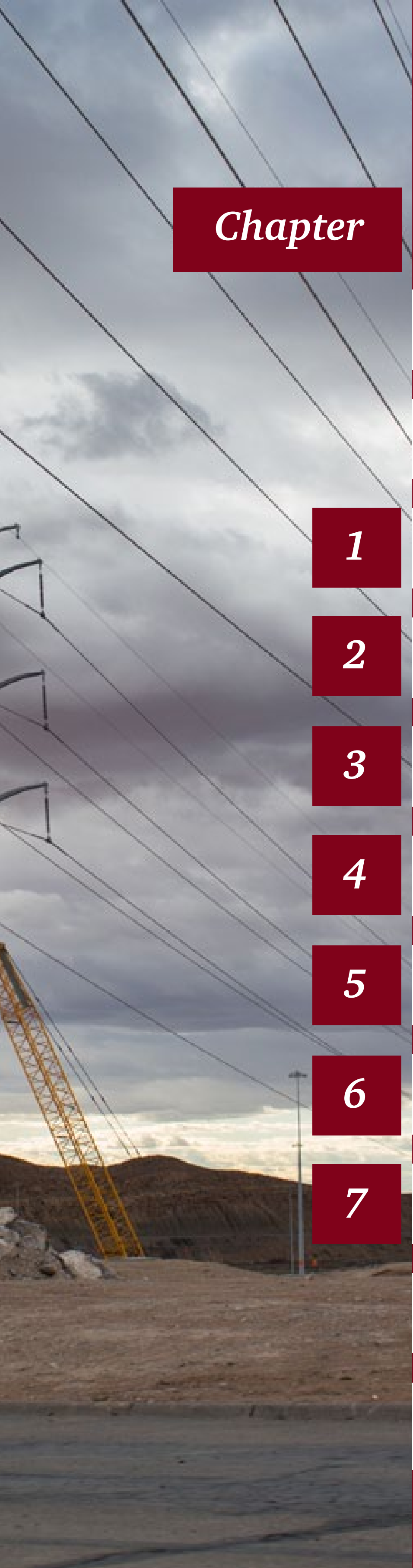
Note:
Totals in tables and charts may not add due to rounding differences.

Regulatory information current to 20 September 2017



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Glossary

Term	Definition
AF	Availability Factor
APLSI	The Independent Power Producers Association (*Asosiasi Produsen Listrik Swasta Indonesia*)
B2B	Business-to-Business
Bappenas	National Development Planning Agency (*Badan Perencanaan Pembangunan Nasional*)
BBTUD	Billion Thermal Units per Day
BKPM	Investment Coordinating Board (*Badan Koordinasi Penanaman Modal*)
BLU	Public Service Agency (*Badan Layanan Umum)*
BOO	Build Own Operate
BOOT	Build Own Operate Transfer
BOT	Build Operate Transfer
BPJS	Social Security Agencies (*Badan Penyelenggara Jaminan Sosial)*
BPP	Electricity Generation Cost (*Biaya Pokok Pembangkitan)*
CJPP	Central Java Power Plant
CMM	Coal Mine-Mouth
CNG	Compressed Natural Gas
COD	Commercial Operations Date
DGE	Directorate General of Electricity (*Direktorat Jenderal Ketenagalistrikan*)
DGNREEC	Directorate General of New and Renewable Energy and Energy Conservation
DGT	Directorate General of Tax
DPR	House of Representatives (*Dewan Perwakilan Rakyat*)
EBIT	Earnings Before Interest and Taxes
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortisation
EBTKE	New and Renewable Energy and Energy Conservation (*Energi Baru, Terbarukan dan Konservasi Energi*)
E&E	Exploration and Evaluation
EIU	Economist Intelligence Unit
EPC	Engineering, Procurement and Construction
FM	*Force Majeure*
FSRUs	Floating Storage Regasification Units

Term	Definition
FTP I	The fast track programme introduced in 2006 mandating PLN to build 10 GW of coal-fired plants across Indonesia
FTP II	The fast track programme introduced in 2010 to build 10 GW of power plants focusing on renewable energy sources and IPP involvement
GEUDP	Geothermal Energy Upstream Development Project
GoI/Government	Government of Indonesia (Central Government)
GR	Government Regulation (*PP* or *Peraturan Pemerintah*)
GSF	Geothermal Support Fund
GW	Gigawatt (1,000 MW)
HBA	Coal Reference Price *(Harga Batubara Acuan)*
HPB	Coal Benchmark Price *(Harga Patokan Batubara)*
ICP	Indonesian Crude Price
IDD	Indonesia Deep Water
IDR	Indonesian Rupiah
IEA	International Energy Agency
IFRIC	International Financial Reporting Interpretations Committee
IFRS/IAS	International Financial Reporting Standards/International Accounting Standards
IIGF	Indonesian Infrastructure Guarantee Fund (also known as PT Penjaminan Infrastruktur Indonesia - "PTPII")
INAGA	Indonesia Geothermal Association
Indonesian ASB	Indonesian Accounting Standards Board
IO	Operating Permit for Generating Electricity for Own Use (*Izin Operasi*, sometimes referred to as *Izin untuk Mengoperasikan Instalasi Penyediaan Tenaga Listrik untuk Kepentingan Sendiri* - "IUKS")
IPB	Geothermal Permit under 2014 Law (*Izin Panas Bumi*)
IPP	Independent Power Producer
ISAK	Interpretations of Indonesian Financial Accounting Standards (*Interpretasi Standar Akuntansi Keuangan*)
IUP	Mining Business Licence (*Izin Usaha Pertambangan*)
IUPK	Special Mining Business Licence (*Izin Usaha Pertambangan Khusus*)
IUJPTL	Electricity support services licence (*Izin Usaha Jasa Penyediaan Tenaga Listrik)*

Term	Definition
IUPTL	Electricity Supply Business Permit (*Izin Usaha Penyediaan Tenaga Listrik* sometimes referred to as *Izin untuk Melakukan Usaha Penyediaan Tenaga Listrik untuk Kepentingan Umum* - "IUKU")
IUPTLS	Temporary Electricity Supply Business Permit (*Izin Usaha Penyediaan Tenaga Listrik Sementara)*
JBIC	Japanese Bank for International Cooperation
JOC	Joint Operating Contract
KPPIP	The Committee for the Acceleration of Prioritised Infrastructure Development (*Komite Percepatan Penyediaan Infrastruktur Prioritas*)
km	Kilometer
kWh	Kilowatt hour
kV	Kilovolt
LMAN	State Assets Management Agency (*Lembaga Manajemen Aset Negara)*
LNG	Liquefied Natural Gas
METI	Indonesian Renewable Energy Society *(Masyarakat Energi Terbarukan Indonesia)*
MKI	The Indonesian Electrical Power Society (*Masyarakat Ketenagalistrikan Indonesia*)
MMBtu	Million British thermal unit
MMSCFD	Million Standard Cubic Feet per Day
MoEMR	Ministry of Energy and Mineral Resources (*Kementerian Energi dan Sumberdaya Mineral*)
MoF	Ministry of Finance (*Kementerian Keuangan*)
MoSOE	Ministry of State-Owned Enterprises (*Kementerian Badan Usaha Milik Negara*)
MoPW	Ministry of Public Works
MoU	Memorandum of Understanding
MSW	Municipal Solid Waste
MTOE	Million Tonnes of Oil Equivalent
MVA	Megavolt Amperes
MW	Megawatt
NEP	National Energy Policy
NRE	New and Renewable Energy
O&M	Operations and Maintenance
OJK	*Otoritas Jasa Keuangan*
PKUK	Authorised Holder of an Electricity Business Licence under the 1985 Electricity Law (*Pemegang Kuasa Usaha Ketenagalistrikan*)

Term	Definition
PLN	The State-owned electricity company (*PT Perusahaan Listrik Negara*)
POME	Palm Oil Mill Effluent
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
PPU	Private Power Utility (electricity generated for own use)
PR	Presidential Regulation (*Perpres* or *Peraturan Presiden*)
PSAK	Indonesian Financial Accounting Standards (*Pernyataan Standar Akuntansi Keuangan*)
PT IIF	PT Indonesia Infrastruktur Financing (a subsidiary of PT SMI)
PT PII	PT Penjaminan Infrastruktur Indonesia (also known as the IIGF)
PT SMI	PT Sarana Multi Infrastruktur (a fund setup to support infrastructure financing in Indonesia)
PTSP	One-Stop Services (*Pelayanan Terpadu Satu Pintu)*
PSP	Preliminary Geothermal Survey Assignment (*Penugasan Survey Pendahuluan)*
PSPE	Preliminary Geothermal Survey and Exploration Assignment (*Penugasan Survey Pendahuluan dan Eksplorasi)*
RUKD	Regional Electricity Plan (*Rencana Umum Ketenagalistrikan Daerah*)
RUKN	National Electricity Master Plan (*Rencana Umum Ketenagalistrikan Nasional*)
RUPTL	Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik*)
SBS	SBS International Ltd
SHP	Small Hydropower
SOE	State-owned Enterprise
SPC	Special Purpose Company
TKDN	Local content (*Tingkat Komponen Dalam Negeri*)
TP	Transfer Pricing
TSCF	Trillion Sandard Cubic Feet
USD	US Dollar
US GAAP	US Generally Accepted Accounting Principles
UPTL	Small Scale Electricity Supply Business (*Usaha Penyediaan Tenaga Listrik*)
VAT	Value Added Tax
WHT	Withholding Tax

Foreword

“

Welcome to the Fifth edition of the PwC Indonesia “Power in Indonesia: Investment and Taxation Guide”.

This publication has been written as a general investment and taxation guide for all stakeholders and those interested in the power sector in Indonesia. We have therefore endeavoured to create a publication which can be of use to existing investors, potential investors, and others who might have a more casual interest in the status of this economically critical sector for Indonesia.

This edition of the Guide has been updated to reflect the substantial volume of regulatory and policy developments in 2017. For instance, the Ministry of Energy and Mineral Resources (“MoEMR”) has signed over 50 new regulations etc. in recent times of which at least 20 directly affect the Power sector (and which are discussed further below). We hope readers will find our updates on these developments particularly timely noting always the interpretational uncertainty that can exist around new regulations.

As outlined in the table of contents page this publication is broken down into chapters which cover the following broad topics:

- An overview of Indonesia’s Power Sector;
- An overview of the legal and regulatory framework;
- A detailed look at IPP investment;
- The use of conventional energy sources;
- A dedicated section on the use of renewable energy;
- An outline of key tax issues; and
- An outline of key accounting issues.

As many readers would be aware, Indonesia’s power infrastructure needs substantial investment if it is not to inhibit Indonesia’s economic growth. Generating capacity, currently standing at around 59.6 GW, is struggling to keep up with the electricity demand from Indonesia’s growing middle class population and its manufacturing sector.

Although the ambitious target of 35 GW of new generating capacity by 2019 is probably no longer achievable, the broader focus on growth is still a key priority of President Joko "Jokowi" Widodo's Government. In fact over the past few years, around 1 GW of capacity has come online, around 15 GW is under construction, and over 10 GW was signed up to via new PPAs. This is still therefore an impressive achievement.

PLN has also recently updated its targets to reflect progress. For instance, in March 2017 the MoEMR issued PLN's revised 2017 – 2026 Electricity Supply Business Plan (*Rencana Umum Penyediaan Tenaga Listrik* – the "2017 RUPTL"). The 2017 RUPTL broadly retains the goals of the 2016 RUPTL but with the increased emphasis on renewables and with certain large thermal coal-fired plants being dropped or postponed.

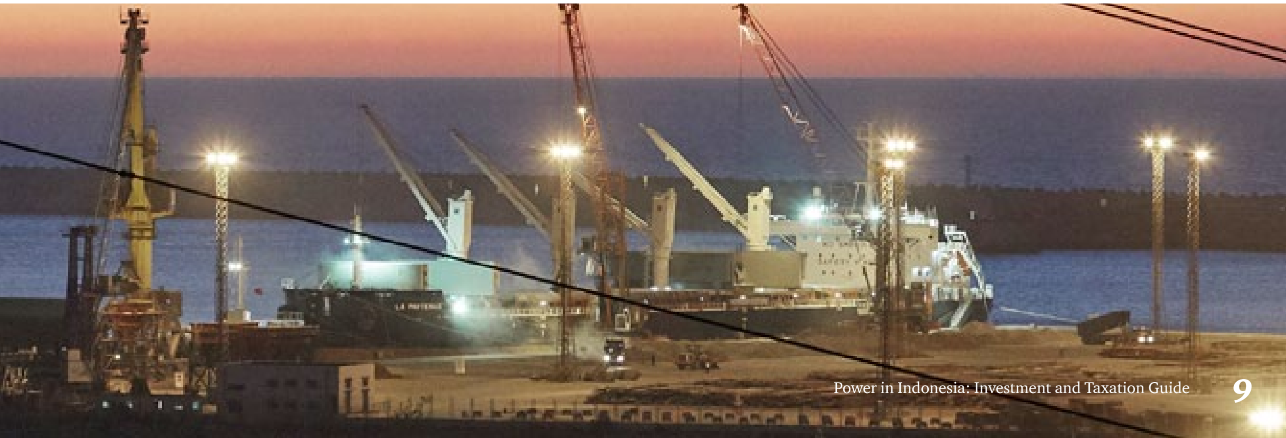
PLN and IPP investors are now expected to construct about 77.9GW of generating capacity by 2026 with 21.0 GW to be constructed by PLN and 42.1 GW by IPPs (with 14.8 GW yet to be allocated).

The capacity targets for renewables were also raised – from 19.6% to 22.5% of total (by 2026) albeit mainly based on hydro and geothermal sources and so potentially overlooking the opportunity that the nascent Solar PV and Wind sectors offer.

However, the 2017 RUPTL does not reflect the MoEMR's new strategy of assigning many fossil fuel projects to PLN subsidiaries, which in turn are expected to seek out private sector partners on a project-by-project basis. Details of this process are expected to become clearer towards the end of 2017.

As outlined above, the past year has seen considerable regulatory activity aimed at directly stimulating project implementation, including via:

- An amendment to Presidential Regulation ("PR") No. 4/2016 on the Acceleration of Power Infrastructure Development (in the form of PR No. 14/2017);
- Allowing PLN to assign certain projects to consortia whose members include PLN subsidiaries (e.g., Riau-1 2×300 MW project announced in September 2017);
- Fine tuning PPAs with regard to risk allocation and introducing a range of new tariffs in the coal, gas and renewable sectors.



On the changes to PPA risk allocation, investor and lender reaction was initially negative. However, the August 2017 reversal of some of the more burdensome aspects (e.g. that Government *Force Majeure* risk should rest with the IPPs) has been welcomed. Concerns do however continue to exist over some of the remaining risk allocation principles.

On the changes to tariffs, the general linking to a published cost benchmark was (in most cases) welcome as was the setting of tariffs that PLN was actually comfortable with in a commercial sense. However, average tariffs for renewables are now lower than before the changes especially in Java-Bali and Sumatera, which may make renewables investment less attractive, in contradiction of the stated aim of increasing the renewables share of generation capacity.

This aside, PPAs covering over 600 MW of renewables were reported as signed between March and August 2017. This represents the most significant progress in the renewables sector in Indonesia for the best part of a decade.

In summary, Indonesia continues to represent a major investment opportunity for domestic and international power companies and investors. Moreover, amongst Indonesian infrastructure opportunities, in general, power arguably remains the largest and most liquid.

Realizing the ambitious goal of the 35 GW program will continue to require massive investment in power generation capacity and this will doubtless involve both fossil fuel and renewable energy sources. This is apart from the huge investment in transmission and distribution infrastructure required (which will rest largely with PLN).

Whilst it is too early to say whether the new regulatory regime will spur investment to the extent desired, our view is that the market is keen to participate if the terms are right.

Understanding the regulatory and investment issues affecting Indonesia's power landscape, including these recent changes, is therefore of vital importance. It is hoped that this guide will provide readers with some of the information necessary to better understand these dynamics.

This guide is not intended to be a comprehensive study on all aspects of the power industry in Indonesia but rather a general guide to certain key considerations related to investment and taxation in the sector. Readers should note that this publication is largely current as at 20 September 2017. Whilst every effort has been made to ensure that all information was accurate at the time of printing, many of the topics discussed are subject to interpretation and continuously changing regulations. In addition, some of the Government's plans/programmes are sometimes inconsistent. As such, this guide should not be used as a substitute for up-to-date professional advice. Please contact your usual PwC contact, or any of the specialists listed on page 188 for further information.

We hope that you find this publication of interest and wish all readers success with their endeavours in the Indonesian power sector.

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1 Overview of Indonesian Power Sector

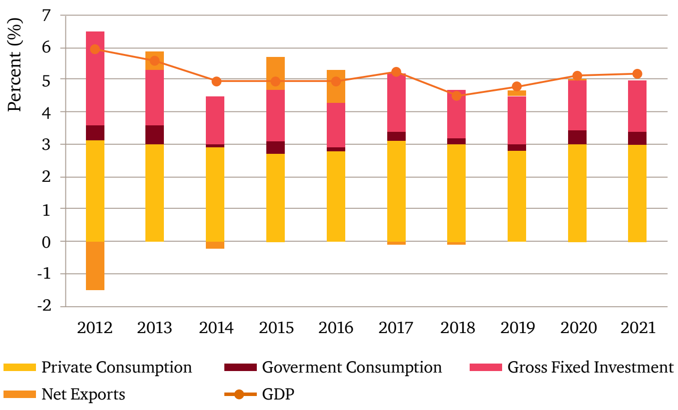
1.1 *Demand for and Supply of Power in Indonesia*

Indonesia is an archipelago with over 18,000 islands, and had a population of over 255 million people in 2016.[1] This makes Indonesia the world's fourth most populous country, and the largest economy in Southeast Asia.

In 2013, the Indonesian economy entered a slowdown period as global commodity prices fell, exacerbated by a slowdown in the Chinese economy. GDP growth in 2013-2016 averaged 5.0% p.a., compared to 6.0% p.a. average growth since 2009. In 2017, as the infrastructure spending initiatives of President Joko Widodo's Government began to have an impact, along with regulatory and subsidy reforms, the outlook improved. The World Bank forecasts 5.2% growth this year (2017), although in the longer run the Economist Intelligence Unit forecasts Indonesia's average growth to remain stable at 5.0% until 2021. PwC's *World in 2050* report (can be found at *https://www.pwc.com/gx/en/issues/economy/the-world-in-2050.html*) indicates Indonesia could be the fifth largest economy in the world by 2030 (based on purchasing power parity) and the fourth largest by 2050. Achieving those levels will require significant investment in infrastructure, including power, to drive higher GDP growth. Separately, the Indonesian Rupiah ("IDR") has been relatively stable in the range of 13,000 – 13,500 per US Dollar ("USD") since May 2015.

Indonesia's GDP is expected to be largely driven by domestic household consumption for the foreseeable future, as no major uptick in commodity or energy prices is expected in the medium term (see Figure 1.1). On the supply side, key sectors have historically included manufacturing (22% of GDP), agriculture (13%), trade, hotels and hospitality (14%), mining (9%) and construction (10%).[2] With the recent slowdown in the mining sector, some rebalancing of economic growth towards manufacturing is likely to take place over the next five years. Industrial activity is also expected to expand outside the traditional industrial heartlands of Western/Central Java and DKI Jakarta to Eastern Java, Southern Sumatera and Kalimantan.[3]

Figure 1.1 - Historical and forecast GDP growth and contribution by expenditure item (% p.a.)

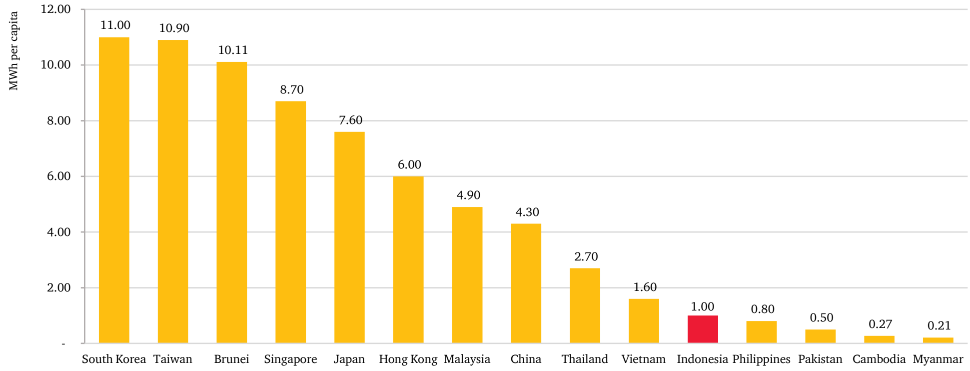


Source: Economist Intelligence Unit ("EIU"), May 2017

1 *http://bps.go.id*
2 *Bank Indonesia, Statistics of Indonesian Economic and Finance ("SEKI"), www.bi.go.id/en/statistik/metadata/seki*
3 *PwC and GE Operations Indonesia ("GE"), Private Power Utilities: The Economic Benefits of Captive Power in Industrial Estates in Indonesia, 2016, p. 15. https://www.pwc.com/id/en/pwc-publications/industry-publications/energy--utilities---mining-publications.html*

Access to electricity and electricity consumption varies across the Indonesian archipelago. Electricity consumption in 2016 was 957 kilowatt hours ("kWh") per capita on a national basis[4], which was relatively lower than neighbouring economies (see Figure 1.2).

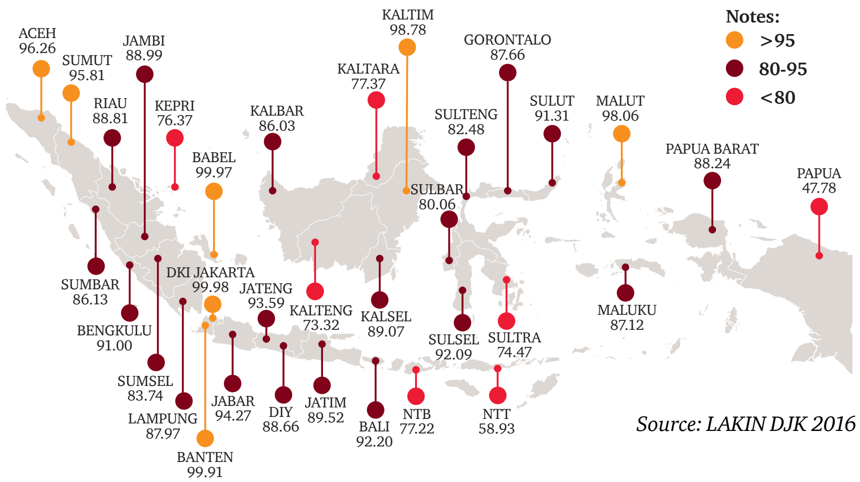
Figure 1.2 - 2016 Electricity consumption per capita in selected countries neighbouring Indonesia



Source: EIU, December 2016

Distribution is also uneven with consumption higher in more industrialised areas, such as the western part of Java. Similarly, the level of access to the grid is mixed with electrification rates in the western part of the country as high as 99.98% (i.e. DKI Jakarta), and in the eastern part of the country as low as 47.78% (i.e. Papua) (see Figure 1.3). The national average electrification rate in 2016 was 91.16%.[5] Based on the 2017 – 2026 PLN Electricity Supply Business Plan (*Rencana Umum Penyediaan Tenaga Listrik* – "2017 RUPTL"), the electrification ratio is set to increase to 97.4% by 2019 and to 99.7% by 2025.

Figure 1.3 – 2016 Electrification rates in Indonesian provinces (in percentage)



Source: LAKIN DJK 2016

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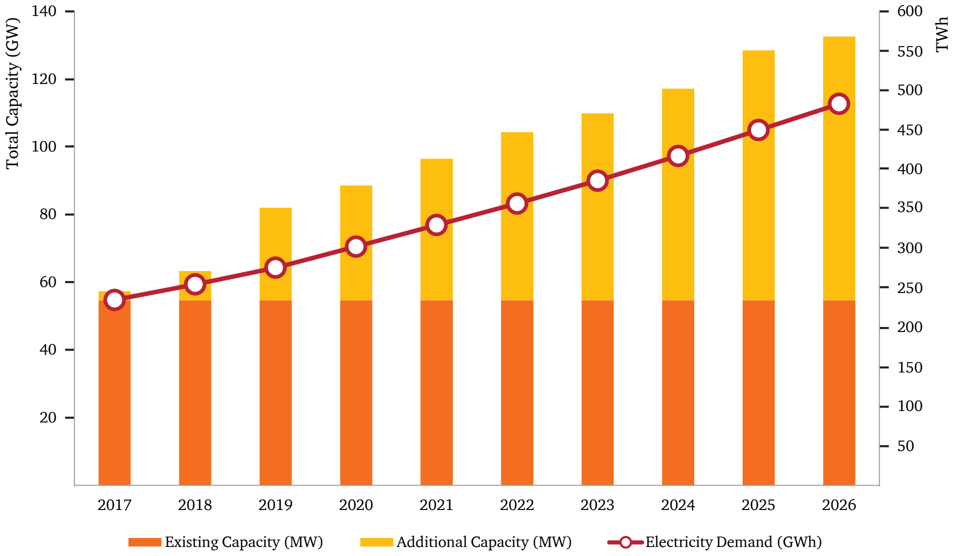
4 *Laporan Kinerja Direktorat Jenderal Ketenagalistrikan ("LAKIN DJK") [2016 Performance Report of Directorate General of Electricity ("DGE")], p. 25*

5 *Ibid, p. 25*

Together, Indonesia's rising population (the middle class population in particular), rising income per capita and structurally lower electrification ratio should imply significant growth in electricity demand. Indeed, PLN projects electricity demand growth of around 8.4% p.a. between 2017 and 2026, reaching a total of 483 TWh of electricity consumed in 2026, compared to 234 TWh in 2017.[6] To meet this demand, the Government set an ambitious target of 35 Gigawatt ("GW") power capacity expansion by 2019. However, after a series of challenges, the development of this capacity has been delayed. PLN's latest plan indicates that there will be only 27 GW of additional power capacity developed by the end of 2019, and 77 GW by 2026 (see Figure 1.4).[7] The improvement of national power generation and electricity access is, however, still part of the Government's wider plan for infrastructure support (as outlined in the Medium Term Development Plan 2015-2019) including road, railway, seaport and airport development, water supply and treatment, oil refining, gas supply and distribution, and fiber-optic broadband.

Figure 1.4 - Electricity capacity (GW) and demand (TWh) 2017 - 2026

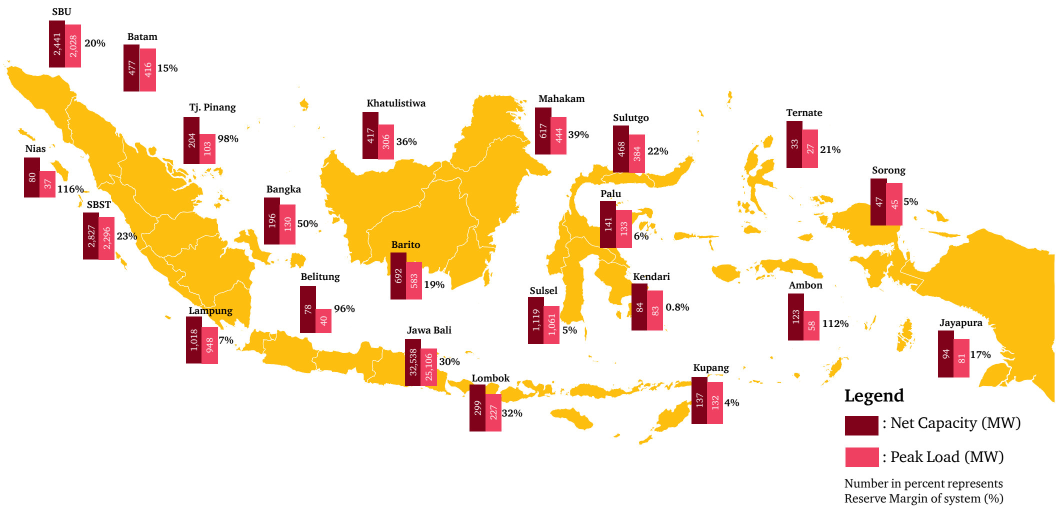


Source: 2017 RUPTL

The 35 GW Programme is also intended to improve Indonesia's power systems from the current critical condition. As of June 2017, only 13 of PLN's 22 large power systems across Indonesia were considered normal, with reserve margins ("RM" – the difference between net capacity and peak demand) above 30%. Another nine power systems were categorised as "on alert" status with RMs below 30% (Figure 1.5).[8]

6 *2017 RUPTL, p. VI-26*
7 *2017 RUPTL, p. VI-38*
8 *PLN, "Efforts to Reduce the BPP for Cheaper Electricity Price", Presentation, 7 August 2017*

Figure 1.5 - Condition of national power system as of June 2017



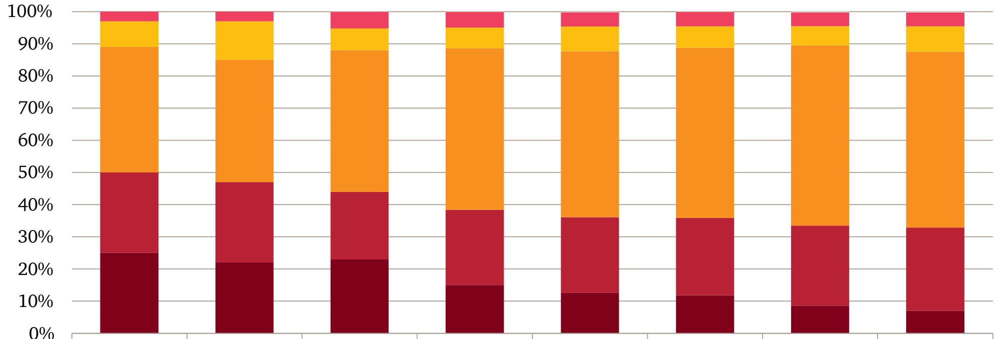
Source: PLN, "Efforts to Reduce the BPP for Cheaper Electricity Price", Presentation, 7 August 2017

1.2 Sources of Energy

In 2016, Indonesia had approximately 59.6 GW[9] of installed power plant capacity, including PLN/IPP plants, Private Power Utilities ("PPU") and those under non-oil operating permits ("IO Non-BBM")[10] (see *Section 2.2.2.1 - Generation* for further details). These power plants generated 290 TWh of electricity.[11] The current power generation fuel mix includes coal (54.69%), gas (25.89%), oil (6.97%) and renewables (12.45 %) as in Figure 1.6.[12]

9 LAKIN DJK 2016, February 2017, p.25
10 The non-oil operating permit ("IO Non-BBM") is the permit that allows electricity provision for self-interests that does not utilise oil (MoEMR Regulation No. 10/2014)
11 DGE, "Policy in National Electricity Provision", Presentation at the 7th IPP Summit, 9-10 May 2017
12 LAKIN DJK 2016, p. 4

Figure 1.6 – Development of fuel mix for power generation



	2009	2010	2011	2012	2013	2014	2015	2016
Other NRE	0.00%	0.00%	0.07%	0.11%	0.16%	0.11%	0.20%	0.24%
Geothermal	3.00%	3.00%	5.13%	4.85%	4.42%	4.44%	4.34%	4.33%
Hydro	8.00%	12.00%	6.80%	6.39%	7.73%	6.70%	5.93%	7.88%
Coal	39.00%	38.00%	44.06%	50.27%	51.58%	52.87%	56.06%	54.69%
Gas	25.00%	25.00%	21.00%	23.41%	23.56%	24.07%	24.89%	25.89%
Oil	25.00%	22.00%	22.95%	14.97%	12.54%	11.81%	8.58%	6.97%

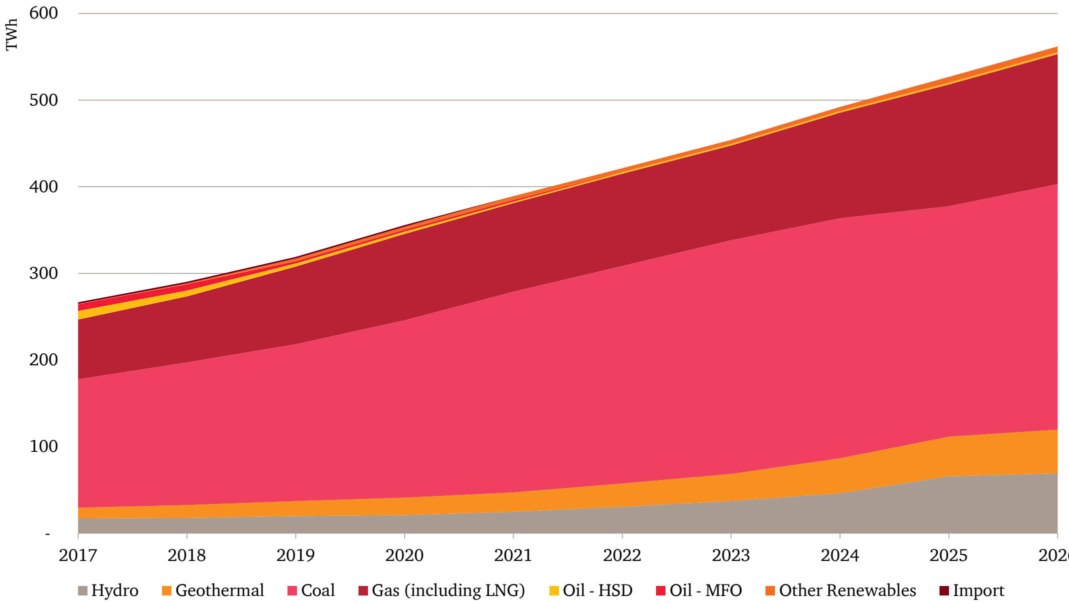
Source: LAKIN DJK 2016

The significant role of fossil fuels reflects Indonesia's natural abundance of hydrocarbons, as outlined in detail in *Section 4 - Conventional Energy*. Key factors and trends in the three major conventional energy sectors include the following:

- **Coal:** Thermal coal forms the single largest share of the fuel mix today. In 2017, coal is set to account for 55.6% of the energy share, but is expected to reduce to a slightly lower share of 50.4% in 2026. Economic and logistical considerations (as well as significant available reserves) have led to coal's ongoing dominance, as it is a low-cost fuel that is easy to extract and transport using existing infrastructure. Indeed, few economical alternatives exist for the development of low-rank coal, other than coal mine-mouth power generation.
- **Natural Gas:** Natural gas power generation is expected to double by 2026 (in TWh terms) from 25.8% of the overall mix in 2017 to 26.7% in 2026. Given the risks of not reaching the renewable energy target and the fact that gas has been determined to be the best substitute in the event of a shortfall, it is possible that the share of gas in the energy mix could be even higher. Being relatively low-carbon compared to coal, as well as being medium-cost, gas is likely to remain a favoured fuel for at least the next decade, especially given Indonesia's extensive gas reserves. A continuing glut of global and Asian (including Indonesian) Liquefied Natural Gas ("LNG") is likely to stimulate further consumption, although the fact that Indonesia is moving closer to being a net energy importer despite its abundant reserves may check this trend. Certainty regarding the upstream oil and gas investment climate and improved physical infrastructure, including pipelines and Floating Storage Regasification Units ("FSRUs"), as well as certainty on the price of gas-for-power, are crucial to enabling a strong long-term role for gas in the Indonesian power generation mix;
- **Oil:** Oil is largely a relic of Indonesia's days as a net oil exporter, with transporting diesel fuel to remote areas now being difficult and expensive. Power generation from refined oil products such as heavy fuel oil and diesel is expected to account for 6.7% of the fuel mix in 2017, but is planned to be all but phased out (0.4%) by 2026. This is noting the high cost (even at today's lower crude oil prices) and because refined fuel is now generally imported.

Note that other forms of non-conventional fossil fuel energy such as coal bed methane or coal gasification technologies also exist and are being developed in Indonesia, but are as yet insignificant. We have not explored these in this Guide because of the limited current usage of these unconventional fuels in the power sector. For a full overview of regulatory, tax and investment issues in the mining as well as oil and gas sectors, please see our separate Investment Guides.[13]

Figure 1.7 - 2017 - 2026 electricity generation (in TWh)



No	Fuel Type	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1	High Speed Diesel ("HSD")	10.0	6.8	3.6	2.7	1.7	1.7	1.7	1.8	2.0	2.0
2	Marine Fuel Oil ("MFO")	7.8	7.2	2.6	2.1	2.0	0.2	0.2	0.2	0.2	0.2
3	Gas (including LNG)	68.9	76.2	89.6	99.7	102.3	106.5	109.4	121.9	140.5	150.1
4	Coal	148.3	164.7	181.2	204.8	231.8	251.2	269.8	277.1	266.1	283.4
5	Hydro	17.0	17.7	19.7	20.9	24.7	30.5	37.2	46.1	65.7	69.1
6	Geothermal	12.4	14.8	17.3	20.2	22.4	26.9	31.2	40.4	45.7	50.5
7	Other renewables	0.4	1.0	3.1	3.4	4.3	4.4	4.4	4.4	6.3	6.3
8	Import	1.9	2.0	1.9	1.9	0.1	0.0	0.1	0.2	0.2	0.2
	Total	**266.7**	**290.4**	**319.0**	**355.7**	**389.3**	**421.4**	**454.0**	**492.1**	**526.7**	**561.8**

Source: 2017 RUPTL

13 *https://www.pwc.com/id/en/pwc-publications.html*

Indonesia also has enormous potential in renewable resources, as outlined in Table 1.1 below. The potential renewable energy resources set out here are based on a technical assessment by the Ministry of Energy and Mineral Resources ("MoEMR") only, and do not consider the financial/economic viability aspects of the relevant projects. However, Government Regulation ("GR") No. 79/2014 on National Energy Policy (the "2014 NEP") requires the development of renewable energy resources to consider the economic viability. The potential resource estimates in Table 1.1 also did not consider location (some renewable energy resources are located in areas of the grid with very low demand). As such, some renewable energy projects may not be economically feasible.

Table 1.1 - Renewable energy resources in Indonesia

Source	Potential Power Generation
Hydropower	75 GW
Geothermal	29 GW
Biomass/biogas	32.6 GW
Solar Photovoltaic ("PV")	207.8 GWp (4.80 kWh/m^2/day)
Wind Power	60.6 GW (3 – 6 m/s)
Ocean	17.9 GW

Source: 2016 EBTKE Statistics issued by Directorate General of New and Renewable Energy and Energy Conservation ("DGNREEC")

Renewable sources of energy are looking increasingly attractive in Indonesia, not only to support environmental policy around CO_2 emissions or urban air pollution, but also on account of their improving cost profile and ability to be deployed in a more decentralised manner. According to the 2017 RUPTL, key factors and trends in the five major renewable energy sectors include:

- **Hydro:** Hydropower is currently the largest single source of renewable power in Indonesia. In 2017, PLN planned for hydro to account for 6.4% of national power generation, and this is expected to grow to 12.3% in 2026. Many prospective sites have good water flow and head. The sector was until recently held back by uncertainty regarding the approval of Power Purchase Agreements ("PPA")[14], tariffs, as well as certain limitations on foreign ownership (see *Section 2.5.2 - The Negative List* for further details). On 2 August 2017 and 8 September 2017, however, the MoEMR gave in-principle, conditional, approval for the signature of at least 50 small hydro (≤ 10 Megawatt ("MW")) PPAs with PLN at tariffs between IDR 780 and 1,050/kWh. At the time of writing, it was unclear how many of these new PPAs were actually signed by PLN and the developers.

14 *http://finance.detik.com/read/2016/05/03/194026/3203059/1034/esdm-dan-pln-sepakat-soal-harga-listrik-mikro-hidro*

- **Solar PV:** Despite naturally high insolation across most parts of the country, current Solar PV deployment remains limited (total 108 MWp[15]) although its potential is estimated to be around 206.7 GWp.[16] There were several major revisions to the regulations underpinning Solar PV pricing and procurement in the past few years, although the stringent regulations regarding local content proved an obstacle (see *Section 2.2.3 - Local Content*). Again, at the time of writing, based on Official Letter of the Minister of Energy and Mineral Resources No. 5827/23/MEM.I./2017, up to six Solar PV PPAs were reported to have been signed;
- **Geothermal:** With Indonesia possessing the second-largest geothermal resources in the world, the geothermal share of the fuel mix is expected to double from 4.7% in 2017 to 9% in 2026.[17] A key strength of geothermal is its ability to act as base-load power, offsetting one of the traditional weaknesses of renewable energy. However, there are only a limited number of concessions under development and PPA approval has been slow. Indonesian state-owned enterprises ("SOEs") are playing a dominant role, although the new Independent Power Producer ("IPP") Sarulla project came online in March 2017 with its Unit-1 (110 MW). The 30 working areas listed in Chapter 5 are also planned to be tendered in 2017 or at a later date;
- **Bioenergy:** The bioenergy market is formed of discrete segments such as agricultural/plantation biomass wastes, Palm Oil Mill Effluent ("POME"), Municipal Solid Waste ("MSW"), and biodiesel. The market at the moment largely consists of power plants with 10 MW or less of capacity. Significant technical potential for power plants remains, with significant agricultural waste and MSW currently being improperly disposed of. However, realising this potential will require changes in the regulatory and contracting environment, especially at the sub-national government level. A wave of MSW PPAs were signed in 2016 with relatively generous tariffs, but with the revocation of Presidential Regulation ("PR") No. 18/2016 by the Supreme Court in late 2016, the fate of MSW is currently unclear. On 2 August 2017, PLN had also signed at least four biomass and five biogas PPAs ≤ 10 MW at tariffs between IDR 890 and IDR 1,555/kWh;
- **Wind:** Historically, wind has not played an important role in the fuel mix. However, significant recent progress has been observed, with several hundred MW under development or under construction in Sulawesi.

15 *Rida Mulyana (Director General of DGNREEC), "Utilisation of Renewable Energy", presentation at the PetroGas Days UI, 12 March 2016*

16 *Laporan Kinerja Direktorat Jenderal Energi Baru Terbarukan dan Konservasi Energi ("LAKIN EBTKE") (2016 Performance Report of DGNREEC), p.2*

17 *2017 RUPTL, p. VI-71*

A large number of regulatory, financial and practical barriers will need to be overcome for Indonesia's full renewables potential to be realised. Barriers common to many technologies include matching supply and demand with better transmission and distribution infrastructure, and the need to establish strong local supply chains and expertise.

In February 2017 the MoEMR released MoEMR Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017) which reforms the tariff regimes by benchmarking tariffs to the PLN average electricity generation cost (*Biaya Pokok Pembangkitan* – "BPP"). This regulation was later revoked by MoEMR Regulation No. 50/2017 (see *Section 5.9 - New Tariff Stipulation for Renewable Energy* for details), but tariffs are still benchmarked to PLN's BPP.

The implied new tariffs are generally significantly lower than previous regulations, with negative consequences for the economic viability of projects in most provinces, although this ultimately depends on the geographical area in which they are operating. Ostensibly, with the large number of renewable PPAs proposed for signature at the end of July 2017, the private sector appears to be still able to make the projects economically viable. However, it remains to be seen whether developers will find investments in renewable energy attractive in the long-run in Indonesia under the new tariffs.

The availability of finance for well-structured projects still does not appear to be a primary barrier, although the limited number of players willing to fund early-stage development (risk equity) remains a limiting factor. Recognising this, the Government is focusing on reforms to promote renewables. Factors supporting renewable deployment include falling costs globally, national carbon emissions targets, the high cost of oil-based generation especially in remote regions, regulatory and physical barriers to gas distribution, substitute demand for gas and oil in the industrial and transport sectors, and Government-provided tax incentives.

Further discussion on renewables, as well as other technologies such as ocean thermal energy conversion, can be found in Chapter 5. Please also see *Section 5.9 - New Tariff Stipulation for Renewable Energy* for more information on MoEMR Regulation No. 50/2017 that stipulates new renewable energy tariffs.

1.3 Electricity Tariffs

Under Law No. 30/2009 (the "2009 Electricity Law"), the electricity tariffs no longer need to be uniform throughout Indonesia, and thus may differ between operating areas or *Wilayah Usaha*. Tariffs are differentiated depending on the end user group. In general, electricity tariffs are set by taking into account the customer's purchasing power, as well as the installed power capacity of each customer group. The higher the installed power, the higher the tariff imposed. The higher the electricity consumption, the higher the multiplier used to determine the tariff imposed in order to encourage customers to use electricity wisely. Different tariffs are subject to different subsidy arrangements; for example, tariffs for low income households are heavily subsidized, with IDR 417/kWh representing a price more than three times lower than the average electricity supply cost of IDR 1,265/kWh in 2016.[18]

Prior to 2013, PLN's revenue was dictated by regulated electricity prices, with tariffs set by the Central Government and ultimately approved by Parliament, except for electricity prices in Batam, which are approved by the respective Regional Government. Since price increases require approval from Parliament, PLN's financial position was directly subject to the political process. Should the regulated price for electricity fall below the cost of production (which has generally been the case), the Ministry of Finance ("MoF") is required to compensate PLN through a subsidy. Since 2013, the electricity subsidy has stabilised due to the stabilisation of the average cost of electricity supply, as well as PLN's ability to pass on increases in inflation, the price of oil and the USD/IDR exchange rate to (non-subsidised) consumers (the "automatic adjustment mechanism") through MoEMR Regulation No. 31/2014, as amended by MoEMR Regulation No. 9/2015 (see Table 1.2). This subsidy includes a public service obligation ("PSO") margin, which was originally set in 2009 at 5% above the cost of electricity supplied. The margin was increased to 8% for 2010 and 2011 and then reduced to 7% from 2012.

18 *PLN Annual Report 2016, p. 254*

Table 1.2 - Average cost, average tariff, and subsidies

Year	Average Cost (IDR/kWh)	Average Tariff (IDR/kWh)	Subsidy (IDR Trillion)
2011	1,351	714	93.2
2012	1,374	728	103.3
2013	1,399	818	101.2
2014	1,420	940	99.3
2015	1,300	1,035	56.6
2016	1,265	991	60.4

Source: 2016 PLN Statistics

The latest subsidy regulation was promulgated through MoF Regulation No. 44/2017 concerning the Procedures for the Provision, Calculation, Payment and Accountability for Electricity Subsidy which revoked MoF Regulation No. 195/2015. Under this regulation, the electricity subsidy applies to customers whose electricity tariff is lower than the average cost of electricity supply. However, this scheme does not apply to customers that have adopted the tariff adjustment mechanism or customers that are not charged by PLN (e.g. industrial estate tenants). The amount of the electricity subsidy is based on the Minister of Energy and Mineral Resources's calculation, which is proposed to the Finance Minister for incorporation into the State Budget Plan (*Rencana Anggaran Pengeluaran and Belanja Negara* – "RAPBN").

Starting in January 2017, the Government finally began to revoke the electricity subsidy for 900 VA customers classified into the high income households category. This follows the previous subsidy removal for 1,300-6,600 VA household customers, >200 kVA business customers, 6,600 VA up to >200 kVA Government offices customers, >200 kVA industrial customers, as well as public street lighting and special services. Therefore, currently, except for 450 VA and some 900 VA customers (not classified as high income households) all others pay market price for electricity.

1.4 Transmission and Distribution ("T&D")

Being an archipelago, Indonesia's electricity is managed through a series of separate T&D grids. There are over 600 isolated grids and eight major networks in total. PLN currently has a de facto monopoly on T&D asset ownership and operations, although the private sector is legally permitted to operate T&D grids (see *Section 2.2.2.2 - Transmission, Distribution and Retailing*). Certain transmission lines are built by IPPs, particularly for power plants in remote areas, in order to connect the power plants to the closest PLN substations. However, ownership of these transmission lines will typically be transferred to PLN upon the completion of construction.

By the end of 2016, PLN served 64.3 million customers in Indonesia through a transmission network comprised of 44,064 kilometer circuits ("kmc") of transmission lines and 98,899 Megavolt Amperes ("MVA") of transmission transformer capacity.

A summary of transmission lines for each significant island in Indonesia is as follows (in kmc):

Region/Islands	25-30 kV	70 kV	150 kV	275 kV	500 kV	Total
Sumatera	-	379	10,245	1,694	-	12,318
Java-Bali	56	3,035	14,406	-	5,056	22,553
Kalimantan	-	123	3,391	163	-	3,677
Sulawesi	4	911	4,124	-	-	5,039
Papua and Maluku	-	221	-	-	-	221
Nusa Tenggara	-	-	256	-	-	256
Total	**60**	**4,669**	**32,422**	**1,857**	**5,056**	**44,064**

Source: 2016 PLN Statistics

A summary of substation transformer capacity for each of the significant islands in Indonesia is as follows (in MVA):

Region/Islands	<30 kV	70 kV	150 kV	275 kV	500 kV	Total
Sumatera	-	615	11,393	1,660	-	13,668
Java-Bali	-	2,921	47,276	-	28,500	78,697
Kalimantan	-	47	2,409	500	-	2,956
Sulawesi	30	1,015	2,138	-	-	3,183
Papua and Maluku	-	125	-	-	-	125
Nusa Tenggara	-	-	270	-	-	270
Total	**30**	**4,723**	**63,486**	**2,160**	**28,500**	**98,899**

Source: 2016 PLN Statistics

During 2016, PLN built 2,382 km of additional transmission lines and 6,248 MVA of substation transformer capacity.[19] Based on the 2017 RUPTL, by 2026 Indonesia will need additional transmission lines of approximately 67,000 km and substation transformer capacity of 165,000 MVA. In connection with the 35 GW Programme, plans are underway to more than double the T&D network by 2019, with 46,597 kmc of additional transmission lines and 108,789 MVA of substation capacity.

There are already limited cross-border transmission lines connecting Indonesia and other ASEAN countries as part of the ASEAN Grid programme. Please refer *Section 2.2.5 - Cross-border Sale and Purchase* for a detailed explanation.

The 2017 RUPTL states that the development plan for the 500 kilovolt ("kV") High Voltage Direct Current ("HVDC") transmission line connecting Sumatera and Java is being reassessed. This project was originally planned to deliver electricity from coal mine-mouth power plants in South Sumatera to the more populous Java Island. Consequently, several of the Sumsel coal mine-mouth power plants were delayed or cancelled until the Sumatera transmission system is ready for plants with larger scale, including Sumsel 9 and 10.

In 2016, the existing distribution network consisted of around 360,000 kmc of Medium Voltage Network, 527,000 kmc of Low Voltage Network and 50,000 MVA of transformer capacity with 434,000 transformers as follows:

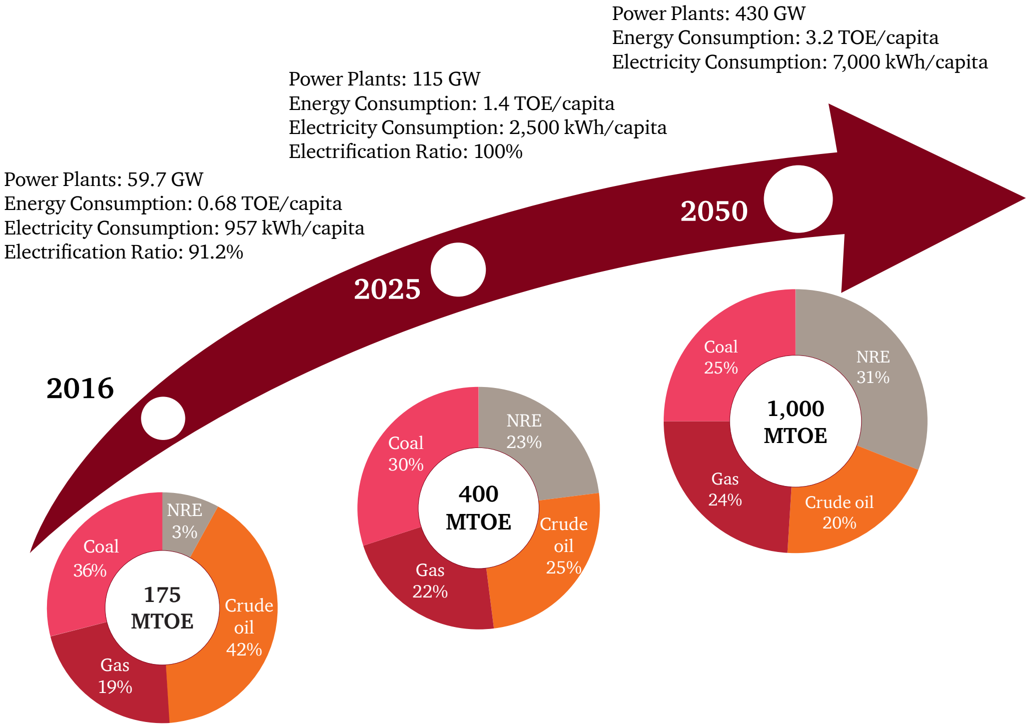
Region/ Islands	Medium voltage			Low Voltage (in kmc)	Number of transformers (in Unit)	Transformer capacity (in MVA)
	6-7 kV	10-12 kV	15-20 kV			
Sumatera	3	3	104,773	138,808	95,739	10,028
Java-Bali	-	-	164,918	301,768	260,909	32,822
Kalimantan	2	-	31,601	33,576	29,018	2,895
Sulawesi	-	-	34,829	32,424	31,477	2,640
Papua	-	-	5,089	6,305	3,623	449
Maluku	-	-	6,325	2,058	3,839	362
Nusa Tenggara	-	-	12,653	12,554	8,906	904
Total	**5**	**3**	**360,188**	**527,493**	**433,511**	**50,100**

Source: 2016 PLN Statistics

19 *2016 PLN Statistics, p. 31*

1.5 *Government's Strategy, Policy and Plan for the Power Sector in Indonesia*

Renewables have increased in importance in recent years due to concerns over global warming and other environmental issues, while certain technologies have become more attractive due to falling costs. These factors are reflected in the target energy mix for primary energy demand in Indonesia, with the renewable energy portion being increased to 23% based on the 2014 NEP, compared to 17% based on PR No. 5/2006. In addition, the 2014 NEP aims to achieve an optimal primary energy mix of: (1) new and renewable energy ("NRE") of at least 23%, oil of less than 25%, coal of at least 30% and natural gas of at least 22% by 2025; (2) NRE of at least 31%, oil of less than 20%, coal of at least 25% and natural gas of at least 24% by 2050. Further, the 2014 NEP aims for a primary energy supply of 400 Million Tonnes of Oil Equivalent ("MTOE") and 1,000 MTOE by 2025 and 2050, respectively or 1.4 TOE/capita and 3.2 TOE/capita, by 2025 and 2050, respectively.



Source: 2014 NEP, BP Statistical Review of World Energy 2017, PwC Analysis

The key points in the 2014 NEP that directly relate to the power sector are as follows:

- To reach power generation installed capacity of 115 GW and 430 GW by 2025 and 2050, respectively;
- To achieve per capita electricity consumption of 2,500 kWh and 7,000 kWh by 2025 and 2050, respectively;
- To achieve an electrification ratio of close to 100% by 2020.

The strategy for the utilisation of national energy sources by the Government and/or Regional Governments includes the following measures:

- Utilisation of renewable energy from waterflow and waterfall, geothermal, sea wave, tidal and ocean thermal energy conversion and wind for electricity generation;
- Utilisation of solar for electricity generation and non-electricity energy for industry, households and transportation;
- Utilisation of biomass and waste for electricity generation and transportation;
- Utilisation of natural gas for industry, electricity generation, households and transportation, specifically in cases that offer the highest value added;
- Utilisation of coal for electricity generation and industry;
- Utilisation of new solid and gas energy sources for electricity generation;
- Utilisation of ocean thermal energy conversion as a prototype for early-stage connection to the power grid;
- Utilisation of PV solar cells for transportation, industry, commercial buildings and households; and
- Maximising and making compulsory the utilisation of solar components and solar power plants that are manufactured domestically.

To create a competitive power sector, the Government shall, among other measures:

a) Determine the prices of certain primary energy sources such as coal, gas, water and geothermal used for power generation;
b) Determine the electricity tariff progressively;
c) Use the feed-in tariff mechanism for determining the selling price of renewable energy;
d) Manage geothermal energy resources through risk-sharing between Electricity Supply Business Licence (*Izin Usaha Penyediaan Tenaga Listrik* – "IUPTL") holders and developers;
e) Reduce electricity subsidy in stages until the population's purchasing power can afford it without subsidy; and
f) Encourage domestic capability to execute geothermal exploration and support the power industry.

To support the achievement of the new and renewable energy mix target based on the 2014 NEP, the power generation energy mix by 2025 should comprise approximately 25% new and renewable energy[20], 50% coal, 24% gas and 1% diesel fuel. In 2016, power generation from new and renewable energy was around 12%, and therefore to achieve 25% by 2025 represents quite an ambitious target. Based on the 2017 RUPTL, PLN projects that involve power generation from renewables will amount to a maximum of 22.5% by 2025/2026. Hence as a contingency plan, PLN would use an additional of 5.1 GW gas-fired power plants to meet any shortfall in renewables in the fuel mix for power generation.[21]

Considering Law No. 30/2007 on Energy and the 2014 NEPs as targeted in GR No. 79/2014, in March 2017, President Joko Widodo issued the implementing regulation for PR No. 22/2017 on the National General Energy Plan (*Rencana Umum Energi Nasional* – "RUEN"). The RUEN is a Central Government policy which consists of a cross-sectorial strategy and implementation plan to achieve the 2014 NEP. The RUEN sets out the results of energy demand-supply modelling until 2050, and the policies and strategies that will be undertaken to achieve those targets. Under the RUEN, the Government seeks to re-emphasise the purpose of energy use as a driver of the national economy.

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20 *There are different targets for the share of renewables in the energy mix (23%) and the power generation fuel mix (25%)*
21 *2017 RUPTL p. VI-70*

1.6 Chronological Development of the Power Sector in Indonesia

Early electricity arrangements in Indonesia were carried out pursuant to the 1890 Dutch Ordinance entitled "Installation and Utilisation of Conductors for Electrical Lighting and Transferring Power via Electricity in Indonesia".

This ordinance was annulled in 1985 with the introduction of Law No. 15/1985 on Electricity (the "1985 Electricity Law"), which ushered in the modern era of the power sector in Indonesia. The 1985 Electricity Law provided for a centralised system with a state-owned electricity company, PLN, holding exclusive powers over the transmission, distribution and sale of electricity. Under this law, limited private participation in power generation was permitted for an entity's own use or for sale to PLN. Essentially, the model involved allowing for private investment in power-generating assets as IPPs. These IPPs were licensed to sell their power solely to PLN pursuant to PPAs. PLN, being the sole purchaser of the power output, became the key driver of the commerciality of the entire value chain. The first major PPA in this new era was signed with PT Paiton Energy to develop the coal-fired Paiton power station in 1991. Several other significant IPPs followed, including a number in relation to geothermal power generation (under a slightly different investment framework). Many other IPP projects made it through various stages of licensing and commercial approval.

This IPP programme, however, was effectively frozen in the late 1990s when the Asian financial crisis hit. Indonesia was badly affected, with GDP contracting by up to 13.5% and the IDR falling from around 2,500 per USD to as low as 16,650 in June 1998.

PLN in turn suffered financially, especially from the devaluation of the Rupiah. A large portion of PLN's costs were denominated in US Dollars, including its PPA offtake prices, but its revenue base, from sales to consumers, was IDR-denominated. With the IPP sector being set up for a USD denominated value chain, the investment economics of the entire sector deteriorated markedly, with around a 75% fall in the value of the local currency. Many of the IPPs that were not yet in production at that time were abandoned. Others could only continue with their PPAs renegotiated down to a much lower offtake price. Overall, a significant degree of investor confidence in the sector was lost. PLN was also left in a position of being unable independently to fund investment in the country's much-needed additional capacity.

In 2002, the Government introduced reforms through the enactment of Law No. 20/2002 on Electricity (the "2002 Electricity Law"). Under this law, the power business was divided into competitive and non-competitive areas, with the former allowing for private participation in the generation and retail areas of the electricity value chain.[22] The 2002 Electricity Law also allowed for electricity tariffs to be determined by the market and for independent regulation through the establishment of the Electricity Market Supervisory Agency.

However, in December 2004, Indonesia's Constitutional Court ruled the 2002 Electricity Law to be unconstitutional on the basis that it contravened Article 33 of the Indonesian Constitution. According to the Constitutional Court, electricity is a strategic commodity and its generation and distribution should remain under the exclusive control of the Government. As a result, the Court effectively re-enacted the previous 1985 Law and from 1999 – 2004 there was very little private investment of any sort in new power projects.

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22 *Article 17(1) and Article 21(3) of the 2002 Electricity Law*

The 1985 Electricity Law was implemented through GR No. 10/1989 on the Provision and Utilisation of Electricity as amended by GR No. 3/2005 and GR No. 26/2006. Based on these regulations, IPPs were permitted to develop and supply power to the Authorised Holder of an Electricity Business Licence (*Pemegang Kuasa Usaha Ketenagalistrikan* – "PKUK") and the Authorised Holder of an Electricity Supply for Public Use Business Licence (*Pemegang Izin Usaha Ketenagalistrikan untuk Kepentingan Umum*), which were essentially limited to PLN.

Other supporting legislation and regulations since then have included the following:

a) PR No. 67/2005 and MoF Regulation No. 38/2006, which set out rules and procedures for Public-Private Partnership ("PPP") arrangements including Government support and guarantees;
b) PR No. 42/2005, which outlined the inter-ministerial Committee for the Infrastructure Development Acceleration Programme responsible for coordinating policy related to the private provision of infrastructure;
c) PR No. 71/2006, which launched the first fast-track programme, and which also allowed direct selection for the first fast-track programme of coal fired power plants;
d) MoEMR Regulation No. 1/2006 on Electrical Power Purchasing and/or Rental of Transmission Lines and MoEMR Regulation No. 5/2009 on Guidelines for Power Purchase by PT PLN (Persero) from Cooperatives or Other Business Entities, which covered the IPP procurement process.

In 2005 the Government began new efforts to attract private investment back into the sector. New PPP legislation was enacted and a list of IPP projects open for private tender was also made available.

In 2006 the Government announced stage one of a fast-track programme ("FTP I") followed by a second programme ("FTP II") in early 2010. Each programme aimed to accelerate the development of 10 GW of generation capacity, with FTP II geared towards IPPs and renewable energy. In 2015, the new Joko Widodo Government announced plans to accelerate the development of 35 GW of generation capacity.

In 2009 the Government passed the 2009 Electricity Law to strengthen the regulatory framework and provide a greater role for Regional Governments in terms of licensing and determining electricity tariffs. The 2009 Electricity Law replaced the 1985 Electricity Law with effect from 23 September 2009. However, unlike the (intervening) 2002 Electricity Law, the 2009 Electricity Law does not eliminate the main role of PLN in the electricity supply business. Under the 2009 Electricity Law, electricity supply is controlled by the state but is conducted by the Central and Regional Governments through a state-owned enterprise. In this case, the Government has given PLN priority rights over the electricity supply business throughout Indonesia. The 2009 Electricity Law also promoted a greater role for private enterprises, cooperatives and self-reliant community institutions (*Lembaga Swadaya Masyarakat*) to participate in the electricity supply business. Refer to *Section 2.2 - The 2009 Electricity Law* for more detailed information.

MoEMR

The MoEMR is charged with creating and implementing Indonesia's energy policy, including the National Electricity Plan (*Rencana Umum Kelistrikan Nasional* – "RUKN") and regulating the power sector through the DGE and the DGNREEC. The MoEMR is also responsible for preparing implementing regulations related to electricity, NRE and energy conservation and endorsing PLN's RUPTL.

House of Representatives (*Dewan Perwakilan Rakyat* – "DPR")

Commission VII of the DPR is charged with developing regulations in the areas of energy, research and technology and environment.

Commission VII is responsible for the approval of energy-related legislation (including electricity) and the supervision of energy-related Government policy.

PLN

PLN is responsible for the majority of Indonesia's power generation, and has exclusive powers over the transmission, distribution and supply of electricity to the public. PLN is regulated and supervised by the MoEMR, the Ministry of State-Owned Enterprises ("MoSOE") and the MoF.

In 2004, PLN was transformed from a public utility into a state-owned limited liability company (or *Persero*). The 2009 Electricity Law removed PLN's role as the PKUK. PLN is now simply the holder of an IUPTL.

The 2009 Electricity Law also grants a right of first refusal to PLN for the supply of electricity in an area before the Central Government or Regional Governments can offer the opportunity to regional-owned entities, private entities, cooperatives or self-reliant community institutions. PLN is also the provider of electricity of last resort, meaning that if PLN is not supplying a particular area and there are no regionally-owned companies, private enterprises or cooperatives that elect to supply electricity in that area, the Government is obliged to instruct PLN to supply electricity in that area.

PLN's financial profile has improved in recent years due to improvements in the subsidy payment cycle as regulated by Minister of Finance Regulation (MoF Regulation) No. 44/2017 on the Procedures for the Provision, Calculation, Payment and Accountability for Electricity Subsidy (which revoked the MoF Regulation No. 195/2015), an improvement in its fuel mix and automatic electricity price adjustments for some consumers based on the exchange rate, inflation and the Indonesian crude price through MoEMR Regulation No. 31/2014, as amended by No. 9/2015. In addition, in 2015 the MoF issued MoF Regulation No. 189/2015 on the "Procedure for Guarantee for Infrastructure Funding through Direct Loans from International Financial Institutions to State-owned Enterprises", whereby the Government will guarantee direct loans obtained from international financial institutions by SOEs that meet certain criteria in order to accelerate the provision of infrastructure to the public (credit enhancement). Further, under PR No. 4/2016 (as amended by PR No. 14/2017), loans obtained by PLN for the development of power infrastructure projects may also be fully guaranteed by the MoF.

Ministry of National Development Planning/ National Development Planning Board (*Kementerian PPN*/Bappenas – "Bappenas")

Bappenas is responsible for carrying out governmental duties in the field of national development planning in accordance with the prevailing laws and regulations. Within Bappenas is the Directorate for PPP – (*Direktorat Kerjasama Pemerintah-Swasta dan Rancang Bangun*), which facilitates cooperation on infrastructure projects between the Government and private investors.

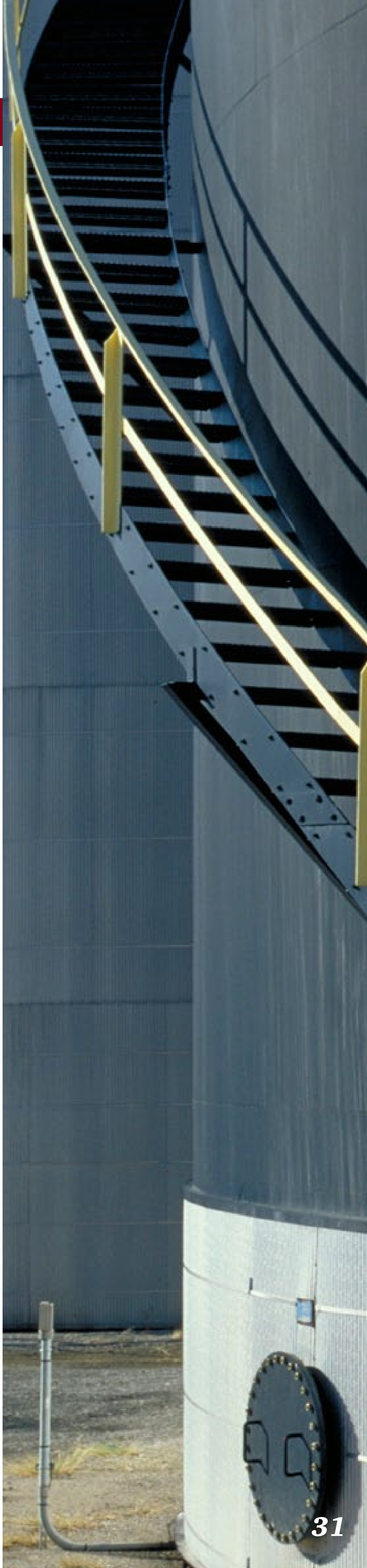
Investment Coordinating Board (*Badan Koordinasi Penanaman Modal* – "BKPM")

From 2015, BKPM has begun issuing electricity supply business licenses. It acts as a "one-stop" integrated service for business start-up and licensing procedures, as well as for facilitating foreign workers' permits. BKPM also offers an Investor Relations Unit to provide information and deal with enquiries from existing and potential investors.

Please also see the discussion in *Section 2.2.4 - IUPTL* and *Section 2.3.6 - Ease of Licensing* for a detailed discussion of the licences issued by BKPM.

Committee for the Acceleration of Prioritised Infrastructure Development (*Komite Percepatan Penyediaan Infrastruktur Prioritas* – "KPPIP")

KPPIP is an inter-ministerial coordinating committee chaired by the Coordinating Minister for Economic Affairs. Other members of KPPIP include the Minister of Finance, the Minister of National Development Planning/Bappenas and the head of the National Land Agency. KPPIP was established with the main objective of coordinating the decision making process. KPPIP is the main point of contact for de-bottlenecking national strategically important and priority projects.



MoF

The MoF approves tax incentives that may be offered by the Government for a power project, as well as any Government guarantees. The Directorate of Government Support Management and Infrastructure Financing (*Direktorat Pengelolaan Dukungan Pemerintah dan Pembiayaan Infrastruktur*) within the MoF is responsible for reviewing guarantee requests. Any approved guarantees are administered by PT Penjaminan Infrastruktur Indonesia ("PT PII") (see below).

The MoF also recommends the maximum level of electricity subsidy to PLN in the national budget and reviews loan arrangements entered into by PLN, including the government's guarantees of PLN's loans.

PT PII or the Indonesian Infrastructure Guarantee Fund ("IIGF")

The IIGF was established on 30 December 2009 to provide guarantees for infrastructure projects. The IIGF also acts as a strategic advisor to the Government and a transaction manager/lead arranger for infrastructure projects. The IIGF is wholly owned by the Government, with IDR 6 trillion in capital injected as at the end of 2015. The Government injected an additional IDR 1 trillion in the following year. For further details, please see *Section 3.3.1 - IIGF – for PPPs*.

Kementerian Negara Badan Usaha Milik Negara – the Ministry of State-owned Enterprises (the MoSOE)

The MoSOE supervises PLN's management, sets its corporate performance targets, and approves its annual budget as well as assessing the achievement of those targets.

PT Sarana Multi Infrastruktur ("PT SMI") and PT Indonesia Infrastructure Finance ("PT IIF")

PT SMI was established on 26 February 2009 with IDR 1 trillion (USD 100 million) in capital. The capital was increased to IDR 30.84 trillion by the end of 2016. PT SMI exists to help investors obtain domestic financing for the debt and equity funding of infrastructure development, including power projects. PT SMI is backed by multilateral agencies including the World Bank. The total financing commitment of PT SMI at the end of 2016 was IDR 45 trillion, with 23% allocated to the power sector.

PT IIF was established on 15 January 2010 and operates as a private non-bank financial institution with an infrastructure project finance focus and with its shareholders being PT SMI, the International Finance Corporation, ADB, Deutsche Investitions- und Entwicklungsgesellschaft GmbH and Sumitomo Mitsui Banking Corporation.

For further details, please see *Section 3.3.4 - The Infrastructure Financing Fund*.

Indonesian Electrical Power Society
(*Masyarakat Kelistrikan Indonesia* – "MKI")

MKI was established on 3 September 1998 and has members from various stakeholders within the power industry. The main objectives of MKI are to provide a forum to discuss matters relating to the industry and to put forward members' views to the Government on topics such as technology, business environment and regulations.

The Indonesian Independent Power Producers Association
(*Asosiasi Perusahaan Listrik Swasta Indonesia* – "APLSI")

The Indonesian Independent Power Producers Association (*Asosiasi Produsen Listrik Swasta Indonesia* – "APLSI") is based in Jakarta and was incorporated on 8 August 2008. APLSI is an organisation and a forum for communication between IPPs and the Government, as well as other parties related to the activities of IPPs. Its vision is to become an efficient and trustworthy association of IPPs in Indonesia, and to make a contribution for the further development of Indonesian IPPs at international level.

Indonesian Geothermal Association ("INAGA")

INAGA was established in 1991 as a forum for communication and coordination in order to improve its members' capabilities, understanding, cooperation and responsibility in relation to geothermal energy development in Indonesia.

Indonesian Renewable Energy Society
(*Masyarakat Energi Terbarukan Indonesia* – "METI")

METI was established in 1999 as a forum that focuses on the development of renewable energy in Indonesia. METI is a member of the World Renewable Energy Network, based in the UK. The management of METI also includes the Heads of the Associations of Geothermal, Hydro, Solar, Biofuel, Biomass, Biogas, Wind, Nuclear and Ocean Energy.

2 Legal and Regulatory Framework

2.1 Introduction

The power sector is regulated by MoEMR and its sub-agencies. These include the DGE and the DGNREEC.

The current regulatory framework is provided by the 2009 Electricity Law and the implementing regulations GR No. 14/2012 (as amended by GR No. 23/2014) on Electricity Business Provision, GR No. 42/2012 on Cross-Border Sales and Purchases and GR No. 62/2012 on Electricity Support Business as well as other implementing regulations issued by the MoEMR, the Minister of Industry, the Minister of Finance, the Minister of Forestry and the Environment, and other Ministers with responsibilities relating to the electricity sector. There are also other laws and regulations that affect the sector such as Law No. 2/2012 on Land Procurement for Public Interest Development (the 2012 Land Acquisition Law) and its implementing regulation PR No. 71/2012 on the Implementation of Land Procurement for Public Interest Development (as amended by PR No. 40/2014, 99/2014, 30/2015 and 148/2015). These laws and regulations provide the framework for acquiring land for infrastructure projects. Further, there are also laws and regulations specific to various subsectors of electricity such as Law No. 21/2014 on Geothermal (the "2014 Geothermal Law").

2.2 The 2009 Electricity Law

Please refer to *Section 1.6 - Chronological Development of the Power Sector in Indonesia* for other information relating to the 2009 Electricity Law.

2.2.1 RUKN and RUPTL

The MoEMR is responsible for developing the RUKN, which sets out, amongst other things, a 20-year projection of electricity demand and supply, the investment and funding policy, and the approach to the utilisation of new and renewable energy resources. The RUKN is developed based on the NEP, which is currently stipulated under GR No. 79/2014, where the RUKN was formulated in collaboration with the Government in the course of several Focus Group Discussions ("FGDs"). Additionally, based on the GR No. 23/2014, the RUKN can only be determined by the Minister of Energy and Mineral Resources after consultation with the DPR. The RUKN is reviewed at least every three years.

The 2009 Electricity Law also provides that Regional Governments should prepare a Regional Electricity Plan (*Rencana Umum Ketenagalistrikan Daerah* – "RUKD") based on the RUKN.

The RUPTL constitutes a ten-year electricity development plan in the operating areas, or *Wilayah Usaha,* of PLN (excluding the *Wilayah Usaha* of PLN's subsidiaries such as PT Pelayanan Listrik Nasional Batam). The RUPTL is based on the National Electricity General Plan (*Rencana Umum Ketenagalistrikan Nasional*) which consists of the RUKN and RUKD. The RUPTL contains demand forecasts, future expansion plans, electricity production forecasts, fuel requirements, projects that are planned to be developed by PLN and IPP investors, respectively. The procurement route for IPPs to build power plants is also based on the RUPTL. As such, the RUPTL is a very important document for all investors in the Indonesian power sector. The RUPTL is reviewed annually.

2.2.2 Electricity Business

The 2009 Electricity Law divides the electricity business into the following two broad categories:

a) Activities involved in supplying electrical power (both public use and captive supply or "own use"):
   i) Electrical power generation;
   ii) Electrical power transmission;
   iii) Electrical power distribution; and
   iv) The sale of electrical power.
b) Activities involved in electrical power support:
   i) Service businesses such as consulting, construction and installation, operation and maintenance, research and development, education, training and certification, and equipment testing and certification; and
   ii) Industry businesses such as power tools and power equipment supply.

Electricity supply for public use can only be carried out in an integrated manner by one business entity within one *Wilayah Usaha*. Restrictions on *Wilayah Usaha* shall also apply to the supply of electricity for public use, which only includes power distribution and/or sales of electricity on a standalone basis.

Under the 2009 Electricity Law, the Government has given PLN priority rights over the electricity supply business throughout Indonesia except for certain *Wilayah Usaha* given to private enterprises, cooperatives, and self-reliant community institutions involved in the electricity supply business.

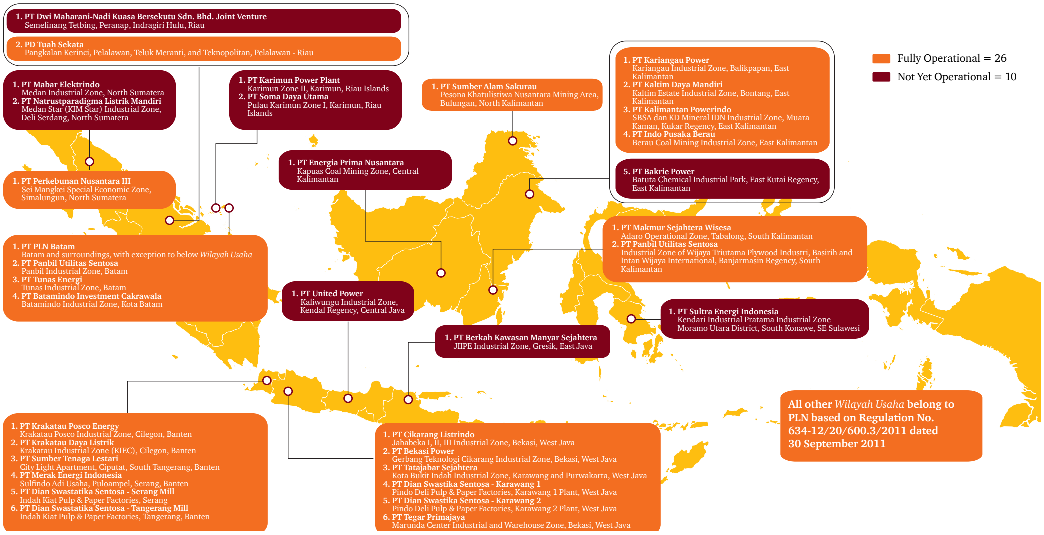
The DGE, on behalf of the MoEMR, sets *Wilayah Usaha* for the electricity supply business. According to MoEMR Regulation No. 28/2012 (as amended by MoEMR Regulation No. 7/2016), *Wilayah Usaha* can be granted to certain parties as described above, with the following conditions:

a) The area is not yet covered by an existing IUPTL holder;
b) The existing IUPTL holder in the *Wilayah Usaha* is not able to provide a good and reliable electricity supply or electricity distribution network; or
c) The holder of the *Wilayah Usaha* has returned some or all of the area to the MoEMR.

To obtain a *Wilayah Usaha*, SOEs, private enterprises, cooperatives, and self-reliant community institutions can make a request to the MoEMR through the DGE, supported by an analysis of the electricity needs and business plans for the requested *Wilayah Usaha* and a recommendation from the Governor or officer from the Provincial Government who has been given the authority to issue recommendations in cases where a *Wilayah Usaha* is contained within a single province. The DGE will assign a technical team to assess the technical feasibility of the request to determine whether the requested *Wilayah Usaha* will be granted.

At the end of 2016, the Government had issued 36 *Wilayah Usaha*, including the *Wilayah Usaha* of PLN with a breakdown of 26 *Wilayah Usaha* already in operation and ten *Wilayah Usaha* not yet operating. The distribution of *Wilayah Usaha* can be seen in Figure 2.1.

Figure 2.1 – The holders of *Wilayah Usaha* in Indonesia in 2016



Source: DGE, "Electricity Business and Primary Energy", Presentation on 7 June 2017

2.2.2.1 Generation

PLN and IPPs

At the end of 2016, the total installed capacity was 59.6 GW, divided between: PLN and its subsidiaries, which accounted for 41 GW (69%); IPPs accounting for 13.8 GW (23%); PPUs accounting for 2.4 GW (4%), with the remaining 2.4 GW belonging to the holders of non-fossil fuel operating licenses (IO Non-BBM).[23] As such, the majority of power-generating assets in Indonesia are controlled by PLN, including by its subsidiaries including Indonesia Power, Pembangkitan Jawa Bali ("PJB") and PLN Batam.

Private sector participation is allowed through IPP or PPP arrangements. IPP appointments are most often granted through competitive tenders, although IPPs can be directly selected or directly appointed in certain circumstances under GR No. 14/2012 (as amended by GR No. 23/2014). A similar situation applies for PPPs under PR No. 38/2015 and its implementing regulation LKPP (*Lembaga Kebijakan Pengadaan Barang dan Jasa Pemerintah* - Government Procurement of Goods and Services Policy Board) No. 19/2015. For a detailed discussion for the IPP/PPP procurement process, please see *Section 3.4 - Procurement Process*.

23 *DGE, "Policy in National Electricity Provision", Presentation at the 7th IPP Summit, 9-10 May 2017*

PPUs

Investors who generate electricity for their own use rather than for sale to PLN are known as PPUs. PPUs with a capacity greater than 200 kVA must hold an operating licence (*Izin Operasi*) to generate, transmit and distribute electricity for their own use or to their own customer base (such as tenants on an industrial estate).[24] PPUs with a capacity between 25-200 kVA must obtain an approval from the relevant Minister, Governor or Mayor, whereas PPUs with a capacity lower than 25 kVA are only required to report to the relevant Minister, Governor or Mayor. The PPU may sell excess capacity to an IUPTL holder (in practice this is most likely to be PLN) or directly to end customers subject to the approval of the relevant Minister, Governor or Mayor. In cases in which PPUs are producing power for their own use and selling directly to other users (e.g. Industrial Estate tenants), PPUs will need a *Wilayah Usaha* and IUPTL permits in addition to an *Izin Operasi* to act as a seller of electricity.

MoEMR Regulation 19/2017 sets a maximum benchmark price for excess power equal to 90% of Regional BPP. Under an excess power arrangement, the PPA may be less or more than one year, depending on local power needs. The price will be revisited anually to accomodate the change in Regional BPP.

With the release of MoEMR Regulation No. 1/2017 on the Parallel Operation of Power Plants With Power Grids of PLN, PPUs may establish a backup connection to PLN under the following specified parameters:

- A Connection Charge: based on the existing Law and related ministerial regulations;
- A Capacity Charge: calculated using the following formula, total power generated (MW) times 40 hours times electricity tariff;
- An Energy Charge:
    - o Normal Energy Charge: applies when PPUs normally operate in parallel systems;
    - o Emergency Energy Charge: when emergency situation occurs, which led PPUs to use electricity supplied by PLN.

24 *PwC and GE Operations Indonesia ("GE"), Private Power Utilities: The Economic Benefits of Captive Power in Industrial Estates in Indonesia, 2016, https://www.pwc.com/id/en/pwc-publications/industry-publications/energy--utilities---mining-publications.html*

It is also stated in the regulation PLN can set the capacity charge without having to receive approval from the Minister of Energy and Mineral Resources. PLN can also apply a higher capacity charge, but this requires the approval of the Minister of Energy and Mineral Resources.

2.2.2.2 Transmission, Distribution and Retailing

The 2009 Electricity Law provides PLN with priority rights to conduct its business throughout Indonesia. As the sole owner of transmission and distribution assets, PLN remains the only business entity involved in transmitting and distributing electrical power. The 2009 Electricity Law and GR No. 14/2012 (as amended by GR No. 23/2014) allows for private participation in the supply of power for public use, and for both transmission and distribution. However, private sector participation that is currently in effect is still limited to the power generation sector. This is set to change following the enactment of MoEMR Regulation No. 1/2015 on “power wheeling”, which aims to allow IPPs and PPUs to use PLN’s existing transmission and distribution networks. Power wheeling is the joint use of the networks to optimise the value of the networks and to speed up the supply of additional generating capacity. However, implementing regulations setting out detailed technical procedures and financial charges for T&D network access are yet to be released.

2.2.2.3 Electricity Support Business

The 2009 Electricity Law classifies electricity support businesses into electricity-supporting services business licenses and electricity-supporting industry business licenses.

Based on GR No. 62/2012, electricity-supporting service business covers the following:

a. Consulting on the installation of electricity;
b. Developments and installations for the provision of electricity;
c. Inspection and examination of electricity installations;
d. Operation of electricity installations;
e. Maintenance of electricity installations;
f. Research and development;
g. Education and training;
h. Laboratory testing of electricity equipment and use of electricity;
i. Certification of electricity equipment adequacy and use of electricity;
j. Certification of electricity engineering competence; and
k. Business or other services directly related to the provision of electricity.

Entities involved in electricity-supporting services business must have an Electricity Supporting Services Business Licence (*Izin Usaha Jasa Penunjang Tenaga Listrik* – “IUJPTL”).

Electricity-supporting business consists of supporting industries for electricity equipment and for electricity utilisation.

2.2.3 Local Content

The 2009 Electricity Law requires holders of an IUPTL or an IUJPTL/IUIPTL to prioritise the use of domestic products and services. Minister of Industry Regulation ("MoI Regulation") No. 54/2012 (as amended by MoI Regulation No. 5/2017) stipulates the minimum required percentage of local goods and services (by value) used for the development of electricity infrastructure. Failure to comply with these local content requirements may result in administrative and financial sanctions.

Imported goods can be used if:
a) The goods cannot be produced locally;
b) The technical specifications of local goods do not meet the requirements; or
c) The quantity of local goods is not sufficient.

The following table summarises the minimum local content requirement for different sources of power generation:

Power Plant	Capacity	Minimum use of domestic products (TKDN)
Coal-fired	up to 15 MW	67.95% for goods; 96.31% for services and 70.79% for goods and services combined
	>15 – 25 MW	45.36% for goods; 91.99% for services and 49.09% for goods and services combined
	>25 – 100 MW	40.85% for goods; 88.07% for services and 44.14% for goods and services combined
	>100 – 600 MW	38.00% for goods; 71.33% for services and 40.00% for goods and services combined
	Above 600 MW	36.10% for goods; 71.33% for services and 38.21% for goods and services combined
Hydro – Non-storage Pump	up to 15 MW	64.20% for goods; 86.06% for services and 70.76% for goods and services combined
	> 15 – 50 MW	49.84% for goods; 55.54% for services and 51.60% for goods and services combined
	> 50 – 150 MW	48.11% for goods; 51.10% for services and 49% for goods and services combined
	Above 150 MW	47.82% for goods; 46.98% for services and 47.60% for goods and services combined
Geothermal	up to 5 MW	31.30% for goods; 89.18% for services and 42.00% for goods and services combined
	5 – 10 MW	21.00% for goods; 82.30% for services and 40.45% for goods and services combined
	10 – 60 MW	15.70% for goods; 74.10% for services and 33.24% for goods and services combined
	60 MW – 110 MW	16.30% for goods; 60.10% for services and 29.21% for goods and services combined
	>110 MW	16.00% for goods; 58.40% for services and 28.95% for goods and services combined
Gas-fired	Up to 100 MW per block	43.69% for goods; 96.31% for services and 48.96% for goods and services combined

Power Plant	Capacity	Minimum use of domestic products (TKDN)
Combined Cycle	Up to 50 MW per block	40.00% for goods; 71.53% for services and 47.88% for goods and services combined
	50 MW – 100 MW per block	35.71% for goods; 71.53% for services and 40.00% for goods and services combined
	100 MW – 300 MW per block	30.67% for goods; 71.53% for services and 34.76% for goods and services combined
	>300 MW per block	25.63% for goods; 71.53% for services and 30.22% for goods and services combined
Solar Home System (off-grid, stand-alone)	Per unit	39.87% for goods; 100% for services and 45.9% for goods and services combined
Communal Solar Power System (mini grid)	Per unit	34.09% for goods; 100% for services and 40.68% for goods and services combined
On-grid Solar Power System	Per unit	37.47% for goods, 100% for services and 43.72% for goods and services combined

The construction of power plants is also regulated as follows:

- The development of coal-fired power plants up to 135 MW, geothermal power plants up to 60 MW, hydropower plants up to 150 MW, and combined cycle power plants or solar power plants shall be undertaken and led by a national Engineering, Procurement and Construction ("EPC") company.
- The development of power plants other than those mentioned above can be undertaken by a consortium of a foreign company and a local company.

On 9 February 2017, MoI Regulation No. 5/M-IND/PER/2/2017 was issued, amending MoI Regulation No. 54/M-IND/PER/3/2012 regarding the guidelines on the use of domestic products for the construction of electricity infrastructure. In MoI Regulation No. 5/M-IND/PER/2/2017, the level of domestic components for solar modules needs to be at least 50% by 2018 and 60% by 2019. This compares to the previous regulation where only 30.14% was required for Solar Home System modules and 25.63% for Communal Solar System modules.

The following table summarises the minimum local content for transmission:

Type	kV	TKDN
High-Voltage Aerial Network	70	70.21% for goods; 100% for services and 76.17% for goods and services combined
	150	70.21% for goods; 100% for services and 76.17% for goods and services combined
Extra-High-Voltage Aerial Network	275	68.23% for goods; 100% for services and 74.59% for goods and services combined
	500	68.23% for goods; 100% for services and 74.59% for goods and services combined
High-Voltage Undersea Cable Network	150	15.00% for goods; 83.00% for services and 28.60% for goods and services combined
High-Voltage Underground Cable Network	70	45.50% for goods; 100% for services and 56.40% for goods and services combined
	150	45.50% for goods; 100% for services and 56.40% for goods and services combined

The following table summarises the minimum local content for main relay stations:

Type	kV	TKDN
High-Voltage Main Relay Station	70	41.91% for goods; 99.98% for services and 65.14% for goods and services combined
	150	40.66% for goods; 99.98% for services and 64.39% for goods and services combined
Extra-High-Voltage Main Relay Station	275	22.42% for goods; 74.54% for services and 43.27% for goods and services combined
	500	21.51% for goods; 74.67% for services and 42.77% for goods and services combined
High-Voltage Gas Insulated Switchgear ("GIS")	150	14.27% for goods; 26.68% for services and 19.24% for goods and services combined
Extra-High Voltage GIS	150	11.19% for goods; 26.68% for services and 17.39% for goods and services combined

The construction of transmission and distribution networks shall be undertaken and led by a national EPC company.

Provisions and procedures for the calculation of local content in goods, services and the combination of goods and services for the respective power plants, main relay stations and transmission/distribution networks are regulated by MoI Regulation No. 15/M-IND/PER/2/2011 regarding Guidance for the Use of Domestic Goods in the Procurement of Government Goods/Services and MoI Regulation No. 16/M-IND/PER/2/2011 regarding Provisions and Procedures for the Calculation of Local Content.

2.2.4 IUPTL

A business licence must be granted before an entity can supply electrical power or run an electrical power-supporting business. Business licenses for the supply of electrical power consist of the following:
a) An IUPTL to supply electricity for public use, which may be issued for a maximum validity period of 30 years and may be extended; and
b) An *Izin Operasi* to supply electricity for own use (i.e. for PPUs) with electricity capacity of more than 200 kVA, which may be issued for a maximum validity period of ten years and may be extended.

An IUPTL can cover any of the following activities:
a) Electricity generation;
b) Electricity transmission;
c) Electricity distribution;
d) Electricity sales;
e) Electricity distribution and sales; and
f) Integrated activities from electricity generation to sales.

An IUPTL may be issued to the following entities:
a) State-owned or private companies;
b) Regional Government-owned companies;
c) Cooperatives and self-reliant community institutions.

From January 2015, BKPM, acting on behalf of the MoEMR, may issue ten types of power-related licenses under MoEMR Regulation No. 35/2014 (as amended by MoEMR Regulation No. 14/2017), namely:

1. An IUPTL;
2. *Izin Operasi*;
3. The determination of *Wilayah Usaha*;
4. An IUJPTL;
5. A cross-border sale and purchase licence;
6. A permit for utilisation of power grid for telecommunications, multimedia and informatics;
7. A geothermal licence (*Izin Panas Bumi* - "IPB");
8. A geothermal preliminary survey assignment;
9. A geothermal support services approval; and
10. A geothermal explosives storage permit.

2.2.5 Cross-border Sale and Purchase

GR No. 42/2012 governs the sale and purchase of power across Indonesia's borders and stipulates that a permit is required from the Minister.

Power can be sold across the Indonesian border only if:
a) The power needs of the local area and its surroundings have been met;
b) The sale prices are not subsidised; and
c) The sale will not compromise the quality and reliability of the local power supply.

Power can be purchased from outside of Indonesia only if:
a) The purchase is intended to meet local electricity needs or to improve/enhance the quality and reliability of electricity supply;
b) Does not harm national sovereignty, security or economic development;
c) The purchase does not ignore the development of the capability to supply electricity in the country; and
d) The purchase does not result in the dependence on the procurement of electrical power from other countries.

Cross-border power sale and purchase arrangements are also subject to the prevailing laws and regulations.

Historically, Indonesia has imported electricity from Malaysia. Purchases increased from 1.26 GWh in 2009 to 12.75 GWh in 2015 due to a shortage of power in West Kalimantan. Given the lack of power supply in West Kalimantan, the Government permitted the development of a 275 kV link between Sarawak, Malaysia and West Kalimantan to import hydro-generated power under a 25-year agreement between PLN and the Sarawak Energy Supply Corporation. This interconnection went live in January 2016. For the first five years, Indonesia is expected to import around 50 MW during non-peak load time and 230 MW at peak load time, after which PLN plans to export power on a net basis after the completion of the Kalbar-1 (2 x 50 MW), Kalbar-2 (2 x 27.5 MW) and Kalbar-3 (2 x 55 MW) steam power plants.[25]

25 *http://www3.esdm.go.id/news-archives/electricity/46-electricity/8114-indonesia-malaysia-cooperate-in-strengthening-electricity-in-borderlines-.html*

The Sarawak-West Kalimantan link could be considered the first Indonesian leg of the ASEAN Power Grid project (connections already exist between a number of ASEAN countries including Thailand, Laos, Malaysia, Singapore, Vietnam and Cambodia). The rationale for the project is to increase flexibility for systems operators to match supply and demand at the lowest possible cost, supporting further intermittent renewable deployment, and increasing energy security. Such an ambitious project with large investment outlays will require a supportive cross-border regulatory environment, cooperation among national utilities on technical issues and more dynamic pricing in order better to match supply and demand.

The other planned ASEAN Power Grid projects in which Indonesia will take part are as follows:

Interconnection transmission network	Earliest Commercial Operations Date ("COD")
Peninsular Malaysia – Sumatera	2019
Batam – Singapore	2020
East Sabah – East Kalimantan	Post 2020
Singapore – Sumatera	Post 2020

Source: International Energy Agency ("IEA"), "Development Prospects of the ASEAN Power Sector: Toward an Integrated Electricity Market", 2015

2.3 PR No. 4/2016 (as Amended by PR No. 14/2017)

A five-year 35 GW power generation programme was announced by President Joko Widodo in late 2014. The introduction of this 35 GW Programme was seen as a continuation of the Government's efforts to enhance Indonesia's electricity infrastructure. The Government had introduced FTP I of 10 GW of coal-fired power generation in 2006, and FTP II of 10 GW, coming largely from renewable energy projects in 2010. The realisation of FTP I and II has not been very promising. After almost ten years, FTP I is not yet 100% completed. FTP II has not progressed as expected, and various projects in this programme have been integrated into the 35 GW Programme under President Joko Widodo's administration.

Based on the experience and obstacles faced in FTP I and II, PR No. 4/2016 (as amended by PR No. 14/2017) on the Acceleration of Power Infrastructure Development was issued to address various issues affecting power project development in Indonesia. This included, among other measures, a Government guarantee for the development of power projects, which covers both projects developed by PLN, and projects developed by PLN or its subsidiaries, in cooperation with IPPs. The regulation also covers licensing, land acquisition and various other issues.

2.3.1 Government Guarantees

Under PR No. 4/2016 (as amended by PR No. 14/2017), an IPP can receive a business viability guarantee from the MoF for PLN's obligations under PPAs. To obtain such a guarantee, PLN's President Director needs to request the guarantee from the MoF before the start of the procurement process of the power projects. PR No. 4/2016 (as amended by PR No. 14/2017) does not provide any criteria for granting a business viability guarantee or for a guarantee-granting mechanism for an IPP Project. Hence, it is at the discretion of PLN to propose the guarantee. Further, the proposed guarantee may also need to be included in the procurement documents, and it is therefore questionable whether at least half of the 35 GW power development projects for which PPAs were signed in 2015, as well as projects tendered prior to the issuance of this PR, are eligible for this guarantee.

Under PR No. 4/2016 (as amended by PR No. 14/2017), loans obtained by PLN in relation to the development of power infrastructure projects will also be fully guaranteed by the MoF. To obtain such a guarantee, PLN's President Director needs to request it from the MoF, which must approve PLN's request within 25 business days from the receipt of a complete submission from PLN.

The procedures for obtaining the business viability guarantees for IPPs as well as loan guarantees for PLN are regulated under MoF Regulation No. 130/2016 (superseding MoF Regulation No. 173/2014).

2.3.2 New and Renewable Energy Projects

The development of electricity infrastructure prioritises new and renewable energy, in order to achieve the targeted energy mix under the NEP. The Central Government and/or Local Governments can provide support in the form of: (1) fiscal incentives; (2) licensing and non-licensing relief; (3) feed-in tariffs for new and renewable energy sources; (4) the establishment of a separate business entity to generate energy from new and renewable sources for sale to PLN; and (5) specific subsidies for new and renewable energy. This support will depend on the feasibility and economics of electricity infrastructure development. As such, PR No. 4/2016 (as amended by PR No. 14/2017) confirms the availability of fiscal incentives for new and renewable energy development.

It is clear that, based on that PR, the Government plans to develop a new and renewable energy aggregator that will buy all of the electricity generated from new and renewable sources and later sell it to PLN and receive specific subsidies. However, it is not clear when this new aggregator will be established, or whether it will be part of PLN or an independent State-owned Enterprise ("SOE").

PR No. 4/2016 (as amended by PR No. 14/2017) clarifies that hydro, geothermal and wind power projects, including the transmission lines, can be developed in Natural Reserve Areas and Natural Conservation Areas in accordance with the prevailing Laws and regulations.

2.3.3 Local Content

PR No. 4/2016 also requires the use of domestic products and services for the development of power infrastructure, which is consistent with the 2009 Electricity Law. PLN, a subsidiary of PLN and/or IPPs can cooperate with foreign enterprises working on the development of equipment and components for electricity equipment, domestic human resources and the transfer of technology required in the implementation of power infrastructure development.

For details of the local content requirements, please see *Section 2.2.3 - Local Content*.

2.3.4 Special Provision on PLN's Cooperation

As PR No. 4/2016 was amended by PR No. 14/2017, in cases where PLN has to work with foreign business entities, priority shall be given to cooperation with foreign business entities owned by the related foreign Government (foreign SOE).

2.3.5 Land Acquisition

Land acquisition for electricity infrastructure development should be undertaken by PLN, a subsidiary of PLN, or by IPPs in accordance with the prevailing laws and regulations on land acquisition for the construction of infrastructure for public use (currently the 2012 Land Acquisition Law and its implementing regulations) using the shortest timeframes (currently the maximum time period is set at 583 days – see further discussion in *Section 2.5.4 - Land Acquisition Law*). For land that has been designated for electricity infrastructure development by the Governor, the land rights cannot be transferred from the landowner to parties other than the National Land Agency.

For the purposes of efficiency and effectiveness, land areas of not more than five hectares can be directly purchased by PLN, a subsidiary of PLN, or by IPPs from holders of land rights in a purchase or exchange or by other means as agreed by both parties. If the landowner disagrees with the appraisal price, PLN, a subsidiary of PLN or an IPP can agree to a purchase price higher than the appraisal price after performing a cost-benefit analysis considering good governance during the process. However, it is questionable whether a cost-benefit analysis can be implemented since this method is not prescribed in the 2012 Land Acquisition Law.

In the event that land acquisition for transmission and/or substations cannot be executed because the landowner disagrees with the price, even when this is set higher than the appraisal price, PLN, a subsidiary of PLN or an IPP can rent or lease the land, or cooperate with the landowners based on another agreement.

In the case of land to be acquired for electricity infrastructure development that is controlled by the people in a forest area, PLN, a subsidiary of PLN or an IPP should ask the National Land Agency to provide information on land ownership. The National Land Agency will provide information on land ownership in coordination with the minister responsible for the environment and forestry. If the National Land Agency states that the public does not have rights to the land located in the forest area, PLN, a subsidiary of PLN, or an IPP will request a forest use permit. People who live in a forest area used for electricity infrastructure development will need to settle this with PLN, a subsidiary of PLN or an IPP together with other ministries/agencies and Local Government, taking into account their needs and social impacts. Settlements agreed will be regulated by a MoMER regulation.

The Central Government and/or Regional Governments can provide support to PLN, a subsidiary of PLN, or an IPP on land acquisition, by giving them priority over the required land, and by providing state-owned/regional-owned land.

As an amendment for PR No. 4/2016, PR No. 14/2017 also includes a new provision that PLN must pay rent for the SOE/ROE-owned government assets, although this requirement may be waived with the approval of the Central or Regional Government.

2.3.6 Ease of Licensing

PR No. 4/2016 (as amended by PR No. 14/2017) provides a platform to simplify the licensing process using one-stop services (*Pelayanan Terpadu Satu Pintu* - "PTSP") at the BKPM as well as PTSP in provinces and regencies, and also to speed up the process of obtaining licences and non-licences (i.e. certain other permissions and documents) in relation to power projects in the following ways:

- PLN, subsidiaries of PLN or IPPs submit applications for licences and non-licences that are required to commence a power project to the PTSP at BKPM including:
  a) An IUPTL;
  b) A determination of location;
  c) An environmental licence;
  d) A borrow-to-use forest area permit (*Izin Pinjam Pakai Kawasan Hutan* - "IPPKH"); and
  e) A building construction permit (*Izin Mendirikan Bangunan* - "IMB").

- PR No. 4/2016 (as amended by PR No. 14/2017) provides a time limit for governmental authorities around licence issuance, as follows:
  a) For licences in relation to which the authority for issuance has been delegated to BKPM: three working days;
  b) For licences over which the authority for issuance has not been delegated to BKPM: five working days, except those covered in points (c)-(e) below;
  c) Environmental licence: 60 working days;
  d) Borrow-to-use forest area permit: 30 working days; and
  e) Non-licence for taxation facility: 28 working days.

  Note that the licence issuance time limits are counted from the day on which the complete application is submitted. If the governmental authorities find that an application is not complete, there is a three-day time limit for the governmental authorities to return the application.

- Licences for activities that do not endanger the environment are approved on the basis of a checklist of steps to be completed by the applicant during the project. The following licences will be included in a checklist:
  a) An IMB;
  b) A disturbance permit; and
  c) Approval for a technical plan for building construction.

In order to expedite the licence processes, BKPM has launched a three hour licensing process for obtaining an IUPTLS (*Izin Usaha Penyediaan Tenaga Listrik Sementara* – "IUPTLS"). This is in line with the MoEMR Regulation No. 15/2016 concerning Three Hours Licensing Services for Infrastructure in Energy and Mineral Resources Sector. The IUPTLS can be used by the investors/project developers as a legal basis for an electricity provider to conduct their project development before obtaining an IUPTL. However, upon receiving the IUPTLS, the company must prepare a letter of commitment to provide all administrative and technical requirements up to 60 calendar days after the issuance of the IUPTLS. In the case that the company fails to provide such requirements, the BKPM Chairman will issue a Revocation Letter of the IUPTLS.

For a checklist to be regarded as an approved permit, the applicant must submit a commitment to fulfill the checklist and register it with the national PTSP, as applicable.

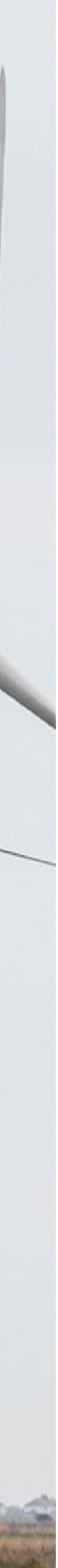
Fulfilment of the checklist is mandatory for the recipient of the licences, and the governmental authorities will oversee the fulfilment throughout the development process. Failure to fulfill the checklist will be subject to sanction in accordance with the applicable laws and regulations.

2.3.7 Spatial Plan *(Tata Ruang)*

PR No. 4/2016 (as amended by PR No. 14/2017) has introduced the following stipulations related to spatial planning:

- In the event that power infrastructure development is not in accordance with the Spatial Plan, the Detailed Spatial Plan for the Area, or the Zoning Plan for Coastal Areas and Small Islands where the power projects are built, then there can be a change in the Spatial Plan, the Detailed Spatial Plan Area, or the Zoning Plan for Coastal Areas and Small Islands;
- In the event that a change in the Spatial Plan, Detailed Spatial Plan for the Area, or the Zoning Plan for Coastal Areas and Small Islands cannot be made due to refusal by the Ministry of Forestry, then the matter shall be settled through the use of a holding zone;[25]
- Power infrastructure developments that utilise water, heat and wind, including transmission lines, are permitted in nature reserve areas and nature conservation areas.

25 *A holding zone is an area for which a change in use has not yet been approved - Kawasan yang Belum Ditetapkan Perubahan Peruntukan Ruangnya*



2.4 Regulation on PPAs

In 2017, MoEMR issued MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017) on the Principles of Power Purchase Agreements.[26] The regulation outlines the principles of PPAs, and the legal basis for the agreement between the PLN and IPPs, covering several key areas including: (a) a new risk sharing and risk allocation concept; (b) the implementation of the Build-Own-Operate-Transfer ("BOOT") business scheme; (c) penalty mechanisms. Note that the regulation does not apply to intermittent renewables, small hydro (below 10 MW), biogas and MSW. MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017) raises new concerns for investors, although our view is that the industry will adapt to the overall changes. The salient features of the regulation are as follows:

- **Risk Sharing and Allocation**
  PLN's previous PPA model was succesful in attracting private investment in the power sector. However, MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017) adopts a major change in risk sharing and allocation.

  Under the previous regulation, *force majeure* ("FM") risks are generally borne by the party most able to bear them, and IPPs were not required to pay damages resulting from events beyond their control. The new regulation, however, appears to place PLN and IPPs in a more equal position if a FM event occurs. There are two types of FM stated, being: (a) those arising from natural disasters ("Natural FM"); and (b) those arising from changes in laws and regulations ("Change-in-Law").

  Based on previous regulations and market precedent, in the case of Natural FM or Change-in-Law, PLN had to bear the Deemed Dispatch payments. PLN was also generally obliged to pay compensation to IPPs through termination payments if these events occured over the long term.

  However, under MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017), both parties are released from their obligations (i.e., no Deemed Dispatch or Termination Payments).

  In the case of a Natural FM that prevents PLN from taking power, it is no longer necessary for PLN to pay Deemed Dispatch, by way of compensation. The PPA may instead be extended by the length of time lost by the disaster and project repairs. However, this may not satisfy lenders, who require regular debt service payments from project cash flow.

  In the case of a Natural FM that causes delay in COD, the PPA may be extended by the length of time lost by the disaster and project repair.

  In the case of a Change-in-Law that requires additional investment or costs in a project, IPPs have the right to a tariff adjustment. In the case of a Change-in-Law that causes a cost reduction, PLN has the right to a tariff adjustment.

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26 https://finance.detik.com/energi/3593621/jonan-rombak-3-aturan-investasi-listrik-lebih-menarik

- **A New Regime on Penalties and Incentives**
  Under previous regulations and market precedent, in most cases, if IPPs fail to meet the plant's availability factor ("AF") as set out in the PPA, IPPs will be penalised through a revenue deduction aligned with the shortfall in AF.

  However, the new regulation appears to move towards a strict "deliver-or-pay" scheme. For example, in the case that IPPs cannot meet their PPA obligations or there is a delay in the COD on account of IPPs, or IPPs fail to meet Availability, Capacity or Outage Factors, then IPPs shall pay a penalty proportionate to the costs to be borne by PLN to replace the unrequited supply.

  A stricter penalty regime will likely sharpen the incentives for IPPs to perform, although they will doubtless factor this risk into their bid prices for PLN. In addition, other penalties are also applied to IPPs if they fail to maintain certain technical performance standards, e.g.: (a) heat rate; (b) reactive power (VAR) within the interconnection system; and (c) frequency and ramp rate.

  Similarly, PLN is required to pay a penalty for the failure of a power uptake on account of PLN, except under certain FM events mentioned above. Meanwhile, in addition to penalties, IPPs have the right to earn additional incentives if requested by PLN to reach COD early.

- **Applying BOOT Business Scheme**
  The new regulation mandates that the period of the concession shall be a maximum of 30 years and that all projects must apply the BOOT business scheme. At the end of the contract, the IPP's facilities shall be transferred to PLN. This implies that no further contract renewal will be possible for IPPs. This is typically not material for a discounted cash flow analysis that is longer than 30 years, and in any case most projects already comply with the BOOT contracts, with the exception of some geothermal and hydro projects that follow Build-Own-Operate ("BOO").

- **Others**
  MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017) also provides that:
  i) **PPA has to be in Indonesian Rupiah (IDR)**
  The payment for power must use the Indonesian Rupiah (IDR), except when granted an exemption by the Bank of Indonesia. If the tariff is denominated in USD, the exchange rate shall refer to the Jakarta Interbank Spot Dollar Rate ("JISDOR"). This provision also reflects the BI Regulation 17/3/PBI/2015 which has already been implemented in practice on numerous power projects.
  ii) **Restriction of Ownership Transfer**
  The regulation clearly prohibits the transfer of ownership rights of the project before reaching the COD. Transfers are permitted before COD if the transfer is to an affiliate in which more than 90% of the shares are owned by the Sponsor. Based on MoEMR Regulation No. 48/2017, such affiliate must be a Business Entity of one level below the transferor (see also *Section 2.6 - Restriction on Changes in Shareholders in Business Enterprises in the Energy and Mineral Resources Sector*) and the transfer obtains approval from PLN. In the case of post-COD ownership, the shareholding transfer is also subject to PLN's approval and must be reported to the Minister via Director General of Electricity.
  iii) **Transitional Provisions**
  This regulation does not apply to any project that has already invited bids, where the bid has closed, where the letter of intent has been signed, or where the PPA has been signed.

2.5 *Other Relevant Laws and Regulations*

2.5.1 Investment Law

Investment Law No. 25/2007 (the "2007 Investment Law") is aimed at providing a one-stop investment framework for investors. This includes key investor guarantees such as the right to freely repatriate foreign currency, and key incentives such as exemptions from import duties and VAT otherwise due on imports of capital goods, machines or equipment for production needs.

Obligations for power plant investors under the 2007 Investment Law include:
a) Prioritising the use of Indonesian manpower;
b) Ensuring a safe and healthy working environment;
c) Implementing a corporate social responsibility programme; and
d) Meeting certain environmental conservation obligations.

BKPM is given the power to coordinate the implementation of investment policy, including pursuant to the 2007 Investment Law.

Foreign investors wishing to participate in the power sector must first obtain a foreign investment licence from BKPM pursuant to the 2007 Investment Law. To do this, an Indonesian incorporated entity must be established and licenced as a PT PMA company (under the 2007 Investment Law and Company Law No. 40/2007). A PT PMA can be licenced for both the geothermal (i.e. generation of steam) and power sectors.

Starting in 2015, once the PT PMA Company is established it must apply through BKPM's one-stop service for an IUPTL and other licences (such as the permanent business licence and in-principle licence).

Refer to *Section 2.2.4 - IUPTL* and *Section 2.3.5 - Ease of Licensing* for a detailed discussion of the licences issued by BKPM.

2.5.2 The Negative List

The "negative list" prescribes a set of business activities that are closed to foreign investment or that have limitations on foreign participation.

The most recent negative list detailed in PR No. 44/2016 prescribes foreign investment limitations in the power sector as follows:
a) Micro power plants (<1 MW) are closed for foreign investment;
b) Small power plants (1 – 10 MW) are open for foreign ownership up to a maximum of 49%;
c) Small geothermal power plants (≤ 10 MW) are now open for foreign ownership up to a maximum of 67%;
d) Power plants with a capacity of more than 10 MW are open for foreign ownership up to a maximum of 95% or 100% for PPP projects;
e) Electrical power T&D is open for foreign ownership up to a maximum of 95% or 100% for PPP projects;
f) Power supply construction and installation (including consultancy) projects and the Operation and Management ("O&M") of electrical power installations are open for foreign ownership up to a maximum of 95%;

g) High-/extra-high-voltage electrical power construction and utility installations are now open for foreign ownership up to a maximum of 49%;
h) Low-/medium-voltage electrical power construction and utility installations are closed for foreign investment;
i) Examination and testing of electrical power installations and high-/extra-high-voltage electrical power utility installations are now open for foreign ownership up to a maximum of 49%;
j) Examination and testing of electrical power installations and low-/medium-voltage electrical power utility installations are still closed for foreign investment; and
k) Geothermal O&M services are open for foreign ownership up to a maximum of 90% and for drilling and surveying services up to a maximum of 95%.

2.5.3 The 2009 Environment Law

Pursuant to Law No. 32/2009, Minister of Environment Regulation No. 5/2012 on the Types of Businesses and/or Activities Required to Have an Analysis of Environmental Impact, IPP investors must comply with specific environmental practices and secure environmental permits before they begin operations as follows:

- Construction of transmission network – high-voltage air lines, high-voltage channel cables, high-voltage submarine cables > 150 kV;
- Construction of diesel, gas-fired, coal-fired, combined cycle power plants ≥ 100 MW in one location;
- Construction of geothermal power plants ≥ 55 MW;
- Construction of hydropower with the height of the weir ≥ 15 m or water pooling area ≥ 200 ha or the capacity of the power plant ≥ 50 MW;
- Construction of waste power plants with methane harvesting process ≥ 30 MW; and
- Construction of other types of power plants (solar, wind, biomass) ≥ 10 MW (in one location).

Businesses and/or activities other that the above should have an environmental management/monitoring effort document (*Upaya Pengelolaan Lingkungan Hidup – Upaya Pemantauan Lingkungan Hidup*) or letter of intent regarding environmental management/ monitoring.

2.5.4 Land Acquisition Law

The 2012 Land Acquisition Law and the Regulation on Land Procurement Procedures for Development and the Public Interest (PR No. 71/2012 and its amendments PR Nos. 40/2014, 99/2014 and 30/2015) aim to expedite the land acquisition process for certain infrastructure projects including power plants. The goal is to help overcome the difficulties encountered when performing compulsory acquisitions of land for public purposes. The 2012 Land Acquisition Law and PR No. 71/2012 and its amendments repeal PR Nos. 36/2005, 65/2006 and 3/2007 set out a maximum timeframe for the four stages of land acquisition, namely planning, preparation, implementation and the transfer of acquired land, and the sources of funding for land acquisition.

Power projects often face land acquisition issues. Before the implementation of this law, Indonesia did not have an established legal procedure for the compulsory acquisition of land for public purposes. PR No. 71/2012 and its amendments also help overcome the obstacle of unregistered land by including holders of 'customary land rights' as being potentially eligible for compensation.

The maximum time period is set at 583 working days from the submission of the land acquisition plan to the issue of the certificate of registration, including time for objections or appeals. An unwilling landowner can be forced to sell their rights for an amount of compensation approved by a court review. Compensation may be in the form of money, replacement land, resettlement, stock ownership or other forms as agreed by the parties.

The State Assets Management Agency (*Lembaga Manajemen Aset Negara* – "LMAN"), was established in December 2016 in order to optimise state asset management. LMAN also aims to optimise the potential State Return on Assets and Non-Tax Revenue (*Penerimaan Negara Bukan Pajak*) from state assets.

So far, the LMAN has received a Government Capital Injection worth IDR 16 trillion. The funds are used for buying land to support National Strategic Projects. The first phase of the LMAN work is concentrated on toll roads, with the upcoming phase allocated for ports, railways, and dams. So far, no energy-related projects have been included in LMAN's work plan.

2.5.5 Bank Indonesia ("BI") Regulation on the Obligation to Use Rupiah

Law No. 7/2011 regarding Currency was issued in 2011. In March 2011, BI issued BI Regulation No. 17/3/PBI/2015 on the Obligation to Use Rupiah for Transactions in Indonesia, which was effective as of 1 July 2015, with the stated aim of stabilising the Rupiah exchange rate.

The MoEMR issued a media release on 1 July 2015 (No. 40/SJI/2015) to outline the agreement between the MoEMR and BI concerning this regulation as it pertains to the oil & gas, mining and power industries following various discussions with the private sector. The media release refers to three categories of transaction as follows:

- Category 1: transactions that are able to be made directly in Rupiah, for example the leasing of offices/houses/vehicles, salary payments for Indonesian employees and payments for various support services, where a transition period of up to six months will be given;
- Category 2: transactions where time is required to implement the provisions of the regulation, for example fuel purchases, import transactions through local agents, long-term contracts and multi-currency contracts, where transactions in fixed-term contracts shall continue to be in foreign currency with the possibility of future amendment;
- Category 3: transactions for which it is fundamentally difficult to fulfill the provisions of the regulation, for example salary payments for expatriates, drilling services and the leasing of ships, where businesses may continue to use foreign currency.

Investors should continue to monitor this issue, as further procedures for the implementation of the BI regulation are expected to be issued by the MoEMR and BI in due course.

We note that PLN is currently still paying invoices denominated in USD. However, for recently signed PPAs, despite the fact that the invoices will be denominated in USD, PLN will pay the invoices in IDR, and will then be converted by SOE banks to USD when payment is transferred to the IPPs' bank accounts. PLN has signed tripartite agreements with the SOE banks and IPPs to ensure that PLN does not violate the regulation requiring the use of IDR, but at the same time does not violate the PPAs. However, there is a concern from the IPPs as to whether this arrangement will cover the entire term of the PPAs or only the period up to full repayment of the IPP's US Dollar-denominated loans. Since the implementation of MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017), payments must now explicitly be made in IDR unless being exempted by BI (see *Section 2.4 - Regulation on PPAs* for further details).

2.5.6 BI Regulation on Foreign Currency Transactions

Based on BI Regulation No. 4/2/PBI/2002 and subsequent revisions, including the latest revisions in Stipulation Letter No. 9/9/DSM dated 9 April 2007, non-financial institution companies with assets of at least IDR 100 billion or annual gross sales greater than IDR 100 billion are required to report to BI foreign currency transactions made with:

a) Overseas banks or overseas financial organisations; and/or
b) Other companies or offices domiciled outside Indonesia.

Companies that have foreign currency financial assets and liabilities are also required to submit reports to BI.

The BI report consists of the following:

a) A monthly foreign exchange transaction report for all the company's financial assets and/or liabilities in foreign currency (to be submitted within a month following the month in which the transaction occurs); and
b) A semi-annual report on the foreign-currency financial assets and/or liabilities position at the end of the relevant period. The BI reports are used by the Government to prepare the Payment Statistics Balance Sheet and Indonesia's International Investment Position.

2.5.7 BI Regulation on Reporting on Foreign Exchange Trading

BI Regulation No. 16/22/PBI/2014 regarding Reporting on Foreign Exchange Trading and Reporting on the Application of Prudential Principles to Foreign Loan Administration for Non-bank Corporations includes a requirement for companies to report their foreign currency loans to BI on a quarterly basis. Further, the fourth quarter report needs to be verified by an independent public accountant. Failure to comply with the reporting obligations triggers administrative sanctions of IDR 10 million.

The prudential principles under BI Regulation No. 16/21/PBI/2014 as amended by BI Regulation No. 18/4/PBI/2016 and Circular Letter No. 16/24/DKEM/2014 as amended by Circular Letter No. 17/18/DKEM/2015 are as follows:

a) Minimum hedging ratio is 25% of the negative difference between foreign exchange assets and foreign exchange liabilities that will be due within three months and that will be due between three and six months from the end of the reporting quarter. Only companies that have "negative difference" of more than US$ 100,000 are required to fulfill the minimum hedging ratio;
b) Minimum liquidity ratio is 70%, calculated by comparing the company's foreign exchange assets and foreign exchange liabilities that will be due within three months from the end of the reporting quarter; and
c) Minimum credit rating of "BB-" or equivalent from credit ratings agencies recognised by BI.

2.6 Restrictions on Changes in Shareholders in Business Enterprises in the Energy and Mineral Resources Sector

On 14 July 2017, the Minister of Energy and Mineral Resources issued MoEMR Regulation No. 42/2017 on the Supervision of Business Enterprises in the Energy and Mineral Resources Sector. However, on 3 August 2017, the regulation was revoked and replaced with MoEMR Regulation No. 48/2017. The intention of the regulation is to ensure that good governance is in place, and to improve the supervision of business activities in the Energy and Mineral Resources Sector.

This regulation subjects all private entities and cooperatives conducting business activities in the field of energy and mineral resources to report to, or to fulfill the requirement for approval from, the Minister of Energy and Mineral Resources. With regard to the electricity business, IPPs, which formerly were primarily regulated by their PPA with PLN, will now be subject to greater reporting requirements from the Government. The regulation sets similar provisions for geothermal developers. Details are as follows:

1. Share transfers or changes in shareholders

- The transfer of shares of an IUPTL Holder must be *reported* to the Minister of Energy and Mineral Resources via the Director General of Electricity no more than 5 (five) working days after the most recent amendment of the Articles of Association is authorised by the Minister of Law and Human Rights;
- IUPTL Holders that sell electricity to PLN shall not transfer shares until the power plant reaches COD. Transfers can be made prior to the COD only if they are made to an affiliate in which more than 90% of the shares are owned by the Sponsor intending to transfer the shares. This is under the condition that such affiliate must be a Business Entity one level below the transferor and the transfer must obtain *approval* from PLN;
- The transfer of shares in the Geothermal Licence (i.e. *Izin Panas Bumi* or IPB) holder or the geothermal contractor under a Joint Operation Contract ("JOC"), through the Indonesian Stock Exchange (we interpret this as meaning via e.g., an Initial Public Offering) upon the completion of exploration, must obtain *approval* from the Minister of Energy and Mineral Resources. Meanwhile, the transfer of shares not listed on the Indonesian Stock Exchange must only be *reported* to the Minister.

2. Changes in corporate management, including changes in the Board of Directors and/ or Commissioners

Changes in the makeup of the board of directors and/or commissioners of an IUPTL Holder or geothermal developer must be *reported* to the Minister of Energy and Mineral Resources via the Director General of Electricity or the Director General of New and Renewable Energy no more than 5 (five) working days after the approval of the latest amendments to the Articles of Association by the Minister of Law and Human Rights.

MoEMR Regulation No. 48/2017 also outlines the required administrative documents and procedures to conduct both transfer of shares and changes in corporate management.

3 IPP Investment in Indonesia

3.1 History of IPPs in Indonesia and the PPP framework

Unlike the oil and gas and mining sectors, power investment has generally not (with the exception of pre-2003 geothermal power) operated pursuant to a stand-alone investment framework. Instead, IPP investment has generally been categorised according to the nature of the relevant off-take arrangements, particularly PPAs.

IPPs have existed in Indonesia pursuant to PPAs since the early 1990s and are classified into three broad generations (as outlined below). IPPs currently account for approximately 23% of Indonesia's total installed capacity of 59.6 GW. Certain IPPs, particularly in recent times, have also operated pursuant to a more general set of PPP arrangements.

The key regulation governing the regulatory framework for Indonesian PPPs is PR No. 38/2015, which replaced PR No. 67/2005 (as amended by PR Nos. 13/2010, 56/2011 and 66/2013), Bappenas Minister Regulation No. 4/2015 contains general guidelines for PPP implementation, and LKPP Regulation No. 19/2015 which contains detailed procurement procedures for PPP Projects.

3.2 IPP generations

3.2.1 First Generation (1991 until the Asian Financial Crisis)

Private participation in Indonesia's power sector started in 1991 with the signing of the PPA with Paiton Energy. Relatively high forecast returns (Internal Rates of Return - "IRRs"), often between 20% and 25%, together with the provision of a Government guarantee in the form of a support letter to cover PLN's obligations under the PPA meant that there was initially high investor uptake during IPP tendering.

However, when the Asian financial crisis struck in late 1997, PLN became financially troubled, particularly as a result of the fall in the value of the Rupiah. PLN had to put many of its IPP projects on hold, and ultimately six projects were terminated, six were acquired by the Government, one project ended up in a protracted legal dispute, and 14 projects continued under renegotiated terms. When renegotiations were completed in 2003, most continuing IPP investors agreed to new PPAs, which generally included lower tariffs than were initially determined.

Nevertheless, this first generation saw generating capacity lifted to 4,262 MW. Landmark projects included the Salak Geothermal Plant, albeit under a JOC framework, the Cikarang Combined Cycle Plant and the coal-fired Paiton Plant (Paiton I). Paiton I was the largest of those IPP projects, with an installed capacity of 2 x 615 MW.

However, during 1999 - 2004 there were no projects tendered.

3.2.2 Second Generation (Asian Financial Crisis to 2009)

The second generation of IPPs commenced during the period 2005-2009. This generation was however not viewed as particularly attractive to investors for the following reasons:

a) No Government guarantees were provided. Rather than providing direct government support to IPP projects, the MoF entered into the Japan Bank for International Cooperation ("JBIC") Umbrella Note of Mutual Understanding for projects (such as Marubeni's Cirebon Plant benefiting from JBIC export credit support);
b) The risk allocation was not viewed as favourable to investors; and
c) The forecast returns were lower (with forecast IRRs often between 12% and 14%).

Out of 126 project proposals, only 18 were awarded.

The largest of these projects included the coal-fired plants of Cirebon (660 MW) and the Tanjung Jati expansion (2 x 660 MW).

3.2.3 Third Generation (2010 Onwards)

The four categories of third-generation IPP projects are PPP projects, FTP II projects, 35 GW Programme projects and IPP projects under PLN's regular programme. Third-generation IPPs that operate as PPPs are subject to the recent revisions to the PPP framework. These differ from second-generation IPPs in that the risk allocation mechanism is intended to be clearer and more supportive of the investor. The four categories are discussed below:

PPP Projects

On 20 March 2015, PR No. 38/2015 on PPPs was issued to replace PR No. 67/2005 and its amendments. PR No. 38/2015 was issued to address a number of concerns around the existing PPP framework. The key enhancements under PR No. 38/2015 are as follows:

a) The sectors covered are wider and now include oil & gas infrastructure (e.g. refineries), urban infrastructure, industrial estates and social infrastructure (e.g. healthcare);
b) SOEs or regionally owned enterprises can act as a Government Contracting Agency ("GCA");
c) The "bundling" of two or more PPP projects is permitted (the projects need to be procured together, e.g. a power plant and related import infrastructure);
d) Land will be procured by the Government (in accordance with the Land Acquisition Law) before the PPP project is offered;
e) A new type of contract, the "performance-based annuity scheme" is available;
f) Projects to be developed through unsolicited bids are encouraged by providing compensation to the proponent of:
    i). An additional 10% price preference in bid evaluation;
    ii). The right to match a lower price bid by a competitor;
    iii). The purchase of the intellectual property rights (e.g. the feasibility study) if the proponent suffers losses.
g) Government support in the form of a cash contribution towards construction costs continues to be available via the Viability Gap Fund and any separately available tax incentives;

h) A Government guarantee to cover the GCA's financial obligations is provided;
i) The cost of preparing a project can include a retainer, fixed fees and success fees. The Government's project preparation costs can be recovered from the winning bidder and can include costs for:
   i). The pre-feasibility study;
   ii). Managing the transaction;
   iii). Compensation to international organisations/consultants in assisting project preparation based on a success fee.
j) A standard PPP agreement framework will be provided including provisions covering change mechanisms and arbitration; and
k) The procurement process can be carried out through tender or direct appointment.

Detailed procurement procedures for PPP Projects are set out in LKPP Regulation No. 19/2015 concerning Procedures for Implementation of Business Entity Procurement in Public Private Partnerships for the Provision of Infrastructure.

The first PPP in the power sector was the Central Java Batang Power Plant ("CJPP") with a capacity of 2 x 1,000 MW and an estimated investment of USD 4.2 billion. The CJPP will operate under a Build, Own, and Transfer ("BOT") structure and was awarded to a consortium of the Adaro Energy, J-Power and Itochu groups in 2011. This project also involved the first utilisation of the IIGF guarantee, which was issued in October 2011. The land acquisition process for this project was completed in late 2015, and the financial closing for this project completed in June 2016. The construction of the power plant is ongoing, with expected COD by 2020.

FTP II Projects

FTP II was launched in January 2010 under PR No. 4/2010 (amended most recently by PR No. 194/2014). The list of projects was set out under MoEMR Regulation No. 15/2010 and amended in MoEMR Regulation No. 40/2014 to 17.4 GW, which focuses on the use of IPPs and the use of coal and renewable sources of energy such as geothermal and hydro. The new five-year 35 GW Programme that was announced by President Joko Widodo has superseded FTP II, and all of the projects planned for completion between 2015 and 2019 have been rolled into the 35 GW Programme.

The 35 GW Programme (2015 - 2019)

A five-year 35 GW Programme was announced by President Joko Widodo in late 2014. The goal is to complete 35 GW of power generation projects by the end of his first term. An additional 46,000 km of transmission lines is also planned.

These projects may be awarded through open tender, direct appointment or direct selection (see *Section 3.4 - Procurement Process*). Based on PR No. 4/2016 (as amended by PR No. 14/2017), they are also eligible for the MoF's business viability guarantee. Further details on the procedures and provisions for the guarantee are regulated by MoF Regulation No. 130/2016.

For further detailed discussions, please see *Section 3.7.2 - The 35 GW Power Development Programme*.

PLN's Regular Programme

PLN's regular programme includes PLN projects, IPP projects and unallocated projects planned for completion after 2019 that can be found in PLN's RUPTL. IPP projects are subject to the same regulations as the 35 GW Programme.

3.2.4 IPP Investment Framework Summary

An outline of the current framework for IPP investment in power generation is as follows:

	Regulations	Guarantees	Examples
PPP	• PR No. 38/2015: cooperation between the Government and business entities for the provision of infrastructure; • Bappenas Regulation No. 4/2015: Guidelines for PPP implementation; • PR No. 78/2010: infrastructure guarantees for PPPs provided through IIGF; • MoF Regulation No. 260/2010, (as amended by MoF Regulation No. 8/2016): implementing guidelines for infrastructure guarantees in PPPs; • LKPP Regulation No. 19/2015.	• Guarantee is provided to the IPP and covers the contracting agency's/ Government's financial obligations as stated in the PPA; • Guarantor is the IIGF, sometimes jointly with the Government of Indonesia ("GoI").	• Central Java 2 x 1,000 MW coal-fired plant
FTP II (superseded by 35 GW program)	• PR No. 4/2010 as amended by PR No. 194/2014, MoEMR Regulation No. 15/2010 and its amendments MoEMR Regulation No. 21/2013, No. 32/2014 and No. 40/2014: the list of projects to accelerate the construction of renewable energy-, coal- and gas-fueled power plants; • Bidding process follows MoEMR Regulation No. 1/2006 and its revision under MoEMR Regulation No. 4/2007; • GR No. 14/2012 (as amended by GR No. 23/2014) on Electricity Business Provision; • MoF Regulation No. 173/2014: Government guarantee for IPPs and PLN obligations to IPPs to purchase power in accordance with the PPA.	• Business Viability Guarantee Letter from MoF provided to existing IPP projects covering PLN's financial viability. Based on PR No. 4/2016 (as amended by PR No. 14/2017), a Business Viability Guarantee Letter from the MoF may be extended to the FTP II projects rolled over to the 35 GW Programme as long as the procurement process for the project has not yet commenced.	• Muaralaboh 2 x 110 MW geothermal power plant, West Sumatera; • Rantau Dadap 2 x 110 MW geothermal power plant, South Sumatera; • Rajabasa 2 x 110 MW geothermal power plant, Lampung; • Wampu 1 x 45 MW hydro power plant, North Sumatera.

	Regulations	Guarantees	Examples
35 GW Programme	• PR No. 4/2016 (as amended by PR No. 14/2017) was issued to accelerate the development of electricity infrastructure, i.e. the 35 GW Programme; • No specific regulation lists the 35 GW Programme projects. Rather, they consist of a combination of the previous FTP II and PLN's regular programme. All are to be completed by 2019; • Bidding process follows MoEMR Regulation No. 1/2006 and its revisions under MoEMR Regulations No. 4/2007; • GR No. 14/2012 (as amended by GR No. 23/2014) permits the direct selection and direct appointment of an IPP in some circumstances; • Under MoEMR Regulation No. 35/2014 (as amended by MoEMR Regulation No. 14/2017), BKPM provides a one-stop service for permits and licensing; • MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017); • MoEMR Regulation No. 19/2017: The Use of Coal for Power Plants and Purchase of Excess Power; • MoEMR Regulation No. 45/2017: Use of Natural Gas for Power Plants; • MoEMR Regulation No. 50/2017: Use of Renewable Energy for Electricity Power Supply.	• Based on PR No. 4/2016 (as amended by PR No. 14/2017), a Business Viability Guarantee Letter from the MoF may be provided for 35 GW projects as long as the procurement process for the project has not yet commenced.	• Riau Kemitraan 2 x 600 MW coal-fired power plant (Sumatera); • Sulut-3 2 x 50 MW coal-fired power plant (North Sulawesi); • Jawa-1 2 x 800 MW combined cycle power plant (West Java).
PLN's Regular Programme	• Projects planned for completion by 2019 are now covered by the 35 GW Programme. Later projects are listed in the RUPTL; • All regulations that apply to the 35 GW Programme also apply to the IPP regular programme.	• Based on PR No. 4/2016 (as amended by PR No. 14/2017) a Business Viability Guarantee Letter from the MoF may be provided for 35 GW projects as long as the procurement process for the project has not yet commenced.	• Various large-scale coal-fired plants, hydropower and geothermal plants on Java, Sumatera and Kalimantan listed in the RUPTL for completion after 2019.

3.3 Financial Facilities Available to IPPs

The Government has established four financial facilities/institutions to support infrastructure projects (including those in the power sector). These are discussed below:

3.3.1 IIGF – for PPPs

The IIGF operates as an infrastructure guarantee fund for PPPs. PR No. 78/2010 and MoF Regulation No. 260/2010 (as amended by MoF Regulation No. 8/2016) are the basis for providing guarantees to PPP projects from the IIGF. Its aim is to accelerate the development of infrastructure projects by reducing the risk of financing for infrastructure investors (including IPPs), by essentially providing sovereign "guarantees" or "letters of comfort" for a fee. The IIGF essentially functions as an insurer of any risk exposure of the private sector for a premium. The IIGF is increasing its guarantee capacity through cooperation with multilateral agencies and bilateral institutions.

As indicated above, in October 2011 the USD 4.2 billion CJPP was the first PPP to receive an IIGF guarantee, which was in the form of a joint guarantee facility from the IIGF and the MoF.

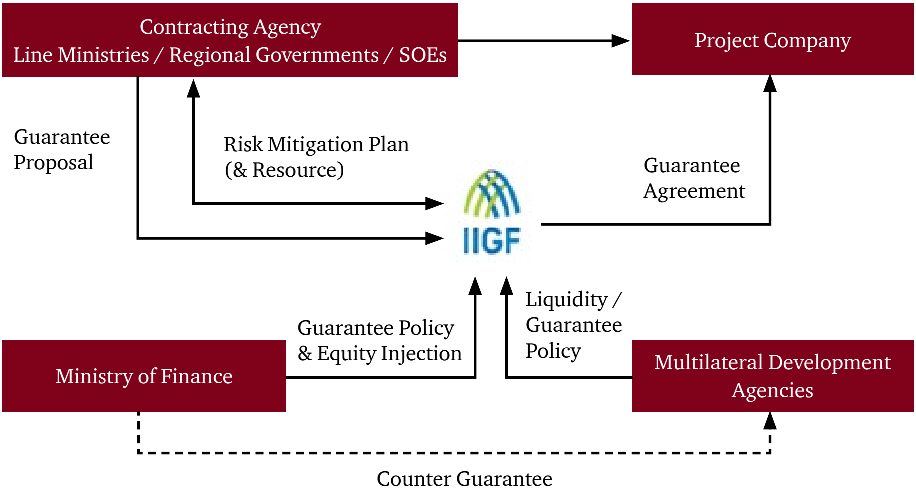
The IIGF will function as a "single window" for all requests for Government guarantees on PPP projects with the following objectives:

a) To improve the quality of PPP projects by establishing a clear and consistent framework for guarantees;
b) To improve the governance and transparency of guarantees;
c) To facilitate the deal flow for contracting agencies by providing guarantees; and
d) To help the Government manage its fiscal risk by ring-fencing Government obligations against guarantees.

The issuer of the Guarantee Agreement is the IIGF, but Multilateral Development Agency or MoF support may also be involved. The guarantee covers the financial obligations of the contracting agency (PLN for electricity) and the addressee is generally the project company (IPP investors for electricity).

To obtain this guarantee PLN must submit a guarantee support proposal to the IIGF for assessment. If agreed, the IIGF will issue a Letter of Intent at the proposal stage. The IIGF may also cover risks associated with project development such as those relating to construction, development and/or operations. The IIGF only provides guarantees for risks for which PLN is responsible. Project sponsors separately bear or seek cover for commercial or other risks beyond PLN's control.

The overall guarantee arrangement is outlined in the following diagram:



Source: PTPII's 2016 Annual Report

*Counter Guarantee for Multilateral Development Agency Guarantee Facility exists only if there is a Co-Guarantee Agreement.

3.3.2 Viability Gap Fund – for PPPs

The Government may provide support in the form of licensing, land acquisition and cash payments to fund some relevant construction costs and/or in other forms to PPP projects in accordance with the prevailing laws and regulations (the Viability Gap Fund). This is allocated by the Government through the state budget under MoF Regulation No. 223/2012, and the guidelines for application and disbursement are contained in MoF Regulation No. 143/2013 as amended by MoF Regulation No. 170/2015. The MoF may also approve the provision of government support in the form of tax incentives and/or fiscal contributions based on the proposal by the Minister/Chairman of Governmental Institution responsible for certain Infrastructure Projects (Transportation, Road, Water, Irrigation, Wastewater, Telecommunication, Electricity and Oil and Gas) or by the Head of Region (Governor or Regent). This is available only if there are no practical means of making an economically feasible and financially viable project. Examples include toll road construction projects outside Java or water supply projects with a higher social rather than commercial element. Power projects are not usually eligible, as most are financially viable.

3.3.3 Business Viability Guarantee Letter – for FTP II and 35 GW Programme IPPs

The IPPs under FTP II have access to the business viability guarantee from the MoF under MoF Regulation No. 173/2014, which is granted on a case-by-case basis. The MoF business viability guarantee takes the form of a letter to the IPP affirming the business viability of PLN. This means that, if PLN fails to fulfill its obligations to the IPP, the Government will step in. Termination and buy-out payments are also covered. The guarantee will terminate if the IPP fails to achieve financial close within 12 months of its issuance (24 months in the case of geothermal projects).

Based on PR No. 4/2016 (as amended by PR No. 14/2017), FTP II programme projects that are rolled into the 35 GW Programme, and other 35 GW projects, are also eligible for MoF's business viability guarantee. Further details of the procedures and provisions for the guarantee are regulated by a MoF Regulation No. 130/2016. Refer to *Section 2.3.1 - Government Guarantees* for further discussion.

3.3.4 The Infrastructure Financing Fund

The Infrastructure Financing Fund operates through two agencies, PT SMI and PT IIF, and was established to help investors obtain domestic finance for the debt and equity funding of infrastructure developments including power projects.

PT IIF provides long-term loans, mezzanine and equity investment as well as guarantees and fee-based services for infrastructure projects.

PT SMI and PT IIF contribute to the acceleration of infrastructure development through advisory services such as project feasibility studies and financing schemes, providing advice to the GoI on forms of incentives, fiscal policy support and regulatory reform, and socialisation through Investor and Infrastructure Forums.

In addition, in 2015 PT SMI was assigned by the Government to manage the Geothermal Fund. For further details, please refer to *Section 5.3.2 - The 2014 Geothermal Law*.

3.4 *Procurement Process*

Investors can participate in power generation projects via PPP arrangements, the 35 GW Programme or PLN's regular programme.

The procurement process for new capacity that follows the old regulation of MoEMR Regulation No. 1/2006 (as amended by MoEMR Regulation No. 4/2007), which generally runs on a competitive tender basis, and also sometimes by direct selection, or direct appointment.[27]

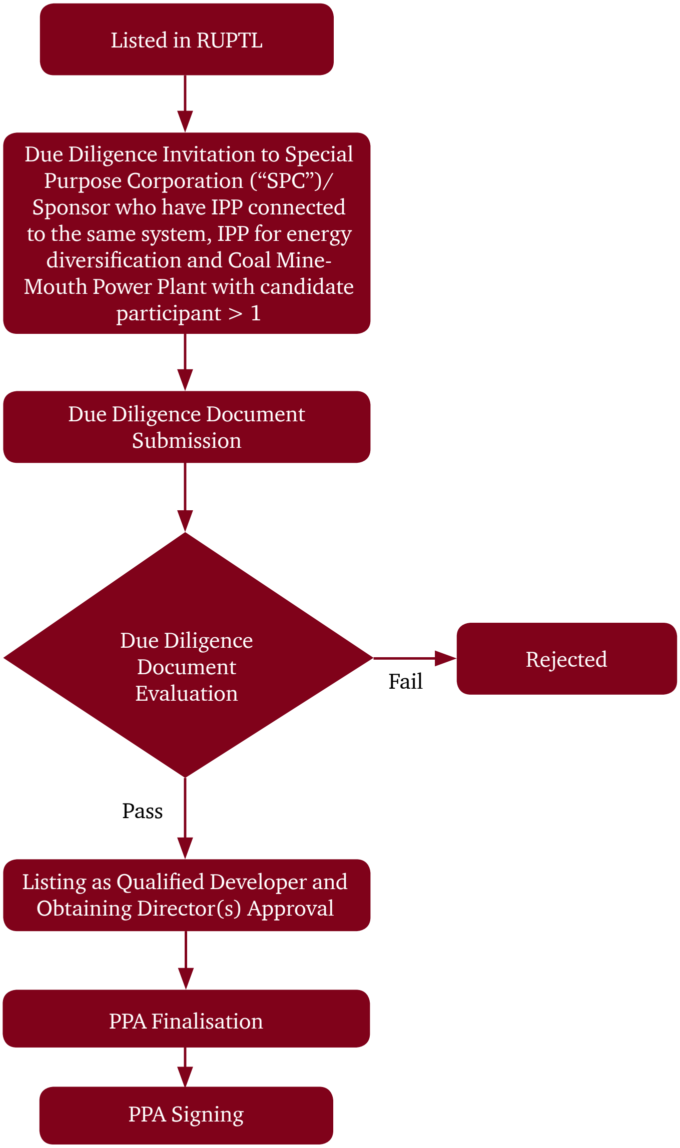
The following are the salient features of procurement methods:

a) Open tender basis;
b) Direct selection is permitted when changing the feedstock of the power plant from diesel to non-diesel and/or adding to the capacity of an existing power plant (expansion), or in the case where a project could otherwise be directly appointed, but there is more than one bidder available; and
c) Direct appointment.

27 *Since the revocation of MoEMR Regulation No. 3/2015, we believe that the procurement process follows MoEMR Regulation No. 1/2006 as amended by MoEMR Regulation No. 4/2007*

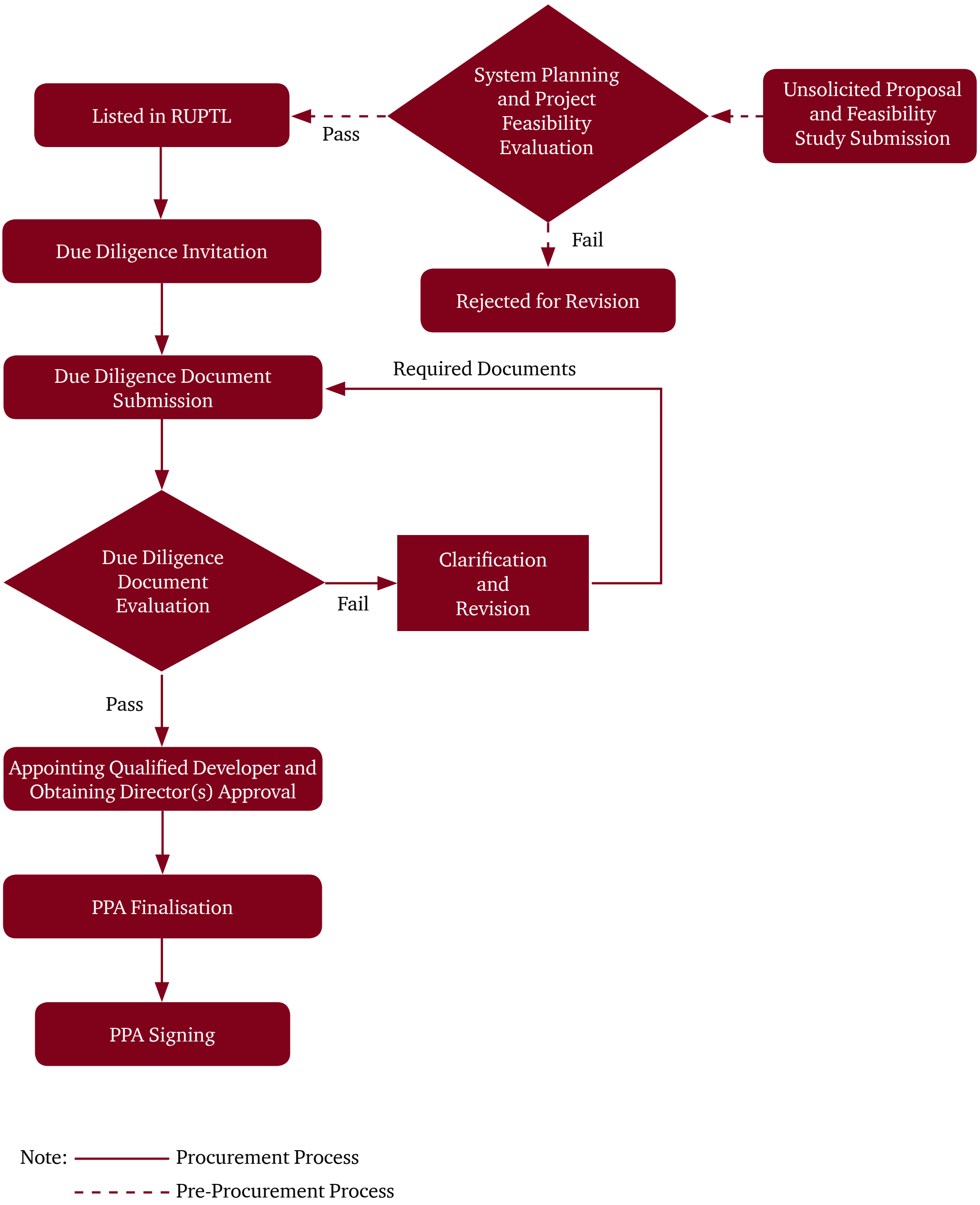
The maximum timeframe for the execution of an open tender is 316 days. On the other hand, direct selection from pre-qualification up to contract arrangement and finalisation will take 150 days[28] and direct appointment will take a maximum of 100 days.

Procurement procedures for direct selection which comply with MoEMR Regulation No. 1/2006, which was amended by MoEMR Regulation No. 4/2007, are as follows:



28 *MoEMR Regulation No. 1/2006 (as amended by MoEMR Regulation No. 4/2007)*

Procurement procedures for direct appointment which comply with MoEMR Regulation No. 1/2006, which was amended by MoEMR Regulation No. 4/2007, are as follow:



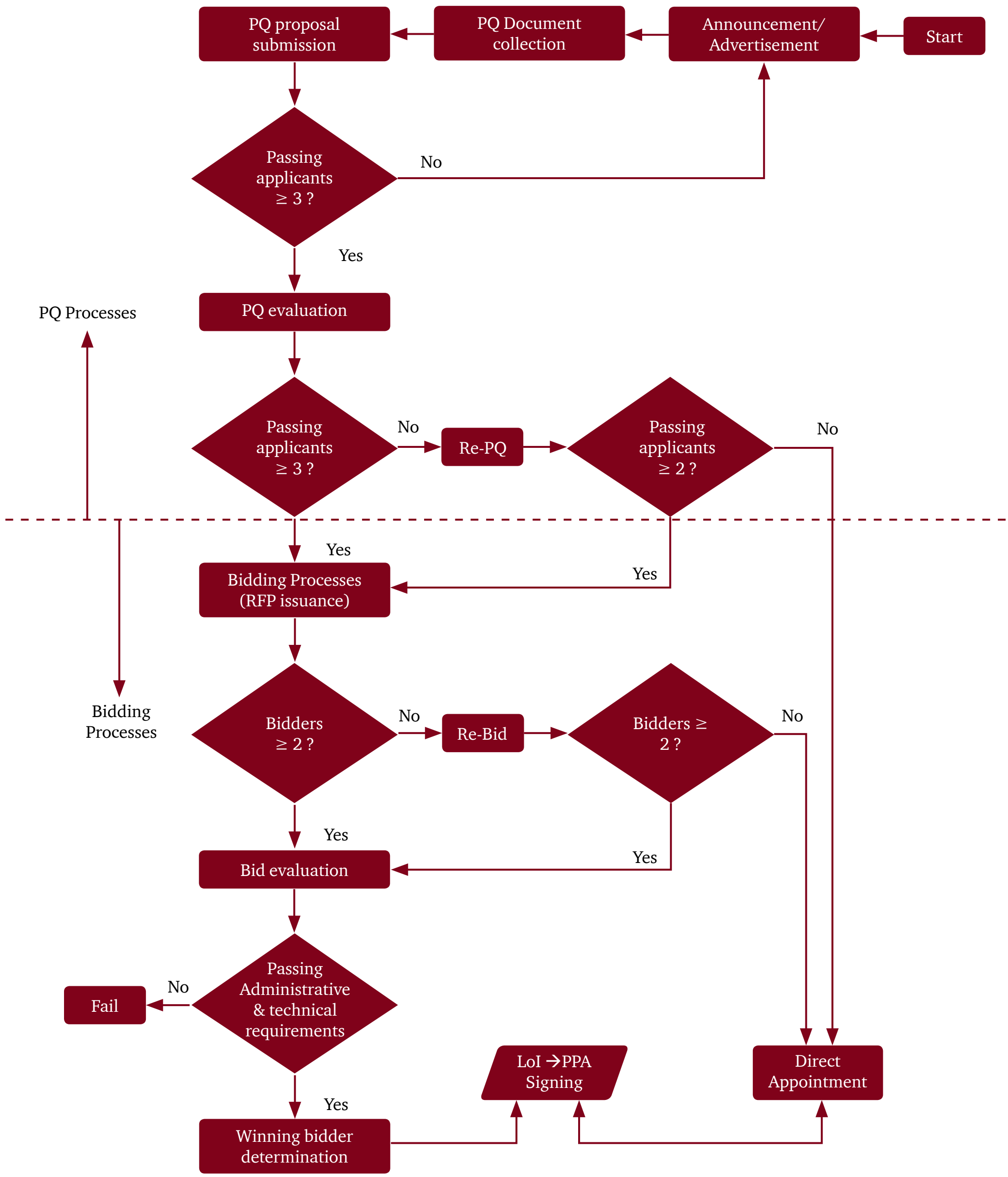
After the revocation of MoEMR No. 3/2015, we believe competitive tendering for a project now reverts to the process set out in MoEMR Regulation No. 1/2006 and its revision under MoEMR Regulation No. 4/2007. Additionally, PPP projects have specific regulations (PR No. 38/2015), while detailed procurement procedures for PPP Projects are explained in LKPP Regulation No. 19/2015.

The MoEMR Regulation No. 1/2006 and its revision under MoEMR Regulation No. 4/2007 state that:
a) The tenders are to be based on the RUPTL;
b) The evaluation and pre-qualification phase is to be based on financial strength and technical capabilities;
c) The requests for proposal are to include a model PPA and the evaluation procedure; and
d) The selection process should identify the best bid based upon:
    i) Administrative and technical parameters;
    ii) The electricity price proposal; and
    iii) The development/construction schedule.

The electricity price will be based on negotiations and/or on the applicable regulations for some renewable energy power plants (see Chapter 5) for direct appointment and on the lowest price proposal submitted by the participants for direct selection or through an open tender.

After the preferred bidder is selected, the process from the awarding of a tender until the COD of the project will involve the following:
a) The issue of a Letter of Intent that contains the agreed terms and conditions and the agreed electricity tariff and basic formula;
b) The signing of the PPA, which requires multiple performance bonds covering the financing period, PLN's corporate approval, MoEMR tariff approval and the establishment of a special-purpose company applying for a temporary business licence in relation to BKPM's one-stop service;
c) Financial close, which requires the EPC Contract, insurance policies required by the PPA, the fuel supply plan (if any), financial agreements, foreign investment approval, the legal opinion issued for PLN, the legal opinion issued for the IPP, legal rights to use the land and control over the site and a performance bond covering the construction period; and
d) The commencement of commercial operations, which requires that the net dependable capacity test procedures be completed.

Procurement procedures for competitive tenders as set out in MoEMR Regulation No. 1/2006 as amended by MoEMR Regulation No. 4/2007 are as follows:



Note: PQ = Pre-qualification, RFP = Request For Proposal

3.5 Project Finance

Project finance is a means of financing projects with significant capital requirements. A key feature is that the financing is typically non-recourse, and is solely reliant on the cash flow of the project. Project finance is typically sought for projects in the energy, utilities, natural resources and infrastructure sectors.

The project finance process can include the following steps:

a) The IPP investors conduct a feasibility study to decide whether the project is viable. A financial advisor may be appointed at or near completion of the feasibility study;
b) The financial advisor assists with the preparation of the request for proposal and choosing the banks to approach;
c) The banks submit expressions of interest, and the financial advisor and investor select the Lead Arrangers and sign term sheets;
d) The banks undertake financial, accounting, tax and insurance due diligence;
e) The banks take the proposal to their credit committees and, if approved, credit committees specify the conditions precedent and conditions subsequent;
f) The IPP investors (or an IPP entity if established), the banks, PLN, the MoEMR and other parties as needed finalise the PPA and other contracts in order to achieve financial close;
g) Once financial close is achieved and conditions precedent have been met then finance is available to be drawn down to fund the construction of the power plant and other related activities;
h) Once the project is completed, the Lead Arrangers may sell down their debt to other banks and post-completion interest rates apply; and
i) The project starts commercial operation generating cash flow, servicing debt and generating returns for the investors.

The main sources of project finance for Indonesian IPPs have been the following:

a) International commercial banks;
b) MDAs such as regional multilateral banks (e.g. ADB and European Investment Bank) and the World Bank (which includes the International Bank for Reconstruction and Development and the International Finance Corporation); and
c) Governmental agencies for investment promotion such as JBIC, China Exim Bank, Korean Exim Bank and the Nederlandse Financierings-Maatschappij voor Ontwikkelingslanden NV.

The MDAs and governmental agencies usually provide direct loans with “soft” provisions such as lower-than-market interest rates and longer grace periods. Financing through local banks is rare, as the liquidity of domestic banks for long-term structured financing is limited.

3.6 Key Project Contracts

Key project contracts for a power plant development in addition to the PPA typically include:
a) Various shareholders' agreements;
b) EPC contracts;
c) Insurance arrangements;
d) A long-term fuel supply contract;
e) O&M agreements; and
f) Financing documents.

These contracts are further discussed in Table 3.2 below.

Table 3.2 - Additional project contract components

Key Project Contracts	Contracting Parties	Purpose of Contract
Shareholders' Agreement	Shareholders in the project's special-purpose vehicle - generally the IPP entity)	Provides for the rights and obligations of shareholders
Shareholders' Loan Agreement	Shareholders in the IPP entity	Covers terms and conditions for any shareholders' loans
PPA	IPP entity and PLN	Sets out terms and conditions of power generation activity
EPC Agreement – Offshore	IPP entity, third party contractors and/or affiliates	Sets out terms and conditions for the supply of offshore design and construction work
EPC Agreement – Onshore	IPP entity, third party contractors and/or affiliates	Sets out terms and conditions for the supply of local construction services
EPC Wrap Agreement (also known as Umbrella or Guarantee and Coordination Agreement)	IPP and contractors	Guarantees the performance of both the offshore and onshore contractors
Long-Term Fuel Supply Agreement	IPP and third party (generally)	Governs the availability of long-term fuel supply
O&M Agreement	IPP and O&M contractors	Governs O&M services, associated fees and overheads
Technical Services Agreement	IPP and affiliates/third parties	Governs the provision of technical services to the IPP entity
Project Finance Documents	Financiers and IPP	To cover the key aspects of project financing including for: • Corporate Lending; • Export Credit Agencies; • Cash Waterfall; • Hedging; • Political Risk Guarantees; • Inter-creditor Agreements; • Security Documents; and • Sponsor Agreements.
Developers'/Sponsors' Agreement	Sponsor and IPP	To provide a developer's fee paid by the IPP entity to the original sponsors

3.6.1 Power Purchase Agreement (PPA)

The PPA is the cornerstone operational contract for IPP investors. Its principal terms and conditions include the following:

a) The objective and scope of the contractual work or service (it is now likely that all PPAs will be BOOT);
b) The period of operation (coal PPAs are generally for 25 years, hydro for 30 years, geothermal for 30 years and gas for 20 years). Since MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017), the maximum period of the power plant operations is 30 years, depending on the type of fuel;
c) The implementation guarantees (i.e. the responsibilities of the relevant IPP and PLN);
d) The implementation and construction of the project;
e) Start-up and commissioning issues;
f) The O&M arrangements of the plant;
g) Covenants;
h) Tariff and payment;
i) Government guarantees (if applicable);
j) Service performance standards;
k) Insurance arrangements;
l) Indemnification and liability arrangements;
m) *Force majeure* scenarios (natural and political);
n) Settlement of disputes;
o) Representation and warranty arrangements;
p) Sanctions;
q) Termination events; and
r) Purchase options, if any (i.e. for PLN).

3.7 *IPP Opportunities and Challenges*

3.7.1 IPP Opportunities and Challenges

As discussed in Chapter 1, Indonesia's IPPs will play a greater role than ever in the Indonesian power sector. In addition, PLN will also be required to make additional investments of around USD 43.7 billion in transmission and distribution networks.

Based on the 2017 RUPTL, IPPs may have access to power generation projects as follows:

Table 3.3 - Accessible IPPs for power generation for 2017-2026

	PLN	IPPs	Unallocated	Total
Coal	6,064	16,536	1,990	24,590
Coal Mine-Mouth	-	7,345	-	7,345
Geothermal	490	4,405	1,395	6,290
Gas/Combined Cycle	10,191	6,293	7,905	24,389
Hydro (including small hydro and pumped storage)	4,239	6,259	3,539	14,037
Other	-	1,224	-	1,224
Total	**20,984**	**42,062**	**14,829**	**77,875**

Source: 2017 RUPTL, PwC Analysis

The 2017 RUPTL is also focused on achieving the 23% energy mix from renewables as dictated by the 2014 NEP. Given the current low levels of power generation from renewables, achieving the 23% target by 2025 means that the renewable power generation in the 2017 RUPTL should represent at least 25% of the fuel mix by 2025. However, based on the 2017 RUPTL, after optimising all renewables potential, the projected fuel mix from renewables is expected to increase from 12% in 2017 to 22.5% in 2026. As such, the utilisation of an additional 5.1 GW of gas-fired generation is planned as a contingency plan if the renewables target cannot be met. The projected composition, by primary energy source, of electricity production in Indonesia by 2026 is planned to be: 50.4% from coal; 26.7% from gas (including LNG); 9% from geothermal; 12.3% from hydro; 0.4% from diesel fuel; and the remaining 1.1% from other fuels (see Figure 1.7). More or less, this is consistent with the draft 2015 – 2034 RUKN which requires a fuel mix of approximately 50% from coal, 24% from gas, 25% from renewables and 1% from diesel fuel.

In the 2017 RUPTL, for the purposes of power plant site selection, PLN will use the principle of regional balance or prioritise the availability or ease of supply of primary energy sources in the local area. Additionally, the 2017 RUPTL also emphasises that power plants will be located closer to energy sources, particularly in Sumatera, Kalimantan, Sulawesi and Papua. This is also emphasised by PLN's plans to develop coal-mine mouth and gas well head-fired power plants.

Coal will continue to play a vital role in the development of power generation in Indonesia for the next ten years due to the relatively lower costs of construction and operation. Coal mine-mouth power plants remain integral to this role, given that Indonesia's large low-rank coal deposits are often located in remote areas with minimal infrastructure, making transportation of the coal uneconomical. The use of more environmentally friendly (lower carbon) technology, such as supercritical and ultra-supercritical boilers is a key priority for PLN and the Government in the development of large scale coal-fired power plants, particularly on the highly populated Java Island. The use of other types of technology, such as integrated combined cycle gasification, carbon capture and storage have not yet been planned for in the 2017 RUPTL.

PLN also plans for the extensive use of LNG for gas-fired power plants. However, because of the relatively higher cost of LNG (compared to pipeline gas) given the need for regasification, PLN plans to use LNG as a peak-load backup rather than for base-load power plants, particularly for the Java-Bali, Sumatera and eastern Indonesia networks, where base-load generation may not be sufficient.

3.7.2 The 35 GW Power Development Programme

The 35 GW Programme was launched in 2015, and since then the total capacity and its composition has undergone several changes – firstly in the 2016 RUPTL and then in the 2017 RUPTL. The initial breakdown of the 35 GW Programme is outlined in the Table below:

Development Scheme	Coal	Gas	Hydro	Geothermal	Other	Total (GW)
PLN	2.2	7.0	1.2	0.1	0.1	10.6
IPP	18.1	6.6	1.1	–	0.1	25.9
Total (GW)	**20.3**	**13.6**	**2.3**	**0.1**	**0.2**	**36.5**

PLN is tracking the programme, which appears to be progressing, albeit slower than hoped. According to PLN, as of 19 September 2017[29]:

- 2% (773 MW) of capacity had reached the Commercial Operations Date;
- 40% (15,266 MW) of capacity was in the construction stage;
- 27% (10,255 MW) of capacity had PPAs signed, but had not yet commenced construction;
- 12% (4,563 MW) was in the procurement stage; and
- 19% (6,970 MW) of capacity was still in the planning stage.

It should be noted that the total above (37.8 GW) differs slightly from the original total (36.5 GW) due to cancelled, amended and substituted projects.

Given construction timeframes of several years from financing, which itself normally takes 6-12 months after PPA signature, it is likely that around half of the 35 GW Programme cannot now come online before 2019 as planned.

The causes of delay are well known, and key risks identified by IPPs include land acquisition difficulties (for the generation site and transmission corridor), infrastructure to transport feedstock to plants (e.g. gas, biomass), the speed of IPP/PPP procurement, the speed of licence and permit acquisition (especially at sub-national level) and gaps in the regulatory framework (including economically unattractive tariffs for some technologies and a lack of sovereign guarantees). These issues are discussed in more detail in the following chapters.

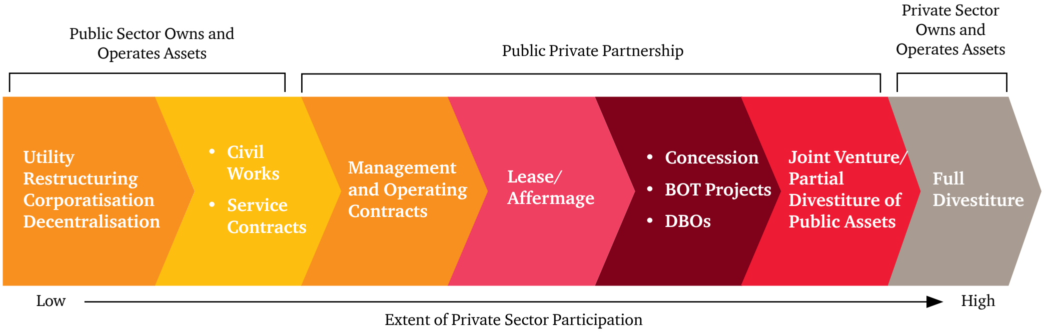
29 *https://finance.detik.com/energi/3650340/jalan-2-tahun-begini-progres-program-35000-mw*

However, we note that the Government recognises these risks to the programme, and has implemented eight Acceleration Steps, including in relation to land acquisitions for power generation, T&D, tariff negotiation, IPP procurement, permits, IPP developer and EPC due diligence, project management capacity, inter-ministerial coordination and legal issues. Furthermore, President Joko Widodo also approved PR No. 4/2016 (as amended by PR No. 14/2017) which aims to address the challenges specific to the 35 GW Programme. Under the Presidential Regulation, a special mandate has been granted to PLN in the form of a sovereign guarantee, expedited permit process and the provision of land under the spatial plan. For further details on PR No. 4/2016 (as amended by PR No. 14/2017), please see *Section 2.3 - PR No. 4/2016 as Amended by PR No. 14/2017*.

3.7.3 PPPs

Currently, there is no widely accepted definition of a PPP. The PPP Knowledge Lab defines a PPP as “a long-term contract between a private party and a government entity, for providing a public asset or service, in which the private party bears significant risk and management responsibility, and remuneration is linked to performance”.

PPPs take a wide range of forms, varying in terms of the extent of involvement of and risks borne by the private party. The terms of a PPP are typically set out in a contract or agreement to outline the responsibilities of each party and clearly allocate risk. The graph below depicts the spectrum of PPP agreements:[30]



Source: World Bank

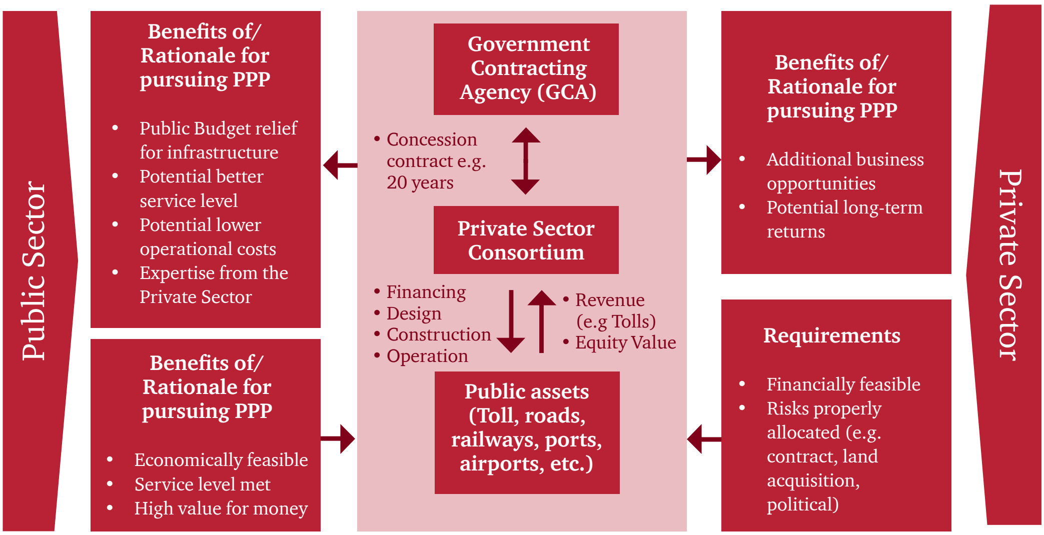
The variety of arrangements provides several options and opportunities for structuring agreements that best fit the project, its associated risks, and the nature of the investors. Leases and contracts have low levels of risk, because they require limited capital outlay. They are often suited to water infrastructure projects, which offer low returns and thus cannot justify a high-risk investment.

Greenfield projects require a significant commitment from investors and thus are often put in place for telecom and energy projects, which have high potential returns. Greenfield agreements are by far the most utilised PPPs worldwide because they offer the greatest opportunity for governments to divest risk, and for investors to earn a significant return. This is especially true of BOO and BOT agreements.

30 *http://ppp.worldbank.org/public-private-partnership/overview/what-are-public-private-partnerships accessed 22 May 2016*

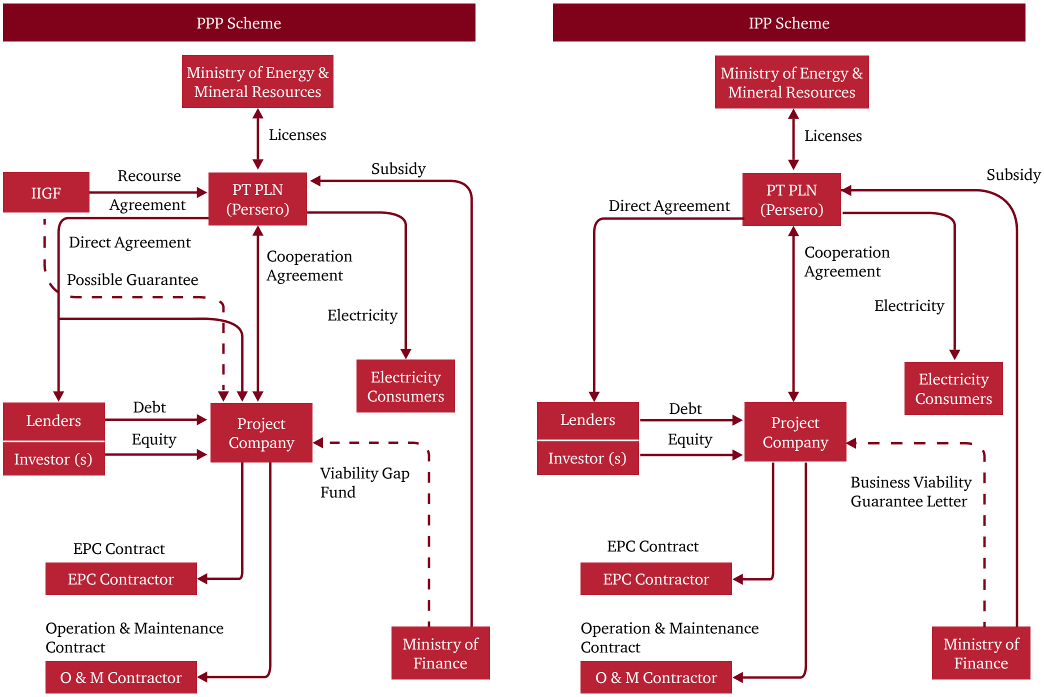
As discussed in Chapter 1 and this chapter, Indonesia is building a significant amount of infrastructure, which requires an enormous amount of investment that the Government cannot afford. As such, PPP arrangements represent a possible means of developing Indonesia's infrastructure. However, the meaning of a PPP in the Indonesian context is slightly different from that in the global context according to the definition from the PPP Knowledge Lab. Under the PPP Knowledge Lab's definition, a contract with an IPP would qualify as a PPP. However, an IPP would not officially be labelled a PPP in Indonesia, where it does not fall under the scope of the PPP regulation (PR No. 38/2015) since an IPP does not have any guarantee from IIGF. All PPP projects are also included in the PPP Handbook issued by Bappenas every year.

A PPP scheme is generally used by the Government to divest its risk and provide opportunities for investors to earn a significant return by assuming that risk. As such, a PPP scheme will only be successful when the objectives of the Government and the investors are met. The Government requires that the projects provide the public with a high-quality service and the investors require that the projects be financially feasible and that the risks be manageable, including contract, political and land acquisition risks. The interaction between the public sector and the private sector is depicted in the diagram below.



Source: PT SMI (Infrastructure Investment 2014)

Under IPP schemes, the partnership with the private sector is allocated only for generation, whereby PLN acts as the off-taker. Under PPP schemes, PLN acts as both the off-taker and contracting agent.



Source: PT SMI (Infrastructure Investment 2014)

In the latest Bappenas "Public-Private Partnerships: Infrastructure Projects Plan in Indonesia" report (the "PPP Handbook 2017"), no power projects are included.

LKPP Regulation No. 19/2015 regulates the Procedures for Implementation of Business Entity Procurement in Public Private Partnerships for the Provision of Infrastructure. The regulation contains detailed procurement procedures for PPP Projects with several key features (i.e. Principles of PPP, procurement organization, restrictions to prevent conflicts of interest, provisions of the procurement committee, and procurement of business entity that can be done through auction or direct appointment, and direct selection mechanism).

3.7.4 The Role of the Private Sector in Rural Electrification

In late November 2016, MoEMR officially launched MoEMR Regulation No. 38/2016 on the Acceleration of Electrification in the Least Developed Rural, Isolated, Border and Populated Small Island Areas through Small Scale Electricity Supply Businesses. Under this regulation, the Government offers opportunities to regional-owned enterprises, private business entities, and cooperatives businesses to become involved in improving the electrification in rural and remote areas by managing an area of business or *Wilayah Usaha*.

This regulation is backed by the concern that there are still 2,510 villages that do not yet have access to electricity, namely in Papua, West Papua, Aceh, North Sumatera, Jambi, Southeast Sulawesi and West Kalimantan. However, PLN, in its planning for rural electrification development until 2019, will only able to offer electricity to 504 more villages.

This regulation is also an attempt to increase the ratio of electrified villages in Indonesia, which currently constitutes only 97% of the total 82,190 villages.[31]

Under MoEMR Regulation No. 38/2016, business entities must optimise the use of local new energy or renewable energy resources. For that, those private investors may also be given fiscal incentive in accordance with the provisions of laws and regulations.

Business entities that are interested can participate in the procurement selection of Small Scale Electricity Supply Business (*Usaha Penyediaan Tenaga Listrik* – "UPTL"). However, in case no business entity is interested, the Governor may appoint regional-owned enterprises to develop such small scale UPTL.

Meanwhile, the electric power tariff determination as described in Article 20 and Article 21 can be with or without subsidy funds. In the event that the subsidy funds are utilised, the tariff follows the PLN average tariff for the 450 VA household customers. However, the business entity can propose subsidy funds to the Government based on certain criteria, i.e. fuel use realisation and plans, operational expenditure, losses, electricity generation cost, and expansion plans which will be evaluated and determined by the DGE. On the other hand, in the case that the electricity tariff does not utilise subsidy funds, the tariff is determined by the Minister or the Governor based on their authority along with the existing Laws and Regulations.

31 *DGE, "Socialisation of MoEMR Regulation No. 38/2016", Presentation at the Coffee Morning Session with DGE, 16 January 2017*

4 Conventional Energy

4.1 Introduction

Global primary energy consumption increased by an average of 1.0% per annum in 2016. This is well below the ten year average of 1.9%. Oil remained the world's leading fuel, accounting for a third of global energy consumption, and has shown an increase in global market share for the second year in a row following a consistent 15-year decline from 1999-2014. Similar growth can be seen in natural gas, the consumption of which grew by 1.5%, although this is still lower than the ten-year average annual growth of 2.3%. In contrast, coal consumption declined by 1.7%, the second annual decline in a row.[32]

Indonesia's primary energy supply increased by 50% from 896 million barrels of oil equivalent ("MBOE") in 2005 to 1,322 MBOE in 2015. Coal and oil remained Indonesia's leading sources of energy supply, accounting for 22% and 38% of Indonesia primary energy supply, respectively. Biomass and biofuel represented a further 19%, followed by natural gas of 17%. Hydro accounted for 2.15%, with the remaining 1.0% from geothermal.[33]

Indonesia's primary energy consumption has also increased by 47% from 814 MBOE in 2005 to 1,130 MBOE in 2015 and 1,198 MBOE in 2016. Oil, coal and natural gas accounted for 41.5%, 36% and 19.5% of final energy consumption, respectively. The remaining consumption was accounted for by renewable energy that consists of hydropower and other renewables, accounting for 3.3% in total.[34] Overall, conventional energy (oil, coal, and gas) has continued to play a dominant role in Indonesia's energy mix.

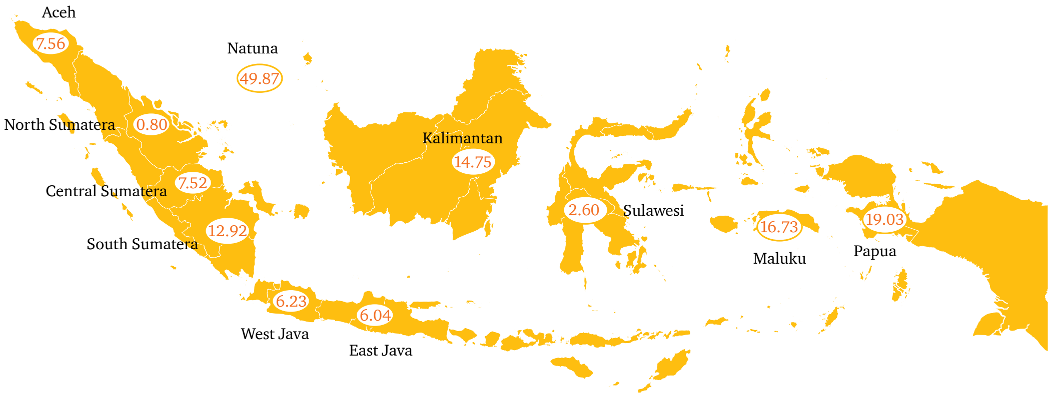
4.2 Gas

4.2.1 Indonesian Gas Reserves, Consumption, and Production

Indonesia has large natural gas reserves, at around 144.06 trillion standard cubic feet ("TSCF") in 2016 (see Figure 4.1 below for more details).[35] The largest undeveloped gas reserves are located in the offshore East Natuna Block, which holds approximately 49 TSCF of gas reserves. Other areas with high potential are West Papua and Maluku.[36] However, assuming there is no discovery of new reserves, and at current rates of consumption, reserves could run out in 40 years.[37]

32 *BP Statistical Review of World Energy 2017, p. 2*
33 *2016 Handbook of Energy and Economic Statistics of Indonesia, p. 11*
34 *BP Statistical Review of World Energy 2017, p. 9*
35 *Laporan Kinerja Direktorat Jenderal Minyak dan Gas Bumi 2016 ("LAKIN DJMGB 2016") [2016 Performance Report of Directorate General of Oil and Gas], p. 26*
36 *International Energy Agency ("IEA"), Indonesia 2015, 2015, p. 42*
37 *Annual Report SKK Migas 2016, p. 18*

Figure 4.1 - Map of Indonesian gas reserves as of 1 January 2016 (in TSCF)



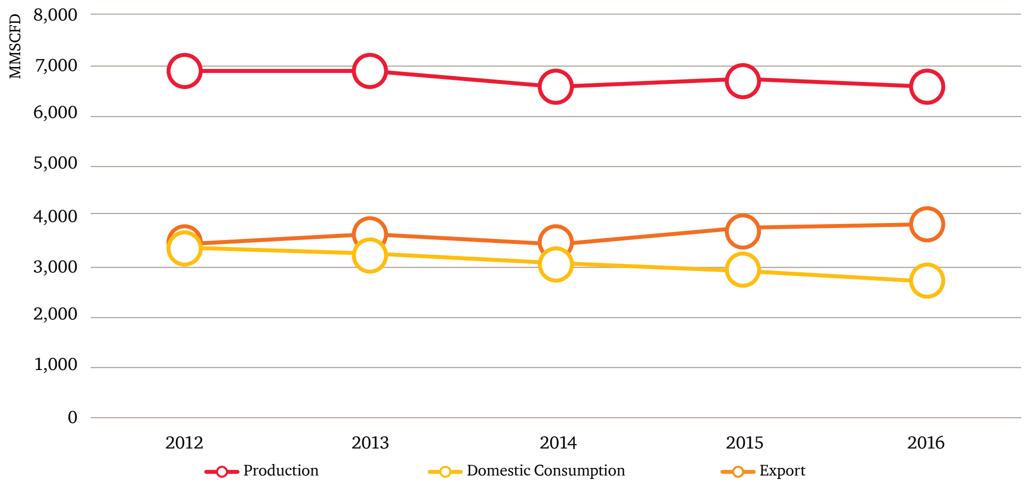
Source: LAKIN DJMGB 2016

Despite the fact that crude oil traditionally played a greater role in Indonesia's energy supply and exports, Indonesia is now a net oil importer. Indonesia's oil and gas production has been dominated by gas for the last couple of years, with the production of natural gas accounting for approximately 60% of total production of oil and gas as a whole, and it is expected to reach 70% in 2020 and 86% in 2050.[38] This situation has also resulted in the Government's shifting focus from oil to natural gas.[39]

Indonesia has experienced a gradually narrowing surplus of gas production over domestic consumption for the past five years (see Figure 4.2). Indonesia's oil and gas industry is under pressure due to declines in the oil and gas price - fundamentally changing the economics of the development of oil and gas fields - and delays in these developments reaching the production stage. This resulted in declining gas production between 2012 and 2016; from 6,870 million standard cubic feet per day ("MMSCFD") ≈ 7,181 Billion Thermal Units per Day ("BBTUD") to 6,560 MMSCFD ≈ 6,857 BBTUD (a 5% decline). In contrast, overall domestic gas consumption in Indonesia increased by more than 10% over the same period. As a result, over the same period, Indonesia's gas exports declined by 19%, which resulted in Indonesia falling from being the world's largest LNG exporter in 2005 to the world's fifth-largest LNG exporter in 2016, behind Qatar, Malaysia, Australia and Nigeria.[40] The Government has a long-term plan to gradually decrease gas export volumes to zero in 2040.[41]

38 *Annual Report SKK Migas 2015 p. 32*
39 *IEA (2015) p. 39*
40 *BP Statistical Review of World Energy 2017, p. 34*
41 *MoEMR. 2015. Ekspor Migas Bakal Jadi Nol Persen, Penuhi Pasar Domestik. 13 August 2015. (https://m.tempo.co/read/news/2015/08/13/090691560/ekspor-migas-bakal-jadi-nol-persen-penuhi-pasar-domestik)*

Figure 4.2 - Indonesian natural gas used for production, domestic consumption, and export (in MMSCFD) for 2011-2015



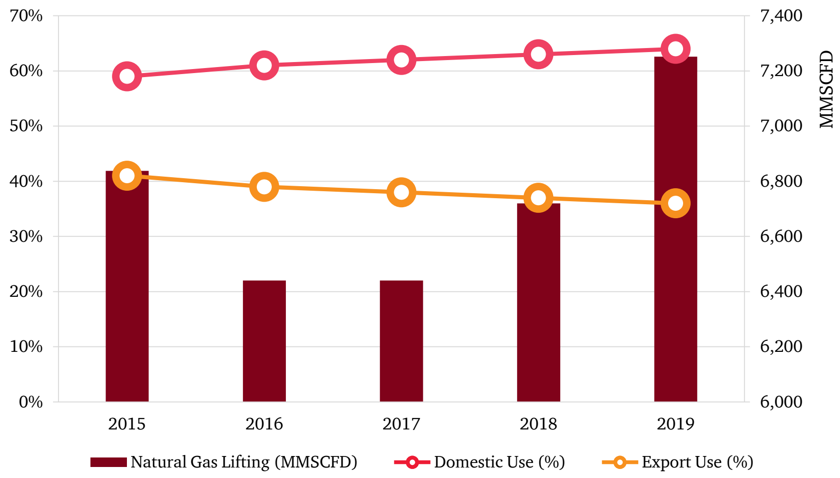
Source: LAKIN DJMGB 2016

The Government expects an increase in gas production from 6,838 MMSCFD in 2015 to 7,252 MMSCFD in 2019. Several new gas development projects have been planned, constructed and/ or have commenced their operations. They include the Indonesia Deep Water ("IDD") Project in Makassar Strait, East Kalimantan by Chevron Indonesia; LNG Wasambo in South Sulawesi by Energy Equity; LNG Abadi Project in Arafura Sea, Maluku by INPEX; LNG Jangkrik in Makassar Strait, East Kalimantan by ENI; LNG Tangguh Train-3 Project in Bintuni, West Papua by British Petroleum; and Jambaran Tiung Biru Project in Bojonegoro, East Java by PT Pertamina EP Cepu.[42] According to the 2017 RUPTL, the LNG from Tangguh will strengthen the gas supplies for PLN's gas-fired power plants in Sumatera and Java (including Jawa-1 Combined Cycle, see *Section 4.2.3 - Current Installed Gas-Fired Power Plant Capacity and Government Plans*) while the gas from Jambaran Tiung Biru shall be allocated for the newcoming Jawa-Bali 3 Combined Cycle (1 x 500 MW) in Banten. Government is also reported to have allocated the gas from Jangkrik for power plant development.[43]

An increase in domestic gas demand, particularly for power generation, is projected over the period from 2017 to 2026. This is consistent with both the 2017 RUPTL and the NEP. For power generation, the total gas required (including LNG) is expected to be 990 billion cubic feet (Bcf) in 2019 and 1,311 Bcf in 2026, as a result of the plan for 24 GW of additional gas-fired power plants by 2026. As a result, the Government plans to increase the allocation of the national gas production for domestic use from 59% in 2015 to 64% in 2019 (see Figure 4.3). In addition to power generation, the expected increase in domestic use would also derive from the current committed and potential demand from industry, particularly the fertiliser industry.

42 *Annual Report SKK Migas 2016, p. 86*
43 *http://www.migas.esdm.go.id/post/read/produksi-lapangan-jangkrik-mayoritas-untuk-domestik*

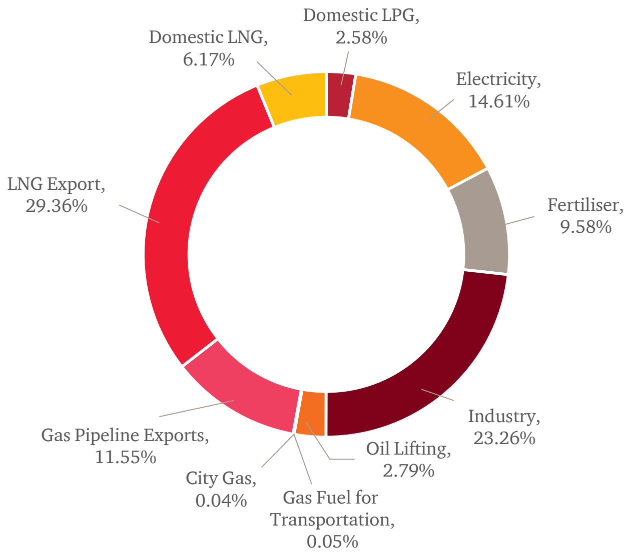
Figure 4.3 - Indonesia natural gas lifting (in MMSCFD) and utilisation targets for 2015 - 2019



Source: LAKIN DJMGB 2015

The Indonesian natural gas utilisation in 2016 was 3,823 MMSCFD. There were five major categories of gas users in 2016: LNG for export, the power sector, the industrial sector, fertiliser sector and gas pipeline exports. LNG exports accounted for more than a quarter of the total natural gas utilisation in Indonesia in 2016 (29.36%). Power, industrial, fertiliser and gas pipeline consumed approximately 14.6%, 23.3%, 9.6% and 11.6% of total Indonesian gas production (see Figure 4.4).

Figure 4.4 - Indonesian natural gas utilisation for 2016

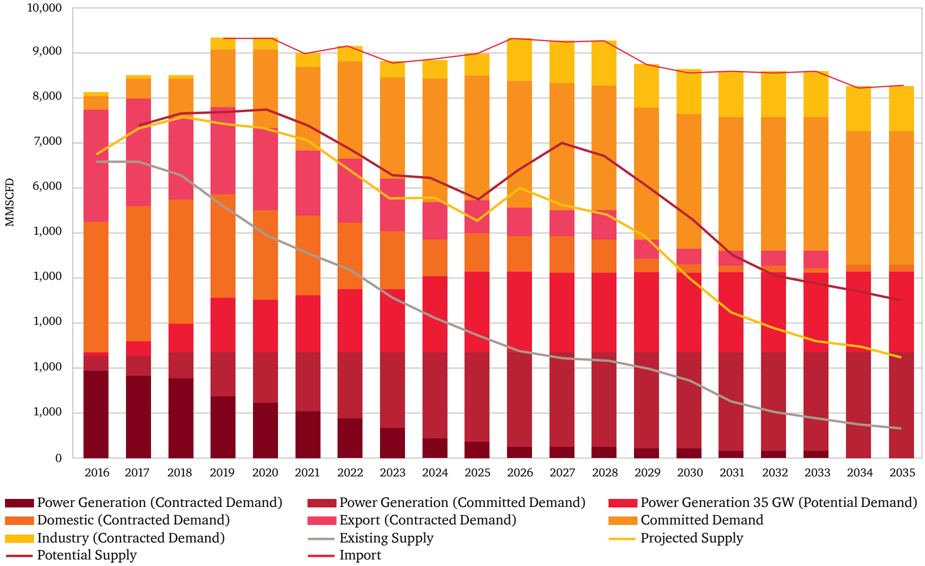


Source: Annual Report SKK Migas 2016

Initially, anticipating continually rising gas demand, the Government planned to import the LNG by 2019 as stated on the National Gas Balance 2014-2030 (as updated by 2016-2035). However, as of July 2017, the Government revised this plan, stating that the country would not need any imported LNG. Moreover, the Government reported that there are 16 - 18 excess consignments of LNG available (no committed buyers as of July 2017). This is mainly caused by the current domestic gas production having increased beyond expectations. However, most gas fields are located in remote areas far from buyers, especially power plants. This means that the gas must first be converted into LNG. Among them is the Jangkrik Project that has surpassed its production target of 450 MMSCFD to 600 MMSCFD.

Furthermore, the use of gas by domestic customers has tended to fluctuate, rather than growing optimally as projected. As a consequence, considering that some new large gas producers such as the LNG Tangguh Train-3 is expected to come online by 2020, as well as LNG Abadi in 2025-2027 (after being delayed from 2024 due to a change to the development plan), the Government estimates that the domestic gas demand growth would still be covered by the domestic gas production. The Government also estimates that until 2035, Indonesia will experience a gas oversupply situation where there will be on average 50-60 excess LNG cargoes available per year.[44] Since the power sector has been allocated a significant proportion of domestic gas (see Figure 4.5), the Government expects and encourages PLN's plans in gas-fired power plants (under the 35 GW Programme) to be put into effect immediately. It was also reported that the Government wanted to review and revise the National Gas Balance by the end of 2017.[45]

Figure 4.5 - Natural gas balance for 2016 - 2035 (in MMSCFD)



Notes: Projected supply means the estimated supply from gas production fields for which the Plan of Development ("PoD") has been, or is being approved; Potential supply means the estimated supply from gas production fields for which the PoD has not been proposed by the gas Contractor, but which has been indicated to have proven economic reserves to develop (National Gas Balance 2016-2035).

Source: IGN Wiratmaja [Director General of Directorate General of Oil and Gas ("DGOG")], "The Impact of Low Oil Price on Gas Projects", 8 February 2017

44 https://www.reuters.com/article/us-indonesia-gas-imports-idUSKBN19X0H5
45 https://m.tempo.co/read/news/2017/07/13/090891043/impor-gas-tahun-2019-batal-mengapa

4.2.2 Prices and Regulation

The domestic pipeline gas prices in Indonesia are negotiated and set out under specific Gas Sales Agreements between the seller and the buyer/end-user. The prices follow a fixed price regime formulated as cost plus annual escalation (depending on agreement) which means that the Indonesian gas pricing regime is not directly connected to the oil price fluctuations (see Table 4.1). In October 2016, the Government was reportedly intending to revise the regime of gas prices to a hybrid scheme (fixed price plus linked oil price), but this has yet to happen.[46]

The pipeline gas price is composed of several components, i.e. upstream investment and operation cost, contractor share, and transportation cost (transmission and distribution, including VAT). As an illustration, the upstream gas prices for domestic pipeline (sold from contractors/oil and gas companies) were released in 2016 at an average of USD 5.9 per Million British thermal units ("MMBtu") with a range of USD 3.63-8.24 per MMBtu. On top of this, gas transmission and distribution costs USD 0.89 per MMBtu and USD 1.5 per MMBtu respectively, are then added.[47]

Table 4.1 – Gas price regimes in the region

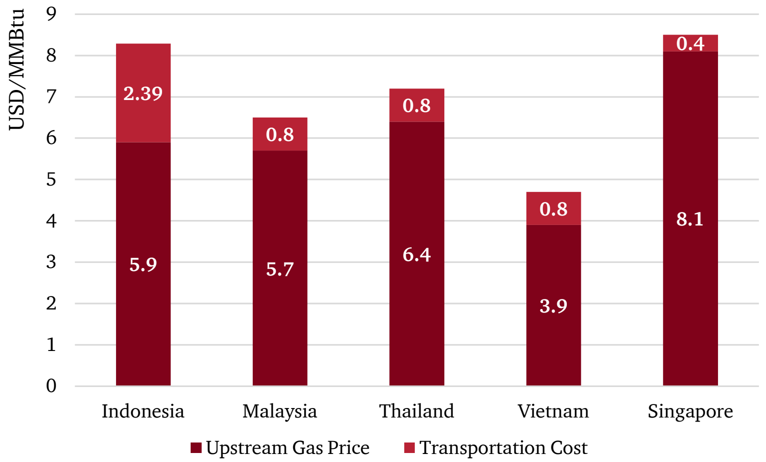
	Indonesia	Singapore	Malaysia	Thailand	Vietnam
Pricing Regime	Negotiated (fixed price)	Negotiated (oil linked)	Negotiated (oil linked)	Pool price	Negotiated (oil linked)
Formula	Cost plus annual escalation (depends on agreement and negotiation)	100-110% of High Speed Fuel Oil (HSFO) price	45-60% HSFO price	Blended purchase price	45% HSFO price
Gas Sellers	Multiple companies e.g. Pertamina, PGN, Regional-owned enterprises	Multiple companies e.g. Pavilion Gas, SembGas, City Gas	Single company i.e. PETRONAS	Single company i.e. PTT	Single company i.e. PetroVietnam

Source: Arividya Noviyanto (President and General Manager of Total E&P Indonesie), "Upstream Perspective on Managing Indonesia Gas Supply and Demand", 8 February 2017, p. 5; http://bisnis.liputan6.com/read/2623349/pemerintah-ingin-ubah-formula-harga-gas-ini-kata-petronas

The Indonesian upstream gas price is considered to be competitive compared to neighbouring countries. However, the Indonesian gas market experiences relatively expensive gas transportation (transmission and distribution) cost, which affects the affordability to the buyer/end-user (see Figure 4.6).

46 *http://m.metrotvnews.com/ekonomi/energi/yKX40pEK-ubah-formula-gas-jadi-hybrid-supaya-lebih-murah*
47 *http://industri.bisnis.com/read/20170217/44/629688/begini-komponen-harga-gas-pipa-dan-lng-di-indonesia*

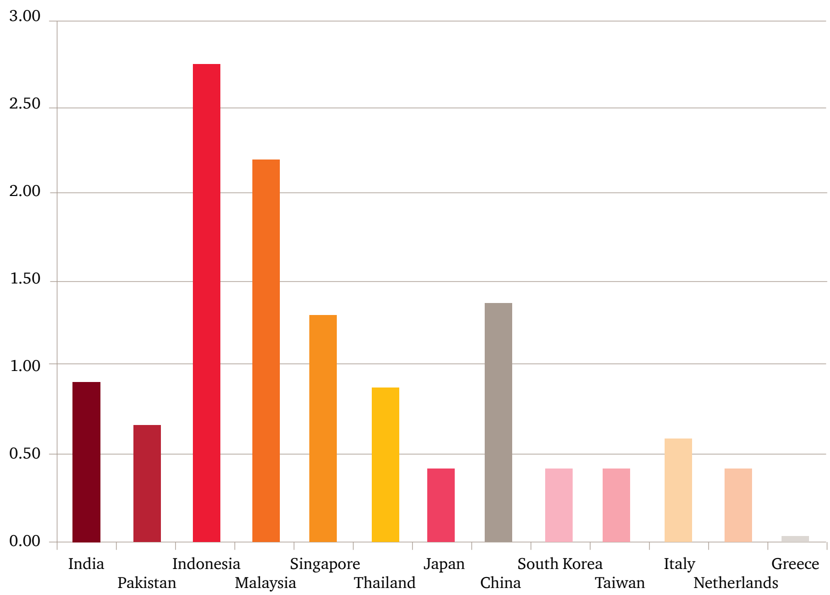
Figure 4.6 – Comparison of domestic pipeline gas prices in the region



Source: Arividya Noviyanto (President and General Manager of Total E&P Indonesie), "Upstream Perspective on Managing Indonesia Gas Supply and Demand", 8 February 2017, p. 5; PwC Analysis

With regard to LNG, the on-board LNG price is on average, USD 6.0 per MMBtu. Shipping and regasification costs are then added - typically around USD 0.6 to USD 2.8 per MMBtu. Subsequently, transportation (transmission and distribution) costs are added. However, although Indonesia is an LNG exporter to various countries, it has the highest regasification cost in the world (Figure 4.7). Thus, despite large domestic gas reserves and not uncompetitive extraction costs, Indonesia faces often unaffordable end-user gas prices.

Figure 4.7 – Comparison of regasification cost in selected countries as of 2016



Source: SKK Migas, "Policies on Natural Gas Pricing in Indonesia", 3 May 2017, p. 22

The allocation and utilisation of natural gas in Indonesia is regulated by MoEMR Regulation No. 6/2016 on Provisions and Procedures on Determination of Allocation and Utilisation and the Price of Natural Gas (an amendment to MoEMR Regulation No. 37/2015), MoEMR Regulation No. 6/2016 on Provisions and Procedures on Determination of Allocation and Utilisation as well as Price of Natural Gas (an amendment to MoEMR Regulation No. 37/2015), which sets new priorities as follows:

1. To support the Government's programme by providing gas for transportation, households and small users;
2. To support national production of oil and gas;
3. To provide raw materials for fertiliser;
4. To support industries that utilise natural gas as a raw material;
5. To provide fuel to be used for electricity production; and
6. To provide fuel to be used by other industries.

Another key point in MoEMR Regulation No. 6/2016 is that the utilisation of natural gas for power generation can be allocated to: (a) a state-owned enterprise assigned to supply electricity, i.e. PLN and its subsidiaries; (b) regional-owned enterprises located in the oil and gas producing areas which hold IUPTLs; (c) state-owned enterprises in oil and gas sector or regional-owned enterprises located in the oil and gas operating areas selling gas to IUPTL-holders; (d) business entities with an IUPTL that own gas-fired power plants; and (e) business entities with a marketing permit to sell gas to IUPTL-holders.

If the entities mentioned in (c) and (e) above are not able to distribute all their gas to IUPTL-holders, then those entities are allowed to sell the excess natural gas to other business entities with marketing permits as long as they meet the following requirements:

a) They own or control gas pipeline infrastructure for distribution to end users;
b) They are selling to end users; and
c) They sell at a reasonable price.

Procedures and regulations for gas allocation and pricing are designed to ensure the efficiency and effectiveness of the availability of natural gas as a fuel, raw materials or for other purposes to meet domestic demand optimally. The revision of the decree is due to the Government's initiatives in pushing the conversion of other power sources to gas, particularly for transportation and household use. Regulators have also sought to ensure that domestic demand has first priority, and the Minister of Energy and Mineral Resources has allowed imports of natural gas in the event that domestic demand cannot be met.

In May 2016, President Joko Widodo issued PR No. 40/2016 on the Provisions for Natural Gas Prices, which was intended to reduce gas prices to a maximum of USD 6 per MMBtu for certain industries, i.e. fertilisers, petrochemicals, oleochemicals, steel, ceramics, glass, and rubber gloves. PR No. 40/2016 is implemented by MoEMR Regulation No. 40/2016 on Prices of Natural Gas for Certain Industries in November 2016. Under this regulation, the Minister of Energy and Mineral Resources established the pipeline gas price at the buyer's plant gates, as well as the gas distribution costs of certain industries, including PT Petrokimia Gresik, PT Krakatau Steel, PT Pupuk Kujang, PT Pupuk Iskandar Muda and PT Pupuk Kaltim to be at a level of USD 6 per MMBtu.[48] Further, the current Minister of Energy and Mineral Resources, Ignasius Jonan, also formally cut the gas price for industrial users in North Sumatera according to Ministerial Decision ("MD") No. 434/K/12/MEM/2017 on Gas Prices for Industrial Customers in Medan and its Surroundings as enacted in February 2017. As a result, the gas for industrial users which was previously sold at USD 13.38 per MMBtu is reduced to the new price of USD 9.99 per MMBtu.[49]

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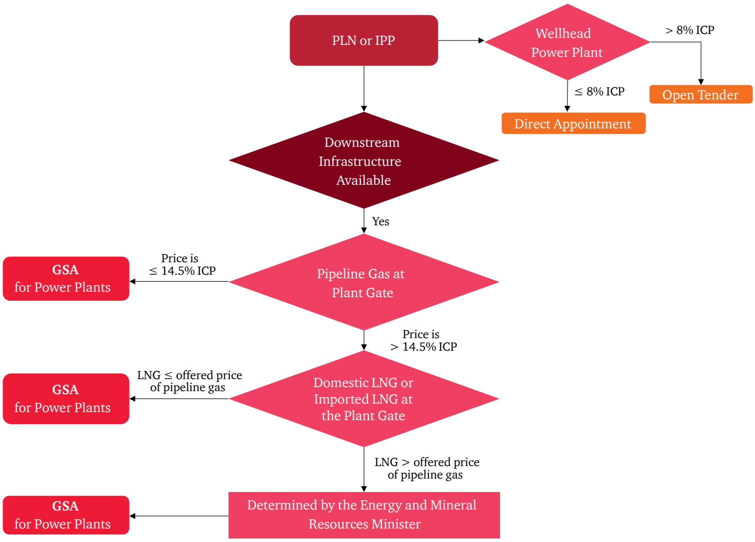
48 *http://migas.esdm.go.id/post/read/pemerintah-putuskan-harga-gas-3-industri-maksimal-us$-6-per-mmbtu*
49 *The Minister of Energy and Mineral Resources Decision No. 434/K/12/MEM/2017; MoEMR presentation at Forum Gas Nasional, 3 May 2017*

Additionally, specifically to the power sector, in July 2017, MoEMR issued MoEMR Regulation No. 45/2017 on the Use of Natural Gas for Power Plants. This regulation revoked the previous MoEMR Regulation No. 11/2017. The key point of MoEMR Regulation No. 45/2017 is that the Government allows PLN or Business Entities to import LNG for electricity generation in order to ensure the availability of natural gas at reasonable and competitive prices for the electricity sector. The provisions for conducting importing LNG is outlined in Figure 4.8 as follows:

Figure 4.8 – MoEMR Regulation No. 45/2017 on the Use of Natural Gas for Power Plants



Source: MoEMR Regulation No. 45/2017, Coffee Morning Session with DGE 10 August 2017

According to MoEMR Regulation No. 45/2017, the gas price (assumed at the initial date of a GSA) for the purpose of power generation is as follows:

- In the case of the utilisation of the gas well head, if the price is ≤8% ICP[50], it can be based on direct appointment. If the price is >8% ICP, it must be based on an open tender. The gas well head supply must be sufficiently guranteed. In the case that the gas well head is used for power generation, the Specific Fuel Consumption must be equal to HSD-equivalent 0.25 litres/kWh;
- In the case that the pipeline gas at the buyer's plant gate (power plant) is ≤14.5% ICP, PLN or IPPs can purchase it;
- In the case that the pipeline gas price at the buyer's plant gate (power plant) is >14.5% ICP, PLN or IPPs can choose either to use domestic LNG or imported LNG with a price lower than the offered pipeline gas price as long as they have access to LNG receiving infrastructure (i.e. a regasification facility). The price is inclusive of all regasification and distribution costs until it is ready to be used by the power plant;
- In the case that the domestic LNG price is equal to the imported LNG price, the domestic LNG must be prioritised; and
- In the case that the conditions above cannot be met, the Minister will determine the policy on the provision of natural gas for power generation.

50 ICP is Indonesian Crude Price formula = Dated Brent + Alpha (Ministerial Decision No. 6171 K/12/MEM/2016). In general, gas at the plant gate means gas at the buyer's plant gate (power plant)

Additionally, MoEMR intends to issue a new regulation on Natural Gas Sales Price on Downstream Oil and Gas Business Activities. The background of this regulation is to reduce the gas price for the end-user and and ensure higher efficiency for different industries. The new regulation will mostly affect gas traders (i.e. pipeline operators)[51] with salient features as follows:

(a) within the new rules, the natural gas traders will no longer be able to establish their own profit margin rate;
(b) the maximum profit margin that natural gas traders can make is 7% (based on an assumption of 15-year depreciation), plus the costs of gas transportation (toll fees), and the maximum IRR is 11%.

However, at the time of writing, the regulation has yet to be signed by the Minister of Energy and Mineral Resources.

4.2.3 Current Installed Gas-Fired Power Plant Capacity and Government Plans

Currently, about 15 GW of gas-fired power plants (including combined cycle) are installed and operated by PLN e.g. in Belawan, Muara Karang, Priok, Cilegon, Muara Tawar, Tambak Lorok, North Bali, and Gresik. In 2016, power generation from gas-fired power plants accounted for 25.9% of total generation. To achieve the NEP target energy mix in 2025 and as targeted in the 2017 RUPTL, it is expected that the share of gas-fired power generation in the power generation fuel mix will increase to 26.7% by 2026, supported by additional gas-fired power plant capacity of 24 GW. Gas consumption in Indonesia is likely to increase significantly if these plants come online. An additional 5.1 GW of gas-fired generation capacity is a contingency in the event that the renewables capacity target is not met by 2025.

Generally, PLN prioritises the use of pipeline gas for its gas-fired power plants, especially for those power plants that are must-run and bear a high electricity load such as Muara Karang, Priok, and Muara Tawar. However, with the intent to ensure the gas supply security, due to the depletion of existing gas fields, PLN has started to use LNG as an additional supply or substitution to the existing pipeline gas. Additionally, PLN is also looking to optimise the use of Compressed Natural Gas ("CNG").

PLN uses LNG mainly for peak load backup power plants rather than for base-load power plants, particularly for the Java-Bali, Sumatera and Eastern Indonesia networks, where base-load generation may not be sufficient. This is because of the relatively higher cost of LNG (compared to pipeline gas) given the need for regasification and other infrastructure. The LNG supplies for PLN currently only come from Bontang and Tangguh. In a few years, supplies are expected to increase from Abadi, Jangkrik, Wasambo, and Donggi-Senoro.

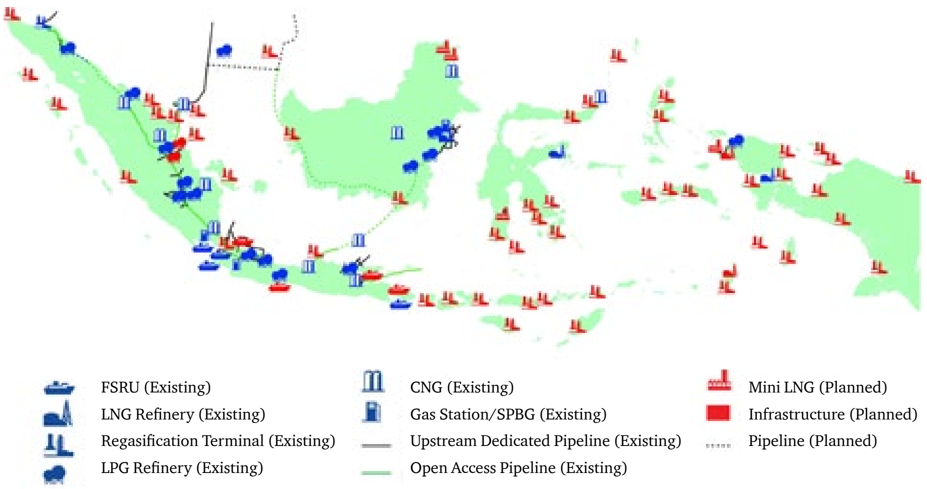
51 *http://www.migas.esdm.go.id/post/read/pemerintah-susun-permen-harga-gas-bumi-hilir-migas*

One of the largest gas-fired power plants planned for the years ahead is the Jawa 1 Combined Cycle (2 x 800 MW). The project tender was won by a consortium of Sojitz, Marubeni and Pertamina, and the PPA was signed in January 2017 priced at USD 5.5 cents/kWh. The Jawa 1 project will be developed in Cilamaya, West Java. It is the first gas-steam combined cycle power plant in Asia that integrates FSRU with a combined cycle power plant. With a capacity of 2 x 800 MW, the project will be the biggest gas combined cycle power plant in Southeast Asia.[52] The gas for Jawa 1 is planned to be supplied by LNG Tangguh as PLN was reported to have a deal with British Petroleum with gas price formula of 11.2% of ICP plus 0.4% for distribution costs.[53] This is a part of PLN's commitment to secure the gas supply for IPP projects, although the policy remains unclear for smaller gas-fired plant projects (see *Section 4.2.5 - Challenges*).

CNG was originally intended to optimise the potential of small-capacity and marginal gas fields by storing such gas in advance for temporary use. However, over time, PLN utilises large-scale CNG to overcome its inability to supply gas to some PLN power plants, especially those whose status has changed from baseloader to load follower. To date, CNG is already used for gas-fired power plants in Riau and Southern Sumatera since 2013. Further utilisation of CNG is planned in Sumatera, Central Kalimantan, and Lombok.

The Government has also developed a "Gas Infrastructure Concept" to support the development of the industry, which is estimated to require USD 48.2 billion of capital investment between 2016 and 2035 (see Figure 4.9 below) with details to construct gas pipelines of USD 12 billion, LNG refineries of USD 25.6 billion, gas station (*Stasiun Pengisian Bahan Bakar Gas* - "SPBG") and CNG of USD 1.93 billion, regasification facilities of USD 6.1 billion, gas network distribution of USD 2.2 billion, and LPG infrastructure of USD 400 million.[54] Gas infrastructure is planned to be developed gradually, and in the short term the Government plans to build natural gas networks for households, gas fuel stations and gas pipelines. Meanwhile, the private sector is also expected to develop a gas receiving terminal to support the 35 GW Programme.

Figure 4.9 - Indonesia gas infrastructure – current and concept (2016-2035)



Source: Neraca Gas Bumi Nasional 2016-2035

52 *http://www.pertamina.com/news-room/siaran-pers/konsorsium-pertamina,-marubeni,-dan-sojitz-tandatangani-ppa-jawa-1-dengan-pln/*
53 *https://www.rambuenergy.com/2017/05/pln-bp-tangguh-reach-agreement-on-lng-price-for-pltgu-jawa-i-power-plant/*
54 *"Indonesia Impor Gas Mulai 2020", Investor Daily, 13 July 2017*

4.2.4 Opportunities

Based on the 2017 RUPTL, the Government aims to increase the proportion of gas in the power generation mix to at least 26.7% in 2026, and initiate the conversion of PLN's existing diesel fuel-fired generation capacity to gas by constructing gas-fired power plants that, once accumulated, will amount to a capacity of 24 GW by 2026. Gas allocation is also prioritised for six groups (see page 86) in the domestic market including power generation, before being exported. Further, the Government has set a plan to reduce gas exports to only 40% of total production by 2019.

There are several IPPs and captive power plants located near supporting infrastructure (natural gas plants, ports, etc.). Of the 24 GW of new gas-fired power capacity planned, 10 GW is planned to be developed by PLN, 6 GW by IPPs and 8 GW remains unallocated between IPPs and PLN.[55] These figures indicate that there are significant opportunities in Indonesia for the private sector. Several notable gas-fired power projects to be tendered in 2017 include Jawa 3 Combined Cycle (1 x 800 MW) – East Java, Sumbagut 1,3,4 Combined Cycle (1 x 800 MW) – North Sumatera, Jawa Bali 3 Combined Cycle (1 x 500 MW) – Banten, Jawa Bali 4 Combined Cycle (1 x 450 MW) - West Java.[56]

The Government also plans to increase the growth of FSRUs across Indonesia. This is possibly due to the fact that the typical costs of developing FSRUs are significantly lower than a land-based terminal of comparable size, and because generally FSRUs are quicker to install than onshore regasification terminals.[57] Moreover, regarding the renewables target, there is also a possibility of an additional 5.1 GW of gas-fired generation capacity as a contingency in the event that the renewables target is not met by 2025. Receiving terminals like these present a potential private sector investment opportunity, especially for captive power generation for Industrial Estates in coastal areas.

The table below lists the PLN-announced gas-fired and combined cycle power plant procurements to be conducted in 2017 (Table 4.2). However, it has since been reported that PLN will allocate several large gas (and coal) power plant projects to its subsidiaries, who will find private sector partners based on their own processes.

Table 4.2 - Gas-fired and combined cycle power plant procurements

No.	Type of Power Plant	Project Name	Installed Capacity (MW)	Location	Estimated Total Project Cost (USD million)	Estimated PPA Date
1	Combined Cycle	Jawa-3	800	Gresik, East Java	1,200	August 2017
2	Combined Cycle	Sumbagut-1, 3, 4	750	Northern Sumatera	1,200	August 2017
3	Combined Cycle/ Gas Machine	Jawa Bali-3	500	Banten	750	October 2017
4	Combined Cycle/ Gas Machine	Jawa Bali-4	450	West Java	750	October 2017

Source: PLN at the Indonesian Infrastructure Forum, Jakarta, 17 May 2017

55 *2017 RUPTL, p. VI-38*
56 *PLN at the Indonesian Infrastructure Forum, Jakarta, 17 May 2017*
57 *Philip Weems, Nick Kouvaritakis and Richard Nelson, "FSRUs: Looking Back at the Evolution of the FSRU Market", December 2015. See http://www.energylawexchange.com/fsrus-looking-back-at-the-evolution-of-the-fsru-market/*

Since the revocation of MoEMR Regulation No. 3/2015, the pricing of power from gas-fired power plants is currently unclear, and will presumably be set by competitive bidding in Open Tenders for the plants mentioned above. However, in 2017 the MoEMR did issue two regulations on the pricing of the gas itself (but not the power generated from gas).

The first of these relates to untapped gas resources at the gas well head. According to MoEMR Regulation No. 45/2017 on the Use of Natural Gas for Power Plants, the gas supply from well heads will be benchmarked to the ICP, with an 8% slope (see *Section 4.2.2 - Prices and Regulation*). The expectation is that this relatively cheap fuel pricing would result in a power price of around USD 3 cents/kWh.[58] There is some private sector interest in this structure. Recently, an Italian oil and gas company, ENI, which operates a concession in Muara Bakau (Jangkrik Complex Project - projected to be one of the largest deep water gas field in Indonesia) announced that it was considering developing Indonesia's first offshore well head gas power plant. The location of the gas power plant is in Makassar Strait with potential capacity of 400-500 MW.

The second of these relates to the use of flare gas. Flare gas is gas produced through oil and gas exploration, production or processing activities. The gas is burned, and is not utilised because it cannot be handled by the available production or processing facilities. There are at least 175 gas flaring chimneys in Indonesia which are particularly spread across Java, Kalimantan and Sumatera, producing 170 MMSCFD.

According to MoEMR Regulation No. 32/2017 concerning Flare Gas Utilisation and Pricing in Oil and Gas Upstream Business Activities, the price of flare gas will be set at a base of USD 3.67/MMBtu (minus correction factors for H_2S and CO_2 content). The floor price for flare gas is USD 0.35/MMBtu, which would be expected to result in very cheap power.

58 *https://www.cnnindonesia.com/ekonomi/20170202165427-85-190903/aturan-pltg-well-head-diklaim-sunat-biaya-listrik/*

4.2.5 Challenges

Lack of sufficient new infrastructure and aging existing infrastructure seems to be one of the bottlenecks in the power industry, and this is especially true for gas-fired power plants. Undeveloped infrastructure may lead to inefficient gas supply for power plants across Indonesia. As the current gas pipelines are not sufficient to distribute gas across Indonesia, especially in eastern Indonesia, the expansion of the pipeline network as well as the development of FSRUs, and the LNG facilities is required to support the distribution of gas.

Gas as component C (fuel) in a power plant is principally a pass-through cost to PLN. In 2016, PLN announced that it will supply fuel for gas-fired power plants of IPPs. However, it has been reported that PLN's policy on gas supply remains inconsistent and is constantly changing. Practically, PLN does appear to supply gas only for large capacity power plant projects, including Jawa-Bali 3 and Jawa-1. Yet, for the smaller capacity such as the Scattered Riau Gas Machine (180 MW) and the Pontianak Gas Machine (100 MW), PLN seemed to exclude the gas supply from consideration. This uncertainty has resulted in no bidders submitting tender documents for the projects mentioned, which could lead to delays in future gas power plant projects.[59]

Additionally, the implications of the power sector being only fifth on the list of priority sectors for gas supply (see page 86) are also yet to be fully understood. Thus far, it does not appear to have had any obvious impact on IPPs.

59 *http://industri.kontan.co.id/news/pln-diminta-konsisten-soal-suplai-gas-pembangkit*

4.3 Coal

4.3.1 Indonesian Resources, Consumption and Production

Coal continues to play a vital role in global energy supply, with steam coal, coking coal and lignite being used for the generation of electricity and commercial heat globally. Currently, the coal industry is facing weak global demand which, accompanied by an oversupply of coal, has led to steep declines in global coal prices over the past few years. This trend was eased in late 2016 through the actions of the Chinese Government to restrict domestic coal production, thus shoring up prices.

In the long term, world coal production is expected to continue to increase from 9 billion tonnes in 2012 to 10 billion tonnes in 2040.[60] Similarly, world coal consumption is also expected to increase, although China's consumption growth is expected to decline due to the implementation of policies addressing air pollution and climate change. As a share of the energy mix, coal is likely to fall in importance over the long term, as natural gas and renewables generation are increasing their market share at the expense of coal in the electrical power sector.[61]

In Indonesia, coal has historically been, and remains, one of the most important sources of fuel for electricity. Coal mining plays a relatively significant role for the Indonesian economy, contributing 2.3% to GDP in 2016.[62] According to the BP Statistical Review of World Energy 2017, Indonesia sits in ninth place in terms of proven coal reserves in the World with 2.3% of global coal reserves. Around 92% of Indonesia's total coal reserves consist of cheaper, lower-quality coal (medium rank) with a calorific value of less than 6,100 kcal/kg (Table 4.3). This type of coal is generally competitively priced on the international market.

Table 4.3 – Indonesia's coal reserves and resources for 2016

Quality	Resources (Million Tonnes)					Reserves (Million Tonnes)		
	Hypothetical	Inferred	Indicated	Measured	Total	Probable	Proven	Total
Low Calorie (<5,100 kal/gr)	599.17	11,263.95	15,913.98	16,420.26	44,197.36	7,108.27	7,121.47	14,229.74
Medium Calorie (5,100 - 6,100 kal/gr)	3,343.53	27,436.16	19,822.35	20,357.92	70,959.96	3,570.70	6,841.66	10,412.36
High Calorie (>6,100 - 7,100 kal/gr)	588.04	3,967.88	2,480.65	2,804.63	9,841.20	541.60	2,769.20	3,310.80
Very High Calorie (>7,100 kal/gr)	2.06	1,726.74	735.33	600.00	3,064.13	264.19	240.21	504.40
Total	**4,532.80**	**44,394.73**	**38,952.31**	**40,182.81**	**128,062.65**	**11,484.76**	**16,972.54**	**28,457.30**

Source: LAKIN Minerba 2016[63]

60 *US Energy Information Administration, International Energy Outlook 2016, p. 3*
61 *PwC, Mine 2017*
62 *Bank Indonesia, Statistics of Indonesian Economic and Finance ("SEKI"), www.bi.go.id/en/statistik/metadata/seki*
63 *Laporan Kinerja Direktorat Jenderal Mineral dan Batubara 2016 ("LAKIN Minerba 2016") [2016 Performance Report of Coal and Mineral ("DGoMC")], p.4*

The three largest provinces with Indonesian coal resources are South Sumatera, South Kalimantan and East Kalimantan. There are also numerous smaller coal reserves across the rest of Sumatera and Kalimantan as well as on the islands of Sulawesi and Papua. The Indonesian coal industry is fragmented with only a few big producers and many small players that own coal mines and coal mine concessions (mainly in Sumatera and Kalimantan). In 2016, Indonesia had coal resources of 128.1 billion tonnes, mainly located in Kalimantan (79.0 billion tonnes), Sumatera (48.5 billion tonnes) and other regions (0.5 billion tonnes). In 2016, coal reserves amounted to 28.5 billion tonnes. Most of South Sumatera's coal reserves and resources are low rank coal, which tends to be used for power generation. This is because it is generally not feasible to transport low rank coal to other regions, unless the coal price paid is significantly higher than average (Table 4.4).

Table 4.4 – Reserves and resources by province for 2016

No	Island	Province	Resource (Million Tonnes)					Reserves (Million Tonnes)		
			Hypothetical	Inferred	Indicated	Measured	Total	Probable	Proven	Total
1	Java	Banten	5.47	38.90	28.45	25.10	97.92	-	-	-
2		Central Java	-	0.82	-	-	0.82	-	-	-
3		East Java	-	0.08	-	-	0.08	-	-	-
4	Sumatera	Aceh	-	423.60	163.69	662.93	1,250.22	95.30	321.38	416.68
5		North Sumatera	-	7.00	1.84	25.75	34.59	-	-	-
6		Riau	3.86	209.80	587.82	689.28	1,490.76	85.57	523.32	608.89
7		West Sumatera	19.90	304.20	278.78	347.38	950.26	1.67	196.17	197.84
8		Jambi	129.16	1,216.50	896.04	1,038.02	3,279.72	314.09	351.62	665.71
9		Bengkulu	-	117.30	171.74	126.48	415.52	16.20	62.92	79.12
10		South Sumatera	3,290.98	10,859.30	14,826.24	12,020.27	40,996.79	5,557.53	5,509.45	11,066.98
11		Lampung	-	122.90	8.21	4.47	135.58	11.74	-	11.74
12	Kalimantan	West Kalimantan	2.26	477.60	6.85	4.70	491.41	-	-	-
13		Central Kalimantan	22.54	11,299.90	3,805.64	2,849.22	17,977.30	910.76	1,090.57	2,001.33
14		South Kalimantan	-	4,739.10	4,402.79	5,893.65	15,035.54	1,308.49	3,961.76	5,270.25
15		East Kalimantan	909.95	13,680.40	13,049.18	15,401.10	43,040.63	2,760.01	4,434.93	7,194.94
16		North Kalimantan	25.79	795.80	595.37	1,041.20	2,458.16	423.34	520.36	943.70
17	Sulawesi	West Sulawesi	8.13	15.10	0.78	0.16	24.17	0.06	-	0.06
18		South Sulawesi	5.16	48.80	128.90	53.09	235.95	-	0.06	0.06
19		Central Sulawesi	0.52	1.98	-	-	2.50	-	-	-
20	Maluku	North Maluku	8.22	-	-	-	8.22	-	-	-
21	Papua	West Papua	93.66	32.80	-	-	126.46	-	-	-
22		Papua	7.20	2.16	-	-	9.36	-	-	-
Total Indonesia			**4,532.80**	**44,394.04**	**38,952.32**	**40,182.80**	**128,061.96**	**11,484.76**	**16,972.54**	**28,457.30**

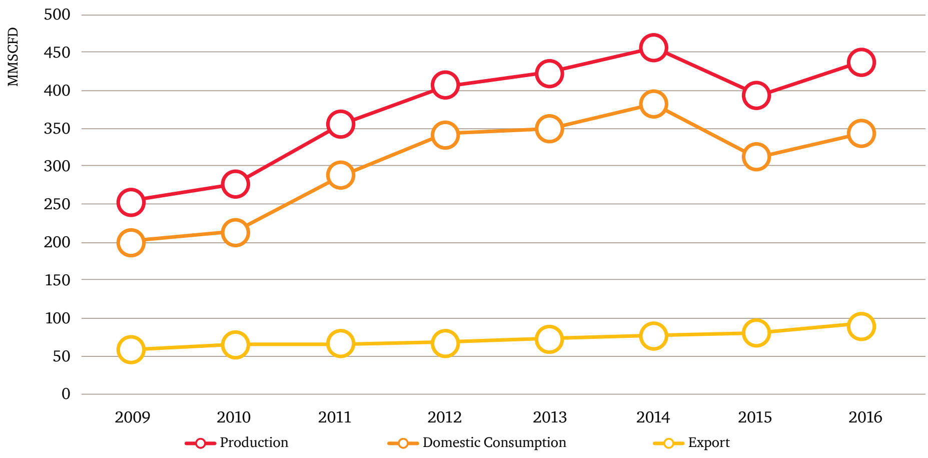
Notes: Information on resources by provinces for 2016 might not be the same with the total Indonesia's coal resources for 2016 in Table 4.3 due to rounding differences.

Source: LAKIN Minerba 2016, p. 8; 2017 RUPTL, p. V-2

As the world's fifth-largest coal producer[64], Indonesia has become the world's second largest exporter of thermal coal.[65] Indonesia's coal production rebounded to 434 million tonnes in 2016, up from 392 million tonnes in 2015. Before the decline in global coal demand, which led to declining coal prices up until Q2 2016, the Government was planning to restrict coal production to only 400 million tonnes by 2019 – so that 60% of production will be consumed domestically.[66]

In 2016, Indonesia exported 344 million tonnes out of a total coal production of 434 million tonnes, generating USD 14.6 billion in export earnings (see Figure 4.10).[67] The main export destinations for Indonesian coal have historically been China, India, Japan and Korea, although other countries such as the Philippines are increasingly looking to import from Indonesia. Trade with China particularly fluctuated in 2016 due to the restrictions (and subsequent relaxations) on Chinese domestic coal mine production days.

Figure 4.10 - Indonesian coal production and consumption for 2009-2016

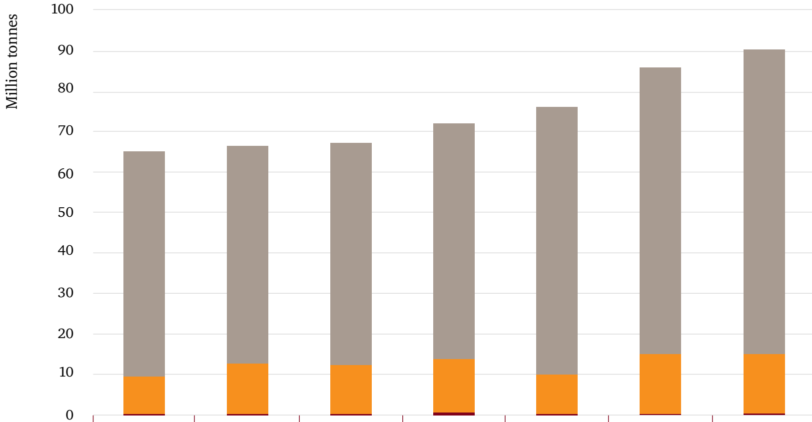


Source: LAKIN Minerba 2016

In recent years, Indonesia's domestic coal consumption increased by 40% from 65 million tonnes in 2010 to 90.5 million tonnes in 2016 mainly due to increased demand from coal-fired power plants (see Figure 4.11). Based on the 2017 RUPTL, coal-fired power plants are expected to consume 111 and 148 million tonnes of coal by 2019 and 2025, respectively.

64 *BP Statistical Review of World Energy 2017, p. 38*
65 *EIU Energy Report 2nd Quarter 2017, p. 6*
66 *Rencana Strategis ("RENSTRA") Kementerian ESDM ("KESDM") 2015-2019 [2015-2019 MoEMR Strategic Plan], p. 85 and 87*
67 *Bank Indonesia, Statistics of Indonesian Economic and Finance ("SEKI"), www.bi.go.id/en/statistik/metadata/seki*

Figure 4.11 – Breakdown by type of coal consumers for domestic use for 2010 - 2016



	2010	2011	2012	2013	2014	2015	2016
Power Plant	55.5	53.5	54.8	58.3	66.0	70.8	75.4
Cement, Fertiliser, Pulp & Textiles	9.2	12.4	12.2	13.1	9.9	14.8	14.7
Metallurgy	0.3	0.3	0.3	0.7	0.3	0.4	0.4
Total	65.0	66.2	67.3	72.1	76.2	86.0	90.5

Source: LAKIN Minerba 2016

4.3.2 Prices and Regulation

In March 2017, MoEMR issued MoEMR Regulation No. 19/2017 on Coal Utilisation for Power Plants and Excess Power Purchases, setting the new tariff base for both coal-fired power plants and coal-mine mouth ("CMM") power plants based on business-to-business ("B2B") or subject to benchmarking against the BPP. With respect to coal fired power plants and CMM power plants, this regulation replaces MoEMR Regulation No. 3/2015 and related previous regulations.

Note that MoEMR Regulation No. 9/2016 which was partially amended by MoEMR Regulation No. 24/2016 provides the legal basis for defining "mine-mouth" power plant. There are four criteria for a mine-mouth power coal supply arrangement: (1) the coal to be used is more economically feasible for utilisation in a mine-mouth power project; (2) the availability of coal supply is guaranteed by the coal mining company throughout the operation of a plant; (3) the power plant is at most 20 km away from the location of the coal mine; and (4) the coal does not include transportation costs except for transportation costs from the mine location to the power plant's stockpile.

In addition, a mine-mouth coal supplier or its affiliate must have a minimum equity interest of 10% in the IPP and must be the holder of a production mining business licence (*"IUP Operasi Produksi"*), a special operation mining business licence (*"IUPK Operasi Produksi"*), or a Coal Cooperation Agreement (*Perjanjian Karya Pengusahaan Pertambangan Batubara* - "PKP2B").

Crucially, the new tariffs may not be as attractive as the previous regime in many cases. In summary, the salient features of the regulation are stated in Table 4.6 and Figure 4.13 as follows:

Table 4.6 - Summary of the MoEMR Regulation No. 19/2017 provisions on tariffs

No.	Type of Power Plant	Maximum Benchmark Price		Remarks
		Regional BPP > National BPP	Regional BPP ≤ National BPP	
1	Coal-fired >100 MW*	National BPP	Regional BPP	Transmission from power plant to the PLN grid (Component E) is conducted based on B2B negotiation.
	Coal-fired ≤100 MW*	B2B or Auction	Regional BPP	
2	CMM	75% National BPP	75% Regional BPP	
3	Excess Power	90% Regional BPP		

**Coal price is principally pass-through for non-CMM plants.*
Source: MoEMR Regulation No. 19/2017

Note that the electrical power purchasing price is set under the assumption that the plant has an 80% Capacity Factor, and the PPA shall follow a BOOT scheme.

Additionally, the regulation specifies the procurement process for power expansion projects as follows:

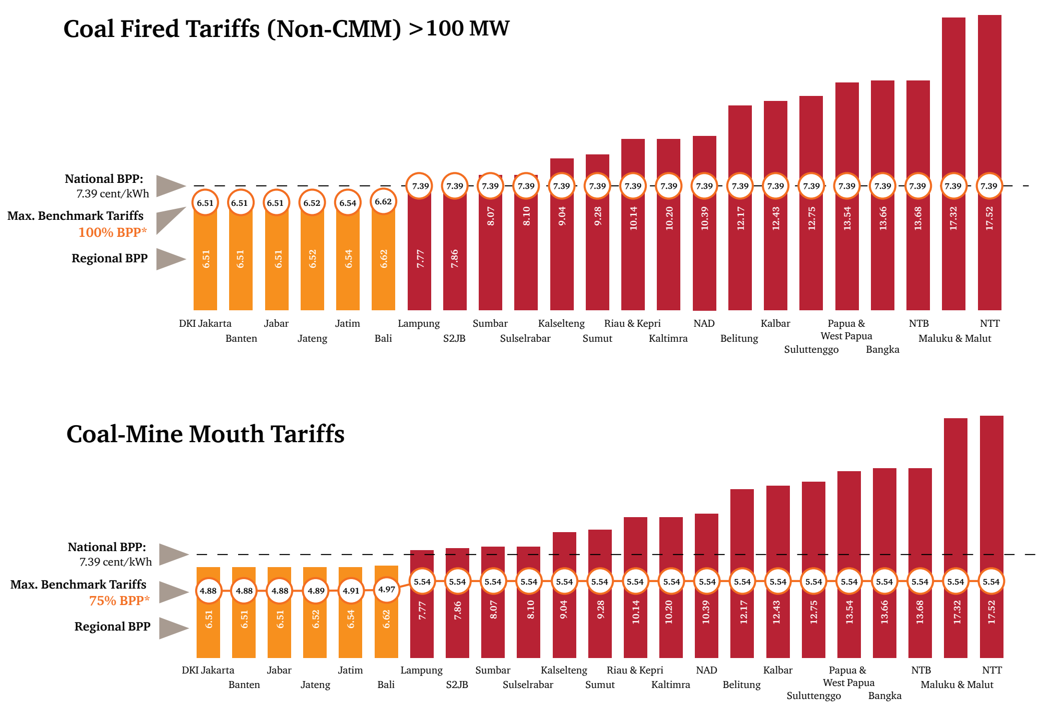
- In the event of the purchasing of power resulting from the expansion of a power plant in the same location, the method could follow direct appointment, but with a lower benchmark price (as above).
- In the event of power purchase from an expansion of power plants in a different location but in the same power system, the method could follow direct selection, but with a lower benchmark price (as above).

The procurement of CMM power plants can be through direct appointment.

Figure 4.12 outlines the maximum tariffs for coal-fired and CMM power plants in selected regions according to MoEMR Regulation No. 19/2017.

The new maximum benchmark price for coal-fired power plant projects ranges from USD 6.51-6.62/kWh for any region where the Regional BPP ≤ National BPP, i.e. in Java and Bali. The new maximum benchmark price follows the national BPP (USD 7.39/kWh) in the case of coal-fired plants with capacity higher than 100 MW if they are installed in any region where the

Figure 4.12- Tariffs for coal-fired and CMM power plants



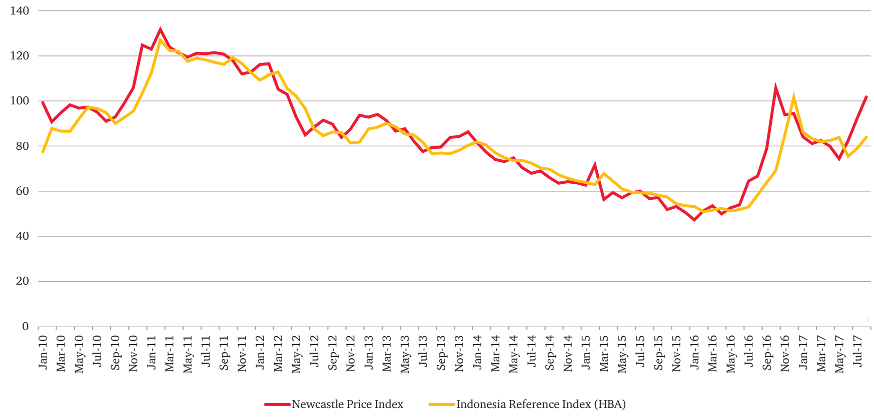
Source: Aksin (PLN), "Indonesia Electricity Supply and the Role of IPP within", Presentation at the 7th IPP Summit, 9-10 May 2017

Regional BPP > National BPP (see Figure 4.12 above). Additionally, specifically for coal-fired power plants with capacity ≤ 100 MW, the tariff is now based on B2B negotiation between PLN and IPPs or an auction.

In addition, the new maximum benchmark price for CMM power plant projects follows 75% of the Regional BPP in the case of the Regional BPP ≤ National BPP (see Figure 4.12 above) or 75% of the National BPP in the case that the Regional BPP is higher than National BPP (see Figure 4.12 above).

In terms of the coal price itself, in recent years, the global coal price has plunged, followed by a sharply declining Indonesian coal reference price (*Harga Batubara Acuan* - "HBA"), resulting in a decrease in coal production growth in Indonesia, as small-scale miners suspended their operations and big players have taken steps to protect margins. The Indonesian coal reference price declined by 58.3% from USD .05/tonne in February 2011 to USD 53/tonne in July 2016. However, it began a strong rally thereafter, peaking at over USD 100/tonne in December 2016 (Figure 4.13). This was mainly due to Chinese Government Policy on domestic coal production discussed above. The reversal of the policy in early 2017 was swiftly followed by a price fall. Later in mid-2017, strong Asian demand (including Chinese power plants stocking ahead of winter) supported another rally.

Figure 4.13 - Indonesian coal price for the periods January 2010 – August 2017



Source: MoEMR, GEM Commodities, World Bank, Bloomberg

The benchmark price for coal sales, specifically steam (thermal) coal, is regulated by the MoEMR Regulation No. 7/2017 (as amended by MoEMR Regulation No. 44/2017), which revoked the MoEMR Regulation No. 17/2010. The regulation states that the sale of coal should be aligned with the benchmark price issued by the Government, commonly referred to as the HPB (*"Harga Patokan Batubara"*). The HPB itself is determined based on a number of factors, namely the HBA and individual coal quality characteristics (i.e. calorific value, moisture content, sulphur content and ash content). The HBA is calculated based on the average coal prices in local and international market indexes, namely the Indonesia Coal Index/Argus Coalindo, Newcastle Export Index, Globalcoal Newcastle Index, Platts Index, Energy Publishing Coking Coal Index, and/or IHS Markit Index. The HBA is determined by the Minister of Energy and Mineral Resources each month.

The HPB is used as a basis for most IPP contracts. It is also applicable to spot sales and long-term sales. For long-term sales, there are several requirements for mining companies to determine the coal price. In cases where the sale of coal is implemented within a certain period (term), the HBA which is used as a reference for stipulating the price of coal in sales contract is calculated based on a formula of 50% (fifty percent) of HBA in the month of contract signing plus 30% (thirty percent) of HBA 1 (one) month prior to contract signing plus 20% (twenty percent) of HBA 2 (two) months prior to the contract signing. Specifically for sales to domestic end-users, the HBA used in the contract can be reviewed every 3 (three) months at the earliest. We believe that while the regulation refers to HBA, the actual reference used in the contract would be HPB.

For CMM plants only, the approved coal base price is not linked to the HPB, but instead can be escalated using a weighted average of the IDR exchange rate, fuel price, Consumer Price Index and regional minimum wage only after the COD of the power plant. The weights are determined on a case-by-case basis. As such, the inflationary risks from the approved coal base price and the COD of the power plant are borne by the coal supplier.[68]

4.3.3 Current Installed Coal-Fired Power Plant Capacity and the Government Plans

In 2016, power generation from coal-fired power plants accounted for 55% of total generation. In order to align with the target NEP energy mix in 2025, it is expected that power generation from coal will fall to 50% by 2025, despite additional coal-fired power plants (including CMM) of 32 GW. Coal consumption in Indonesia will likely be significantly increased due to these additional power plants.

As discussed in *Section 3.7.1 - IPP Opportunities and Challenges*, coal will likely continue to play a vital role in the development of power generation in Indonesia for the next ten years. CMM power plants remain integral to the Government's plans given that Indonesia's low-rank coal deposits are often located in remote areas with minimal infrastructure, making transportation of the coal uneconomical.

4.3.4 Opportunities

Of the 32 GW coal-based power generation as planned in the 2017 RUPTL, regular coal-fired power plants account for 24.6 GW, while CMM power plants account for 7.3 GW.

On the one hand, of the regular coal-fired power plant, about 6 GW coal-fired power plants are planned to be developed by PLN, while another 16.5 GW is to be developed by IPPs. The remaining 2 GW projects are still unallocated. On the other hand, about 7.3 GW of CMM power plant capacity has been allocated to IPPs.[69]

These figures indicate that there are significant opportunities in Indonesia for the private sector. In 2017, PLN has planned to open a procurement process for several coal-fired and CMM power plants as shown in Table 4.5 below. However, it has since been reported that PLN will allocate several large coal (and gas) plants to its subsidiaries, who will find private sector partners in line with their own processes.

68 *Coal Asia, 25 June – 25 July 2016, p. 54*
69 *2017 RUPTL, p. VI-39*

Table 4.5 – Procurement of coal-fired and coal mine mouth power plant in 2017

No.	Type of Power Plant	Project Name	Installed Capacity (MW)	Location	Estimated Total Project Cost (USD)
1	Coal-fired	Jawa-9 & 10	2,000	Banten	3,380 million
2	Coal-fired	Meulaboh-3 & 4	400	Aceh	540 million
3	Coal-fired	Sumut-2	600	North Sumatera	900 million
4	Coal-fired	Kalbar-2	200	West Kalimantan	300 million
5	Coal-fired	Sumbagsel-1	300	Southern Sumatera	450 million
6	Coal-fired	Sulbagut-3	100	Northtern Sulawesi	150 million
7	Coal-fired	Jawa-6	2,000	West Java	750 million
8	CMM	Jambi (Phase I)	600	Jambi	900 million
9	CMM	Kaltim-5	200	East Kalimantan	300 million
10	CMM	Kalselteng-3	200	South/Central Kalimantan	300 million
11	CMM	Kaltim-3	200	East Kalimantan	300 million
12	CMM	Kaltim-6	200	East Kalimantan	300 million
13	CMM	Sumsel-6	600	South Sumatera	900 million
14	CMM	Riau-1	600	Riau	900 million
15	CMM	Jambi (Phase II)	600	Jambi	900 million
16	CMM	Kalselteng-4	200	Kalimantan Selatan/Tengah	300 million
17	CMM	Kalselteng-5	200	South/Central Kalimantan	300 million

Source: PLN at the Indonesian Infrastructure Forum, Jakarta, 17 May 2017; Jakarta Post, 30 August 2017

In the 2017 RUPTL, there are several changes of status from non-mine-mouth to mine-mouth power plants, for example, the Riau-1 600 MW and Sumut-2 600 MW projects. Coal mine-mouth remains a promising opportunity especially for coal mining companies interested in diversifying their business downstream into power generation – there is about 3.6 GW planned to be procured in 2017 (see Table 4.5 above).

4.3.5 Challenges

Indonesia has large geological reserves of coal. However, although mature in some areas, coal transport infrastructure still contributes significantly to Free On Board ("FOB") coal prices in many areas. Efficient solutions such as railways (with high capital requirements but generally lower lifetime costs) will need to be accelerated if inland coal is to be accessed cost-effectively.

Licensing requirements could also hinder the progress of the coal-fired power plant development programme since many concessions for coal mining are expected to expire before the corresponding Coal Supply Agreements (in the early 2020s). The Government may need to signal to reputable miners that it will commit to renewing Mining Business Licenses (*Izin Usaha Pertambangan* – "IUP") or PKP2B.

Compared to the previous benchmark price stipulated in MoEMR Regulation No. 3/2015, the price for coal-generated power as stated in the MoEMR Regulation No. 19/2017 is generally lower.[70] Indeed, from the Government's standpoint, it is expected that under the new regulation regional BPPs may be more effective and efficient, which could ultimately drive greater competition on electrical power prices. Seemingly, what drove the MoEMR to implement this regulation was their goal of reducing the burden of electrical power subsidies on the national budget, while also ensuring better accessibility for society as a whole. The expected outcome from the revised mechanism is lower electricity supply costs for PLN. However, this may come at a cost in terms of investor interest if the profitability for coal-fired and CMM power plants is reduced.

Further, certainty regarding the planning stage has become a concern (i.e. the clarity of PLN's plan and ability of PLN to evacuate the generated electricity). Some coal-fired and CMM projects, specifically the Sumsel 9 and 10 projects have been delayed due to PLN having recently adjusted its plan for the construction of the HVDC infrastructure which was previously planned to evacuate the generated electricity from such power plant projects. This illustrates the general uncertainty of investing in the sector.

4.4. Oil

In 2016, Indonesia's total crude oil production amounted to 0.83 million barrels per day, around 70% of its 2005 daily production.[71] Meanwhile, in recent years up to 2016, Indonesia's total oil consumption has grown continuously at an average rate of 3.2% annually to 1.62 million barrels per day causing Indonesia to be a net oil importer country.[72] However, instead of power generation, most of the oil is consumed by the transportation sector.

In term of the power sector, oil, mainly HSD and MFO, currently plays a relatively insignificant share. Generally, PLN uses oil to provide electricity in rural or isolated grid areas. In the years ahead, the 2017 RUPTL indicates PLN's plan to continuously reduce the use of oil consumption in its total electricity generation (i.e. HSD from 10% to only 2% and MFO from 7.8% to 0.2%, see Figure 1.7). This is motivated by efforts to reduce the BPP and increase efficiency.

However, separately, in regard to captive generation facilities, oil (diesel) is also used by non-electrified communities in rural and remote areas as well as by the industrial sector. Specifically to industries, this is caused by a surge in demand for electricity, while capacity growth has not kept up, and sometimes PLN has been forced to implement blackouts in some provinces. Thus, many industries operate their own backup diesel generators.[73]

70 Please see our Power Investment Guide 2016 - https://www.pwc.com/id/en/energy-utilities-mining/assets/power/power-guide-2016.pdf
71 Annual Report SKK Migas 2016, p. 10; LAKIN DJMGB 2016, p. 15
72 BP Statistical Review of World Energy 2017, p. 15
73 PwC, Oil and GE Operations Indonesia ("GE"), Private Power Utilities: The Economic Benefits of Captive Power in Industrial Estates in Indonesia, 2016, p. 18

5 Renewable Energy

5.1 Overview of Indonesia's Renewable Energy Development

Despite an abundance of renewable energy resources (see Table 1.1), Indonesia has been relatively slow to develop renewable energy. In the past, fuel subsidies, low electricity tariffs, complex regulations, legal uncertainties, logistical challenges and extensive cheap coal resources have deterred potential renewables investments. Following years of under-investment, Indonesia's production of renewable energy remains modest.

Indonesia's primary objectives in expanding its use of renewable energy appear to be threefold:

a) To improve domestic energy security by diversifying the feedstocks used by PLN and IPPs to generate power and encourage the use of renewable energy as an ancillary source where it is readily available and untapped;
b) To accelerate improvements to the electrification ratio and access to energy infrastructure, particularly for that part of the population without grid access in rural, remote and border areas and on islands with a target to achieve a 97% electrification rate by 2019; and
c) To contribute towards GHG emissions targets and encourage the green economy as the Government would like to cut GHG emissions by 29% by 2030.

Similarly, the present utilisation of renewable energy sources for power generation in Indonesia can be broken down into three classes:

a) Energy sources already being used in commercial operations (e.g. geothermal, hydro energy and biomass);
b) Energy sources being developed commercially but on a limited basis and with some concerns over regulatory and commercial issues (e.g. solar and wind); and
c) Energy sources at the research stage only (e.g. ocean energy).

The most recent 2014 NEP sets a goal for the percentage of the national energy mix from new and renewable energy sources to be 23% by 2025 and 31% by 2050. Under Law No. 30/2007 on Energy, new energy sources are defined to include liquefied coal, coal bed methane, gasified coal, nuclear energy and hydrogen. Renewable energy sources are defined to include geothermal resources, hydropower, bioenergy, solar, wind and ocean energy. The composition of the 23% target has been reported by the MoEMR consisting of: 10% bioenergy, 7% geothermal, 3% hydropower and 3% other new and renewable energy. However, with only 0.36% average growth per year[74], the new and renewable energy share in Indonesia remains unchanged at approximately 6.8% of the national energy mix.[75] This situation indicates that achieving a 23% renewable energy share by 2025 will be a challenging task, especially given the small quota under the 35 GW Programme.

With regard to the regulatory framework, tariffs and pricing are among the most sensitive issues in renewable energy investment and development. Until 2016, the regulation on tariffs had been designed with private investors in mind. However, the release of MoEMR Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017) on the Utilisation of Renewable Energy Resources for Electricity caused concern that there was little to incentivise new investments, especially in low-cost areas such as Java and Sumatera. The release of MoEMR Regulation No. 50/2017 which revoked MoEMR Regulattion No. 12/2017 (as amended by MoEMR Regulation No. 43/2017), alleviated some of these concerns, mainly through increasing tariffs, or providing flexibility for many provinces especially in Java and Sumatera. Please see *Section 5.9 - New Tariff Stipulation for Renewable Energy* for more information on tariffs or renewable tariffs.

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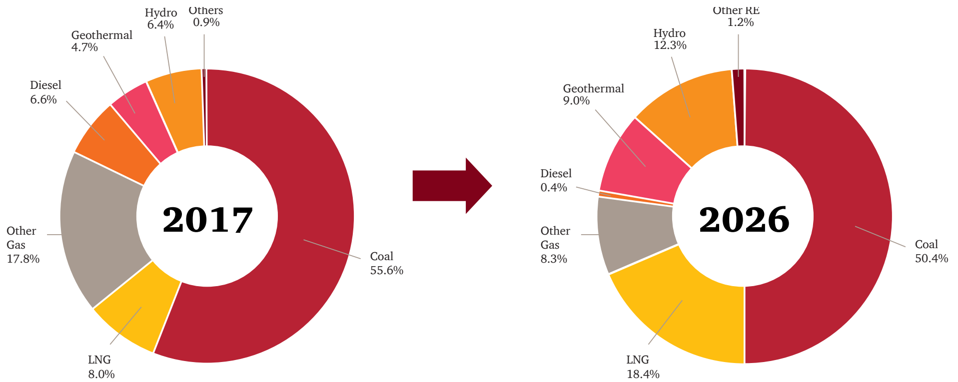
74 2016 New and Renewable Energy and Energy Conservation Statistics ("2016 EBTKE Statistics"), p. vii

75 MoEMR, "Action for Achieving the 2025 Renewable Energy Target", Presentation at the Bali Clean Energy Forum (http://bceforum.org/?page_id=2625), 12 February 2016

5.2 Renewable Energy in RUPTL

Despite the potential issues in Indonesia's renewable energy sector from the investors' perspective, particularly concerning new power purchase tariffs, both PLN and MoEMR remain optimistic about renewable energy development. In the 2017 RUPTL, the target for renewable energy deployment in the fuel mix increases from 11% in 2017 to 22.5% by 2026 which will mainly be supported by hydropower for 12.3% and geothermal energy for 9% (Figure 5.1).

Figure 5.1 – Fuel mix projection in the electricity sector as in RUPTL 2017-2026



Source: 2017 RUPTL, p. VI-71 and PwC Analysis

5.3 Geothermal Energy

Geothermal power generation relies on the thermal energy of the Earth's core to heat water or other fluids. The condensate from the heated fluid is used to turn a turbine and generate electricity. After cooling, the fluid is directed back down toward the geothermal resource to repeat the process. Indonesia is a geothermal-rich country, as the country is situated on the world's most active volcanic fault (the Ring of Fire). Additionally, Indonesia's significant geothermal energy potential is closely related to the fact that Indonesia lies between two of the Earth's major active tectonic plates (Pacific and Eurasia) and a minor plate (the Philippine plate) which allows geothermal energy from the Earth to be transferred to the surface through a fracture system.

Geothermal is regarded as a "clean" energy, emitting up to 1,800 times less carbon dioxide than coal-fired burning plants and 1,600 times less than oil-fired burning plants. Being a renewable resource, geothermal energy is unaffected by changes in hydrocarbon prices. It is also the only renewable source with a potential capacity factor close to 100%.

Indonesia's geothermal potential reaches 28,589 MW (Table 5.1) across 331 locations, and represents the second largest geothermal resource in the world, at 28% of total global resources.[76]

76 *Rencana Strategis KESDM – "RENSTRA KESDM" 2015-2019, p. 70*

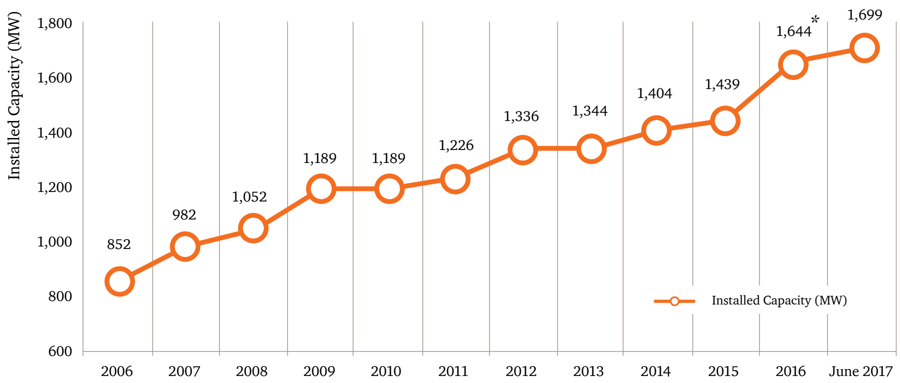
Table 5.1 – Resources, reserves and installed capacity of Indonesian geothermal as of June 2017

No	Island	No. of Locations	Potential Energy (MW)					Total - MW	Installed Capacity – MW
			Resources		Reserves				
			Speculative	Hypothetical	Possible	Probable	Proven		
1	Sumatera	97	2,893	1,935	5,097	930	917	11,772	342
2	Java	73	1,410	1,689	3,949	1,373	1,865	10,286	1,224
3	Bali	6	70	22	122	110	30	354	-
4	Nusa Tenggara	27	225	409	848	-	15	1,497	13
5	Kalimantan	14	152	17	13	-	-	182	-
6	Sulawesi	78	1,221	314	1,242	80	140	2,997	120
7	Maluku	33	560	91	775	-	-	1,426	-
8	Papua	3	75	-	-	-	-	75	-
Total		**331**	**6,606**	**4,477**	**12,046**	**2,493**	**2,967**	**28,589**	**1,699**
			11,083		**17,506**				

Source: DGNREEC, "Doing Business in Geothermal", August 2017[77]

The physical location of geothermal resources across Indonesia and their lack of "tradability" means that this power source is well-placed to assist with improving domestic energy security. However, the development of Indonesia's geothermal sector has been low and slow. The growth of geothermal energy development in Indonesia is presented in Figure 5.2. To date, there are only ten working areas (or concessions) operating and producing, despite the fact that the Government has identified 70 potential working areas.[78] Currently, the total installed capacity is 1,699 MW (see Table 5.2 for the operating working areas), equivalent to only 6% of the total estimated resources.

Figure 5.2 – Installed capacity of geothermal energy in Indonesia (MW)



**2016 figure included Sarulla where COD was in early 2017 but has sold power in December 2016*

Source: DGNREEC, "Doing Business in Geothermal", August 2017, p. 29

77 *DGNREEC, "Doing Business in Geothermal", August 2017 on http://igis.esdm.go.id/igis/*
78 *LAKIN EBTKE 2016, p. 70*

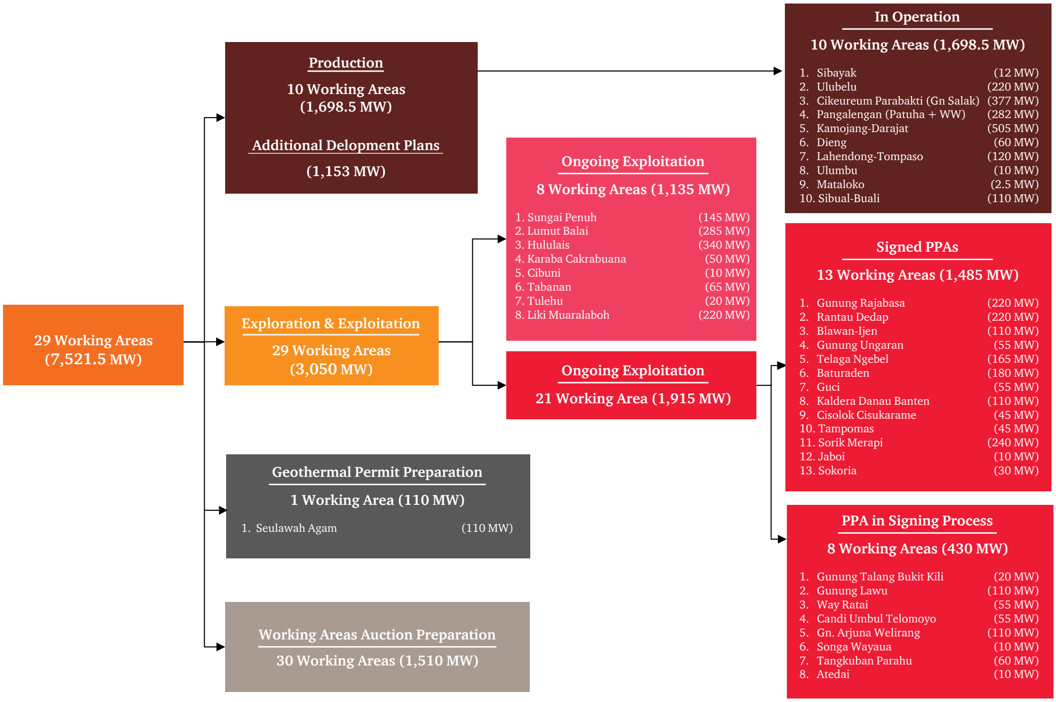
Table 5.2 – Installed geothermal capacity by the licence holder and developer as of June 2017

No	Geothermal Working Area Location	Licence Holder	Developer	Power Plant	Turbine Capacity (MW)	Installed Capacity (MW)
1	Sibayak – Sinabung, North Sumatera	PT Pertamina Geothermal Energy ("PGE")	PGE	Sibayak	1 x 10 2	12
2	Cibeureum – Parabakti, West Java	PGE	JOC - Star Energy Geothermal Salak, Ltd. (formerly Chevron Geothermal Salak, Ltd.)	Salak	3 x 60 3 x 65.67	377
3	Pangalengan, West Java	PGE	JOC – Star Energy Geothermal Wayang Windu, Ltd	Wayang Windu	1 x 110 1 x 117	227
	Pangalengan, West Java	PT Geo Dipa Energi ("GDE")	GDE	Patuha	1 x 55	55
4	Kamojang – Darajat, West Java	PGE	PGE	Kamojang	1 x 30 2 x 55 1 x 60 1 x 35	235
	Kamojang – Darajat, West Java	PGE	JOC – Star Energy Geothermal Darajat II (Formerly Chevron Geothermal Indonesia, Ltd.)	Darajat	1 x 55 1 x 94 1 x 121	270
5	Dataran Tinggi Dieng, Central Java	GDE	GDE	Dieng	1 x 60	60
6	Lahendong – Tompaso, North Sulawesi	PGE	PGE	Lahendong	6 x 20	120
7	Way Panas, Lampung	PGE	PGE	Ulubelu	4 x 55	220
8	Ulumbu, NTT	PT PLN Geothermal ("PLN G")	PLN G	Ulumbu	4 x 2.5	10
9	Mataloko, NTT	PLN G	PLN G	Mataloko	1 x 2.5	2.5
10	Sibual-buali, North Sumatera	PGE	Sarulla Operation Ltd	Sarulla	1 x 110	110
					Total Installed Capacity (MW)	**1,698.5**

Source: DGNREEC, "Doing Business in Geothermal", August 2017, p. 27, PwC Analysis

As of June 2017, there were 70 geothermal working areas stipulated by the Government, comprised of 19 existing working areas identified prior to the issuance of Law No. 27/2003 on Geothermal, 46 working areas stipulated after the issuance of Law No. 27/2003 and five working areas identified after the issuance of Law No. 21/2014 (see Figure 5.3).

Figure 5.3 – The status of the 70 geothermal working areas as of June 2017



Notes: Of the 1,510 MW working areas to be tendered, we note that it was reported that several working areas would be assigned to PLN under the direct appointment mechanism (see Table 5.4)

Source: DGNREEC, "Doing Business in Geothermal", August 2017; Investor Daily, 12 September 2017; PwC Analysis

In February 2017, the Government issued a new regulation on geothermal development i.e. GR No. 7/2017 on Geothermal for Indirect Utilisation. To expedite the development of geothermal energy in open areas that have not yet been stipulated as working areas, the Government shall conduct a Preliminary Survey and Exploration by itself or offer either a Preliminary Geothermal Survey Assignment (*Penugasan Survey Pendahuluan* – "PSP") to a Public Service Agency (*Badan Layanan Umum* – "BLU")[79], research institute, university, or a Preliminary Geothermal Survey and Exploration Assignment (*Penugasan Survey Pendahuluan dan Eksplorasi* – "PSPE") to Business Entities. In addition, in June 2017, the MoEMR released two further new regulations, i.e. MoEMR Regulation No. 36/2017 on Procedures for Geothermal Preliminary Survey Assignment ("PSP") as well as Geothermal Preliminary Assignment and Exploration Assignment ("PSPE") and MoEMR Regulation No. 37/2017 on Geothermal Working Areas for Indirect Utilisation. Both regulations are implementing regulations of GR No. 7/2017.

79 *A BLU is an entity under a Government Agency that also has the role to provide and sell certain products and/or services to citizens. There are several BLUs under MoEMR: LEMIGAS, P3EBTKE, Tekmira, etc.*

A PSP is assigned by the Minister of Energy and Mineral Resources to research institutes, universities or BLUs. In the course of implementation, a PSP is limited to a preliminary survey without well drilling. The period to conduct the PSP is limited to one year with an option to extend by up to six months.

On the other hand, the Minister of Energy and Mineral Resources shall issue a PSPE permit to a Business Entity (IPP) interested in geothermal development to conduct a survey in an open area. The period of a PSPE is a maximum of 3 (three) years and may be extended for a maximum of 2 (two) times, each time for a period of 1 (one) year. In a PSPE, a Business Entity is required to conduct the geothermal preliminary survey (geological, geochemical and geophysical). In addition, an assigned PSPE Business Entity must also perform/drill at least one exploration well in order to obtain an estimation of geothermal reserves. If two or more Business Entities are interested in conducting a PSPE, the Minister of Energy and Mineral Resources will choose only one of those Business Entities, based on a contest mechanism.

A Business Entity that is assigned to conduct a PSPE reserves the right to obtain fiscal facilities, and has an obligation to place an Exploration Commitment amounted to USD 5 million or USD 10 million (depending on capacity plan development). It is expected that either a PSP or PSPE will be able to convert open areas into working areas that can be developed. Specifically for a Business Entity assigned a PSPE, they will have privileges as first rank order when entering the tender process for the assigned working area.[80]

5.3.1 Recent Trends in Geothermal Development in Indonesia

Under its five-year plan for 2015-2019,[81] the Government indicated that it would like to achieve a target of 3,200 MW of installed capacity of geothermal power plants by 2019. However, according to the 2017 RUPTL, PLN indicated that by 2019 Indonesia will only achieve 2,264 MW of installed geothermal capacity.

PLN also planned that by 2026 Indonesia would like to add an additional 6,290 MW in installed geothermal capacity.[82] The total installed capacity will be 7,699 MW at the end of 2026 if all of the 2017 RUPTL projects go as planned. The projects are listed in Table 5.3 as follows:

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80 *Under GR No. 7/2017, there is no longer a "right to match" scheme for tenders. All working area tender participants will have to submit a proposal that consists of analysis and business commitments. The Tender Committee will evaluate all proposals, but a Business Entity that performs PSPE will have some privileges in the tender process (see Section 5.3.2 - The 2014 Geothermal Law). "Right to match" is still available only for a Business Entity that has been assigned a PSP subject to the previous regulation (transitional provision – Article 123-126 of GR No. 7/2017)*

81 *RENSTRA KESDM 2015-2019, p. 91*

82 *However, the summary of the list of geothermal projects in the 2017 RUPTL indicates only 6,110 MW*

Table. 5.3 – List of geothermal project development plans for the period 2017-2026

Name	Power System Region	Project Developers	Plan of COD and Installed Capacity									
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Sarulla I	Sumbagut	IPP	220	110								
Sorik Marapi						80						160
Seulawah Agam										55	55	
Sipoholon Ria-Ria									20			
Sarulla II											110	
Simbolon Samosir											110	
Lumut Balai	Sumbagselteng	IPP		55	55			55		55		
Ulubelu 3,4			55									
Muara Laboh					80					140		
Rantau Dedap						86						134
Rajabasa								110			110	
Suoh Sekincau											220	
Way Ratai								55				
Danau Ranau								40				
Bonjol											60	
Hululais					55		55					
Sungai Penuh							55	55				
PLTP Tersebar (SBU)	Sumbagut	Unallocated									165	
PLTP Tersebar (SBST)	Sumbagselteng	Unallocated				10	30	20	145	60	415	
Tangkuban Parahu-Ciater	Jawa-Bali	PLN							60			
Patuha		IPP						55	55			
Kamojang-5												
Karaha Bodas			30						55			
Ijen							55	55				
Iyang Argopuro											55	
Wilis/Ngebel							55			110		
Cibuni							10					
Cisolok-Cisukarame											50	
Ungaran										55		
Wayang Windu								110		110		
Dieng							55	55				
Tampomas											45	
Baturaden									220			
Guci									55			
Rawa Dano							110					

Name	Power System Region	Project Developers	Plan of COD and Installed Capacity									
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Umbul Telomoyo											55	
Gunung Ciremai											110	
Gunung Endut											40	
Bedugul						10					55	
Gunung Galunggung											110	
Gunung Lawu								55		55		
Arjuno Welirang											185	
Gede Pangrango											85	
Songgoriti											35	
Gunung Wilis											20	
Gunung Pandan											60	
Candradimuka										40		
Dieng											55	
Dieng Binary								10				
Dieng Small-Scale					10							
Mangunan-Wanayasa											40	
Masigit											20	
Lahendong 7	Sulbagut	IPP				20						
Lahendong 8							20					
Lahendong Small-Scale					5							
Lahendong Small-Scale							5					
Kotamobagu		Unallocated									80	
Bora Bulu	Sulbagsel	Unallocated									40	
Marana											20	
Laenia											20	
Sembalun	Lombok	PLN								20		
PLTP Unnamed - Additional	Maluku	IPP & PLN				30					45	
Total			**305**	**165**	**205**	**236**	**450**	**675**	**610**	**700**	**2,470**	**294**

Source: 2017 RUPTL, PwC Analysis

In 2015, Kamojang 5 – 35 MW came onstream. Additionally, in July 2016, the Ulubelu Unit 3 – 55 MW entered the operations stage. Following this, in December 2016 the Lahendong Geothermal Project Unit 5 and 6 – 2 x 20 MW also reached COD.

In March 2017, Sarulla Geothermal Project Unit-I in Sibual-Buali, North Sumatera reached the COD for the first 110 MW of capacity. The project is being developed by a consortium of investors from Japan, the US and Indonesia. The Sarulla Geothermal Project was initiated in 1990. It achieved financial close in 2014 and is the first greenfield Indonesian geothermal project financed on a limited recourse basis since the Wayang Windu project in 1997. Overall, the Sarulla Geothermal Project is designed to have 330 MW capacity. Another 110 MW of Sarulla Unit-II is expected to be operated by September 2017 which will be followed by 110 MW of Sarulla Unit-III in May 2018.

Additionally, Pertamina was reported to have successfully sped up the development of Ulubelu Geothermal Project Unit 4 -55 MW, so that the project reached COD on 30 March 2017.[83] There are other new geothermal power projects which are expected to reach COD in 2017 i.e. the Karaha Bodas Unit 1 – 30 MW and Sorik Marapi 20 MW.[84]

However, despite having ambitious targets and achieving encouraging results, the Government has continued to struggle in attracting investment in geothermal exploration. In 2015-2016 the MoEMR failed to find participants in several geothermal auctions (i.e. the Danau Ranau, Marana, Gunung Galunggung, Gunung Wilis, and Gunung Ciremai working areas) due to no company being interested in participating in the tender.[85]

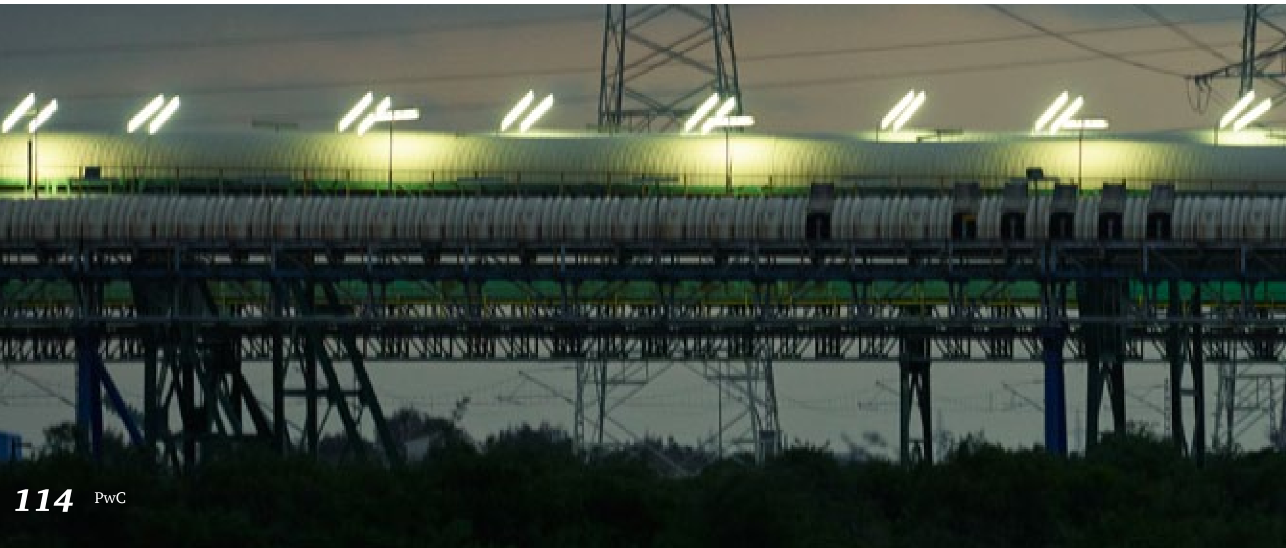
Apart from new CODs, in 2016 there was a secondary market transaction that had a significant impact on the geothermal market in Indonesia. In April 2016, Chevron announced an open bidding process to sell its assets and stakes in the Salak and Darajat Geothermal Projects, which was won by Star Energy. This corporate action made Star Energy the largest geothermal company in Indonesia.

There are about 30 working areas to be tendered in 2017 or at a later date, totaling 1,510 MW (see Table 5.4).

83 *http://www.pertamina.com/news-room/siaran-pers/pltp-ulubelu-4-beroperasi,-panas-bumi-sumbang-25-kebutuhan-listrik-lampung/*
84 *https://m.detik.com/finance/energi/d-3558904/ada-4-pembangkit-listrik-baru-dari-harta-karun-energi-tahun-ini*
85 *LAKIN EBTKE 2016, p. 68*

Table 5.4 – List of geothermal working area tenders

Working Area	Province	Capacity Development Plan (MW)	Estimated Investment (USD)	Status
Bora Pulu	Central Sulawesi	40	160 million	Will be tendered in 2017
Danau Ranau	South Sumatera, Lampung	40	160 million	Open**
Graho Nyabu	Jambi	110	440 million	Open; the first stage of the tender was held in late 2016
Gunung Ciremai	West Java	110	440 million	Open**
Gunung Endut	Banten	40	160 million	Open
Gunung Galunggung	West Java	110	440 million	Open**
Gunung Gede Pangrango	West Java	55	220 million	Open
Gunung Geuredong	NAD	55	220 million	Open*
Gunung Hamiding	North Maluku	20	80 million	Open
Gunung Pandan	East Java	40	160 million	Open
Gunung Wilis	East Java	20	80 million	Open**
Hu'u Daha	NTB	20	80 million	Open
Iyang Argopuro	East Java	55	220 million	Open
Jailolo	North Maluku	20	80 million	Open***
Kepahiang	Bengkulu	110	440 million	Open
Kotamobagu	North Sulawesi	80	320 million	Open
Laenia	SE Sulawesi	20	80 million	Open*
Marana	Central Sulawesi	20	80 million	Open**
Sekincau	Lampung	220	880 million	Open*
Sembalun	NTB	20	80 million	Open
Simbolon Samosir	North Sumatera	110	440 million	Open
Songgoriti	East Java	20	80 million	Open
Suwawa	Gorontalo	20	80 million	Open
Tanjung Sakti	South Sumatera	55	220 million	Open*



Working Area	Province	Capacity Development Plan (MW)	Estimated Investment (USD)	Status
Telaga Ranu	North Maluku	5	20 million	Open*
Wapsalit	Maluku	N/A	N/A	Open
Oka Ile Ange	NTT	10	40 million	Will be tendered in 2017****
Bonjol	West Sumatera	60	240 million	Will be tendered in 2017
Gunung Sirung	NTT	5	20 million	Will be tendered in 2017****
Sipoholon Ria-ria	North Sumatera	20	80 million	Open****

Sources: DGNREEC, "Doing Business in Geothermal", August 2017; MoEMR[86]; Investor Daily, 14 September 2017; PwC Analysis

* *Working areas stipulated based on PSP (GR No. 59/2007 with several amendments) and prior to the issuance of GR No. 7/2017, when they are tendered, the Business Entity who performed the PSP has the "right to match".*

** *Tender failed in 2016 – no participants, option to re-tender.*

*** *The Geothermal Licence (IPB) of Jailolo was terminated at the end of 2016, option for re-tender.*

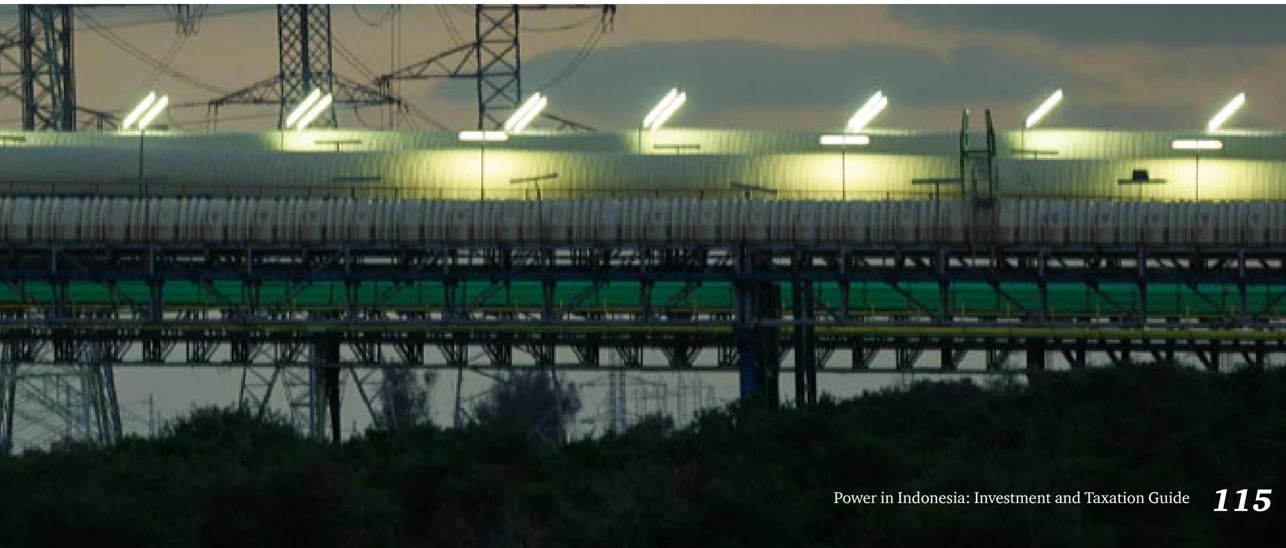
**** *On 14 September 2017, it was reported that geothermal areas in Oka Ile Ange, Gunung Sirung and Sipoholon Ria-ria are assigned to PLN.*

On 4 April 2017, the MoEMR reportedly would like to open the first geothermal auctions in 2017 for the following five geothermal working areas:

- Gunung Hamiding in North Maluku with a capacity development plan of 20 MW, and COD targeted for 2024;
- Simbolon Samosir in North Sumatera, capacity development plan 110 MW, and COD targeted for 2024. The first stage of the tender of Simbolon Samosir was won by Ormat Consortium;
- Oka Ile Ange in East Nusa Tenggara, capacity development plan 10 MW, COD target 2024;
- Bora Pulu in Central Sulawesi, capacity development plan 40 MW, COD target 2025; and
- Gunung Sirung in East Nusa Tenggara, capacity development plan 5 MW, COD target 2025.

Since 2016 we have seen many geothermal projects assigned to SOEs. This trend will likely continue.

86 *http://ebtke.esdm.go.id/post/2017/04/18/1629/percepat.pengembangan.panas.bumi.pemerintah.luncurkan.5.upaya.terobosan*



5.3.2 The 2014 Geothermal Law

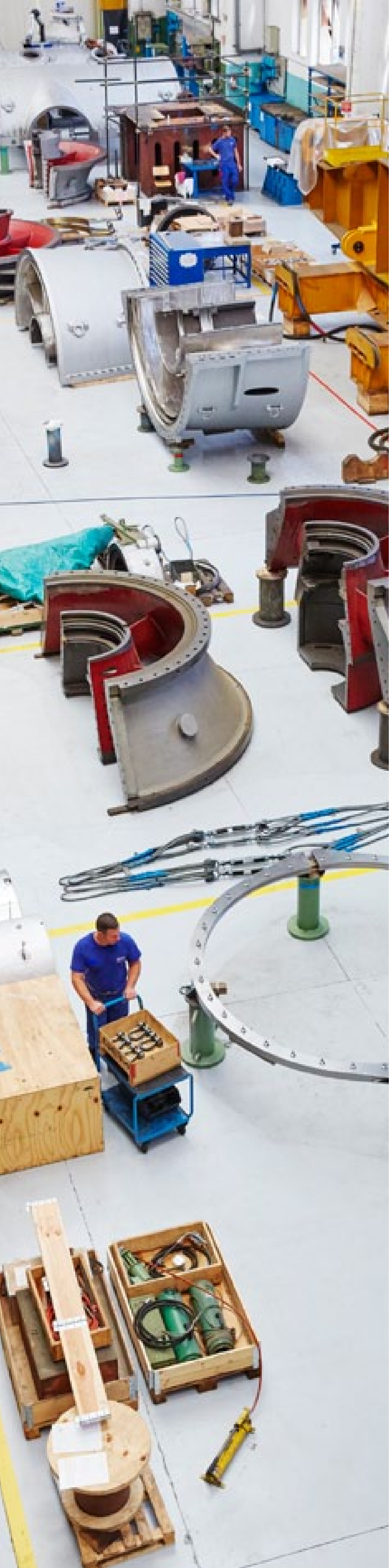
Law No. 27/2003 (the "2003 Geothermal Law") granted the private sector control over geothermal resources and the sale of base load electricity to PLN. The 2003 Geothermal Law took over from the integrated geothermal and power arrangements covered under the former Joint Operations Contract framework. The 2003 Geothermal Law passed the authority to grant geothermal permits (IUP - Geothermal) to Regional Governments with input from the MoEMR. The permits were granted through competitive tendering.

In the past there were arguably inconsistencies between the tendering process at the regional level and the subsequent price negotiations under the PPAs with PLN. This may be because PLN is centrally controlled, while the IUP - Geothermal may be granted by the Central, Provincial or Local Government depending upon the location of the work area and whether it crosses provincial or local boundaries. This means that investors were effectively negotiating with two parties.

To expedite the utilisation of geothermal, on 17 September 2014, the Government issued Law No. 21/2014 on Geothermal (the "2014 Geothermal Law"). Under the 2014 Geothermal Law, geothermal operations are classified as being either for direct use, for example hot springs, or indirect use, that is for electricity generation. Only the Central Government can issue a Geothermal Licence or IPB and conduct a tender for geothermal working areas. Direct-use licences can be issued by the Central or Regional Governments.

One of the biggest changes in the 2014 Geothermal Law is that geothermal activities are no longer considered to be mining activities. As a corollary of this, the law specifically allows geothermal activities to be conducted in production, protected and conservation forest areas, where a significant proportion of Indonesia's geothermal resources are found (an estimated 42%). Previously, as geothermal activities were considered mining, working areas were restricted under the Forestry Law.

The 2014 Geothermal Law requires Geothermal Permit holders to provide a "production bonus" to the Regional Government covering the permit holder's working area, which will be a specified percentage of the gross revenue from the date of commercial operations of the first unit. The amounts and procedures for bonus payments are regulated under GR No. 28/2016.



5.3.3 Working Area Tenders since GR No. 7/2017

The granting of a Geothermal Licence or IPB for a geothermal working area is carried out through a tender consisting of two stages. In the first stage, the tender committee shall evaluate the qualification of the Business Entity based on its administrative criteria, financial strength and performance. The second stage of the tender evaluates the "geothermal development proposal" and exploration commitment of the Business Entity, the results of which are later used by the Minister to choose the tender winner and grant the IPB. The IPB Licence Holder has to conduct exploration well drilling to demonstrate the proven reserves. The exploration is further followed by exploitation and production activities for a maximum period of 30 years.

For the working areas stipulated based on PSPE, GR No. 7/2017 explains that a Business Entity which has carried out a PSPE and is interested in moving on to detailed exploration and development, can compete in a two stage tender process to obtain an IPB for a geothermal working area. In this case, the MoEMR will open a tender only for the assigned Business Entity and a state-owned enterprise working on geothermal (as a competitor in the tender). A Business Entity that has perfomed a PSPE and participated in the assigned working area tender shall be given privileges as the first ranked participant (prioritised) in the tender, while any state-owned enterprise shall be second ranked.

In order to determine the tender winner, the tender committee will assess the geothermal development proposal submitted by the tender participants which should include:

a) A review of Geothermal Data and Information to estimate the feasibility of the Working Area for Geothermal operations;
b) The exploration and exploitation implementation strategy, completion targets, and cost budget plan; and
c) The commitment regarding the COD.

The tender winner is determined by the Minister of Energy and Mineral Resources. Within four months after being declared the winner, such Business Entity has to pay the base price for the working area data as a Non-Tax State Revenue and put in place the Exploration Commitment.

The Minister of Energy and Mineral Resources also reserves the right to a conduct direct appointments, even of a private Business Entity. This is allowable in the event that there is still only one participant even after the tender is repeated.

5.3.4 Challenges for Geothermal Development

Geothermal investment is characterised by a long lead time for commercial operations, and project financing is only commonly available for the last few years of this process. This means that a typical geothermal project will require significant investor contributions in the form of upfront equity. To assist with this, the GoI established the Geothermal Fund in the 2011 State Budget and had allocated IDR 3 trillion (equivalent to USD 250 million) by the end of 2013.

The Fund's aim was to make geothermal projects financially viable and bankable by providing high-quality information on greenfield geothermal sites verified by reputable international institutions to investors during the tendering process for new work areas. This in turn should mitigate the exploration risks of developers.

Pursuant to the revised 2015 State Budget, responsibility for the management of the Fund was transferred to PT SMI (see Chapter 1 and 3 for details of PT SMI) from Pusat Investasi Pemerintah ("PIP"). Following the transfer of responsibility to PT SMI, the MoF has given policy directives stating that the current so-called Geothermal Support Fund ("GSF") should now be able to finance both the exploration and exploitation phases of geothermal projects.[87] It has also been stipulated that PT SMI should leverage the funds with other sources of funds from the private sector or international multilateral agencies. However, until 2017 no funds were able to be disbursed from the Fund due to the inability of the MoF and PIP/SMI to decide upon an operational model.

In order to expedite the implementation and disbursement of the GSF, the Finance Minister Sri Mulyani issued MoF Regulation No. 62/2017 on the Fund Management and Infrastructure Financing for Geothermal. Based on the MoF Regulation, the Government through SMI provides funding for geothermal sector infrastructure. The funds may be used for the following activities: (a) lending; (b) equity participation; and/or (c) the supply of geothermal data and information (exploration drilling).

PT SMI will implement lending and equity participation activities under the corporate business framework of PT SMI. Meanwhile, PT SMI will provide geothermal data and information acting as a Government representative on the basis of a special assignment from the Minister of Finance. Especially for exploration activities, the provision of funds is expected to significantly reduce risks for developers, thereby attracting higher participation from developers and banks in financing and developing geothermal projects. Additionally, PT SMI will apply a revolving fund scheme, as well as conducting exploration drilling in the geothermal working area by appointing a third party. If the working area has been auctioned, the auction winner shall reimburse the expenses so that the cost may be used to finance drilling in other areas.

In addition to the GSF allocated from the state budget (IDR 3 trillion), the Government also proposed financial support to the World Bank for the development of geothermal infrastructure under the Geothermal Energy Upstream Development Project ("GEUDP"). Similarly to the GSF, the GEUDP also applies a revolving fund scheme.[88]

In February 2017, the GEUDP proposal was approved by the World Bank, which then disbursed a grant worth USD 55.25 million. About USD 49 million of the grant was allocated from the Clean Technology Fund ("CTF") scheme for the purpose of financing the exploration activities, while

87 *Brahmantio Isdijoso (Directorate of Sovereign Risk Management, Directorate of Budget Financing and Risk Management, MoF), "Government Supports for Geothermal Energy Development", Presentation at Bali Clean Energy Forum, February 2016*

88 *www.ebtke.esdm.go.id/post/2017/04/18/1629/percepat.pengembangan.panas.bumi.pemerintah.luncurkan.5.upaya.terobosan*

the remaining USD 6.25 million was allocated from the Global Environmental Facility ("GEF") scheme for the purpose of supporting technical assistance and increasing capacity related to geothermal exploration, including safeguarding due diligence.[89]

The Government has decided that the GSF and the GEUDP funding schemes will be available for several geothermal working areas: Waisano and Inelika in East Nusa Tenggara and Jailolo in North Maluku.[90]

Additionally, specific challenges for investors in the geothermal space have included the following:
a) Difficulty in obtaining land permits, particularly where the resources are in a forest area;
b) Historical issues with inadequate tariffs, with an imbalance between upstream exploration risks and the utility-style economic returns, noting that the ultimate tariff depends on what level of capacity is determined as commercially feasible after exploration is finished;
c) Opposition from local communities;
d) The need to finance significant upfront expenditure (with equity), for example preliminary surveys, exploration and test drilling expenditure;
e) The poor quality of data provided on working areas prior to tender rounds, which in turn has increased the exploration risk of developers;
f) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, which makes for difficult access and logistics at some sites, which may require the developer to fund infrastructure (e.g. access roads); and
g) Long lead times from exploration to production of seven to eight years.

Fundamentally, under the Indonesian model of geothermal development, the developer shoulders the exploration risk and hence the obligation to fund the exploration phase. While this may be tolerable for larger investors with strong balance sheets who are pursuing large projects, the approach is less likely to incentivise the development of smaller fields (below 30 MW), such as those in Eastern Indonesia. The alternative approach, used in certain countries, is to assume part of the upfront exploration risk by providing support for this phase of activity by way of drilling insurance, direct grants, or the use of revolving funds, in relation to which the Government has recently released a new policy.

With regard to the purchase tariff for geothermal, according to MoEMR Regulation No. 50/2017 which revoked MoEMR Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017) on Utilisation of Renewable Energy Resources for Electricity, the purchase tariffs for renewable energy projects including geothermal currently follow the Regional BPP as benchmarks or is based on B2B negotiations. Please see *Section 5.9 - New tariff Stipulation for Renewable Energy* for further explanation.

It should also be noted that, as set by GR No. 7/2017 and MoEMR Regulation No. 50/2017, the determination and agreement (with PLN) of tariffs for geothermal projects can be conducted only for projects that already have "proven reserves" after exploration. However, at the same time, this provision will further raise the risks for geothermal investment considering the following factors:
a) Geothermal projects have long lead times;
b) BPP changes annually;
c) This regulation will lead investors to spend their capital expenditure ("CAPEX") without knowing any certain tariff and commitment of PLN to purchase the electricity.

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89 *www.worldbank.org/en/news/press-release/2017/02/09/world-bank-approves-5525-million-grant-to-help-develop-geothermal-power-in-indonesia*
90 *"Tugaskan BUMN Garap Panas Bumi", Jawa Pos, 20 April 2017*

It is likely that investors can negotiate a Heads of Agreement ("HoA"), as a preliminary substitute for a PPA, with PLN prior to exploration. However, a HoA is not a binding contract like a PPA. Hence, a tariff that is subject to change later may result in uncertainty and a high risk profile for geothermal development especially for greenfield projects.

5.4 Hydropower

Hydropower uses the energy from falling or flowing water to turn a water turbine and generate electricity. This can be a natural flow from a river ("run-of-river" plants) or an artificial flow resulting from a dam/reservoir or an irrigation canal. Hydropower is considered as the most robust and mature of the renewable technologies. Up to 2016, Indonesia had an installed hydroelectric capacity of around 5,332 MW (including off-grid) out of roughly 75 GW of potential capacity (based on a hydropower potential study conducted in 1983) (see Figure 5.4), making it the most utilised source of renewable energy. Potential hydropower sites are spread out across the country, with substantial potential for large-scale projects in the middle and eastern part of Indonesia, such as Kalimantan and Papua.

Figure 5.4 – Hydropower potential capacity in selected regions of Indonesia

Source: RENSTRA DITJEN EBTKE 2015-2019 , p. 36

A Master Plan Study for Hydro Power Development in Indonesia conducted by Nippon Koei in 2011 found total hydropower potential of significantly less than 75 GW, at only 26,321 MW. Based on economic, social and environmental considerations, realistically only 8 GW of additional hydropower is likely to be built in addition to the current existing power plants of 10,294 MW (projects in operation, in construction or planned). The prioritised a list of candidate hydropower projects is on Table 5.5 as follows:[91]

91 *2017 RUPTL, p. III-7*

Table 5.5 – List of priority candidate hydropower projects

No	Name	Type	Province	Cap. (MW)
1	Peusangan 1-2	ROR	Aceh	86
2	Jambo Papeun-3	ROR	Aceh	25
3	Kluet-1	ROR	Aceh	41
4	Muelaboh-5	ROR	Aceh	43
5	Peusangan-4	ROR	Aceh	31
6	Kluet-3	ROR	Aceh	24
7	Sibubung-1	ROR	Aceh	32
8	Seunangan-3	RES	Aceh	31
9	Teunom-1	RES	Aceh	24
10	Woyla-2	RES	Aceh	242
11	Ramasan-1	RES	Aceh	119
12	Teripa-4	RES	Aceh	185
13	Teunom-3	RES	Aceh	102
14	Tampur-1	RES	Aceh	330
15	Teunom-2	RES	Aceh	230
16	Padang Guci-2	ROR	Bengkulu	21
17	Warsamson	RES	Papua	49
18	Jatigede	RES	West Java	175
19	Upper Cisokan-PS	PST	West Java	1,000
20	Matenggeng	PST	West Java	887
21	Merangin-2	ROR	Jambi	350
22	Merangin-5	RES	Jambi	24
23	Maung	RES	Central Java	360
24	Kalikonto-2	RES	East Java	62
25	Karangkates Ext.	RES	East Java	100
26	Grindulu PS-3	PST	East Java	1,000
27	Kalikonto-PS	PST	East Java	1,000
28	Pinoh	RES	West Kalimantan	198
29	Kelai-2	RES	East Kalimantan	168
30	Besai-2	ROR	Lampung	44
31	Semung-3	ROR	Lampung	21
32	Isal-2	RES	Maluku	60
33	Tina	ROR	Maluku	12
34	Tala	RES	Maluku	54
35	Wai Rantjang	ROR	NTT	11
36	Bakaru (2nd)	ROR	South Sulawesi	126
37	Poko	RES	South Sulawesi	233
38	Masuni	RES	South Sulawesi	400

No	Name	Type	Province	Cap. (MW)
39	Mong	RES	South Sulawesi	256
40	Batu	RES	South Sulawesi	271
41	Poso-2	ROR	Central Sulawesi	133
42	Lariang-6	RES	Central Sulawesi	209
43	Konaweha-3	RES	Central Sulawesi	24
44	Lasolo-4	RES	Central Sulawesi	100
45	Watunohu-1	ROR	South-East Sulawesi	57
46	Tamboli	ROR	South-East Sulawesi	26
47	Sawangan	ROR	North Sulawesi	16
48	Poigar-3	ROR	North Sulawesi	14
49	Masang-2	ROR	West Sumatera	40
50	Sinawar-2	ROR	West Sumatera	26
51	Sinamar-1	ROR	West Sumatera	37
52	Anai-1	ROR	West Sumatera	19
53	Batang Hari-4	RES	West Sumatera	216
54	Kuantan-2	RES	West Sumatera	272
55	Endiklat-2	ROR	South Sumatera	22
56	Asahan 3	ROR	North Sumatera	174
57	Asahan 4-5	RES	North Sumatera	60
58	Simanggo-2	ROR	North Sumatera	59
59	Kumbih-3	ROR	North Sumatera	42
60	Sibundong-4	ROR	North Sumatera	32
61	Bila-2	ROR	North Sumatera	42
62	Raisan-1	ROR	North Sumatera	26
63	Toru-2	ROR	North Sumatera	34
64	Ordi-5	ROR	North Sumatera	27
65	Ordi-3	ROR	North Sumatera	18
66	Siria	ROR	North Sumatera	17
67	Lake Toba	PST	North Sumatera	400
68	Toru-3	RES	North Sumatera	228
69	Lawe Mamas	ROR	Aceh	50
70	Simpang Aur	ROR	Bengkulu	29
71	Rajamandala	ROR	West Java	58
72	Cibareno-1	ROR	West Java	18
73	Mala-2	ROR	Maluku	30
74	Malea	ROR	South Sulawesi	182
75	Bonto Batu	ROR	South Sulawesi	100
76	Karama	RES	South Sulawesi	800
77	Poso-1	ROR	Central Sulawesi	204
78	Gumanti-1	ROR	West Sumatera	16
79	Wampu	ROR	North Sumatera	84

RES: Reservoir, ROR: Run-of-River, PST: Pump Storage
Source: 2017 RUPTL, p. III-7

5.4.1 Large-scale Hydropower

As part of the 35 GW programme and PLN regular programme, several IPP projects are under construction. These are the IPP Batang Toru (510 MW), Hasang (39 MW), Peusangan 1-2 (86MW), Semangka (2 x 28 MW), Bonto Batu (100 MW) and Malea (2 x 45 MW). However, other projects, i.e. Karangkates and Kesamben (137 MW)[92] and Merangin (350 MW)[93] were reportedly delayed. In addition, on 8 September 2017, PLN signed a PPA for three IPP projects of Buttu Batu (2 x 100 MW) in South Sulawesi with a tariff of USD 7.63 cents/kWh, Air Putih (21 MW) in Bengkulu (USD 7.8 cents/kWh), and Pakkat (18 MW) in North Sumatera (USD 8.6 cents/kWh), based on MoEMR Regulation No. 50/2017.[94]

The 35 GW Programme also lists two PLN hydro projects at the construction stage, which are the 4 x 260 MW Upper Cisokan pumped-storage plant in West Java and Asahan 3 (2 x 87 MW). However, on 2 May 2017, the World Bank cancelled funds worth USD 596 million for Upper Cisokan pumped-storage plant and will not provide any further financing Upper Cisokan project, forcing the project to be restructured.[95]

There are also construction projects under PLN's regular programme, namely Masang 2 (55 MW) and Jatigede (2 x 55 MW). In August 2015, the Government started the first inundation for Jatigede Dam which later will be augmented with a 2 x 55 MW hydropower system. The Jatigede project has been delayed for more than 50 years, since it was planned in 1963, due to social disputes over land compensation and the resettlement of local people. Additionally, there are nine further IPP hydro projects to be allocated by direct appointment totalling 413 MW under the 35 GW Programme. In 2016, the IPP Wampu hydropower project (45 MW) achieved COD.

The Ministry of Public Works (the "MoPW") reported their intention to further encourage the private sector to utilise existing dams for hydropower. This is planned for around 18 dams operated by the MoPW, including the Jatigede (West Java), Lodoyo (East Java), Berjaya (Riau), and Jatibarang (Central Java) dams. Together with PLN, the MoPW would like to calculate the potential of electricity generation from the 18 dams. In May 2017, the MoPW issued MoPW Regulation No. 9/PRT/M/2017 concerning the procedures for the cooperation of business entities in the leasing of dams for the acceleration of power projects (including large and small-scale hydropower as well as floating Solar PV).

Specific challenges for large-scale hydropower include the following:

a) The need for substantial amounts of land, of which the ownership may be unclear or subject to overlapping claims;
b) Overlapping permits (for example where small hydro permits have been issued on a section of a larger watercourse) and lack of data on historical water permits issuance by sub-national Governments;
c) Environmental, resettlement, and flora and fauna issues; and
d) Permits for forest use.

92 *http://properti.kompas.com/read/2017/06/22/214559921/13.proyek.baru.bakal.masuk.prioritas.kppip*
93 *http://jambi.tribunnews.com/2016/09/27/anggota-dprd-heran-tak-ada-laporan-pembangunan-plta-batang-merangin-yang-terhenti-sejak-2015*
94 *http://katadata.co.id/berita/2017/09/08/pln-beli-listrik-291-mw-dari-pembangkit-energi-baru-terbarukan*
95 *World Bank. World Bank Implementation Status & Results Report on Upper Cisokan PST Project (P112158), 2017*

On 8 August 2017, the MoEMR issued Regulation No. 50/2017 which revoked MoEMR Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017) on the Utilisation of Renewable Energy Resources for Electricity to set new tariffs for renewable energy projects. Please see *Section 5.9 - New Tariff Stipulation for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

5.4.2 Small-scale Hydropower

Small hydropower ("SHP") plants have a capacity of less than 10 MW and utilise a run-of-river systems. In most cases, SHP plants (especially micro hydropower, with less than 100 kW capacity) are used for off-grid or rural electrification in Indonesia. However, the Government supports the development of SHPs by regulating the purchase tariff (feed-in tariff) to the point where SHP plants become attractive renewable energy projects for investors.[96] SHP uses mature technology compared to some other small-scale renewables, resulting in a relatively cheap investment cost per MW.

To date, there are 323 MW of SHPs (both private and owned by PLN) connected to the grid that are in operation and are expected to contribute 1% of national electricity generation.[97] Recently, in May 2017, the state-owned construction industry company PT Brantas Abipraya (Persero) officially launched the commercial operation of a 3.2 MW Padang Guci SHP located in Bengkulu. Meanwhile, in Sumatera, PLN also signed a PPA with PT Dwi Jaya Makmur for an SHP project of PLTM Semendo 9 MW and 23 Memoranda of Understanding (MoUs) for SHP project developments in Sumatera totaling 150 MW.[98]

Further, on 2 August 2017 and 8 September 2017, PLN signed PPAs for 50 SHP projects (some of the 23 SHP projects that signed MoUs mentioned above also signed PPAs on that day) totaling 292 MW. The applicable tariffs for such projects signed on 2 August 2017 were based on MoEMR Regulation No. 12/2017 (the MoUs and PPAs were signed before the issuance of MoEMR Regulation No. 43/2017) while those projects signed on 8 September followed MoEMR Regulation No. 50/2017 (see Table 5.6 for further detail of projects).

Table 5.6 – SHP projects that signed a PPA on 2 August 2017 and 8 September 2017

No.	SHP Project	Capacity (MW)	IPP/Developer	Tariffs	
				cUSD/kWh	IDR/kWh
1	Ordi Hulu, North Sumatera	10.00	PT Sumatera Energi Lestari	7.89	1,050
2	Aek Situmandi, North Sumatera	7.00	PT Bukit Cahaya Powerindo	7.89	1,050
3	Aek Sigeaon, North Sumatera	3.00	PT Gading Energy Prima	7.89	1,050
4	Sisira, North Sumatera	9.80	PT Energy Alam Sentosa	7.89	1,050
5	Rabi Jonggor, West Sumatera	4.50	PT Mega Energi Karyatama	7.89	1,050
6	Endiklat, South Sumatera	7.00	PT Prasetia Bajra Prima	6.68	889
7	Babatan, Lampung	5.00	PT Mega Energi Karyatama	6.68	889
8	Lawang Agung, South Sumatera	2.50	PT Galenium Aksata Energi	6.68	889

96 *http://ebtke.esdm.go.id/post/2016/01/08/1077/175.permohonan.pembangunan.pltmh.dengan.investasi.rp1094.triliun*
97 *Insight RUPTL 2017-2026, p. 7*
98 *http://listrikindonesia.com/ini_perusahaan_pengembang_ebt_yang_telah_mou_dengan_pln_2583.htm*

No.	SHP Project	Capacity (MW)	IPP/Developer	Tariffs	
				cUSD/ kWh	IDR/ kWh
9	Karyanyata, South Sumatera	4.00	PT Mega Energi Karyatama	6.68	889
10	Sarolangun, Jambi	1.00	PT Suwarnadwipa Umun Energi	6.68	889
11	Klingi, South Sumatera	2.70	PT Multi Energi Dinamika	6.68	889
12	Klaai, Bengkulu	2.60	PT Klaai Dendan Lestari	6.68	889
13	Simpang, South Sumatera	3.10	PT Pat Petulai Energi	6.68	889
14	Tunggang, Bengkulu	10.00	PT Mega Hydro Energi	6.68	889
15	Padang Guci 2, Bengkulu	7.00	PT Brantas Hidro Energi	6.68	889
16	Puguk, Bengkulu	5.25	PT Malaka Guna Energi	6.60	878
17	Simonggo, North Sumatera	10.00	PT Syailendra Utama Energi	7.89	1,050
18	Sungai Buaya, North Sumatera	3.00	PT Landasan Tata Laksana	7.89	1,050
19	Bingai, North Sumatera	7.00	PT Global Green Energy	7.89	1,050
20	Aek Pungga, North Sumatera	2.00	PT Raisan Energi Indonesia	7.89	1,050
21	Aek Sibundong, N. Sumatera	8.00	PT Aek Sibundong Energy	7.89	1,050
22	Kineppen, North Sumatera	10.00	PT Simalem Bumi Energi	7.89	1,050
23	Kandibata 2, North Sumatera	10.00	PT Senina Hidro Energi	7.89	1,050
24	Batang Toru 4, North Sumatera	10.00	PT Indah Alam Lestari Energi	7.89	1,050
25	Batang Toru 5, North Sumatera	7.50	PT Nusantara Hidro Utama	7.89	1,050
26	Anggoci, North Sumatera	8.00	PT Alabama Energy	7.89	1,050
27	Pulau Panggung, Lampung	9.00	PT Dwi Prima Jaya	6.68	889
28	Tanjung Agung, S. Sumatera	6.00	PT Energy Hydgen	6.68	889
29	Bindu 1, South Sumatera	10.00	PT Indo Hydro Energi	6.68	889
30	Bindu 2, South Sumatera	10.00	PT Indocoal International	6.68	889
31	Ketaun 3, Bengkulu	3.00	PT Ketaun Hidro Energi	6.68	889
32	Kanzy 3, South Sumatera	6.50	PT Kanz Sapta Energi	6.68	889
33	Sako 1, South Sumatera	6.00	PT Brantas Cakrawala Energi	6.86	913
34	Bukit Sileh, West Sumatera	0.70	PT Pandu Lembang Jaya	6.86	913
35	Tonggar, West Sumatera	6.00	PT Optima Tirta Energy	6.86	913
36	Bayang Nyalo, West Sumatera	6.00	PT Bayang Nyalo Hidro	6.86	913
37	Curup Gangsa, Lampung	1.20	PT Megaraja Setya Energi	6.60	878
38	Wae Meleson, Lampung	2.80	PT Graha Hidro Nusantara	6.60	878
39	Batu Brak, Lampung	7.70	PT Tiga Oregon Putra	6.60	878
40	Sumber Jaya, Lampung	6.00	PT Adimitra Energi Hidro	6.60	878
41	Cileunca, West Java	1.00	PT Indonesia Power	6.51	866
42	Pareang, West Java	2.80	PT Akasu Energi Utama	6.51	866
43	Cimandiri (MoPW Dam), W. Java	4.40	PT Megah Energi utama	5.86	780
44	Taman Asri, East Java	0.80	PT Akasa Eko Energi	6.54	870
45	Tras, West Sumatera	1.60	PT Hensan Andalas Putra	6.86	913

99 *http://katadata.co.id/berita/2017/09/08/pln-beli-listrik-291-mw-dari-pembangkit-energi-baru-terbarukan*

No.	SHP Project	Capacity (MW)	IPP/Developer	Tariffs	
				cUSD/ kWh	IDR/ kWh
46	Sion, North Sulawesi	10.00	PT Citra Multi Energi	7.89	1,050
47	Kandibata 1, North Sumatera	10.00	PT Karo Bumi Energi	7.89	1,050
48	Parmonangan 2, N. Sumatera	10.00	PT Bina Godang Energy	7.89	1,050
49	Batu Gajah, Riau	10.00	PT Thong Langkat Energi	7.89	1,050
50	Kunci Putih, Central Java	0.90	PT Kunci Hidro Energi	6.52	868

Source: Official Letter of the MoEMR No. 5827/23/MEM.I./2017, Katadata[99], PwC Analysis

The peak period of SHP development was from 2014 until late 2015 as reported by the Director General of NREEC. During this period, proposed SHP investment values reached IDR 10.94 trillion (USD 783 million) for 175 projects. At that time, the Government encouraged SHP projects by setting purchase tariffs ranging from USD 8 cents/kWh (based on MoEMR Regulation No. 12/2014)[100] which were increased to USD 19 cents/kWh (based on MoEMR Regulation No. 16/2015), excluding the multiplication factor "F" that depended on the voltage grid connection and installation location. However, such purchase tariff regulations, especially the latest, were reportedly being disputed by PLN. PLN was unwilling to sign PPAs under the latest MoEMR Regulation, as they were too expensive compared to PLN's general power generation costs. PLN then issued PLN Circular Letter No. 47/REN.01.01/DITREN/2016 which determined the hydro power tariff of USD 7-8 cents/kWh. Nevertheless, all tariffs currently follow MoEMR Regulation No. 50/2017 which revoked MoEMR Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017). Please see *Section 5.9 - New Tariff Stipulation for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

Further challenges for investment in SHPs include the following:

a) A limit on foreign investor equity ownership. As outlined in *Section 2.5.2 - The Negative List*, the most recent negative list detailed in PR No. 44/2016 sets certain limitations on foreign investment, as micro power plants (<1 MW) are closed for foreign investment and small power plants (1– 10 MW) are open for foreign ownership up to a maximum of 49%;
b) The need to invest in transmission lines from the SHP site to the interconnection point if transmission lines are not sufficient;
c) The relatively high front-end investment costs, with smaller developers struggling to fulfill their 30% equity requirement. PPAs for SHP generally will not have a take-or-pay provision, so there is an off-take risk borne by investors;
d) Access to finance: with investments of USD 2.0 - USD 2.5M per MW required, typically the investment size is too small for project finance in Indonesia and is likely to require substantial collateral from the Sponsors;
e) The quality of hydrological data;
f) Unclear status of development in certain water concessions/permits held by private companies;
g) Ongoing O&M by local communities;
h) Distances from equipment providers; and
i) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, making for difficult access and logistics at some sites, resulting in higher transportation and delivery costs of equipment.

100 MoEMR Regulation No. 12/2014 set tariff to be IDR 1,075/kWh, the number is converted assuming 1 USD = IDR 12,500 (in Year 2014)

5.5 Bioenergy

Bioenergy refers to the renewable energy obtained from biomass or biogas to generate electricity and heat, or to produce liquid fuels (e.g. biodiesel or bioethanol) for transport use. Biomass is the organic matter derived from recently living plants or animals and includes agricultural products, forestry products, municipal and other waste. Biogas refers to the gases produced by the decomposition of organic matter in the absence of oxygen. For example, biogas can be obtained from animal waste, POME or MSW. Additionally, as Indonesia is the world's second largest palm oil producer, palm plantation waste is a potential source for biomass power generation.

In terms of bioenergy for power generation, there are basically two process categories to generate electricity, i.e. biological and thermal processes. The biological process uses anaerobic digestion technology, where feedstock is decomposed by microorganisms to produce methane (CH_4) gas (biogas) that is combusted by the system for power generation. This process requires feedstock with a high organic content (e.g. POME, vegetables, food or agro waste). On the other hand, the thermal process mainly uses technologies of incineration or gasification. The incineration technology requires a high calorific value and low moisture (dry) content feedstock (e.g. paper, plastics, wood, textiles, etc.) which is commonly shredded or pelletised. The feedstock is combusted to provide heat that flows to the boiler to produce steam that is used to turn the turbine and generate electricity. Meanwhile, for gasification, feedstock is subject to partial combustion in the event of a limited supply of oxygen to produce synthetic natural gas ("syngas") that is used to generate electricity.

Based on several resources, the potential of bioenergy for power generation in Indonesia is estimated to be 32.6 GW with 1.8 GW of current installed capacity (Table 5.7)[101] where most of this capacity is off-grid. To date, bioenergy power plants connected to the PLN electricity grid only have a total installed capacity of around 131.4 MW. Upon the inauguration of the Asian Agri POME Biogas Plant in early 2016, the DGNREEC indicated that by 2018 the Government would oblige companies producing waste to utilise the waste for power generation. The intent of the policy was reported as being to encourage the conversion of waste-to-energy, but it could also have the additional benefit, in certain cases, of avoiding the release of climate change-causing methane gas into the atmosphere. The Government plans further growth in biogas and biomass plants, albeit more private-sector driven, but this itself will be supporting the development of waste-to-power plants.

Table 5.7 - Potential bioenergy resources for power generation (in MW)

No.	Type of Bioenergy	Sumatera	Kalimantan	Java-Bali-Madura	NTB/ NTT	Sulawesi	Maluku	Papua	Total
1	Palm	8,812	3,384	60	-	323	-	75	12,654
2	Cane	399	-	854	-	42	-	-	1,295
3	Rubber	1,918	862	-	-	-	-	-	2,780
4	Coconut	53	10	37	7	38	19	14	178
5	Rice Husk	2,255	642	5,353	405	1,111	22	20	9,808
6	Corn	408	30	954	85	251	4	1	1,733

101 RENSTRA EBTKE 2015-2019, p. 34

No.	Type of Bioenergy	Sumatera	Kalimantan	Java-Bali-Madura	NTB/ NTT	Sulawesi	Maluku	Papua	Total
7	Cassava	110	7	120	18	12	2	1	270
8	Wood	1,212	44	14	19	21	4	21	1,335
9	Cow Dung	96	16	296	53	65	5	4	535
10	MSW	326	66	1,527	48	74	11	14	2,066
	Total	**15,589**	**5,061**	**9,215**	**635**	**1,937**	**67**	**150**	**32,654**

Source: RENSTRA EBTKE 2015-2019

The most recent data indicates that about 131.4 MW of installed capacity of biomass power has already been connected to the grid (see Table 5.8).

Table 5.8 - On-grid bioenergy power plants

No.	Company	COD	Type of Contract	Location	Type of Bioenergy	Contract (MW)
1	PT Growth Asia	2011	Excess Power	North Sumatera	Palm Waste	10.0
2	PT Listrindo Kencana	2006	IPP	Bangka	Palm Waste	5.0
3	PT Growth Sumatera 1	2006	Excess Power	North Sumatera	Palm Waste	9.0
4	PT Indah Kiat Pulp & Paper	2006	Excess Power	Riau	Palm Waste	3.0
5	PT Belitung Energy	2010	IPP	Belitung	Palm Waste	7.0
6	PT Growth Sumatera 2	2010	Excess Power	North Sumatera	Palm Waste	10.0
7	PT Navigat Organic	2011	IPP	Bali	MSW	2.0
8	PT Navigat Organic	2011	IPP	Bekasi	MSW	12.0
9	PT Growth Asia	2012	Excess Power	North Sumatera	Palm Waste	10.0
10	PT Navigat Organic	2012	IPP	Bekasi	MSW	2.0
11	Harkat Sejahtera	2013	Excess Power	North Sumatera	Palm Waste	10.0
12	Rimba Palma	2013	Excess Power	Jambi	Palm Waste	10.0
13	Austindo ANE	2014	IPP	Belitung	POME	1.2
14	PLN	2014	PLN	Gorontalo	Corncob	0.4
15	Victorindo	2015	Excess Power	North Sumatera	Palm Waste	3.0
16	Sumber Organik	2015	IPP	Surabaya	MSW	1.6
17	Meskom Agro Sarimas	2015	Excess Power	Riau	Palm Waste	10.0
18	Maju Aneka Sawit	2015	Excess Power	South Kalimantan	POME	1.0
19	Sukajadi Sawit	2015	Excess Power	South Kalimantan	POME	2.4
20	Mutiara Bunda	2015	Excess Power	South Sumatera	POME	2.0
21	Sampurna	2016	Excess Power	South Sumatera	POME	2.0
22	PT Riau Prima Energy	2016	Excess Power	Riau	Biomass	15.0
23	PTPN III	2016	Excess Power	North Sumatera	Palm Waste	1.8
24	Siringo-ringo	2016	Excess Power	North Sumatera	POME	1.0
					Total Capacity On-Grid	**131.4**

Source: LAKIN EBTKE 2016, p. 43

The Government has ambitious goals for increasing the on-stream capacity of bioenergy power plants from 2015 - 2019 as follows:

	2015	2016	2017	2018	2019
Installed capacity – beginning of year	1,740	1,892	2,069	2,292	2,559
Biogas	46	43	76	101	126
State budget	1	1	1	1	1
Private	45	42	75	100	125
Biomass	77	76	87	97	107
State budget	1	2	2	2	2
Private	76	74	85	95	105
Municipal waste	29	58	60	69	80
Private	1	1	1	1	1
State budget	28	57	59	68	79
Installed capacity – end of year	1,892	2,069	2,292	2,559	2,872
Construction of bioenergy power plants	152	177	223	267	313

Source: RENSTRA KESDM 2015-2019

Pertamina has indicated that it is working with partners to develop biogas from POME in North Sumatera in the Sei Mangkei Special Economic Zone, with biogas-to-electricity potential of 1.6 MW and with a tenant being the off-taker. This facility is targeted to reach its COD before 2020.

In March 2017, PLN signed MoUs for several bioenergy projects (see Table 5.9). In May 2017, PLN also signed a PPA for a 9 MW biogas power project located in Bengkulu with PT Mitra Puding Mas.[102]

Table 5.9 – Bioenergy project developments signed MoUs with PLN in March 2017

No.	Type of Bioenergy	Capacity (MW)	IPP/Developer	Location
1	Forest Waste (Biomass)	0.7	PT Charta Putra Indonesia and IKPT	Mentawai, West Sumatera
2	Palm Waste (Biomass)	10.0	PT Cahaya Manggala Power	Kobar, Central Kalimantan
3		10.0	PT Biogreen Power Kobar	Kobar, Central Kalimantan
4		10.0	PT Fajar Mitra Energi	Sukamara, Central Kalimantan
5		10.0	PT Intika Accord Power	Sintang, West Kalimantan
6		10.0	PT Carpediem Elektrikal Nusantara	Sintang, West Kalimantan

102 *https://finance.detik.com/energi/d-3502834/6-pembangkit-di-kalimantan-bakal-sulap-cangkang-sawit-jadi-listrik*

No.	Type of Bioenergy	Capacity (MW)	IPP/Developer	Location
7	Biomass	4.0	PT Pundi Global Investama	Kubu Raya, West Kalimantan
8		10.0	PT Biomas Energy Abadi	NAD
9		10.0	PT Subulussalam Green Energy	Subulussalam, NAD
10		7.0	PT Pasadena Biofuels Mandiri	Rokan Hulu, Riau
11		5.0	PT Inhil Sarimas Kelapa	Ssarimas, Indragiri Hilir, Riau
12		4.0	PT Sentosa Jaya Bersama	N/A
13		3.0	PT Karya Energi Jambi	Batanghari, Jambi
14		6.0	PT Energi Karya Persada	N/A
15	Biogas	10.0	PT Sentosa Jaya Purnama	N/A
16		10.0	PT Rezeca Isa	Bangko Sampurna, Rokan Hilir, Riau
17		46.0	PTPN V	Kampar, Riau
18		3.0	PT Pasadena Biofuels Mandiri	Ujung Batu, Rokan Hulu, Riau
19		3.0	PT Green Energy Spesialist One	Rumbai, Riau

Source: Detikcom, PwC Analysis

On 2 August 2017, PLN signed four biomass and five biogas PPAs ≤ 10 MW at tariffs between IDR 889 and IDR 1,545/kWh (some of the 19 bioenergy projects that signed MoUs mentioned on Table 5.9 also signed PPAs on that day). The applicable tariffs for such projects were based on MoEMR Regulation No. 12/2017 (the MoUs and PPAs were signed before the issuance of MoEMR Regulation No. 43/2017) (see Table 5.10).

Table 5.10 – Bioenergy projects that signed a PPA on 2 August 2017

No.	Type of Bioenergy	Capacity (MW)	IPP/Developer	Location	Tariffs	
					cUSD/ kWh	IDR/ kWh
1	Biogas	1	PTPN II	Pagar Merbau, North Sumatera	7.89	1,050
2		1	PTPN II	Kwala Sawit, North Sumatera	7.89	1,050
3		10	PT Rezeca Isa	Bangko Sampurna, Rokan Hilir, Riau	8.62	1,147
4		3	PT Pasadena Biofiuels Mandiri	Ujung Batu, Rokan Hulu, Riau	8.62	1,147
5		3	PT Green Energy Specialist One	Rumbai, Riau	8.83	1,175
6	Biomass	10	PT Cipta Multi Listrik Nasional	Deli Serdang, N. Sumatera	7.89	1,050
7		5	PT Inhil Sarimas Kelapa	Sarimas, Indragiri Hilir, Riau	8.62	1,147
8		3	PT Karya Energi Jambi	Mersam, Jambi	6.68	889
9		6	PT Energi Karya Persada	Energi Karya Persada, Sumatera	11.61	1,545

Source: Official Letter of the MoEMR No. 5827/23/MEM.I./2017, PwC Analysis

Challenges to investment in bioenergy projects include the following:
a) The availability of biomass feedstock on a continuous and reliable basis;
b) The suitability of grid infrastructure or distance from grid connections;
c) The coordination required between PLN and various authorities (central and regional);
d) Permissions and licensing issues (land, water, environmental) and clarity at the regional level on the associated fees and processes;
e) The availability of regional EPC contractors with the right experience and skills; and
f) The availability of spare parts and after-sales service.

5.5.1 Municipal Waste-to-Energy

Concerning the increase in waste production, the limited waste treatment capacity and the capability of most landfill facility areas, municipal waste-to-energy is believed to be one of the most effective solutions for waste management, which remains an unsolved problem in many big cities in Indonesia. Similar to bioenergy in general, the feedstock used in this scheme is municipal waste. However, in practice in the Indonesian context, the application of these technologies is not simple. The waste produced in Indonesia is typically mixed and unsorted: organic and non-organic waste, wet and dry garbage. Therefore, additional effort is needed to manage this. Unsorted waste can be fed directly to the incinerator, but the high moisture content of the waste reduces the thermal efficiency needed for complete combustion. The potential of municipal solid waste production for electricity generation in selected cities/regencies in Indonesia is presented in Table 5.11.

Table 5.11 – Municipal waste-to-energy potential per province in Indonesia

Province	Municipal Waste Availability (Tonne/Year)	Total Techno-Eco Potential (MW)
Aceh	15,741	0.94
North Sumatera	664,173	31.35
West Sumatera	143,509	7.14
Riau	122,640	7.69
Riau Islands	240,535	17.21
Jambi	39,858	1.63
Bengkulu	6,114	0.37
South Sumatera	187,976	12.24
Lampung	101,343	5.09
West Kalimantan	109,500	4.97
Central Kalimantan	44,713	1.83
South Kalimantan	73,000	3.48
East Kalimantan	192,082	8.84
Banten	206,681	13.09
West Java	3,508,138	227.59
Central Java	800,755	50.32
DI Yogyakarta	202,657	13.10
Bali	370,752	23.65
NTB	148,543	8.87
East Java	1,237,010	77.89

Province	Municipal Waste Availability (Tonne/Year)	Total Techno-Eco Potential (MW)
NTT	15,046	0.90
North Sulawesi	66,704	3.99
Gorontalo	16,973	1.01
South Sulawesi	182,500	11.90
West Papua	10,494	0.63
National Total	**8,707,437**	**535.72**

Source: 2016 EBTKE Statistics

The Government has continued its efforts to develop municipal waste-to-energy to overcome the city waste problem and also to provide clean energy. In line with the Strategic Plan of the MoEMR, which focuses on the construction of municipal waste-to-energy plants funded by the State budget, on 13 February 2016, President Joko Widodo issued PR No. 18/2016 on The Acceleration of Municipal Waste-to-Energy Power Plant Development. The Government named seven cities as pilot projects of thermal municipal waste-to-energy development, namely: Jakarta, Bandung, Tangerang, Semarang, Surabaya, Solo and Makassar.

In its implementation, the President instructed the regional mayor to assign regionally-owned enterprises, or appoint private business entities, to undertake the project development. This regulation also obliges PLN to sign the PPA of the mentioned municipal waste-to-energy projects. Nonetheless, since negative sentiment regarding technological challenges and concerns over environmental pollution remain, in early 2017 the regulation was challenged by a number of environmental activists in the Supreme Court, which consequently revoked the regulation. However, it has been reported that the Government has continued to develop the municipal waste-to-energy plan despite the court ruling. The Government assumes that there is no other effective way besides waste-to-energy conversion to solve the waste problem in big cities in Indonesia.[103]

Some observed constraints and challenges for investment in municipal waste-to-energy include the following:

a) Delays in securing the PPA and off-take arrangements for electricity from MSW;
b) The insufficiency of feed-in tariffs for MSW and ambiguity as to whether a share of tipping fees is required (in some cases, the Regional Government is unwilling to pay sufficient tipping fees);
c) Concerns from Regional Governments over management and responsibility for implementation of waste-to-energy plants due to a lack of experience at Regional Government level regarding waste-to-energy and lack of knowledge of power purchase mechanisms;
d) Negative sentiment from the local community over public health and safety issues;
e) Socio-economic concerns over livelihoods for waste pickers/scavengers;
f) The concerns of financiers over the use of new or unproven technologies; and
g) The security or enforceability of contracts signed with sub-national Governments.

The MoEMR issued Regulation No. 50/2017 on the Utilisation of Renewable Energy Resources for Electricity to set new tariffs for renewable energy projects. *Please see Section 5.9 - New Tariff Stipulation for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

103 *Jakarta Post, 17 January 2017, "Govt sticks with incinerator plan despite court ruling"*

5.6 Solar PV

In the context of power generation, the conversion of solar energy (sunlight) into electricity is done either directly using PV technology or indirectly using thermal technology, as in the case of concentrated solar power ("CSP"). CSP involves using mirrors or lenses to concentrate the solar energy and convert this into heat. The heat is used to create steam, which drives a turbine to generate electricity.

With average daily insolation of approximately 4.8kWh/m^2 [104], Indonesia is estimated to have 206.7 GWp[105] potential for solar power based electricity. The level of insolation varies across the Indonesian archipelago (see Table 5.12) but is regarded as offering good solar potential by international standards, and represents a viable source of power for the population in remote or island locations that are off-grid.

Table 5.12 - Solar energy potential in Indonesia

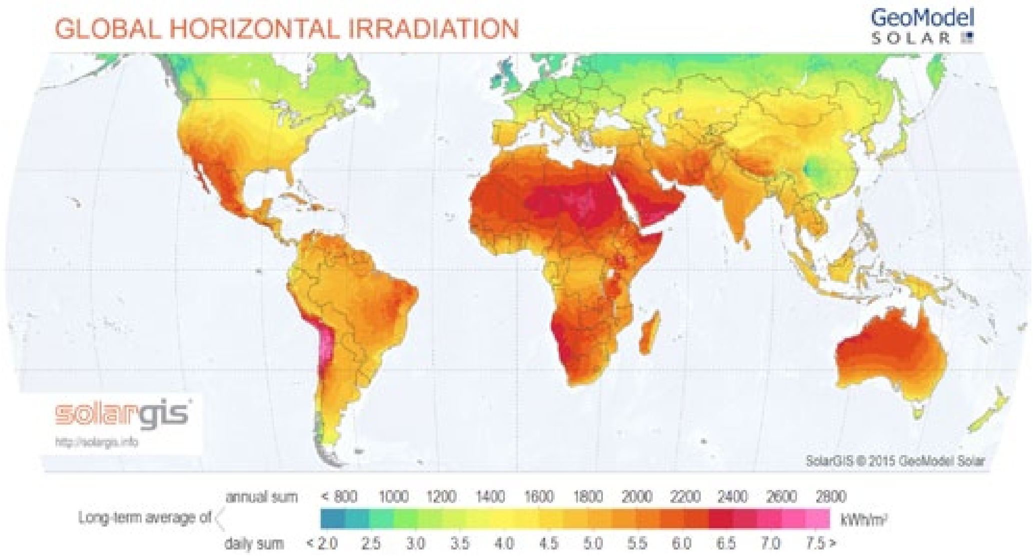
No.	Regency/City Location	Province	Geographic Position	Average Irradiation (kWh/m^2/day)
1	Banda Aceh	Nanggroe Aceh Darussalam	4°15'N;96 °52'E	4.10
2	Palembang	South Sumatera	3°10'S;104°42'E	4.95
3	Menggala	Lampung	4°28'S; 105°17' E	5.23
4	Jakarta	DKI Jakarta	6°11'S;106°SE	4.19
5	Bandung	West Java	6°56'S;107°38'E	4.15
6	Lembang	West Java	6°50'S;107°37'E	5.15
7	Citius, Tangerang	West Java	6°07'S;106°30'E	4.32
8	Darmaga, Bogor	West Java	6°30'S;106°39'E	2.56
9	Serpong, Tangerang	West Java	6°11'S;106°30'E	4.45
10	Semarang	Central Java	6°59'S;110°23'E	5.49
11	Surabaya	East Java	7°18'S;112°42'E	4.30
12	Kenteng, Yogyakarta	DI Yogyakarta	7°37'S;110°01'E	4.50
13	Denpasar	Bali	8°40'S;115°13'E	5.26
14	Pontianak	West Kalimantan	4°36'N;9°11'E	4.55
15	Banjarbaru	South Kalimantan	3°27'S;144°50'E	4.80
16	Banjarmasin	South Kalimantan	3°25'S;114°41'E	4.57
17	Samarinda	East Kalimantan	0°32'S;117°52'E	4.17
18	Manado	North Sulawesi	1°32'N;124°55'E	4.91
19	Palu	Central Sulawesi	0°57'S;120°0'E	5.51
20	Kupang	West Nusa Tenggara (NTB)	10°09'S;123°36'E	5.12
21	Waingapu, Sumba Timur	Central NT	9°37'S;120°16'E	5.75
22	Maumere	East NT	8°37'S;122°12'E	5.72

Source: 2014 EBKTE Statistics

104 2014 EBKTE Statistics, p. 82
105 DGNREEC, "Policy on Development of New and Renewable Energy and Energy Conservation", MoEMR, May 2017

A visual guide to the level of irradiation in Indonesia compared to the rest of the world can be seen in the Figure 5.5 as follows:

Figure 5.5 – Level of global horizontal irradiation map



Source: SolarGIS © 2015 GeoModel Solar

At the end of 2016, the current installed capacity was about 108 MW[106], with the dominant portion of capacity being off-grid, mostly in the form of solar home systems or small-to-medium off-grid systems (many of these are hybrid systems associated with small-scale diesel plants) and only 13 MW are on-grid to date.[107] Indonesia had previously planned to increase this installed capacity to 260.3 MW by 2019 with an additional 189.3 MW over five years, which was a relatively modest target.

	2015	2016	2017	2018	2019
Installed capacity – beginning of year (MW)	67.1	76.9	92.1	118.6	180.0
Construction of solar power plants (MW)	9.8	15.2	26.5	61.4	80.3
- Solar non-state budget (MW)	-	5.0	15.0	50.0	70.0
- Solar state budget - MoEMR (MW)	2.8	3.0	4.0	3.5	2.0
- Solar special allocation fund (MW)	7.0	7.2	7.5	7.9	8.3
Installed capacity – end of year (MW)	**76.9**	**92.1**	**118.6**	**180.0**	**260.3**

Source: Rencana Strategis KESDM – "RENSTRA KESDM" 2015-2019

106 Rida Mulyana (DGNREEEC), "Utilisation of Renewable Energy", Presentation at the PetroGas Days UI, 12 March 2016 in the PetroGas Days UI
107 2017 RUPTL

In April 2017, President Joko Widodo released PR No. 47/2017 on Provision of Energy Saving Solar Lamps for Communities who Have Not Gained Access to Electricity. Provisions include those for planning, procurement, distribution, installation and maintenance. The PR No. 47/2017 is implemented through MoEMR Regulation No. 33/2017 on Guidelines on Energy Saving Solar Lamps Provision for Unelectrified Communities. The intended beneficiaries are Indonesian citizens whose residences have not been connected to electricity and are situated in border, lagging, isolated areas, and/or outer islands. On top of that, these programs are also a means of allocating the budget saved from the electricity subsidy removal to ensuring the equality of energy access across Indonesian society.[108]

5.6.1 Previous On-grid Procurement

The first on-grid procurement for private Solar PV in Indonesia took place in July 2013 under MoEMR Regulation No. 17/2013. The procurement was set for a 140 MW capacity quota and several locations, and tariffs were bid within the range of USD 0.25-0.30/kWh (depending on local content). However, MoEMR Regulation No. 17/2013 was challenged by a local manufacturing association, and was revoked by the Supreme Court in 2014.

Following the revocation of MoEMR Regulation No. 17/2013, in July 2016 the MoEMR approved MoEMR Regulation No. 19/2016, which replaced MoEMR Regulation No. 17/2013. At least 5,000 MW was to be offered, starting with a Phase 1 of 250 MW. The feed-in tariffs were fixed by province, and ranged from USD 0.145/kWh in Java (150 MW) to USD 0.25/kWh in Papua (2.5 MW) for the first phase. The procurement process was overseen by the MoEMR (using an online platform) on a first-come-first-served basis and verified by the Task Force from the DGNREEC, DGE and PLN, while PLN was the signatory of the PPAs.

However, MoEMR Regulation No. 19/2016 was superseded in late January 2017 by MoEMR Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017) on the Utilisation of Renewable Energy Resources for Electricity (see below) which was later revoked by MoEMR Regulation No. 50/2017, both regulations set tariffs for Solar PV based on benchmark to the BPP. Please see PwC's Power Investment and Taxation Guide 2016 for historical details of the previous on-grid Solar PV procurement.

5.6.2 New On-grid Procurement

In late January 2017, the MoEMR issued MoEMR Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017) on the Utilisation of Renewable Energy Resources for Electricity which was later revoked by MoEMR Regulation No. 50/2017. The pricing and procurement mechanism for Solar PV has again changed. Under MoEMR Regulation No. 50/2017, PLN will undertake the direct selection directly based on quota capacity while the tariffs for PV shall be on B2B negotiations or benchmarked to the BPP.

108 *https://www.esdm.go.id/en/media-center/news-archives/permen-esdm-nomor-38-tahun-2016-upaya-pemenuhan-kelistrikan-daerah-terpencil*

In March 2017, PLN signed some MoUs with Solar PV and hybrid power developers as follows (See Table 5.13):

Table 5.13 – New Solar PV (and hybrid) projects signed MoUs with PLN in March 2017

No.	Location	Type of Power Projects	Capacity	Company
1	Jakabaring, South Sumatera	Solar PV	2 MW	PDPE Sumsel and Sharp
2	Sulawesi	Solar PV	5 MW	PT Cakrawala Energi Sulawesi
3	Lombok, Bangka, Karimun Islands, Kupang, Minahasa and Gorontalo	Solar PV hybrid with Diesel/Gas Machine	N/A	PT Arsari Enviro Industri and Sunpower Systems SARL
4	Sumbawa, Bima/Sape, Lombok, Ambon, Madura/Ketapang/ Bawean, Waena, Bombana, Bangka/Belitung and Nias	Solar PV hybrid with Diesel/Gas Machine	N/A	PT Sumberdaya Sewatama
5	Selayar Island, Kei Kecil Island, Ambon and Buru Island	Solar PV hybrid with Wind/Small Hydro	N/A	PT UPC Renewable Indonesia and PT Binatek Energi Terbarukan

Source: Rambuenergy[109]

In May 2017, PLN announced the first open tender of Solar PV capacity under the new regulations for the Sumatera region as follows, with the pre-qualification documentation period ending on 2 June 2017 (see Table 5.14):

Table 5.14 – Tender for Solar PV quota in Sumatera region

No.	Location	Capacity (MW)
1	Aceh	20.00
2	North Sumatera	35.00
3	Riau, Riau Islands, and Bangka Belitung	38.68
4	North Sumatera	16.00
5	South Sumatera, Jambi, Bengkulu (S2JB)	33.00
6	Lampung	24.90

Source: PLN

On 13 September 2017, PLN reported that there are 50 IPPs have passed the pre-qualification stage of the Solar PV tender in Sumatera. The tender winners themselves would be announced in 2018. It also reported that PLN will open the next Solar PV procurement for Kalimantan Area.[110]

109 https://www.rambuenergy.com/2017/03/pln-signs-5-hoas-to-develop-30-mw-of-solar-power-plants/
110 Investor Daily, 13 September 2017, "Pengumuman Pemenang Lelang PLTS Ditunda Tahun Depan"

On 2 August 2017, PLN also signed PPAs for six Solar PV project developments (see Table 5.15).

Table 5.15 – Solar PV project developments which signed PPAs on 2 August 2017

No.	Solar PV Project	IPP/Developer	Capacity
1	PLTS Gorontalo	PT Quantum Energi	10 MW
2	PLTS Sengkol, Lombok	PT Infrastruktur Terbarukan Cemerlang	5 MW
3	PLTS Selong, Lombok	PT Infrastruktur Terbarukan Buana	5 MW
4	PLTS Kuta, Lombok	NV Vogt Pte. Ltd., PT Delapan Menit Energi	5 MW
5	PLTS Pringgabaya, Lombok	PT Infrastruktur Terbarukan Adhiguna	5 MW
6	PLTS Likupang, Minahasa	PT Infrastruktur Terbarukan Lestari	15 MW

Source: Official Letter of PLN No. 1364/DAN/01.01/DITDAN/2017, Rambuenergy, http://www.synergy-renewable.com/projects.html

The challenges to solar power plant development in Indonesia include the following:
a) The lack of appropriate regulatory support and attractive tariffs;
b) The need for greater Government, investor and stakeholder coordination on issues including: obtaining permits, land acquisition and grid conditions. For example, land availability with valid certification and suitability (e.g. not flood-prone), access to sites and a suitable grid should be confirmed prior to a bidding round;
c) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, which makes for difficult access and logistical challenges on some sites, resulting in higher transportation and equipment delivery costs;
d) Access to the right human resources/expertise and experience in Solar PV technology compounded by stringent local content (*see Section 2.2.3 - Local Content)*;
e) Limited technical experience within PLN teams to understand the implications of solar deployment for on-grid stability and how to manage risks.

The MoEMR issued Regulation No. 50/2017 on the Utilisation of Renewable Energy Resources for Electricity to set new tariffs for renewable energy projects. Please see *Section 5.9 - New Tariff Stipulation for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

5.7 Wind Energy

Wind energy relies on the flow of air to turn a wind turbine, converting mechanical energy into electricity using a generator. Wind energy is regarded as consistent from year to year, but can vary by the hour, day or season. The estimated potential of wind energy in Indonesia has historically been regarded as relatively limited, primarily because wind velocity in Indonesia is (in general) relatively low. The exception is the eastern islands, where wind velocity can reach levels sufficient to power small-to-medium-scale wind turbines. The summary data from wind resources assessment and research for 153 sites is as follows (see Table 5.16):

Table 5.16 – Wind site potential in Indonesia

Resource Potential	Wind Speed at 50 m, (m/s)	Wind Power Density, at 50 m, (W/m²)	Number of Sites	Provinces
Lowest	< 3.0	< 45	66	West Sumatera, Bengkulu, Jambi, Central Java, South Kalimantan, West Nusa Tenggara, East Nusa Tenggara, South-East Sulawesi, North Sulawesi and Maluku.
Low (Small-Scale)	3.0 – 4.0	< 75	34	Lampung, Yogyakarta, Bali, East Java, Central Java, West Nusa Tenggara, South Kalimantan, East Nusa Tenggara, South-East Sulawesi, Central Sulawesi, North Sumatera and West Sulawesi.
Medium (Medium-Scale)	4.1 – 5.0	75 – 150	34	Bengkulu, Banten, DKI, Central Java, East Java, East and West Nusa Tenggara, South-east, South and Central Sulawesi and Gorontalo.
High (Large-Scale)	> 5.0	> 150	19	Central Java, Jogyakarta, East and West Nusa Tenggara, South and North Sulawesi.

Source: RENSTRA EBTKE 2015 - 2019

MoEMR studies argue that wind potential in Indonesia is as high as 61 GW.[111] However, the ADB has also come up with a wind potential figure in Indonesia that might be no higher than 9 GW.[112] It also should be noted that the areas in Indonesia with the most wind (i.e. Eastern Indonesia) are also the least populated, and have no existing transmission infrastructure to distribute electricity to larger population centres. Recently, in collaboration with the Indonesian Ministry for Energy and Mineral Resources, the Danish Embassy in Indonesia through its Environmental Support Program has funded the development of a wind map across Indonesia. The 3 km resolution wind map is accessible to the public (http://indonesia.windprospecting.com/).

The locations showing the highest potential for commercial-scale wind energy in Indonesia are as follows:

Locations	Potential Energy
Sumatera	7,397 MW
Banten and West Java	8,793 MW
Central, East Java and Bali	15,218 MW
Kalimantan	2,526 MW
Sulawesi	8,380 MW
East Nusa Tenggara	12,793 MW
Maluku and Papua	5,540 MW
Total	**60,647** MW

Source: 2016 EBTKE Statistics, p. 17

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111 *Rida Mulyana (Director General of DGNREEC), "Utilisation of Renewable Energy", presentation at the PetroGas Days UI, 12 March 2016*

112 *ADB Paper No. 9, Summary of Indonesian Energy Sector Assessment December 2015. Soeripno Martosaputro and Nila Murti of WHyPGen also cites the MoEMR as assessing the total Indonesian wind capacity at 9.29GW in "Blowing the Wind Energy in Indonesia" presented at the Indonesia Renewable Energy & Energy Conservation Conference and Exhibition [Indonesia EBTKE CONEX 2013] online at Energy Procedia Volume 47, 2014, p. 273–282*

Additionally, an initial study by BPPT-WHyPGen in Java and Sulawesi indicates wind energy potential of around 970 MW distributed across the following specific locations (see Table 5.17):

Table 5.17 – BPPT and WHyPGen wind energy assessment studies in Java and Sulawesi

No.	Locations	Potential Energy	No.	Locations	Potential Energy
1	Lebak	100.0 MW	8	Jeneponto	62.5 MW + 100.0 MW
2	Sukabumi Selatan	100.0 MW	9	Oelbubuk	10.0 MW
3	Garut Selatan	150.0 MW	10	Kupang	50.0 MW (Indicative)
4	Purworejo	67.5 MW	11	Palakahembi	5.0 MW (Indicative)
5	Bantul	50.0 MW	12	Selayar	10.0 MW
6	Gunung Kidul	15.0 MW	13	Takalar	100.0 MW (Indicative)
7	Sidrap	100.0 MW	14	Bulukumba	50.0 MW (Indicative)

Source: BPPT-WHyPGen

At the end of 2016, installed wind power capacity was reported to be 2.4 MW.[113] The largest wind farms are at Nusa Penida in Bali (0.735 MW) and at Sangihe and Selayar in Sulawesi (combined capacity of 0.54 MW). These generation facilities are on-grid and are the result of cooperation between the MoEMR and PLN. The planned development of wind energy by the MoEMR appears to be very modest (see the table below) when compared to a number of private-sector developments which are beginning to take shape.

The Government has planned for additions to the on-stream capacity of wind power plants from 2015 – 2019 as follows:

	2015	2016	2017	2018	2019
Wind non-state budget (MW)	2.0	5.0	7.0	9.0	13.0
Wind state budget - MoEMR (MW)	0.5	0.2	0.5	1.0	2.0
Wind special allocation fund (MW)	0.2	0.5	0.8	1.0	1.2
Construction of wind power plants (MW)	**2.7**	**5.7**	**8.3**	**11.0**	**16.2**

Source: Rencana Strategis KESDM – "RENSTRA KESDM" 2015 - 2019

The continuing advances in wind power technology, the increase in its operation efficiency, and its wide and established utilisation in other countries seem to attract interest in investing in Indonesian wind energy. To date, records indicate several wind power projects that were planned to be constructed in Indonesia are already in progress, most supported by foreign funds. Several big areas from the initial study by BPPT-WHyPGen have now been developed, such as Sidrap and Jeneponto.

113 LAKIN EBTKE 2016 p. 24

PLN signed a PPA with UPC Sidrap Bayu Energy (a consortium of UPC Renewables Asia I Ltd., PT Binatek Energi Terbarukan and Sun Edison Inc.) in August 2015 for the 70 MW Sidrap wind farm in South Sulawesi. This facility is being constructed after obtaining financial assistance amounting to USD 120 million from the Overseas Private Investment Corporation in April 2016 so that it can come online at the beginning of 2018.[114] Furthermore, in March 2017, UPC Renewables was also reported as having signed a Memorandum of Understanding ("MoU") with PLN to develop a hybrid power plant consisting of wind and Solar PV/small hydropower in Selayar Island, Maluku.

PACE Energy Pte Ltd and PLN (Persero) has signed a MoU during the Investment Seminar on Electricity Development of Renewable Energy in Indonesia in March 2017. This MoU covers eight innovative renewable energy (wind/solar) projects across Indonesia.[115]

Additionally, in early 2017, Siemens Wind Power and PT Siemens Indonesia in consortium with PT Pembangunan Perumahan (Persero) Tbk. also reported their plans to build a wind power project: the Tolo I Wind Farm in Jeneponto, South Sulawesi. For this project, Equis Asia Fund II, through its Indonesian Platform, Redaya Energi and PT Energi Bayu Jeneponto had signed EPC and O&M contracts. Tolo I Wind Farm will install 20 Siemens direct drive wind turbines, injecting power into PLN's Jeneponto substation via a high-voltage transmission line. The expected Commercial Operations Date of this wind farm is 2018.[116]

Challenges in developing wind power investments include the following:

a) The historic lack of an established competitive purchase tariff and an established regulatory framework;
b) Limited infrastructure (e.g. ports and roads), particularly in rural and remote areas, making for difficult access and logistics at some sites, resulting in higher transportation and delivery costs of equipment;
c) Concerns over maintenance and the availability of qualified technicians in remote areas with timely access to spare parts;
d) The need for improved wind data resource assessments, with accurate and reliable wind mapping (although projects currently moving ahead appear to have taken responsibility for this);
e) The relatively high front-end investment costs;
f) The high need for imports of equipment manufactured overseas;
g) The need for greater collaboration between all stakeholders including the Government, PLN and investors; and
h) Limited technical experience within the PLN's team to understand the implication of wind deployment for on-grid stability and how to manage the risk.

With regard to the purchase tariff for wind energy, the MoEMR issued Regulation No. 50/2017 on the Utilisation of Renewable Energy Resources for Electricity to set new tariffs for renewable energy projects. Please see *Section 5.9 - New Tariff Stipulation for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

114 www.upcrenewables.com/indonesia and Bisnis Indonesia 8 April 2016
115 http://pace.co.id/index.php/news-media/
116 http://equisfg.com/wp-content/uploads/2017/02/20170224-Tolo-EPC-Press-Release.pdf

5.8 Ocean Energy

Ocean energy refers to the renewable energy obtained from the sea, either as mechanical energy from the tide and waves, or thermal energy from the sun. Wave energy uses the energy of ocean waves or swells to generate electricity. Tidal energy arises from tidal movements, utilising the vertical changes in sea levels or the horizontal movement of the seas and currents to generate electricity. Ocean thermal energy conversion ("OTEC") uses the difference in temperature between the warmer surface or shallow waters and the cooler deeper waters to generate electricity.

To date, the most common application of ocean energy is the conversion of the kinetic energy of waves into electricity. Some countries that have successfully harnessed it are Scotland, Sweden, France, Norway, England, South Korea and the United States. In the Indonesian context, the highest potential for the utilisation of ocean energy may be in strait areas.[117] As an archipelagic state consisting of islands and straits, the potential of ocean energy in Indonesia is totalled at 17.9 GW.[118] Studies carried out by the MoEMR with foreign donors identified that the most potential areas are: Kelang, Maluku (500 MW); Alas Strait (9 MW); and Larantuka Strait (3 MW). However, especially for Kelang, considering that the demand growth is very low, only 3.2 MW of capacity would be developed.[119]

In 2015, the MoEMR indicated that Indonesia would encourage the use of energy potential from the sea as part of the Government's marine development policy.[120]

The MoEMR currently has two pilot projects underway, one at Nusa Penida and another at Nusa Tenggara. The MoEMR's plan is that 1 MW of ocean energy pilot plants should be ready by 2019.[121]

Pertamina has committed to developing 3 MW of ocean energy by 2019 and in February 2015 signed a MoU with Akuo Energy to collaborate on renewables, including on OTEC.[122] To date, the project is still at the feasibility study stage.

In August 2015, PLN signed a MoU with SBS International Ltd ("SBS") to develop ocean energy in the Alas Strait, Lombok Strait and Badung Strait with capacities of 12 to 140 MW at a reported total cost of USD 350 million.[123] In April 2016, it was announced that SBS would partner with Atlantis Resources Ltd, a Singapore company whose shares are AIM (UK)-listed, to establish a joint venture to develop a 150MW tidal stream site in Indonesia in several stages. The investment costs have been estimated at USD 750 million, with the feasibility study already done by SBS and the project supported by a 25-year PPA with PLN.[124]

Recently, it was reported that the Indonesian and Dutch Government will work together to develop tidal energy. The project has been awarded to Tidal Bridge BV – a joint venture between the construction engineering company Strukton International and private equity firm Dutch Expansion Capital. The project will be designed in an 800-meter Pancasila-Palmerah

117 MoEMR and Indonesian Ocean Energy Association, Ocean Energy Potential in Indonesia (in Bahasa). March 2014
118 Rida Mulyana (Director General of DGNREEC), "Utilisation of Renewable Energy", presentation at the PetroGas Days UI, 12 March 2016
119 Agence Française Development. Tidal Energy Project in Indonesia. January 2017
120 Jakarta Post, 3 June 2015
121 "RENSTRA KESDM" 2015-2019 p. 137
122 Pertamina press release dated 19 August 2015.
123 www.acnnewswire.com August 20, 2015
124 www.atlanticresourcesltd.com/atlantis-announcements.html 2016 April

bridge connecting Flores, Adonara Island and East Nusa Tenggara. The turbine will be installed under the bridge and can generate electricity by utilising ocean currents. For the first phase, it is expected that this system will be able to produce 18 to 23 MW of electricity household. The project later will be developed to have 90 to 115 MW of installed capacity for the second phase. The first phase of the project has a contract value of up to USD 200 million and is scheduled to be completed by the end of 2019.[125]

An Indonesian Ocean Energy Association also exists, and in 2013 a draft road map for ocean energy regulation was released with their involvement. In 2016, with the support of the UK and Indonesian Governments, the South-East Asian Marine Energy Centre was established in Indonesia.

Ocean energy is not only a renewable, but also a source of new energy for Indonesia, and therefore a well-maintained cross-sectorial coordination among stakeholders is important for future development. Additionally, challenges for ocean energy in Indonesia include the following:

a) The domestic availability of technologies and the early state of pilot projects and evaluations in the country;
b) Geographical distances, the logistics of locations and absence of infrastructure; and
c) The need to develop a market and the economics of ocean energy electricity generation.

With regard to the purchase tariff for ocean energy, the MoEMR issued Regulation No. 50/2017 on the Utilisation of Renewable Energy Resources for Electricity to set new tariffs for renewable energy projects. Please see *Section 5.9 - New Tariff Stipulation for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

125 https://www.esi-africa.com/news/indonesia-house-largest-tidal-power-project/

5.9 New Tariff Stipulation for Renewable Energy

In late January 2017, the MoEMR issued MoEMR Regulation No. 12/2017 on the Utilisation of Renewable Energy Resources for Electricity. However, the regulation was amended by MoEMR Regulation No. 43/2017 in July 2017, which changed some points on Solar PV and hydropower pricing. In August 2017, the Minister of Energy and Mineral Resources revoked both MoEMR Regulation No. 12/2017 and MoEMR Regulation No. 43/2017 under MoEMR Regulation No. 50/2017.

MoEMR Regulation No. 50/2017 provides new mechanisms to determine the tariffs of renewable energy for electricity generation, including Solar PV, wind, hydro, biomass, biogas, waste-to-energy, and ocean energy. The purchase of electricity generated using these technologies will now be determined by benchmarking against the BPP or based on negotiations between IPP and PLN. Additionally, Component E that reimburses investors for transmission line spending from the power plant to the PLN grid is conducted through B2B negotiations between PLN and IPPs. The salient features of MoEMR Regulation No. 50/2017 (Table 5.18) are as follows:

Table 5.18 – Salient features and explanation of MoEMR Regulation No. 50/2017

Items	Description	Ref.
Key Features	• This regulation sets out guidance for PLN regarding the purchase of electricity from IPPs that utilise renewable energy, i.e. PV, hydro, biogas, biomass, wind, geothermal, municipal waste-to-energy, and ocean energy power projects. • PLN "must-run" renewable energy power plants up to 10MW (i.e. PLN must evacuate and pay for all power produced).	Articles 3, 4
Hydropower	• The provision covers hydro that is based on waterflow/fall or on the utilisation of a multi-purpose dam/irrigation channel. • Hydro ≤ 10 MW should operate at a minimum capacity factor of 65%. • Hydro > 10 MW should operate with a capacity factor aligned with the system requirements.	Article 7
Biomass & Biogas	• Biomass and biogas projects can only be done by IPPs that have sufficient feedstock for the whole operational period and shall be conducted through direct selection mechanism.	Articles 8, 9
Municipal Waste-to-Energy	• The municipal waste-to-energy technologies include: (a) sanitary landfill; (b) anaerobic digestion; and (c) thermochemical technology. In addition, IPPs may receive additional facilities and incentives according to current existing Laws and regulations.	Article 10
Geothermal	• The purchase of electricity from geothermal can only be done by IPPs that have working areas with "proven reserves" after exploration.	Article 11
Tariff for Renewable Electricity	• Generally, the tariff for renewable electricity is determined through negotiations between IPPs and PLN by benchmarking against the regional BPP in the region where the project is installed. For details of the tariff for each type of technology please see Table 5.19 below.	Articles 5, 6, 7, 8, 9, 10, 11
BOOT	• The BOOT scheme is applied to all projects except waste-to-energy.	Articles 7, 11
Local Components	• In the procurement process for IPPs, PLN will prioritise an IPP that uses local components as stated in the prevailing regulations.	Article 15

Others	• The purchase of electricity must obtain approval from the Minister. • PLN is obliged to: (a) inform the public of any regional power systems that are ready to utilise renewable electricity; (b) make available the regional BPP to IPPs intending to develop renewable projects; (c) provide standard documents on the procurement and the PPA model. • The IPP selected as the developer of a renewable energy project is obligated to complete the construction of the power plant in accordance with the PPA. Any lateness in completing the construction as shall be subject to sanction and/or penalty as set out in the PPA.	Articles 14, 16, 17, 18
Transitional Provisions	• IPPs working in renewables projects and which have signed PPAs for the purchase of electricity shall comply with the existing PPAs. • IPPs that have not yet signed PPAs, the purchase of electricity shall comply with MoEMR Regulation No. 50/2017. • IPPs that have been appointed as geothermal tender winners, and SoEs that have been assigned for geothermal development shall comply the previous MoEMR Regulation (i.e. Regulation No. 17/2014. • IPPs have obtained tariff approval from the Minister based on MoEMR Regulation No. 12/2017 (as amended by MoMR Regulation No. 43/2017) and not yet signed PPAs, the purchase of electricity shall comply with MoEMR Regulation No. 12/2017. • The ongoing Solar PV quota capacity tender shall be continued and will comply with MoEMR Regulation No. 50/2017 (see Page 135).	Articles 19, 20, 21, 22, 23, 24

Table 5.19 – Tariff stipulation based on MoEMR Regulation No. 50/2017

<table>
<tr><th rowspan="2">No.</th><th rowspan="2">Type of Renewable Energy</th><th rowspan="2">Method of Procurement</th><th colspan="2">Maximum Benchmark Price</th></tr>
<tr><th>Regional BPP > National BPP</th><th>Regional BPP ≤ National BPP</th></tr>
<tr><td>1</td><td>Solar PV</td><td rowspan="2">Direct Selection based on Capacity Quota</td><td rowspan="5">85% Regional BPP</td><td rowspan="5">B2B Negotiations</td></tr>
<tr><td>2</td><td>Wind Power</td></tr>
<tr><td>3</td><td>Biomass</td><td rowspan="4">Direct Selection</td></tr>
<tr><td>4</td><td>Biogas</td></tr>
<tr><td>5</td><td>Ocean Energy</td></tr>
<tr><td>6</td><td>Hydropower</td><td rowspan="3">Regional BPP</td><td rowspan="3">In the regions of Sumatera, Java, and Bali or other systems where regional BPP ≤ National BPP, the tariff shall be based on B2B negotiations.</td></tr>
<tr><td>7</td><td>Municipal waste-to-energy</td><td rowspan="2">Based on laws and regulations*</td></tr>
<tr><td>8</td><td>Geothermal</td></tr>
</table>

Notes: Laws and regulations for geothermal refer to GR No. 7/2017 on Geothermal for Indirect Utilisation which states that the geothermal procurement is based on open tender or direct appointment method. Whilst waste-to-energy refers to GR No. 14/2012 (as amended by GR No. 23/2014) on Electricity Business Provision in which the procurement can be based on open tender, direct selection, or direct appointment. Specific to waste-to-energy in Jakarta, Tangerang, Bandung, Semarang, Surakarta, Denpasar, and Makassar, that are included as National Strategic Projects, the procurement refers to PR No. 3/2016 (as amended by PR No. 58/2017) on Acceleration of the Implementation of National Strategic Projects in which the procurement applies direct appointment. The 2016 National BPP is USD 7.39 cents/kWh (as presented in MD No. 1404/K/20/MEM/2017).

Source: MoEMR Regulation No. 50/2017; Coffee Morning Session with DGE, 10 August 2017

The new regulation represents a move back towards PLN having control over the tariff negotiations through B2B arrangements. Moreover, instead of evaluating the tariff through the marginal economic value of the project investment, the regional BPP becomes the main benchmark for the tariff. In this case, investors have to note that project development timelines may extend over many years, and there is a substantial risk for them that their target tariff will change due to BPP updates (perhaps even annually).

For Solar PV, wind power, biomass, biogas and ocean energy, in the cases that Regional BPP > National BPP, the maximum benchmark tariffs are 85% of Regional BPP, whilst B2B will be used in the cases that Regional BPP is less or equal to National BPP.

For hydropower, geothermal, and municipal waste-to-energy, in the case that Regional BPP > National BPP, the maximum benchmark tariff is Regional BPP. In the cases in Sumatera, Java, and Bali or other systems where the Regional BPP is less than or equal to National BPP, the tariff shall be conducted based on B2B negotiations between IPPs and PLN.

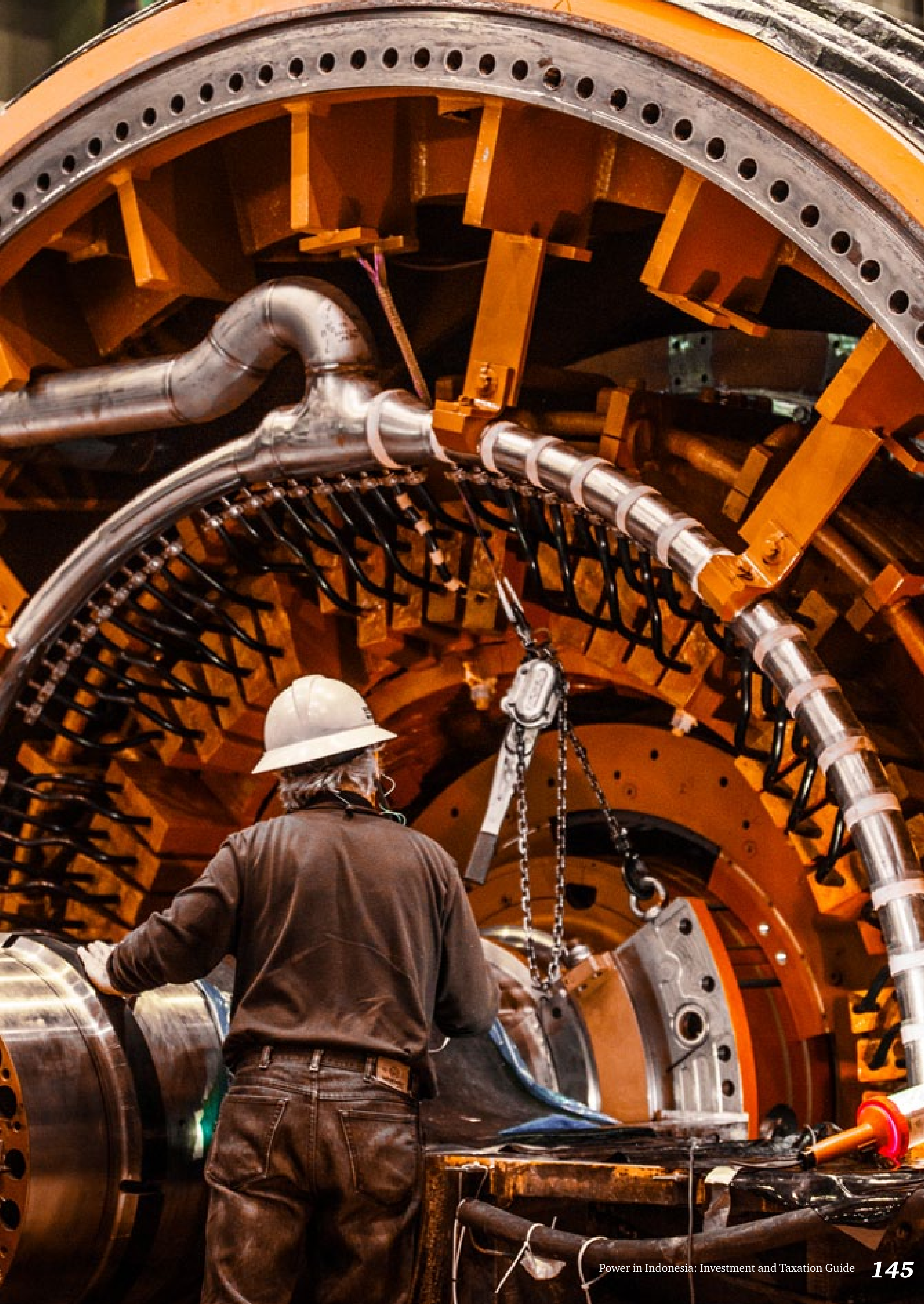
This also raises questions regarding projects located in Sumatera, Java, or Bali and which have a Regional BPP > National BPP (e.g. North Sumatera where the Regional BPP is USD 9.28 cents/kWh). The MoEMR appeared to prioritise geography over Regional BPP. For example, the price for North Sumatera shall be based on B2B negotiations rather than benchmarking against Regional BPP (see Table 5.19).[126]

With such provisions, the regulation has the advantage of providing an incentive to PLN to sign PPA and provides clear benchmarks (at least in the case where Regional BPP>National BPP). However, compared to the previous regulations (i.e. MoEMR Regulation No. 19/2015, No. 19/2016, and No. 21/2016), the new tariffs are generally lower, so will likely lead to a decrease in an IPP's investment returns. In the case where the benchmark price is a maximum and not a fixed point, this gives PLN significant bargaining power.

Specific risk exposures also exist for geothermal project development. Mandating that tariff negotiation can only be done for projects with "proven reserves" after exploration might discourage investors, who will now generally have to spend several years and millions of dollars before obtaining certainty regarding the tariff (see *Section 5.3.4 - Challenges for Geothermal Development)*.

Additionally MoEMR Regulation No. 50/2017 adds a new provision that the selected IPP is obligated to complete the construction of the power plant in accordance with the PPA. Penalties and sanctions are imposed on IPPs that fail to finish the project by the agreed COD.

126 DGE, "Principles of Regulation No. 45/2017, 49/2017, and 50/2017", Coffee Morning Session with DGE, 10 August 2017



6 Taxation Considerations

6.1 Overview

This Chapter provides a general overview of the tax issues relevant to private investors in power generation projects in Indonesia (with specific tax issues for renewable energy projects set out in *Section 6.4 - Taxation Issues for Renewable Power Generation*). These comments focus on the tax regime relevant to equity investors but also touch upon the taxes likely to be encountered by asset constructors, capital equipment suppliers, employees and financiers.

The taxes relevant to power generation projects in Indonesia fall under the following general headings:

a) Income Tax due on in-country profits;
b) (Income Tax) withholding (WHT) obligations generally due on service, royalty and interest payments;
c) (Income) Tax due on capital gains such as those arising on asset sales and upon any project divestment;
d) Value Added Tax (VAT) due on the import of, and in-country supply of, most goods and services;
e) Various employment related taxes including WHT on employee cash and non-cash remuneration; and
f) Other taxes including:
    i) Import taxes;
    ii) Various regional taxes; and
    iii) Taxes due on the ownership of land and buildings.

6.2 Taxes

6.2.1 Income Tax

Indonesian Income Tax is currently levied pursuant to Income Tax Law No. 36/2008 (the 2008 Income Tax Law). Unlike the oil and gas and mining sectors, this Income Tax regime is largely that which applies to general business activities. That is, there are very few power-sector-dedicated Income Tax rules and, in particular, there are no provisions allowing for tax stability over the life of a power investment. As discussed below, this could mean that the tax regime is deficient in a number of key areas, at least from a private power project investor's perspective.

Indonesia's general Income Tax arrangements are, internationally speaking, quite conventional and offer rates of tax that are quite competitive even on a regional basis.

The principal features include the following:
a) A flat rate of Income Tax due at (currently) 25% of taxable profits. This rate will however move with the prevailing tax rules (i.e. there is no guarantee of rate stability). IDX listed entities which satisfy a minimum listing requirement of 40% and other conditions may also be able to enjoy a further 5% reduction of this rate to 20%;
b) A general entitlement to deduct/depreciate most spending connected to income generation;
c) Emerging restrictions around the entitlement to deduct financing costs (see comments below);
d) An increasing focus on transfer pricing ("TP") compliance and thus the potential for TP related adjustments;
e) A five year tax loss carry forward entitlement; and
f) A document intensive tax administration environment with automatic tax audits before the payment of any tax refunds.

Overall, the taxable income calculation largely follows the conventional accounting profit with largely conventional adjustments for various timing and permanent differences (although see below on the *Interpretasi Standar Akuntansi Keuangan* ("ISAK") 16 accounting rules). The regime is however single-entity focused with no ability to calculate tax on a consolidated or group basis or to transfer tax losses between entities.

For more detailed information on Indonesia's general tax rules please refer to our "Indonesia Pocket Tax Book" publication.

One recent development was the commencement of PLN imposing a 1.5% "withholding" of (Article 22) Income Tax on payments made to IPP companies (given PLN's status as a state owned enterprise) with effect from 1 January 2016. The 1.5% tax is however creditable to the IPP company and so represents a cash flow concern only.

Accounting Rules

As outlined in Chapter 7, the accounting rules relevant to many long term power projects have, from 1 January 2012, resulted in the respective parties (generally PLN and the IPP) having to book their arrangements as being in the nature of a lease or (more likely) as a service concession. This treatment could have a significant impact on the books of the IPP if, for example, in a service concession arrangement, the power asset is reclassified as part of a financial asset.

There is no formal guidance on the tax impact of these accounting changes from the Indonesian Tax authorities. In a general sense, whilst the accounting treatment can be persuasive for Income Tax purposes, this is generally only the case where the Income Tax treatment is not well regulated. On this basis the likely result is that the Income Tax outcome should continue to follow the legal form of the business. This position also appears to have been accepted by the Indonesian Tax authorities in practice, although there were a number of early attempts to apply ISAK 16 for tax. Developments in this regard should be monitored.

Deductibility Issues

Whilst there is a general entitlement to deduct all expenditure associated with the generation of income there are a number of categories of specifically non-deductible expenses. These include:

a) *Non-arm's length payments made to related parties:* the general tax rules entitle the tax authorities to adjust the pricing agreed between parties under a "special relationship" where that pricing was not considered to be arm's length. A special relationship is deemed to exist at a relatively low 25% common equity threshold. The tax authorities have also recently enhanced the documentation requirements to support such pricing. This reflects Indonesia's increasingly aggressive monitoring of TP concerns;

b) *Limitations on tax losses carried forward:* the carry forward is generally limited to five years from the year in which the loss was incurred. This expiration period can be an issue in the context of a project with a large upfront capital commitment because of the early generation of significant depreciation/amortisation charges;

c) *Pre-establishment expenses:* whilst not specifically denied, the general tax rules do not easily accommodate costs incurred prior to the establishment of the taxpayer;

d) *Depreciation/amortisation rules:* Indonesia's Income Tax law effectively requires the capitalisation of all expenditure with an economic life in excess of 12 months. The law then allows depreciation to the extent that the spending relates to tangible assets and amortisation to the extent that the spending relates to intangible assets.

   Depreciable costs include all expenditure incurred to purchase, install and construct an asset, which generally extends to interest incurred during the construction period where that interest is construction related.

The tax law breaks depreciation/amortisation on (non-building) tangible and non-tangible assets into four categories and two depreciation methods (straight line and double declining rate) as follows:

	Effective Life max. (years)	Straight Line Rate (%) p.a.	Declining Balance Rate (%) p.a.
i)	4	25.00	50.00
ii)	8	12.50	25.00
iii)	16	6.25	12.50
iv)	20	5.00	10.00

Power generation equipment is generally treated as having a useful life of 16 years, and thus attracts a straight line rate of 6.25% or a declining balance rate of 12.5%. Depreciation generally commences from the date of expenditure. However, where an asset is "constructed" depreciation commences at the time of completion. With DGT's approval, commencement can be delayed until operations begin;

e) *Land and buildings:* while "tangible assets" with a useful life of more than one year can be depreciated at the above rates, "buildings" are treated as separate tangible assets and attract a straight line rate of 5%. The option to use the declining balance rate is not available. Land cannot be depreciated and also does not usually include buildings. Where assets are attached to the ground and cannot be moved without being dismantled, they may be constituted as buildings. Uncertainty can therefore exist regarding the classification of tangible assets connected to land such as roads, fences, wharfs, reservoirs and pipelines;

f) *(Thin capitalisation) debt:equity requirements:* on 9 September 2015 the Minister of Finance issued Regulation No. 169/2015 which introduced a general debt and equity ratio ("DER") limitation of 4:1 for Income Tax purposes. MoF 169 first applied from 1 January 2016. Where debt exceeds equity by a factor of 4 (determined on a monthly basis) the interest attaching to the "excessive debt" is non-deductible. There are preliminary debt and equity definitions provided. MoF 169 does however provide an exemption from the DER rules for certain industries, including for those involved in "infrastructure" albeit without an "infrastructure" definition. In a recent development the tax authorities seem to be of the view that the meaning of "infrastructure" should follow the definition set out in Presidential Regulation No. 38/2015 pertaining to public-private partnerships. This definition extents to IPP activity. Formal implementing regulations on the DER arrangements were however outstanding at the time of writing, meaning that this area continues to carry some uncertainty.

g) *Payments of non-cash employment benefits:* see more detailed comments below under 6.2.5 Personnel taxes.

6.2.2 Withholding Tax ("WHT")

In an Indonesian context WHT constitutes an obligation to withhold Income Tax at a set percentage of a relevant payment and to remit the amount withheld to the Tax Authorities.

Some WHT is "non-final" in that the WHT is creditable against the withheld party's annual Income Tax obligation in Indonesia. Non-final WHT will typically apply to payments made to Indonesian resident service providers and will typically be at a rate of 2% of the relevant payment. In these cases the service provider would be required to submit an annual Indonesian Income Tax return, to credit the WHT against the annual tax liability, and then be entitled to a refund of any excess.

Types of payments subject to creditable/non-final WHT include:

a) Payments to residents for the rent of moveable property (rate of 2%);
b) Payments to residents for consulting, management or technical services (rate of 2%);
c) Payments to residents constituting royalties (rate of 15%);
d) Payments to IUP holding companies for coal purchases (rate of 1.5%).

WHT is also collected on a "final tax" basis. This WHT is still calculated as a percentage of the gross payment, but there is no additional Income Tax due from the recipient on that income and also no refund potential (i.e. irrespective of the actual profit derived from the payment).

EPC related services are subject to this "final tax" regime via a WHT mechanism by the relevant IPP. Depending upon the structure and the EPC provider's construction qualifications the WHT rates vary between 2% and 6%.

Other types of payments subject to non-creditable/final WHT include:

a) Payments to residents for the rent of certain non-movable property (rate of 10%);
b) Payments to non-residents for most services as well as for interest and royalties (rate of 20% before any treaty relief); and
c) Dividends paid to non-resident investors (rate of 20% before any treaty relief).

6.2.3 Capital Gains Tax

Indonesia's Income Tax rules do not focus on the distinction between revenue and capital receipts. Instead "profits" made from the sale of assets are generally simply treated as income.

An exception is made for the sale of assets made by non-residents. In this case, Income Tax is currently limited to the sale of shares in non-public Indonesian entities (and the sale of luxury goods such as paintings, jewelry, etc.). The Income Tax is effectively due at the flat rate of 5% on the transaction proceeds (i.e. irrespective of whether any economic profit has been made).

Further, for the sale of shares in Indonesian entities listed on the IDX Income Tax is due at the flat rate of 0.1% of transaction proceeds. To be eligible for this rate, founder shareholders must pay tax at 0.5% of the market price of their shares upon listing, otherwise gains on subsequent sales are taxed under normal rules.

6.2.4 Value Added Tax ("VAT")

Indonesia imposes a broad based VAT, as currently set out pursuant to VAT Law No. 42/2009 (the 2009 VAT Law). The general VAT rate is 10%, although supplies constituting exports of goods or exports of some services attract a 0% VAT rate.

Indonesia's VAT system is quite conventional, with VAT required to be charged (as output VAT) on the value of most supplies of goods and services made within Indonesia and with each person being charged such VAT (as input VAT) being entitled to a credit, providing that this person themselves incurs VAT on its own VAT-able supplies.

Input VAT and output VAT are therefore not generally included in the calculation of Income Tax.

The supply of electricity is technically VAT-able but, because electricity represents a "strategic good", the supply of electricity is effectively VAT exempt. This outcome is discussed further below in relation to the VAT exemption for strategic goods.

6.2.5 Personnel Taxes

Income Tax on Remuneration

Employment related cash remuneration is subject to Indonesian Income Tax at a (maximum) rate of 30% for resident employees, or at a (flat) rate of 20% for non-residents. Non-cash remuneration (or benefits in kind) is typically treated as non-taxable in the hands of the employee, but with the cost of the benefit being non-deductible to the employer.

Residents are taxed on worldwide remuneration (including investment income) while non-residents are taxed on Indonesian sourced remuneration only.

Foreign nationals (and their dependents) will generally be deemed to be tax residents if they stay in Indonesian for more than 183 days in any year, or they arrive in Indonesia with the intention to stay for more than 183 days.

Social Security Contributions

Indonesian employment arrangements require both the employer and employee to make contributions to a number of schemes (see details in the table below). These schemes apply to all employees (now including expatriates).

A new social security scheme, known as the Social Security Agencies or *Badan Penyelenggara Jaminan Sosial* ("BPJS"), replaced the former Jamsostek scheme (which generally did not apply to expatriates) from 1 January and July 2015 for local employees and expatriates respectively.

The BPJS can be summarised as follows:

Insurance component	Agency		Scope	Contribution rate (as a percentage of regular salaries/wages)	
	Previous	New		Borne by employers	Borne by employees
Worker's Social Security	• PT Jamsostek • PT ASABRI • PT TASPEN	BPJS for worker's social security *(BPJS Ketenagakerjaan)*	a) Accident insurance;	0.24% - 1.74%	
			b) Old age savings;	3.70%	2.00%
			c) Death insurance;	0.30%	
			d) Pension.	2.00%	1.00%
Health	• PT Jamsostek • PT Askes • Ministry of Health • Ministry of Defence, National Army, Police Department	BPJS for health insurance *(BPJS Kesehatan)*	Basic health insurance	4.00%	1.00%

6.2.6 Import taxes

General

The physical importation of most capital equipment will be subject to the following taxes:

a) Import Duty: this is due at the "harmonised" duty rate which will vary according to the type of goods in question;
b) VAT: this is due at 10% of "the Import Duty inclusive" CIF value of the relevant goods;
c) "Article 22" Income Tax: this is an Income Tax prepayment and is (generally) due at 2.5% of the "Import Duty inclusive" CIF value (for importers with an appropriate Import Licence) of the relevant goods.

Pursuant to the Import Duty regulations, the Import Duty rates applying to typical power related imports include:

Import Item	Duty Rate
Turbines	Up to 5%
Steel	Up to 15%
Boiler Furnaces	Up to 10%
Transformers	Up to 10%
Electricity Transmission Cables	Up to 10%

Master List Exemption – Import Duty

A concession (known as a "master list") is generally available for all BKPM licensed investments and provides an exemption from the Import Duty otherwise applicable to imports of "machines, goods and materials" used for the establishment or development of a facility used to produce goods (which includes electricity) or to provide a limited number of services. The master list is currently regulated under MoF Regulation No. 76/2012 (as amended by MoF Regulation No. 188/2015).

Customs Exemption – Import Duty

A separate Import Duty concession (currently regulated under MoF Regulation No. 66/2015) may provide an Import Duty exemption on the import of capital goods (being machines, equipment and tools but not spare parts) where these are imported by:

a) PLN;
b) An IUPTL holder in a designated business area;
c) IPPs holding a PPA (or designated Finance Lease Agreement) with PLN; or
d) IPPs holding a PPA with another IUPTL holder in a designated business area.

This exemption should be outlined in the relevant agreement.

Historically this concession was sought from the Customs Office but is now sought from BKPM.

Free Trade Area ("FTA") Agreements – Import Duty

A further Import Duty concession (as an exemption or reduced Import Duty rate) may be available via Indonesia's various FTA Agreements.

Indonesia's FTAs currently include those with ASEAN, Australia, New Zealand, China, India, Korea, Japan and Pakistan.

VAT Exemption – Strategic Goods

Capital goods (being plant, machines and equipment but not spare parts) are considered to be "strategic goods". Under GR No. 12/2001 (as amended by GR No. 81/2015 and MoF Regulation No. 268/2015) a VAT exemption is available for the importation and local delivery of strategic goods where the goods are used to produce VAT-able goods.

As indicated above pursuant to GR No. 81/2015, the supply of electricity is VAT-able, but it is exempted from VAT as a "strategic good" (except for supplies to households above 6600 watts). Therefore, even though power producers (including PLN) are generally VAT-exempt, a VAT registration entitlement exists and this generally allows access to the VAT exemption on imported capital goods. Further, and starting 1 January 2016, VAT registration was made mandatory for IPPs even though electricity supplies remained VAT exempt. As a result IPPs are are now required to issue VAT invoices on their electricity deliveries with the VAT invoices stamped by stating that the relevant delivery is exempt from VAT.

To obtain a VAT exemption on imports, the IPP needs to submit an application along with the relevant import/purchase documents, to the Directorate General of Tax ("DGT").

Article 22 Exemption - Imports

The tax authorities may allow an Article 22 Income Tax exemption upon application. The requirements include:

a) That the taxpayer is a newly established entity;
b) That the taxpayer has obtained a "master list" facility (see above); and
c) That the taxpayer will not be in an Income Tax underpayment position.

In practice these exemptions can be difficult to obtain. However, in the case of IPPs using renewable energy an automatic Article 22 Exemption may be separately be available – see *Section 6.4 - Taxation Issues for Renewable Power Generation* for further discussion.

VAT for Operations and Maintenance ("O&M") Services

The provision of O&M services constitutes an electrical power support business and is subject to VAT. On this basis an O&M company should be a VAT-able firm, meaning that its input VAT will be creditable against its output VAT (although the VAT charged on O&M services to the IPP will not be creditable to the IPP).

6.2.7 Regional Taxes

With the passage of the Regional Autonomy Law No. 32/2004 and its amendments (subsequently replaced by Law No. 23/2014 and its amendments) certain taxing powers were transferred exclusively to Indonesia's Provinces and Regions. These arrangements are currently set out in Law No. 28/2009 (partially replaced by Law No. 23/2014) which provides a closed list of regional taxes and maximum rates of tax. Each tax is subject to local implementation.

A summary of the regional tax arrangements is as follows:

Type of Regional Tax		Maximum Tariff	Current Tariff	Imposition Base
A. Provincial Taxes				
1	Taxes on motor vehicles and heavy equipment	10% p.a.	Non-public vehicles	
			1% – 2% for the first private vehicle owned	Calculated with reference to sales value and a weight factor (size, fuel, type, etc.) Government tables will be published annually to enable calculation.
			2% – 10% for the second and more private vehicles	
			0.5% – 1% public vehicles	
			0.1% – 0.2% heavy equipment vehicles	
2	Title transfer fees on motor vehicles, above-water vessels and heavy equipment	20%	Motor vehicles	
			20% on first title transfer	
			1% on second or more title transfer	
			Heavy equipment	
			0.75% on first title transfer	
			0.075% on any title transfers after the first	
3	Tax on motor vehicle fuel	10%	Public vehicles: at least 50% lower than tax on non-public vehicle fuel (depending on each region)	Sales price of fuel (gasoline, diesel fuel and gas fuel)
4	Tax on the collection and utilisation of underground water and surface water	10%	Tariff on surface water only	Purchase value of water (determined by applying a number of factors).
B. Regency and Municipal Taxes				
5	Tax on street lighting	10%	3% utilisation by industry	Sales value of electricity (power bill)
			1.5% personal use	
6	Tax on non-metal minerals and rocks (formerly C-Category mined substance collection)	25%	Set by region	
7	Tax on groundwater	20%	Set by region	Purchase value
8	Land and buildings tax	0.3%	Set by region	Only on certain types of land and buildings
9	Duty on the acquisition of land and building rights	5%	Set by region	Land and buildings sale value

6.2.8 Stamp Duty

Indonesian Stamp Duty is due on the execution of most documents required as evidence of transactions. This includes the transfer of shares, the conveyance of real estate or other property, and most rental and lease agreements.

In some countries, Stamp Duty is calculated as a percentage of the value of the underlying transaction being evidenced (with a fixed rate for low value transactions), and thus it can be substantial.

In Indonesia however, Stamp Duty is due at nominal values, typically less than USD1, and thus is rarely a concern.

6.3 Issues for Conventional Power Generation

6.3.1 Income Tax

As indicated, the tax arrangements relevant to Indonesia's power generation sector rely heavily on the general tax rules. This is unlike the arrangements that have historically applied to other large capital intensive projects, such as in the natural resources sector. There is also uncertainty around whether the tax arrangements will be impacted by the introduction of ISAK 8 or ISAK 16, see discussion of Accounting Consideration in *Section 7.1 - Accounting for Conventional Power Generation*.

These issues aside, the commercial profile of a power project is generally more analogous to a large natural resources project than (say) an industrial, manufacturing or service investment. For instance, a power generation project will typically involve:

a) A relatively long and expensive period of pre-project feasibility studies often involving the establishment of relationships with multiple investing parties, the completion of detailed reviews and modelling of project viability, extensive liaison with potential project financiers, etc.;
b) A large upfront capital requirement (relative to the overall project cost) often with complex debt to equity requirements driven by third party (including quasi-Government) financing requirements;
c) A relatively long but non-volatile pay-back period with potentially only one customer and pricing pegged only to key operational costs; and
d) A high level of economic sensitivity to the speed at which tax free cash can be generated to stakeholders and so the considerable relevance of depreciation and amortisation rates, capitalisation policies including in relation to interest deductibility, and depreciation classifications (i.e. land, buildings, other tangible assets, etc.).

Specific issues on these points which can arise under Indonesia's current tax regime include:

a) The lack of certainty around deductions for founder and other pre-establishment costs;
b) The impact of modelling a long term project within an investment framework with no tax stability including any minimum capitalisation requirements (unless the 4:1 DER applies- see above);
c) The potential for deductions to be lost due to a 5 year tax loss carry forward limitation; and
d) The incremental project costs arising from a VAT exemption on electricity supplies (see above).

6.3.2 VAT

With regard to VAT, as indicated above, the supply of electricity will generally be (effectively) exempt from VAT on the basis of constituting a "strategic good".

Quite importantly, where a supply is exempt from VAT the Input VAT incurred by that supplier will not be creditable. As such, for a power project in Indonesia making only supplies of electricity, all input VAT of that project will essentially become an outright cost to the project (although the VAT itself should be tax deductible). This is quite different in an economic sense to instances in which Input VAT is creditable and so constitutes a cash flow concern only.

In a general sense therefore, and assuming an Income Tax rate of 25%, the after-tax financial impact of being a VAT exempt supplier is (in a broad based VAT environment) potentially up to 7.5% project costs (i.e. 10% VAT x (1 – 0.25% tax rate)). This potential cash impact therefore makes the availability of VAT relief on capital imports and local delivery (such as those highlighted above) quite critical.

6.4 Taxation issues for renewable power generation

6.4.1 State Revenues and Taxes – Geothermal Regimes

The "old" geothermal regime was covered under a JoC framework introduced via Presidential Decree ("PD") 45/1991 (an amendment of earlier PD No. 22/1981) whereby PERTAMINA (now PGE) and its contractors could undertake integrated geothermal and power activity. That is, they could explore and exploit a geothermal source, build power plants and sell electricity to PLN and other consumers. PERTAMINA (now PGE) was responsible for managing the operations, while the Contractor was responsible for producing geothermal energy (i.e. steam), converting the steam into electricity and delivering steam and/or electricity.

From a tax perspective, a JoC is subject to a *"lex specialis"* arrangement within the JoC itself which generally outlines how to calculate net operating income which is then subject to a 34% tax. The 34% tax (generally called the "Government Share") is considered an "all inclusive" payment which is assumed to discharge the Contractor from other tax obligations including Income Tax, VAT, import taxes and land and buildings tax otherwise due under a normal tax regime.

Geothermal Law No. 27/2003 (the 2003 Geothermal Law) however removed the all-inclusive rate of 34% and, under Geothermal Law No. 21/2014, there are no (at least as yet – see below) specific tax regulations for geothermal activities. This means that the prevailing tax laws and regulations should apply for non-JoC geothermal projects. This also means that most of the Income Tax issues outlined in earlier sections of this chapter will also apply for all non-JoC geothermal projects (that is, projects licensed since the 2003 Geothermal Law was enacted).

On this basis, profits from both the geothermal/steam and power generation activities (noting that geothermal projects are now licensed on a disaggregated basis) are taxable at the standard rate of 25%.

6.4.2 VAT on Geothermal Projects

Steam generated from geothermal activity is considered to be a product of mining, excavation or drilling taken directly from the source. Under the prevailing VAT rules the supply of steam is therefore VAT exempt. This means that, under the post-2003 arrangements, input VAT related to supplies of both steam and electricity would not be creditable irrespective of whether connected to the steam or power generation activities (the VAT should instead be deductible).

This also contrasts with JoC arrangements, where VAT was generally reimbursable. Procedures on VAT reimbursement under the "old JoC regime" can be found in MoF Regulation No. 142/2013.

6.4.3 Draft GR on Income Tax for Geothermal Activities

In late December 2009, the DGT circulated a draft GR on the proposed Income Tax arrangements for the (non-JoC) geothermal sector. Key points outlined in the draft GR included:

a) That the tax calculation will generally follow the prevailing Income Tax Law. An exception however could be an extension of the tax loss carried forward (to seven years). Fixed retributions, production retributions and bonuses should also be deductible; and
b) That all geothermal contracts signed prior to Presidential Decree No. 76/2000 (i.e. under the old JoC regime) should be amended within three years to comply with the provisions of the GR.

At the time of printing the GR remained in draft.

6.4.4 Incentives for Renewable Power Generation

A number of fiscal incentives exist for renewable power generation projects. These include:

a) GR No. 18/2015 (as amended by GR No. 9/2016): this provides Income Tax incentives which include:
   i) A reduction in taxable income of up to 30% of qualifying expenditure on fixed assets (including land). The reduction is prorated at 5% over 6 years from commercial production;
   ii) An extended tax loss carry forward period of up to ten years;
   iii) Accelerated depreciation and amortisation rates; and
   iv) A maximum dividend WHT rate of 10%.

   GR No. 18 indicates that it applies to IPPs involved in "renewable energy".
b) MoF Regulation No. 177/2007: this provides an exemption from Import Duty on the import of goods used in "geothermal business activities". This is subject to the business entity having received a geothermal work area, preliminary survey data or an IUP;
c) MoF Regulation No. 142/2015: this provides an Import VAT exemption facility for geothermal projects in both the exploration and exploitation phases; and
d) MoF Regulation No. 21/2010: this provides an Article 22 exemption for imports by IPPs involved in renewable energy.

A specific regulation pertaining to incentives for geothermal projects is known to be under consideration by the Ministry of Finance and expected to become effective in the near future. The incentives may be similar to the incentives provided under GR No. 18/2015 but include an additional VAT exemption applying during both the exploration and exploitation stages.

A more substantial Income Tax "holiday" incentive applies for taxpayers operating in a "Pioneer Industry". Pursuant to MoF Regulation No. 103/2016 such investors may be entitled to a CIT reduction of 10 - 100% for 5-15 years. The reduction can be extended to 20 years if the project is deemed to be in the national interest. The application process is centralised through the BKPM and ends on 15 August 2018.

Qualifying criteria include:
a) That the business is in a "pioneer industry" which includes economic infrastructure (other than those constituting PPP projects);
b) That the project involves a capital investment of at least IDR1 trillion;
c) That the investor deposits at least 10% of the total capital investment with an Indonesian bank which cannot be withdrawn prior to the realization of the investment;
d) That the project is carried out through an Indonesian legal entity established after 14 August 2011; and
e) That the taxpayers satisfy the DER stipulated in a separate MoF regulation (see page 160).

MoF Regulation No. 103/2016's predecessor regulation removed "renewable energy" from the definition of pioneer industries but continues to allow "infrastructure" projects. It is therefore not clear whether renewable energy IPPs could still qualify for this incentive. In our view the GR No. 18/2015 incentive (see page 160) is likely to be more suited for renewable projects in any case.

7 Accounting Considerations

7.1 *Accounting for Conventional Power Generation*

Indonesian Financial Accounting Standards ("PSAKs") have been brought substantially into alignment with International Financial Reporting Standards ("IFRS") for annual reporting periods beginning 1 January 2012. This process of alignment has had an impact on the way many IPPs will need to account for their activities.

7.1.1 Arrangements that May Contain a Lease

PSAKs require that arrangements that convey the "right to use an asset" in return for a payment or series of payments must be accounted for as a lease. This is the case even if the arrangements do not take the legal form of a lease.

Tolling arrangements may also convey the use of the asset to the party that supplies the fuel in such a manner as to constitute a lease. Such arrangements have become common in the renewable energy business in particular where all of the output of wind or solar farms or biomass plants might be contracted to a single party under a PPA.

Pursuant to ISAK 8 - Determining Whether an Arrangement Contains a Lease (equivalent to International Financial Reporting Interpretation Committee ("IFRIC") 4), guidelines are provided on how to determine when such an arrangement might constitute a lease.

Once such a determination is reached, the arrangement must then be classified as either a finance or operating lease according to the principles set out in Indonesian Financial Accounting Standard (*Pernyataan Standar Akuntansi Keuangan* - "PSAK") 30 - Leases (equivalent to IAS 17). In this regard, a lease that conveys the majority of the risks and rewards of operation is treated as a finance lease. A lease other than a finance lease is treated as an operating lease.

The classification is significant for the following reasons:
a) A lessor in a finance lease would derecognise its generating assets and would instead recognise a finance lease receivable;
b) A lessee in a finance lease would recognise a fixed asset and a corresponding lease liability rather than account for the PPA as an executory contract.

Classification as an operating lease therefore leaves the lessor with the fixed asset on its balance sheet and the lessee with an executory contract.

PSAKs in relation to arrangements that may contain a lease will change further after the issuance of PSAK 73. Refer to *Section 7.5 - PSAK 73 – A New Era of Lease Accounting* where we discuss the financial implications of the new lease accounting standards.

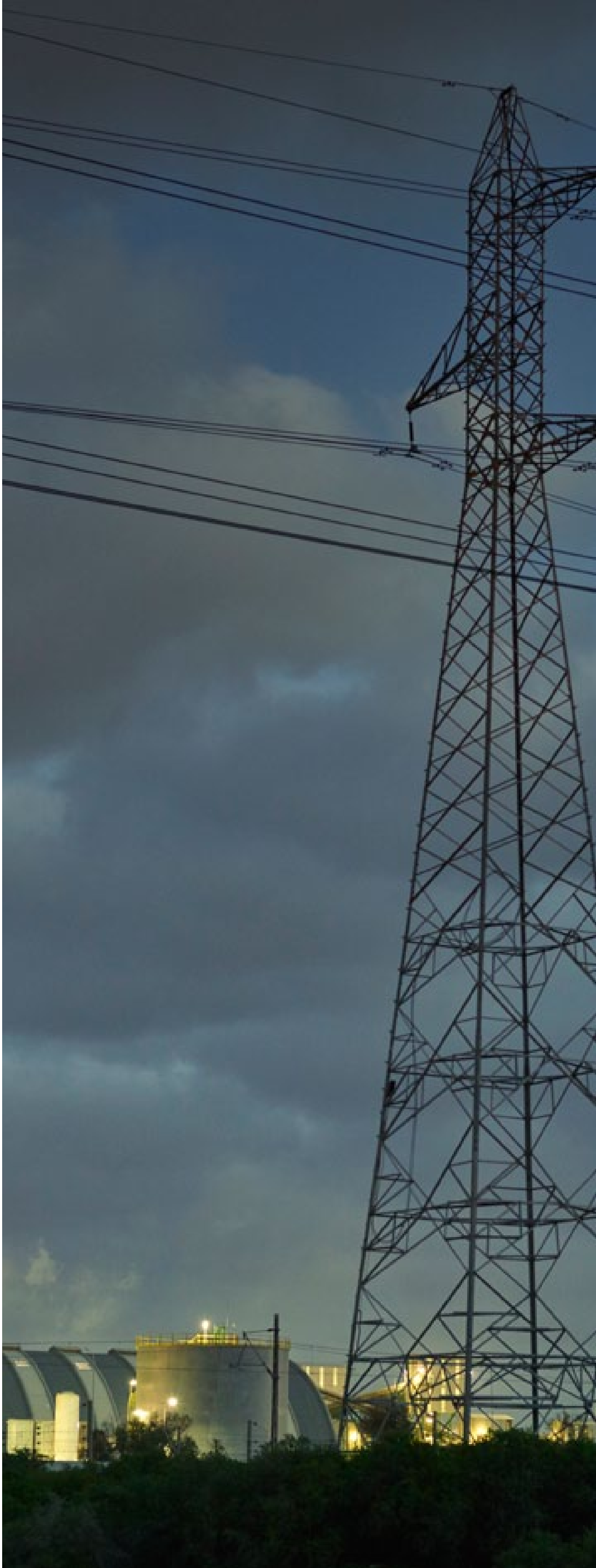
In March 2017, *Otoritas Jasa Keuangan* ("OJK"), the Indonesian Financial Services Authority, issued *Peraturan Otoritas Jasa Keuangan* No. 6 POJK.04/2017 ("POJK No. 6/2017") regulating the accounting treatment for the purchase and sale of electricity by a company with publicly traded debt/equity instruments in Indonesia (the "Issuer"). This matter is further discussed in *Section 7.1.3 - Accounting Treatment for the Purchase and Sale of Electricity by an Issuer in Indonesia* below.

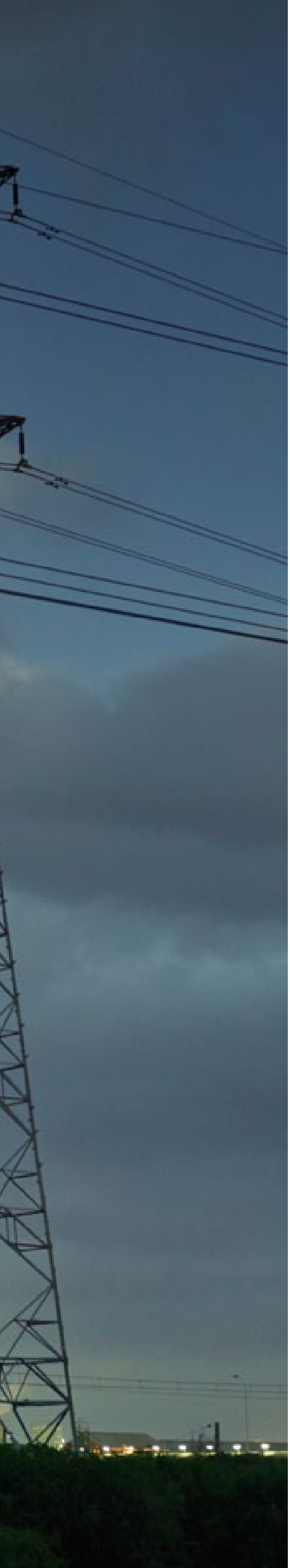
PPAs

It can be difficult to determine whether a PPA constitutes a lease in this sense. For instance, even if the purchaser takes all or substantially all of the output from a specified facility, this does not necessarily mean that the purchaser is paying for the "right to use the asset" rather than for its output pursuant to ISAK 8. If the purchase price is a "fixed per unit of output" or equal to the "current market price at the time of delivery", the purchaser is presumed to be paying for the output rather than leasing the asset.

There have been some debates over the meaning of "fixed per unit of output" in ISAK 8 and two approaches have emerged in practice. "Fixed per unit of output" is interpreted by some entities in a manner that allows for no variability in pricing whatsoever over the entire term of the contract (i.e. fixed equals fixed). However, other entities have concluded that the fixed criterion is met if, at the inception of the arrangement, the purchaser and seller can determine what the exact price will be for every unit of output sold at each point in time during the term of the arrangement (i.e. fixed equals predetermined). There is support for both views, and the interpretation of "fixed" is an accounting policy election. The accounting policy should be disclosed and applied on a consistent basis to all similar transactions.

The "current market price at the time of delivery" criterion is narrowly interpreted. For example, arrangements that include caps/floors would not be considered to reflect the current market price at the time of delivery because the price at delivery might be different from the spot market price.





7.1.2 Service Concession Arrangements

A PPP is an arrangement whereby the Government attracts private sector participation in the provision of infrastructure services. As outlined in earlier chapters, these arrangements include power generation. These types of arrangements are often described as concessions and many fall within the scope of ISAK 16 - Service Concession Arrangements (equivalent to IFRIC 12).

Arrangements within the scope of ISAK 16 are those where a private-sector entity may construct the infrastructure (a power-generating plant in this instance) then maintain it and provide the service to the public (via PLN in the case of power generation). The provider may be paid for its services in different ways. Many concessions require that the related infrastructure assets be returned or transferred to the Government at the end of the concession.

ISAK 16 applies to arrangements where the grantor (the Government or its agents) controls or regulates what services the operator can provide using the infrastructure, to whom it must provide them and at what price. The grantor also controls any significant residual interest in the infrastructure at the end of the term of the arrangement.

The most common example of such arrangements will, in this context, be a power plant constructed on a Build-Own-Operate-Transfer arrangement with a national utility such as PLN.

Power generation arrangements can fall within the scope of ISAK 16 as these have many of the features of a service concession arrangement.

The two accounting models under ISAK 16 that an operator applies to recognise the rights received under a service concession arrangement are:

a) Financial asset – an operator with a contractual and unconditional right to receive specified or determinable amounts of cash (or another financial asset) from the grantor recognises a financial asset rather than a fixed asset (i.e. derecognises the power plant in this case and replaces it with a financial asset);
b) Intangible asset – an operator with a right to charge the users of the public service recognises an intangible asset. There is no contractual right to receive cash when payments are contingent on usage.

Arrangements between Government and service providers are generally complex. Detailed analysis of the specific arrangement is necessary to determine whether the arrangement is within the scope of ISAK 16. Once within the scope of ISAK 16 the appropriate accounting model may not always be obvious. Entities should be analysing arrangements in order to draw conclusion on whether the arrangement falls under the financial asset or intangible asset models. Some complex arrangements may have elements of both models for the different phases. It may be appropriate to account separately for each element of the consideration.

7.1.3 Accounting Treatment for the Purchase and Sale of Electricity by an Issuer in Indonesia

POJK No. 6/2017 should be applied by all Issuers (i.e. a company with publicly traded debt/equity in Indonesia) to account for the purchase and sale of electricity in Indonesia. Issuers should account for all purchases and sales of electricity in Indonesia as normal purchase and sales transactions. In practice, OJK is providing a temporary exemption for Issuers that sell electricity to PLN from applying the lease (discussed in 7.1.1) and service concession (discussed in 7.1.2) accounting model.

POJK No. 6/2017 was issued to support Presidential Regulation No. 4/2016 (which was later amended by Presidential Regulation No. 14/2017) to accelerate the development of power generation infrastructure in Indonesia. It is believed that temporarily exempting Issuers from the financial implications of lease, or service concession, accounting will help advance the development of power generation projects in Indonesia. POJK No. 6/2017 is only applicable to Issuers that are under the supervision of OJK. In many cases, however, IPPs that sign PPAs with PLN do not issue publicly traded instruments. Privately owned project companies are established by a consortium of investors to sign PPAs with PLN. These privately owned IPPs are not Issuers subject to Capital Market Laws in Indonesia and consequently they cannot apply the provisions of POJK No. 6/2017, and must follow the provisions of the PSAKs.

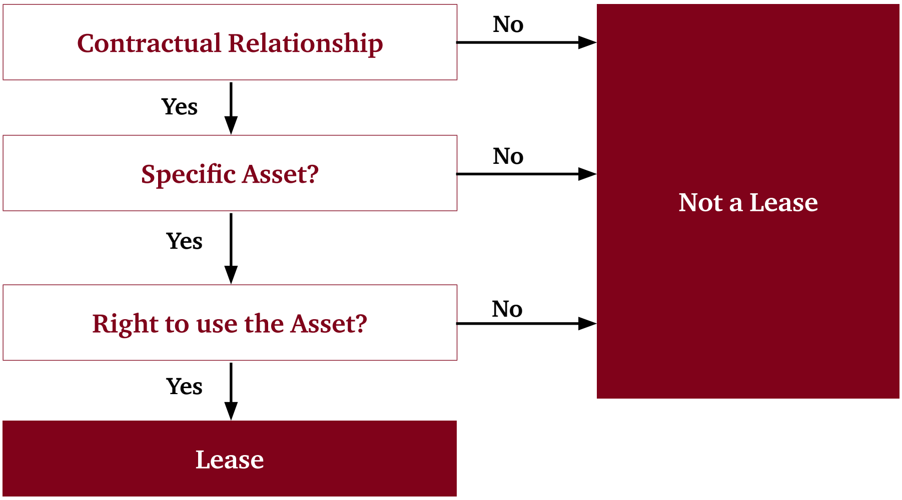
POJK No. 6/2017 is applied prospectively starting on 1 January 2017 and can be adopted early for the financial year which began on 1 January 2016. This temporary exemption is only available as long as Presidential Regulation No. 4/2016, subsequently amended by Presidential Regulation No. 14/2017, is in effect. After the temporary exemption period is over, Issuers will have to apply all the provisions of PSAK or IFRS that are in effect in the future.

It is not entirely clear how POJK No. 6/2017 will be applied in a group situation where a parent listed entity (an Issuer) controls a privately owned IPP that signs a PPA with PLN. As it is currently written, it does not appear that the temporary exemption is applicable to the group unless the parent Issuer sells electricity directly to PLN. This is an issue that requires further elaboration; therefore we recommend that you consult with your PwC advisors before applying the temporary exemption of POJK No. 6/2017 in such a situation.

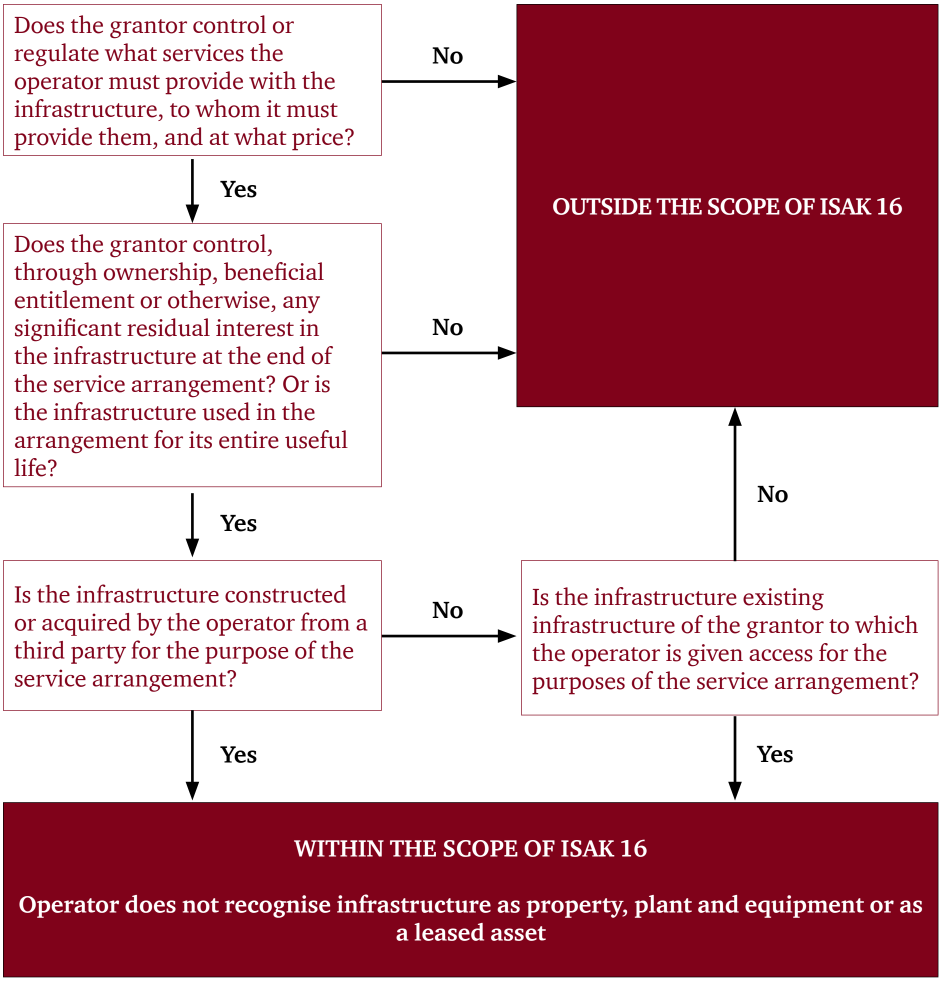
7.1.4 Application of accounting standards

The following diagrams summarise the method of determining when to apply ISAK 8 and ISAK 16.

ISAK 8 – Determining whether an arrangement contains a lease



ISAK 16 – Determining whether a service concession arrangement exists



PSAKs that apply to typical types of PPP arrangements

Except for Issuers that apply the temporary exemption of POJK No. 6/2017, the table below sets out the typical types of arrangements for private sector participation in the provision of public sector services and provides references to PSAKs that apply to those arrangements. The list of arrangement types is not exhaustive. The purpose of the table is to highlight the continuum of arrangements. It is not our intention to convey the impression that bright lines exist between the accounting requirements for PPP arrangements.

Category	Lessee	Service Provider			Owner	
Typical arrangement types	Lease (e.g. Operator leases assets from grantor)	Service and/or maintenance contract	Rehabilitate-operate-transfer	Build-operate-transfer	Build-own-operate	100% Divestment/ Privatisation/ Corporation
Assets ownership	Grantor				Operator	
Capital investment	Grantor		Operator			
Demand risk	Shared	Grantor	Operator and/or Grantor		Operator	
Typical duration	8-20 years	1-5 years	25-30 years			Indefinite (or may be limited by licence)
Residual interest	Grantor				Operator	
Relevant PSAKs	PSAK 30 - Leases	PSAK 23 - Revenue	ISAK 16 - Service Concession Arrangements		PSAK 16 - Fixed Assets	

In accordance with POJK No. 6/2017, Issuers account for all purchases and sales of electricity as normal purchase and sale transactions as long as Presidential Regulation No. 14/2017 is in effect, please see discussion in *Section 7.1.3 - Accounting Treatment for the Purchase and Sale of Electricity by an Issuer in Indonesia* above.

7.1.5 Key Accounting Standards under PSAK, US Generally Accepted Accounting Principles ("US GAAP") and IFRS

The table below summarises the key standards and differences related to conventional power generation companies under PSAK, US GAAP and IFRS. For details of the key general accounting standards, please refer to our publication "IFRS and Indonesian GAAP (PSAK): Similarities and Differences 2015".

Accounting for Conventional Power Generation			
A general comparison between Indonesian GAAP, US GAAP and IFRS			
Area	**IFRS**	**US GAAP**	**Indonesian GAAP**
Identification and classification of concession arrangements	PPP service concession arrangements that meet certain conditions must be analysed to determine whether the concession represents a financial asset or an intangible asset.	Consistent with IFRS in all significant respects	Consistent with IFRS in all significant respects, except for Issuers applying POJK No. 6/2017 as explained in *Section 7.1.3 - Accounting Treatment for the Purchase and Sale of Electricity by an Issuer in Indonesia* above.

Accounting for Conventional Power Generation			
A general comparison between Indonesian GAAP, US GAAP and IFRS			
Area	**IFRS**	**US GAAP**	**Indonesian GAAP**
Arrangements that may contain a lease: retrospective action	Arrangements that convey the right to use an asset in return for a payment or series of payments are required to be accounted for as leases if certain conditions are met. This requirement applies even if the contract does not take the legal form of a lease. The IFRS guidance that requires this analysis, IFRIC 4, requires all existing arrangements to be analysed upon adoption (i.e. no grandfathering of existing arrangements).	Similar to IFRS except that the US GAAP guidance, EITF 01-8 (codified into ASC 840), was applicable only to new arrangements entered into (or modifications made to existing arrangements) after the effective date (i.e. grandfathering of existing arrangements was provided).	Consistent with IFRS in all significant respects

7.2 O&M Accounting

There are no specific accounting standards promulgated for power generation O&M businesses. Instead, generally accepted accounting standards usually apply.

7.3 Accounting for Geothermal Power Generation

Key accounting standards for renewable energy projects are the same as those relevant for conventional power generation.

However, the accounting treatment for geothermal exploration and evaluation ("E&E") is similar to activities in the oil & gas industry, which can be used as guidance in treating E&E costs.

Exploration, as defined in PSAK 64 Exploration and Evaluation of Mineral Resources (equivalent to IFRS 6) starts when the legal rights to explore have been obtained. Expenditure incurred before obtaining the legal rights is generally expensed.

Two broadly acknowledged methods have traditionally been used under local GAAP to account for E&E and subsequent development costs:
a) Successful efforts; and
b) Full cost.

Debate continues within the industry on the conceptual merits of both methods although neither is wholly consistent with the PSAK framework. PSAK 64 provides an interim solution for E&E costs, pending the issuance of more comprehensive accounting standards for the extractive industries.

An entity should account for its E&E expenditure by developing an accounting policy that complies with the PSAK framework or in accordance with the exemption permitted by PSAK 64.

PSAK 64 allows an entity to continue to apply its existing accounting policy under national GAAP for E&E. However an entity can change its accounting policy for E&E only if the change results in an accounting policy that is closer to the principles of the IFRS framework.

Costs incurred after the probability of economic feasibility has been established are capitalised only if the costs are necessary to bring the resource to the commercial production stage. Subsequent expenditure should not be capitalised after commercial production commences, unless it meets the asset recognition criteria.

For a summary of the key differences between PSAK and IFRS, please refer to our publication "IFRS and Indonesian GAAP (PSAK): Similarities and Differences".[127] For the major accounting practices adopted by the power industry under IFRS, please refer to our publication "Financial Reporting in the Power and Utilities Industry".[128]

7.4 PSAK 72 – A New Model to Recognise Revenue

Effective 1 January 2020, all financial statements will have to apply the new PSAK 72, "Revenue from Contracts with Customers", to determine the timing and amount of revenue that can be recognised for the sale of goods and services. PSAK 72 is adopted from IFRS 15, "Revenue from Contracts with Customers". PSAK 72 introduces a new revenue recognition model that emphasises the satisfaction of performance obligations identified in a contract with customers for a seller to recognise revenue. Entities will now have to apply a five-step approach to determine when and how much revenue can be recognised:

Step 1 : Identify the contract with the customer
Step 2 : Identify the separate performance obligations in the contract
Step 3 : Determine the transaction price
Step 4 : Allocate the transaction price to separate performance obligations
Step 5 : Recognise revenue when (or as) the performance obligation is satisfied

Entities will need to exercise judgment when considering the terms of the contract and all of the facts and circumstances, including implied contract terms. The introduction of a new revenue recognition model may change the timing and amount of the top-line revenue of many power companies.

Below, we have highlighted a number of potential scenarios that are likely to change the current revenue recognition practice for power companies following the adoption of PSAK 72. Our analysis has not been written to provide a comprehensive list of all potential cases, as there may be other areas of complexity identified in the different forms of contract that power companies currently use. We may identify additional issues as more power companies begin to apply PSAK 72 and our views may evolve during that process.

127 https://www.pwc.com/id/en/publications/assets/assurance/acs/ifrs-and-indonesia-gaap-ifas-2016-r1.pdf
128 https://www.pwc.com/id/en/publications/assets/utilities-ifrs.pdf

Potential impact on power companies

Potential scenario	Potential impact
Take-or-pay arrangement	• Take-or-pay arrangements are often found in PPAs where a customer agrees to purchase, and pay for, a minimum amount of electrical power from the supplier over a contracted period. • Where a PPA with a take-or-pay arrangement is not subject to the scope of PSAK 73, 'Leases' (see below for further analysis of this standard), PSAK 72 prescribes specific accounting principles to account for revenue where a customer does not exercise all of its contractual rights (i.e. breakage). • Breakage is commonly found in cases where a customer has prepaid the minimum guaranteed amount but does not exercise its rights to take all of the guaranteed electrical output. • The existing accounting literature does not have any specific guidance for breakage, but PSAK 72 allows a power company to estimate the amount of breakage that it expects to benefit from over a contract period (i.e. the amount of unexercised rights by customer) and account for the breakage revenue in proportion to the pattern of rights exercised by its customer. • This means that, in some cases, a power company may recognise more revenue upfront if it can reasonably predict the amount of electrical output that is guaranteed but will never be consumed by the customer. Otherwise, breakage is recognised as revenue only when the likelihood of a customer exercising its rights becomes remote.
Contingent consideration	• Contingent consideration is another common feature found in PPAs where payment for the electrical supply is adjusted for actual heat rate, performance bonus, step-up prices, etc. • PSAK 72 allows a power company to estimate the amount of variable consideration upfront and include them in the measurement of the total transaction price of a contract. • However, a power company may only recognise revenue from contingent considerations if it is highly probable that the amount of revenue recognised will not be subject to significant future reversals when the uncertainty is resolved. Otherwise, the power company will have to defer the recognition of revenue from contingent consideration until the uncertainty has been resolved. • Effectively, power companies need to make decisions using their judgment based on the facts and circumstances of their arrangements, as the profile of revenue recognition may change as a result of PSAK 72.
Contract costs	• There is currently little guidance on how power companies should account for the costs spent to obtain a PPA. PSAK 72 allows power companies to capitalise certain costs of obtaining a contract, which may include the commission fees payable to agents to obtain a PPA. • Once contract costs are capitalised, they should be amortised on a systematic basis over the contract period. Consequently, the new PSAK 72 treatment may change the pattern of cost recognition, and operating profit, over the contract period.

Potential scenario	Potential impact
Contract modification	• Another potential area requiring judgment in the implementation of PSAK 72 is the new guidance on contract modification. For example, a power company may agree to extend the period of a contract and create a blended price for the remaining volume of electrical power to be delivered over the extended contract period. • A power company may account for the blend-and-extend arrangement in one of two ways: – Account for the arrangement prospectively. In this case the blend-and-extend agreement is treated as a separate contract from the original arrangement, given that the modification results in additional volume of electrical power to be delivered, and the new price reflects the stand-alone selling price of the additional electrical output delivered (e.g. the new blended rate equals the market rate at the time of extension); or – Apply the blended rate to all remaining units in cases where the original contract is terminated and a new contract is created. This is the case where the modification results in an additional volume of electrical power to be delivered, but the new price does not represent the stand-alone selling price of the additional output (e.g. the new blended rate is actually higher/ lower than the market rate at the time of negotiation). Arguably, there is an economic relationship between the original agreement and the modified contract. • Under the existing accounting literature, many power companies simply apply the new blended rate to all remaining units, similar to option 2 above. Under PSAK 72, however, the revenue recognition pattern may change depending on the assessment of the new blended rate against the stand-alone selling price of electricity to be delivered at the time of contract extension.

Transitional provisions

PSAK 72 is effective for reporting periods beginning on or after 1 January 2020. Earlier adoption is permitted. Power companies may have to change their processes and information systems to capture the information they need.

7.5 PSAK 73 – A New Era of Lease Accounting

In September 2017, the Indonesia ASB issued PSAK 73, 'Leases' with an effective date of 1 January 2020. PSAK 73 is adopted from IFRS 16, 'Leases'. In contrast to the existing PSAK 30 standard on leasing that requires a lessee to make a distinction between a finance lease (balance sheet) and an operating lease (off-balance sheet), the new PSAK 73 model will require lessees to capitalise nearly all leases on the balance sheet to reflect the right to use an asset for a period of time and the associated liability for payments to use the asset, except for certain short-term leases that are less than twelve months and leases of low-value assets. PSAK 73 did not prescribe the threshold for low-value assets unlike IFRS which determined low-value assets are assets below USD 5,000. As such, judgment is required in determining low-value assets in Indonesia.

PSAK 73 will therefore affect almost all commonly used financial ratios and performance metrics including debt-to-equity, current ratio, interest coverage, earnings before interest and taxes ("EBIT"), earnings before interest, taxes, depreciation and amortisation ("EBITDA"), return on capital employed and operating and financing cash flows. In fact, according to an IASB study published in January 2016, it is estimated that the top energy companies in the world are expected to add USD 288 billion in lease liabilities and assets to their balance sheets as a result of the implementation of IFRS 16.

These changes may affect the loan covenants, credit ratings, borrowing costs, and could drive other changes to the business models of companies.

Why is PSAK 73 important to power companies?

Currently, there is no significant difference in the accounting treatment of an operating lease and a supply contract. The existing ISAK 8, "Determining Whether an Arrangement Contains a Lease" provides guidance on the evaluation of whether a supply contract may contain an embedded lease element, with the result that many companies are simply focusing on identifying whether the arrangement actually results in a finance lease. This is because the accounting treatment of an operating lease is almost identical to that of a supply contract, as both arrangements are effectively off-balance sheet and the expenses are capitalised as incurred in profit or loss over a period of time.

Under PSAK 73, however, the treatment of the two arrangements will differ. With the removal of the off-balance sheet model under the new standard, the determination of whether an arrangement contains a lease becomes far more important. The new definition of a lease under PSAK 73 will be of particular interest to power companies when assessing long-term arrangements for the purchase of inputs and the sale of electrical outputs. Once it is determined that an electrical power supply contract contains a lease, the power purchaser will almost certainly have to account for the right to use the asset (e.g. a power plant) and the associated liability for payments on the balance sheet.

What is a lease?

PSAK 73 prescribes that a contract contains a lease when:

a) There is an identified asset; and
b) The contract conveys the right to control the use of the identified asset for a period of time in exchange for consideration.

Identified asset

An asset can be identified implicitly or explicitly in the contract. A contract may explicitly define a particular asset (e.g. a specific power plant that will have to be used in a specific location); or implicitly when the supplier can fulfill the contract only through the use of a particular asset (e.g. it is practically uneconomical to bring in another power plant from another location to fulfill the contract). A right to substitute an asset if it is not operating properly, or if there is a technical update required, does not prevent the contract from being dependent on an identified asset.

Right to control the use of an identified asset

The definition of a lease is now much more driven by the question of which party to the contract controls the use of the underlying asset for the period of use. A customer no longer needs only to have the right to obtain substantially all of the benefits from the use of an asset (the 'benefits' element), but must also have the ability to direct the use of the asset (the 'power' element).

This conceptual change becomes obvious when looking at a contract to purchase substantially all of the output produced by an identified asset (for example, a power plant). If the price per unit of output is neither fixed nor equal to the current market price, the contract would be classified as a lease under IFRIC 4. IFRS 16, however, requires not only that the customer obtains substantially all of the economic benefits from the use of the asset but also an additional 'power' element: namely, the right of the customer to direct the use of the identified asset (for example, the right to decide the amount and timing of power delivered).

The right to control the use of an identified asset is the key distinguishing factor, because in a lease, the customer has control over the right to use the identified asset, whereas under a simple supply contract, the supplier retains control over the use of the particular asset.

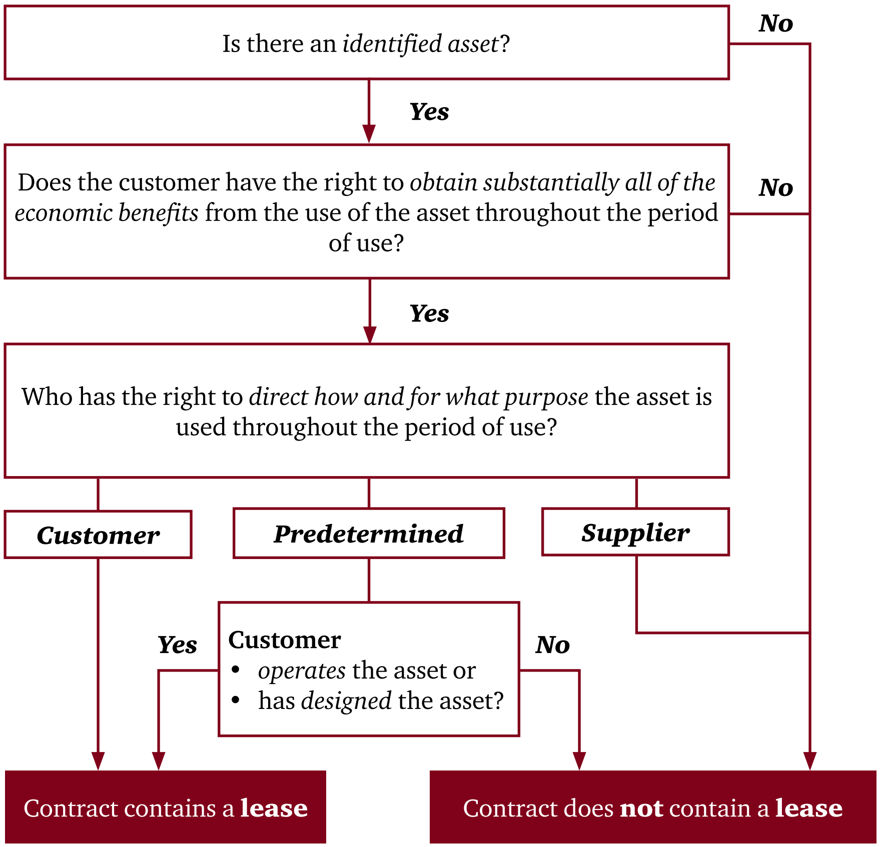
The key question to address, therefore, is which party (that is, the customer or the supplier) has the right to direct how and for what purpose an identified asset is used throughout the contract period. PSAK 73 gives several examples of relevant decision-making rights:

a) The right to change what type of output is produced;
b) The right to change when the output is produced;
c) The right to change where the output is produced;
d) The right to change how much of the output is produced.

The list is not exhaustive and none of the above criteria is independently exclusive, meaning there is no threshold to determine whether any of the criteria are more important than the others. The relevance of each of the decision-making rights depends on the underlying asset being considered. In a typical electrical power supply arrangement, for example, it is important to address which party has the rights to determine:

a) How much power will be delivered and when;
b) When to turn the power plant on/off;
c) Which party has physical access to the power plant;
d) Whether the customer has the rights to manage the power plant operations, even though it may choose not to do so.

The flowchart below summarises the analysis that needs to be made to determine whether a contract contains a lease:



Illustrative Applications

PSAK 73 includes three illustrative examples of how a contract to purchase electrical power from a solar farm can be assessed to determine whether a lease element is embedded in the contract. We have analysed all of the three examples from the standard and tailored them to illustrate the features commonly found in the Indonesian context.

Background information

An industrial complex (customer) enters into a contract with a power company (supplier) to purchase all of the electricity produced by a 10 MW gas-fired power plant for 20 years. The power plant is built next to the industrial complex.

A permanent gas pipeline from a local gas supplier is constructed and connected exclusively for the use of the plant. Due to the quantity of gas needed to fire the power plant, it is uneconomical for the supplier to purchase and transport gas from other locations.

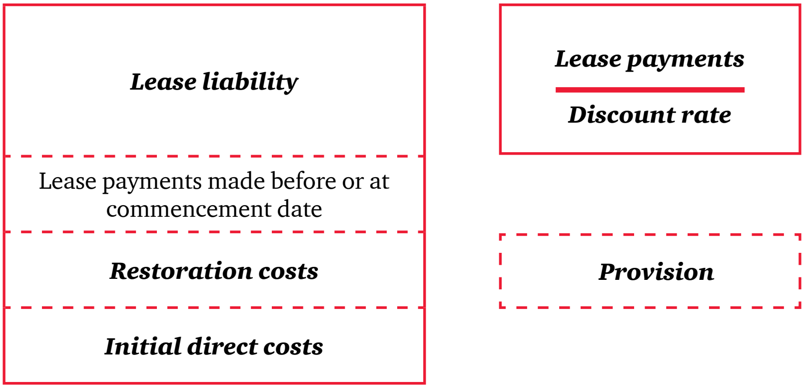
Customer's rights	Supplier's rights	Conclusion
Example 1 The customer designed the power plant before it was constructed. The customer then hires experts to assist in the procurement and engineering of the equipment to be used in the power plant. The customer has access to inspect and monitor the operations of the power plant at any time. There are no decisions to be made about whether, when, or how much electricity will be produced because the design of the asset has predetermined those decisions.	The supplier is responsible for building the power plant to the customer's specifications, and then operating and maintaining it.	The contract contains a lease for the following reasons: • There is an identified asset, and it is uneconomical for the supplier to substitute the plant with another asset from a different location; • The customer has the right to obtain substantially all of the economic benefits from the use of the power plant over the 20-year period; and • The customer is deemed to have the rights to direct the use of the power plant even though the customer does not operate the power plant directly. The design of the power plant has, in effect, programmed into the power plant any relevant decision-making rights about how and for what purpose the power plant is to be used. The customer's substantial involvement in the design of the plant has given it the right to direct the use of the plant.

Customer's rights	Supplier's rights	Conclusion
Example 2 The customer has the right to obtain substantially all of the economic benefits from use of the identified power plant over the 20-year period of use. The contract sets out the quantity and timing of power that the power plant will produce throughout the period of use, which cannot be changed except in extraordinary circumstances (for example, emergency situations). The customer has no right to access the power plant.	 The supplier designed the power plant when it was constructed some years before entering into the contract with the customer; the customer had no involvement in that design. The power plant is owned and operated by the supplier. The supplier operates and maintains the plant on a daily basis in accordance with industry-approved operating practices. The supplier has the right to sell excess capacity to other customers without being required to obtain the approval of the industrial complex's management.	 The contract does not contain a lease for the following reasons: • Even though there is an identified asset because the power plant is explicitly specified in the contract, the customer does not have the right to control the use of the power plant because the customer does not direct how and for what purpose the plant is used; • How and for what purpose the plant is used (i.e. whether, when and how much power the plant will produce) is predetermined in the contract; • The customer has the same rights in relation to the use of the plant as if it were one of many customers obtaining power from the plant. The supplier can sell excess power to other customers; • The customer has no rights to change how and for what purpose the plant is used. The customer has no other decision-making rights about the use of the power plant (for example, it does not operate the power plant) and did not design the plant; and • The supplier is the only party that can make decisions about the plant by making decisions about how the plant is operated and maintained.
Customer's rights	**Supplier's rights**	**Conclusion**
Example 3 The customer has the right to obtain substantially all of the economic benefits from the use of the identified power plant over the 20-year period of use. The customer issues instructions to the supplier about the quantity and timing of the delivery of power. The power plant is not operated in the event that no power is purchased by the customer.	 The supplier operates and maintains the plant on a daily basis in accordance with industry-approved operating practices.	 The contract contains a lease for the following reasons: • There is an identified asset; • The customer has exclusive use of the power plant; it has a right to all of the power produced; • The customer has the right to direct the use of the power plant because the customer makes the relevant decisions about how and for what purpose the power plant is used; • Through the regular issuance of instructions, the customer determines whether, when and how much power the plant will produce; and • Finally, because the supplier is prevented from using the power plant for another purpose, the customer's decision-making about the timing and quantity of power produced, in effect, determines when, and whether, the plant produces output.

Initial recognition

There is no longer a distinction between a finance lease contract and an operating lease; all lessees are required to capitalise a right-of-use asset and a corresponding lease liability for almost all lease contracts. The lease liability is initially capitalised on the date of commencement and measured at an amount equal to the present value of the lease payments during the lease term that are not yet paid. The value of the right-of-use of the asset is equal to the lease liability at the commencement of the lease plus any direct costs incurred to obtain the contract and contractually obligated restoration costs.

There is no change to the approach to determining the discount rate for the lease. The lessee uses as its discount rate the interest rate implicit in the lease. If this rate cannot be readily determined, the lessee should instead use its incremental borrowing rate.



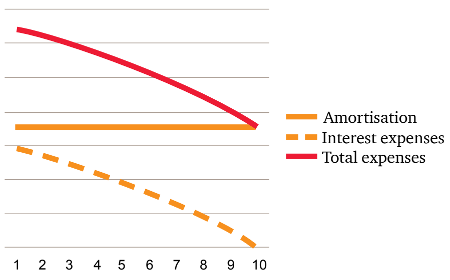
The effect of this approach is a substantial increase in the amount of capitalised financial liabilities and assets for entities that have entered into significant lease contracts that are currently classified as operating leases.

Subsequent measurement

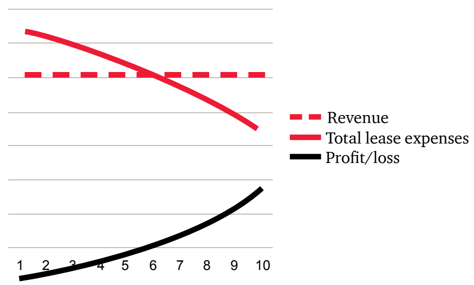
The lease liability is measured in subsequent periods using the effective interest rate method. The right-of-use asset is depreciated in accordance with the requirements in IAS 16, “Property, Plant and Equipment”, which will result in depreciation on a straight-line basis or another systematic basis that is more representative of the pattern through which the entity expects to consume the right-of-use asset.

The combination of the straight-line depreciation of the right-of-use asset and the effective interest rate method applied to the lease liability results in a decreasing total lease expense throughout the lease term. This effect is sometimes referred to as *frontloading*.

Lease expenses

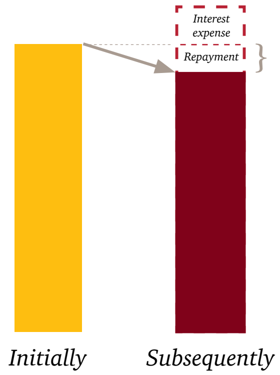


Profit/loss

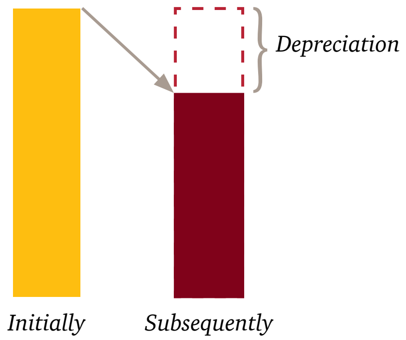


The carrying amount of the right-of-use asset and the lease liability will no longer be equal in subsequent periods. Due to the frontloading effect described above, the carrying amount of the right-of-use asset will, in general, be below the carrying amount of the lease liability.

Lease liability



Right-of-use asset



Potential impact on the lessee's key performance indicators

Below, we summarise the potential impact on a typical lessee's financial performance of the new PSAK 73 requirement to capitalise substantially all leases on the balance sheet:

Indicator	Impact from PSAK 73
Debt-to-equity	This will increase because all lessees will now capitalise the lease liabilities arising from operating leases (which were recorded off-balance sheet under PSAK 30).
EBIT	This will increase because typically the depreciation of the right-of-use of the asset added to this measure is lower than the removal of lease payments that were previously presented as operating expenses under PSAK 30.

Indicator	Impact from PSAK 73
EBITDA	This will increase because of the removal of lease payments that were previously presented as operating expenses under PSAK 30.
Operating cash flow	This will increase because operating lease payments that were previously presented as part of operating cash flow are now presented as part of financing cash flow; even though this is offset by higher cash outflows from the finance costs of the lease.
Financing cash flow	This will decrease because operating lease payments that were previously presented as part of operating cash flow are now presented as part of financing cash flow. The financing cash flow may also be further reduced by the cash outflow related to the financing cost element of a lease.
Asset turnover Sales/total assets	This will be lower because of the additional right-of-use of the leased asset that now has to be capitalised on the balance sheet.

Lease Accounting for a Lessor

The accounting for a lessor is practically the same under PSAK 73 as it was under PSAK 30. The lessor still has to classify leases as either finance or operating, depending on whether substantially all of the risk and rewards incidental to ownership of the underlying asset have been transferred. For a finance lease, the lessor recognises a receivable at an amount equal to the net investment in the lease, which is the present value of the aggregate of lease payments receivable by the lessor and any unguaranteed residual value. If the contract is classified as an operating lease, the lessor continues to present the underlying assets.

Transitional Provisions

PSAK 73 is effective for reporting periods beginning on or after 1 January 2020. Earlier application is permitted, but only in conjunction with PSAK 72. This means that an entity is not allowed to apply PSAK 73 before applying PSAK 72.

Entities are not required to reassess existing lease contracts but can elect to apply the guidance regarding the definition of a lease only to contracts entered into (or changed) on or after the date of initial application ("grandfathering"). If an entity chooses this expedient, it shall be applied to all of its contracts. Acknowledging the potentially significant impact of the new lease standard on a lessee's financial statements, PSAK 73 does not require full retrospective application, but instead allows a simplified approach. Full retrospective application is optional.

Appendices

Tax Incentives: Comparison for Conventional and Renewable Power Plants

		Conventional				Renewable			
Regulations	Incentives	Income Tax	Import Duty	VAT	Article 22	Income Tax	Import Duty	VAT	Article 22
GR No. 18/2015	Investment allowance of 30% (over 6 years), accelerated depreciation and amortisation, reduced WHT on dividends paid to non-residents.	–	–	–	–	Potentially yes	–	–	–
MoF Regulation No. 177/2007	Import duty exemption on imports of goods used in "geothermal business activities" (requires a working area, survey licence or geothermal mining business licence). Goods and materials must: a) Not be produced in Indonesia; b) Be produced in Indonesia but not meeting the required specifications; or c) Be produced in Indonesia but in insufficient quantity.	–	–	–	–	–	Yes for geothermal investments	–	–
MoF Regulation No. 66/2015	Import Duty exemption for imports of capital goods ("machines, equipment and tools, not spare parts") for PLN and some IPPs. Needs to be outlined in the agreement with PLN.	–	Yes	–	–	–	Yes	–	–
MoF Regulation No. 176/2009 (as amended by 76/2012 and 188/2015)	Import Duty exemption on imports of "machines, goods and materials for establishment and development" of facilities to produce goods (including electricity) and limited services.	–	Yes	–	–	–	Yes	–	–
MoF Regulation No. 142/2015	Import VAT exemption for importation (on which the associated import duty is also exempt).	–	–	–	–	–	–	Yes, for Geothermal only and only in exploration stage	–
GR No. 12/2001 (as amended by GR No. 81/2015 and as implemented by MoF Regulation No. 268/2015)	VAT exemption on imports of "strategic" capital goods ("plant, machines and equipment but not spare parts").	–	–	Yes, to VAT-able entrepreneurs (IPPs can qualify).	–	–	–	Yes, to VAT-able entrepreneurs (IPPs can qualify).	–
MoF Regulation No. 21/2010	Art. 22 exemption for imports by IPPs involved in renewable energy.	–	–	–	–	–	–	–	Yes

Appendix B

Commercial & Taxation Issues by Stage of Investment

Stage of Investment	Issues Common to Conventional Power and Renewable Energy	Renewable Energy Specific Issues for Geothermal (Non-JOC post 2003) and Hydro
Bid/Feasibility Stage	• PPA drafting/closing (consider base case fiscal terms); • Preparation of investment model tax & accounting assumptions; • Site & land acquisition (regional land and building taxes); • Forestry borrow & use permits – non-tax State revenue charges; • Consider if there are any Environmental Law issues/levies; and • Spatial Zoning issues.	• Tariffs; • Consider eligibility for tax incentives; and • Post 2012 CDM feasibility for carbon credits/CER's.
Pre incorporation SPV	• Cash calls; • Spending pre-incorporation; • Choice of Jurisdiction – of holding companies; and • EPC contracting for long lead items.	• Consider KBLI (Business Classification) for RE incentives.
SPV Establishment	• USD bookkeeping; • ISAK 8 / ISAK 16 vs. conventional accounting (for tax); • Tax/VAT registrations; • Import Licenses; and • Recharging of pre-incorporation spending.	• Licensing clarification (KBLI).
Ownership of Infrastructure	• Mine-Mouth or captive plants; • Transfer of distribution facilities –land & building taxes; and • Ownership of any separate infrastructure.	• Consider use of affiliates; and • Tax treatment of earthworks (specific for hydro).
Key Project Contracts stage	• See separate Table below for Tax and Commercial issues embedded in: - Shareholder Agreement; - Shareholder Loan; - Power Purchase Agreement (PPA); - Engineering Procurement & Construction (EPC) Agreement – Offshore; - EPC Agreement – Onshore; - EPC Wrap Agreement; - Long Term Fuel Supply Agreement; - Technical Services Agreement; - Project Finance Documents; and - Developer's/Sponsors' Agreement.	• Note that the PPA will be different for geothermal and for hydropower. For Hydro also: • Water use agreement; and • Consider water usage fees.

Stage of Investment	Issues Common to Conventional Power and Renewable Energy	Renewable Energy Specific Issues for Geothermal (Non-JOC post 2003) and Hydro
Construction	• Treatment of EPC costs – subject to final construction services tax or not; • PE risk for offshore contractor; and • WHT compliance for onshore project.	For hydro only: • Ownership of waterway diversion facilities.
Importation of Equipment	• Importation issues – special approach to VAT; • Import duty; • Article 22 import tax – 2.5%; and • Treatment of spares or non-capital goods (materials).	• Renewable Energy (RE) incentives.
Operation	• Input VAT costs; • Regional taxes & levies; • ISAK 8 / ISAK 16 vs. conventional accounting (for tax); • VAT registration & compliance; • WHT on electricity sales – 1.5%; • O&M Fees – transfer pricing if paid to affiliate; • Forestry Licence fees; • Profit repatriation; and • Cash repatriation.	• Article 74 of the Company Law on Corporate Social Environmental Responsibility (CSER). Is spending required, given the use of natural resources?; • Environmental Levies under the Environmental Law; and • Forestry Licence fees. For hydro also: • Regional taxes and water levies.
Overhaul Stage	• Capitalisation of expenditure & amortisation; and • Deductibility of repairs/improvements.	
Handover of Facility Stage	• Taxes on divestment; • Manpower costs – change of control provisions; • Environmental provisions for site rehabilitation; and • Implications for any foundations established for CSR/Pension purposes.	

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PwC is organised into five Lines of Service, each staffed by highly qualified experienced professionals who are leaders in their fields. The lines of service are:

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  - Risk Assurance
  - Financial Audit
  - Capital Market Services
  - Accounting Advisory Services
  - Actuarial Services
- **Tax Services** optimise tax efficiency and contribute to overall corporate strategy through the formulation of effective tax strategies and innovative tax planning. Some of our value-driven tax services include:
  - Corporate Tax
  - International Tax
  - Transfer Pricing ("TP")
  - Mergers and Acquisitions ("M&A")
  - VAT
  - Tax Disputes
  - International Assignments
  - Customs
  - Investment and Corporate Services
- **Advisory services** implement an integrated suite of solutions covering deals and transaction support and performance improvement. Some of our value-driven advisory services include:
  - Business Recovery Services
  - Capital Projects and Infrastructure
  - Corporate Finance
  - Corporate Value Advisory
  - Deal Strategy
  - Delivering Deal Value
  - Transaction Services
- **Consulting services** help organisations to work smarter and grow faster. We consult with our clients to build effective organisations, innovate and grow, reduce costs, manage risk and regulations and leverage talent. Our aim is to support you in designing, managing and executing lasting beneficial change through value-driven consulting services including:
  - Management Consulting
  - Risk Consulting
  - Technology Consulting
  - Strategy Consulting
- **Legal services** provide responsive value-added services through the provision of cutting edge legal solutions to support and facilitate legal developments in Indonesia. We work with you to understand your commercial objectives. We express our advice in commercial terms and offer you seamless end-to-end service across the life cycle of your project. We structure and manage transactions from start to finish to help you navigate today's complex legal requirements with a forward-looking edge within your broader business needs. We bring together the best of our specialists in Legal services and other disciplines such as tax, consulting, assurance and deals to work alongside you as trusted business advisers through value driven legal services including:
  - Mergers & Acquisitions
  - Capital Markets and Securities
  - Corporate Advisory
  - Finance
  - Employment
  - Litigation and Dispute Resolution

PwC Indonesia (www.pwc.com/id)

For companies operating in the Indonesian power sector, there are some compelling reasons to choose PwC Indonesia as your professional services firm:

- The PwC network is the leading adviser to the power industry, both globally and in Indonesia, working with more electricity producers and related service providers than any other professional services firm. We have operated in Indonesia since 1971 and have over 1,700 professional staff, including 53 Indonesian national partners and expatriate technical advisors, trained in providing assurance, advisory, tax and legal services to Indonesian and international companies.
- Our Energy, Utilities and Mining ("EU&M") practice in Indonesia is comprised of over 300 dedicated professionals across our Lines of Service. This body of professionals brings together deep local industry knowledge and experience with international power expertise and provides us with the largest group of industry specialists in the Indonesian professional market. We also draw on the PwC global EU&M network which includes more than 12,000 people focused on serving energy, power and mining clients.
- Our commitment to the power industry is unmatched and demonstrated by our active participation in industry associations around the world and our thought leadership on the issues affecting the industry.
- Our client service approach involves learning about your organisation's issues and seeking ways to add value to every task we perform. Detailed power knowledge and experience ensures that we have the background and understanding of industry issues and can provide sharper, more sophisticated solutions that help clients accomplish their strategic objectives.

Contact us to discuss your plans for investment in the Indonesian power sector.

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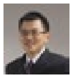

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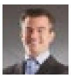

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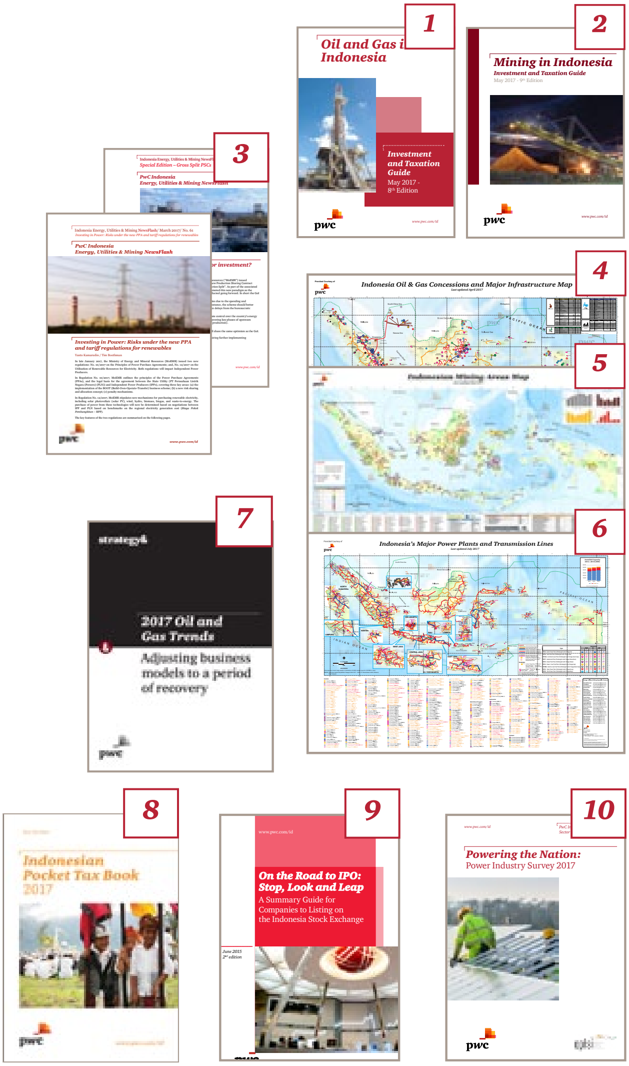

Acknowledgements

We would like to convey our sincere thanks to all the contributors for their efforts in supporting the preparation of this publication.

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