Power In Indonesia

Investment and Taxation Guide

November 2018, 6th Edition

Extensively revised and updated, including new 2018 regulations

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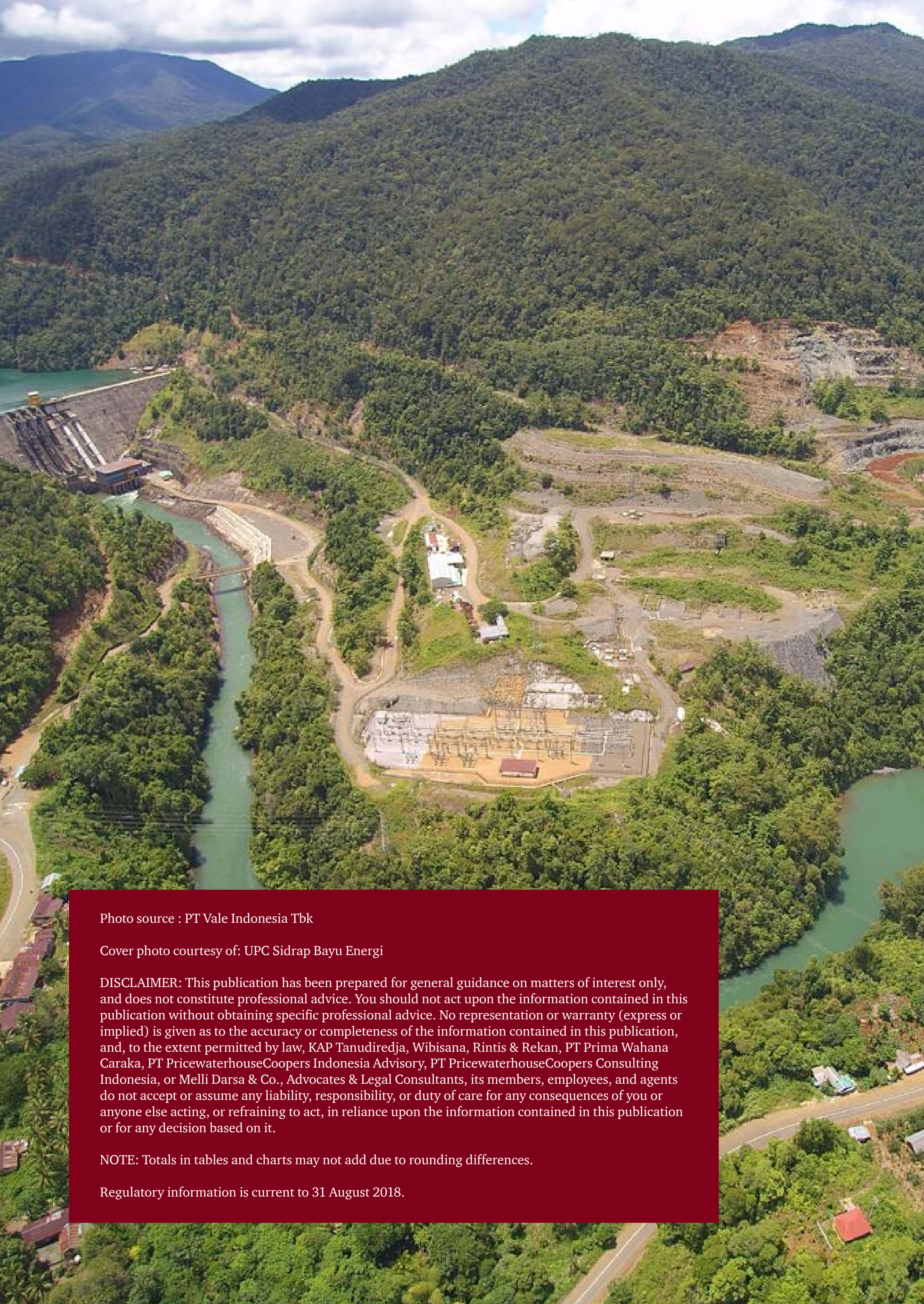

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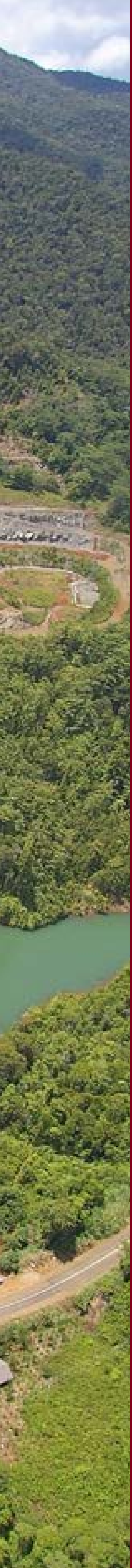
NOTE: Totals in tables and charts may not add due to rounding differences.

Regulatory information is current to 31 August 2018.



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Glossary

Term	Definition
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	Billions British 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 Agency (*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 Operation 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
EPC	Engineering, Procurement and Construction
FM	*Force Majeure*
FSRU	Floating Storage Regasification Unit
FTP I	The fast track programme introduced in 2006, mandating PLN to build 10 GW of coal-fired plants across Indonesia

Term	Definition
FTP II	The fast track programme introduced in 2010 for building 10 GW of power plants focusing on renewable energy sources and IPP involvement
GEUDP	Geothermal Energy Upstream Development Project
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
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 Licence 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 Licence under the 2014 Law (*Izin Panas Bumi*)
IPP	Independent Power Producer
ISAK	Interpretation of Indonesian Financial Accounting Standards (*Interpretasi Standar Akuntansi Keuangan*)
IUJPTL	Electricity Supporting Services Licence (*Izin Usaha Jasa Penyediaan Tenaga Listrik)*
IUP	Mining Business Licence (*Izin Usaha Pertambangan*)
IUPK	Special Mining Business Licence (*Izin Usaha Pertambangan Khusus*)

Term	Definition
IUPTL	Electricity Supply Business Licence (*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	Japan Bank for International Cooperation
JOC	Joint Operation Contract
KPPIP	The Committee for the Acceleration of Prioritised Infrastructure Development (*Komite Percepatan Penyediaan Infrastruktur Prioritas*)
km	Kilometre
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*)
MMBOE	Million Barrels of Oil Equivalent
MMBtu	Millions of British thermal units
MMSCFD	Millions of 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 and People's Housing (*Kementerian Pekerjaan Umum dan Perumahan Rakyat*)
MoU	Memorandum of Understanding
MSW	Municipal Solid Waste
MTOE	Million Tonnes of Oil Equivalent
MVA	Megavolt Amperes
MW	Megawatts
NEP	National Energy Policy
NRE	New and Renewable Energy
O&M	Operations and Maintenance
OJK	*Otoritas Jasa Keuangan*
OSS	Online Single Submission

Term	Definition
PKUK	Authorised Holder of an Electricity Business Licence under the 1985 Electricity Law (*Pemegang Kuasa Usaha Ketenagalistrikan*)
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*)
PSP	Preliminary Geothermal Survey Assignment (*Penugasan Survey Pendahuluan)*
PSPE	Preliminary Geothermal Survey and Exploration Assignment (*Penugasan Survey Pendahuluan dan Eksplorasi)*
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 set up to support infrastructure financing in Indonesia)
PTSP	One-Stop Services (*Pelayanan Terpadu Satu Pintu)*
RUKD	Regional Electricity General Plan (*Rencana Umum Ketenagalistrikan Daerah*)
RUKN	National Electricity General Plan (*Rencana Umum Ketenagalistrikan Nasional*)
RUPTL	Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik*)
SHP	Small Hydropower
SOE	State-Owned Enterprise
SPC	Special Purpose Company
TKDN	Local content (*Tingkat Komponen Dalam Negeri*)
TP	Transfer Pricing
TSCF	Trillions of Standard Cubic Feet
TWh	TeraWatt hours
USD	US Dollar
US GAAP	US Generally Accepted Accounting Principles
VAT	Value Added Tax
WHT	Withholding Tax

Foreword

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Welcome to the sixth edition of the PwC Indonesia ***Power in Indonesia: Investment and Taxation Guide***.

This Guide 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 Guide which can be of use to existing investors, potential investors, and others with an interest in the status of this economically critical sector for Indonesia.

This edition of the Guide has been updated to reflect the regulations issued in late 2017 to mid 2018 (which are notably fewer and less substantial than last year). However, in this edition we have placed a greater focus on the tracking of actual transactions and project implementation, particularly in light of the wave of Power Purchase Agreements ("PPAs") signed last year. We hope readers find our comments on these developments helpful but reinforce the interpretational uncertainty that exists around the regulatory environment in Indonesia.

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

- An overview of the Indonesian Power Sector;
- An overview of the legal and regulatory framework;
- A detailed look at the status of Independent Power Producer ("IPP") investment;
- An outline of the use of conventional energy sources;
- A dedicated section on renewable energy;
- An outline of key tax issues; and
- An outline of key accounting issues.

As many readers will be aware, Indonesia's power infrastructure needs substantial investment if it is not to inhibit Indonesia's economic growth. In many parts of the country the generating capacity – which currently stands at around 60.7 GW – struggles to keep up with electricity demand. Blackouts remain common across Sumatera, Kalimantan, Sulawesi and areas of Eastern Indonesia. However, over the past 12-18 months it has become apparent that generating capacity is generally surplus to requirements on the largest grid being that of Java-Bali. This is due to the successful commissioning of several large power plants and reduced PLN forecasts for electricity demand from households and industry.

Given the revised demand forecasts, as well as the status of the construction programme, the ambitious plan for the deployment of 35 GW of new generating capacity by 2019 has been officially delayed until 2024 (with even more recent adjustments to the targets to reflect concerns over pressure on the Rupiah). However, the broad focus on capacity growth remains a key priority of President Joko “Jokowi” Widodo’s Government. In fact, since Jokowi’s inauguration around 2 GW of capacity has come online, around 17 GW is under construction and an additional 13 GW has been signed via new PPAs which are yet to commence construction. Given the cancellation of a number of high profile PPAs, and the difficulties facing many developers in raising finance under the new regulations and commercial structures, the market is closely watching the progress of this latter 13 GW – whether these projects ultimately reach financial close and start construction (noting again the recent policies seeking to defer certain power projects in the pre-PPA stage).

The formal changes to the 35 GW programme are reflected in the 2018-2027 Electricity Supply Business Plan (*Rencana Umum Penyediaan Tenaga Listrik* – the “2018 RUPTL”). The 2018 RUPTL dramatically reduces both demand forecasts and planned capacity targets. In terms of technology these changes have been applied across-the-board with both large thermal coal- and gas-fired plants being dropped or postponed. There is also reduction in the share of renewables. PLN and IPP investors are now expected to construct about 56 GW of generating capacity by 2027 with 16.6 GW by Perusahaan Perseroan (Persero) PT Perusahaan Listrik Negara (“PLN”) and 32 GW by IPPs (and 7.4 GW yet to be allocated).

Together with PLN, the private sector has been playing and will continue to play a significant role in the construction of generating capacity across Indonesia. There have been challenges in the past relating to regulatory, technical, socio-economic and cultural aspects which still stand as barriers to achieving the Government’s goals. In our view these challenges have increased in line with the frequency of changes in regulation and the Government’s plans for the development of the sector.

The 2017 strategy of assigning many fossil fuel-based projects to PLN’s subsidiaries has continued and is now being applied to some renewables projects. At present, PLN generally expects its subsidiary to take a 51% shareholding in a project’s Special Purpose Vehicle (“SPV”). However, given PLN funding constraints, significant non-debt financing is still required from the private sector investors in particularly in the form of Shareholders’ Loans. Various partnerships have been announced although, to our knowledge, no projects procured under such commercial arrangements had reached financial close as of 31 July 2018.

The Government has however continued to listen to the industry on key issues such as the “bankability” of certain clauses in the new PPA template. In February 2018, the Ministry of Energy and Mineral Resources (the “MoEMR”) issued Minister of Energy and Mineral

Resources Regulation ("MoEMR Regulation") No. 10/2018 to further rollback some of the provisions in MoEMR Regulation No. 10/2017 which had received a negative reaction from investors and lenders. Concerns nevertheless continue to exist over some of the new PPA template's remaining risk allocation principles and these concerns have contributed to the low number of projects reaching financial close.

Despite this, power generating capacity originally procured under pre-2017 regulations and PPAs continued to be progressed and several projects achieved financial close during 2017 and 2018 including for geothermal, solar PV and coal-fired plants.

A minor uplift (of around 2%) in the reference benchmark prices ("BPP") issued in March 2018 became applicable to most renewables and coal-fired power plants and was welcomed by the industry. However, this reflects the steep rise in fossil fuel prices being faced by PLN and, perhaps as a result, the MoEMR issued Decree No. 1395K/30/MEM/2018 in March 2018 capping the maximum reference price for coal sold to power plants at USD 70/tonne. The MoEMR is thought to be considering a similar move for natural gas. This has obvious implications for fuel suppliers to the power sector.

In summary, Indonesia continues to represent a major investment opportunity for domestic and international power companies and investors, albeit at a slightly lower capacity and less aggressive timetable than what was envisaged in 2015. In part, this represents the success of the capacity roll-out over the past few years – including the fact that the Java-Bali grid is not in urgent need of more power capacity. Investors who were fortunate enough to achieve financial close in the past few years have found a robust secondary market for their assets. Among Indonesian infrastructure opportunities, power arguably remains the largest and most liquid.

Realising the ambitious goal of the 35 GW programme, no matter what the target date ends up being, 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 required in the associated transmission and distribution infrastructure (which will largely rest with PLN).

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 however intended to be a comprehensive study of all aspects of the power industry in Indonesia but rather provide a general guide to key investment and taxation considerations. Readers should also note that this Guide is largely current as at 31 August 2018. 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 changing regulations. In addition, 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 185, for further information.

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

Photo source: PT Adaro Power

1 Overview of the Indonesian Power Sector

1.1 Demand for and Supply of Power in Indonesia

Indonesia is an archipelago of over 18,000 islands with a population of over 260 million in 2017. This makes Indonesia the world's fourth most populous country and the largest economy in Southeast Asia.[1]

In 2013, the Indonesian economy entered a slowdown period as global commodity prices fell. This was exacerbated by a slowdown in the Chinese economy. Gross Domestic Product ("GDP") growth in 2013-2017 averaged 5% p.a. compared to 6% 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 and an improvement in key commodity prices, the outlook improved. 2017 to early 2018 saw the upgrading of Indonesia's sovereign credit rating by two credit rating agencies (from Baa3 to Baa2 by Moody's and BB+ to BBB- by S&P), reflecting the domestic economy's resilience to external shocks. The World Bank's forecast GDP growth rate for Indonesia is 5.3% p.a. for 2018-2020. The Economist Intelligence Unit forecasts average growth of 5.1% until 2022.

PwC's World in 2050 report[2] indicates that Indonesia could be the fifth largest economy in the world by 2030 (based on purchasing power parity) and the fourth largest by 2050. However, this will depend upon significant investment in infrastructure, including power, to drive higher GDP growth. Since April 2018, the Indonesian Rupiah ("IDR") has been trading above 14,000 per US Dollar ("USD") a higher rate than the previously stable rate of 13,000-13,500 per USD. The Bank of Indonesia believes that the recent weakening of the Rupiah is still within a "normal" range and is largely reflective of expectations of the US Federal Reserve's action to increase interest rates in 2018/19. However policy developments at the time of writing suggest emerging currency concerns, particularly, in relation to capital imports relevant to power infrastructure. Developments should be monitored.

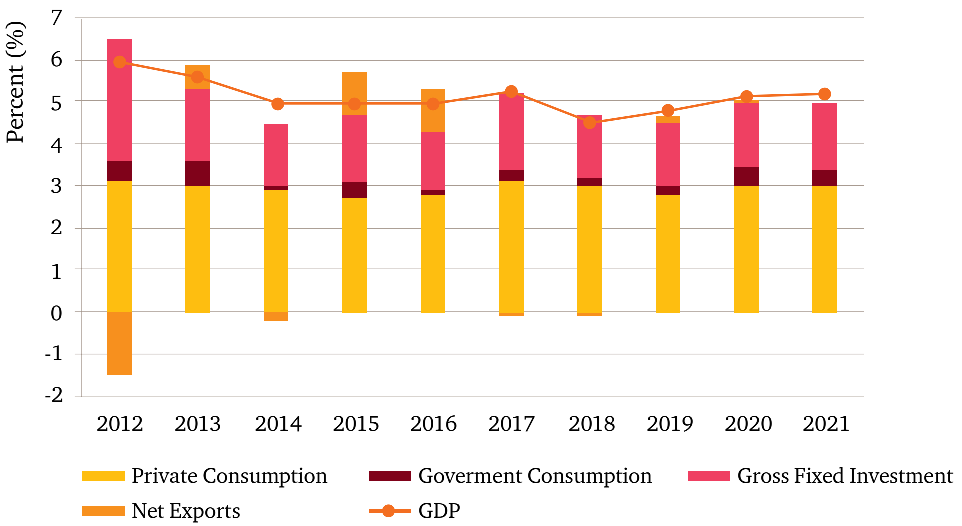
1 Indexmundi
2 PwC, *https://www.pwc.com/gx/en/issues/economy/the-world-in-2050. html*


Photo source: PwC

Indonesia's GDP is forecast to be largely driven by domestic household consumption for the foreseeable future, supported by the relatively low level of inflation, and improved commodity prices. There is also an expectation that the Government will at least keep fuel and electricity prices stable until the end of 2019 in order to maintain the strength of the people's purchasing power.

On the supply side, key sectors have historically included manufacturing (20% of GDP), agriculture (13%), wholesale and retail trade (13%), construction (10%) and mining (8%).[3] With the slowdown in the mining sector in 2013-2016 some rebalancing of economic growth towards manufacturing has been taking place (although mining rebounded on the back of higher commodity prices in 2017 and has continued in 2018). Interestingly, even as manufacturing jobs rose by 1.5 million in 2017 [4], the 2018 RUPTL forecast for power consumption growth was reduced by 19.6% for commercial activities and another 38.9% for industrial activities. PLN expects this growth to slow further until 2027. Electricity distribution is uneven with higher consumption in more industrialised areas such as the western part of Java. Similarly, the level of access to the grid is mixed with electrification rates as high as 100% in the western part of the country (i.e. DKI Jakarta, Banten, West Java and DI Yogyakarta) and as low as 59.85% in the south east part of the country (i.e. NTT) (see Figure 1.3). However, the most eastern part of Indonesia, Papua, has experienced a significant improvement in the electrification rate from 47.78% in 2016 to 61.42% in 2017. The national average electrification rate in 2017 was 95.35% up from 91.16% in 2016. Based on the 2018 RUPTL the electrification rate is set to increase to 96.7% by 2019 and to 99.5% by 2027. [5]

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

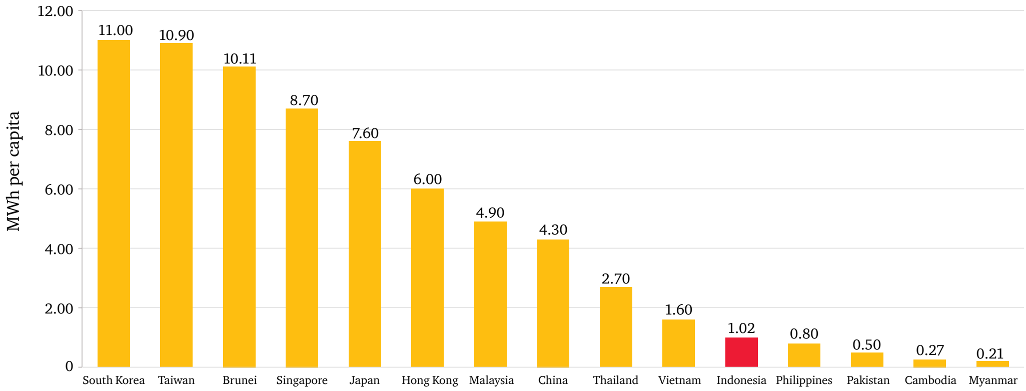


Source: Bank Indonesia, Statistics of Indonesian Economic and Finance ("SEKI"), (www.bi.go.id/en/statistik/metadata/seki)

3 *Bank Indonesia, Statistics of Indonesian Economic and Finance ("SEKI"), www.bi.go.id/en/statistik/metadata/seki*
4 World Bank, Indonesia Economic Quarterly, March 2018
5 2018 RUPTL, p. V-24

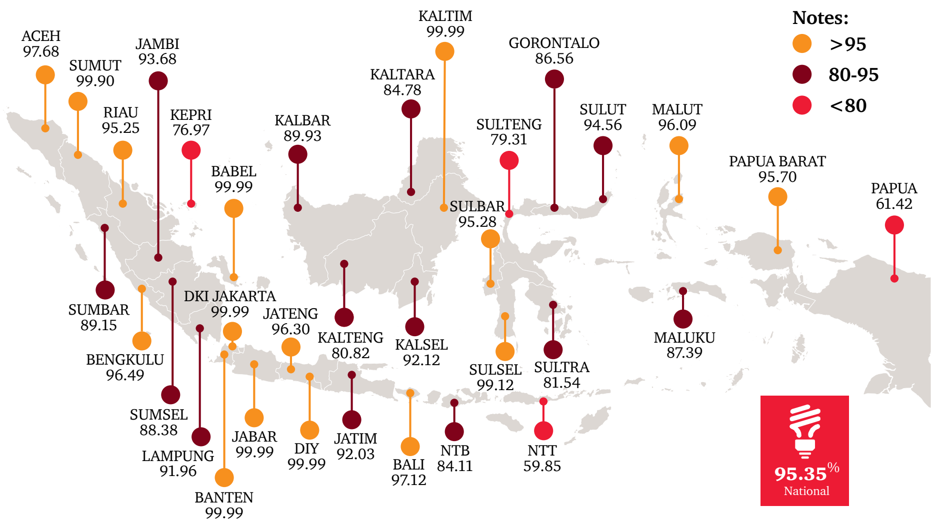
Electricity consumption in 2017 saw a slight increase from the 2016 number of 957 kilowatt hours ("kWh") per capita to 1,021 kWh on a national basis. [6] This was however still relatively low compared to most neighbouring countries (see Figure 1.2).

Figure 1.2 – 2017 Electricity consumption per capita in selected countries neighbouring Indonesia



Source: US Energy Information Administration, Business Monitor International, and Statistics Department, and MoEMR

Figure 1.3 – 2017 Electrification rates in Indonesian provinces (in percentages)



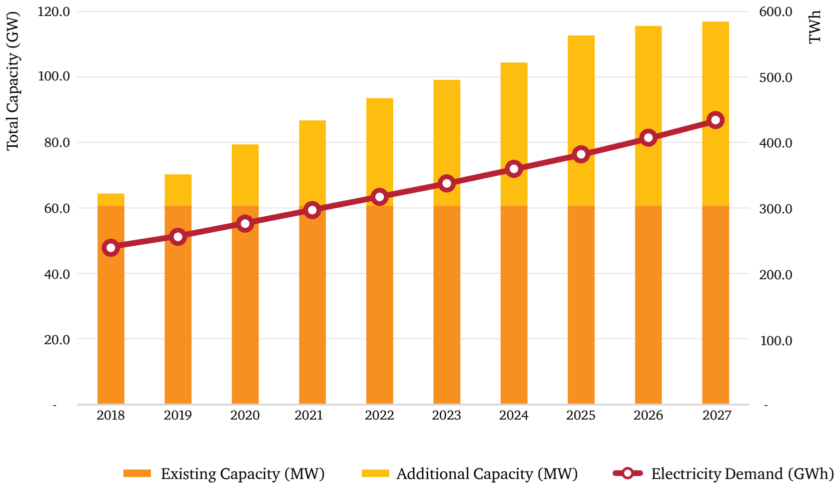
Source: Laporan Kinerja Tahun 2017 Direktorat Jenderal Ketenagalistrikan ("LAKIN DJK 2017") [2017 Performance Report of Directorate General of Electricity ("DGE")]

6 LAKIN DJK 2017, p. 19

Indonesia's rising middle class and income per capita, accompanied by a structurally lower electrification ratio, should spur significant growth in electricity demand. However, PLN has recently revised its target down from 78 GW of new power generation capacity by 2026 in the 2017 RUPTL to 56 GW by 2027 in the 2018 RUPTL. One of the main reasons for PLN's move is the decrease in the expected average electricity demand growth rate. This has been revised from 8.3% in the 2017 RUPTL to 6.9% in the 2018 RUPTL thereby reducing the estimated total electricity demand in 2026 from 483 Terawatt hours ("TWh") to 407 TWh (a 15.7% decrease).[7]

Despite a series of challenges the Government's plan for a 35 GW power capacity expansion by 2019 is still on track albeit with a completion date of 2024 (see *Section 3.7.2 – The 35 GW Power Development Programme* for the latest progress). PLN's latest plan indicates that there will only be 9.47 GW of additional power capacity developed by the end of 2019 and 56 GW by 2027.[8] The 56 GW target represents a 28% reduction (e.g. as per 78 GW in the 2017 RUPTL). The improvement of national power generation and electricity access is however, still a significant part of the Government's wider plan for infrastructure support (as outlined in the Medium Term Development Plan 2015-2019) covering roads, railways, seaports and airport development, water supply and treatment, oil refining, gas supply and distribution, and fibre-optic broadband.

Figure 1.4 - Electricity capacity (GW) and demand (TWh) 2018-2027

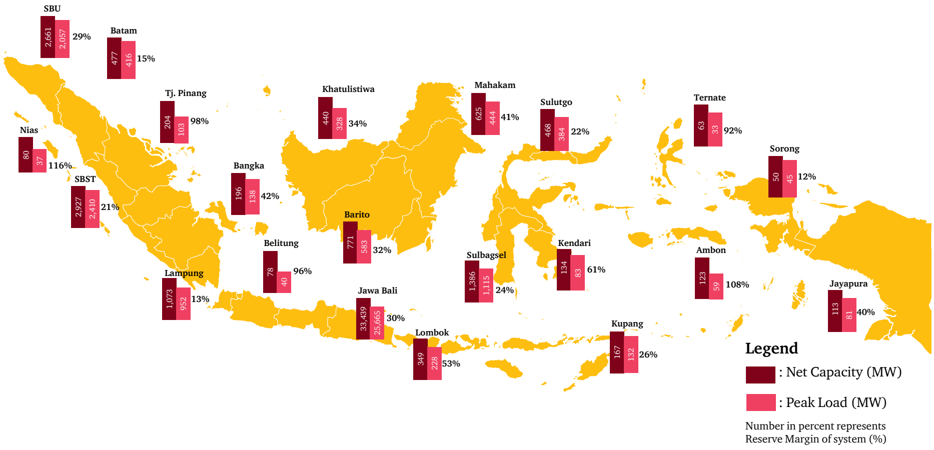


Source: 2018 RUPTL

The 35 GW programme is intended to drive a general improvement in Indonesia's overall power systems *vis-a-vis* the current status. As of December 2017, only 13 of PLN's 21 large power systems across Indonesia were considered "normal" with reserve margins ("RM" – the difference between net capacity and peak demand) above 30%. Another eight power systems were considered "on alert" status with RMs below 30% (Figure 1.5).[9]

7 2018 RUPTL, p. V-25
8 2018 RUPTL, p. V-35
9 "Listrik" magazine Vol. 61, p. 34, 20 February 2018

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

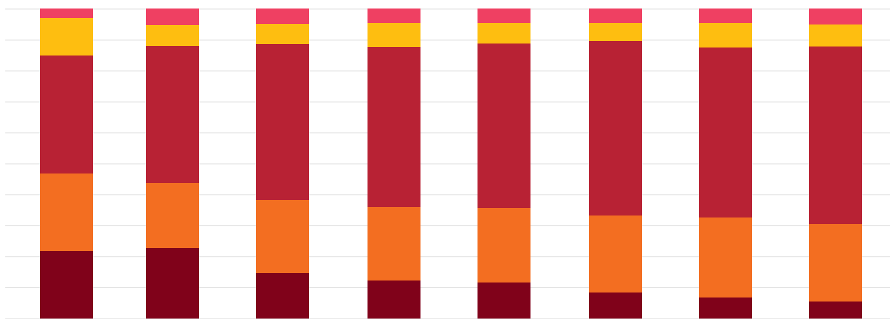


Source: "Listrik" magazine Vol. 61, p. 34, 20 February 2018

1.2 *Sources of Energy*

In 2017, Indonesia had approximately 60.7 GW of installed power plant capacity [10] including PLN/IPP power plants, Private Power Utilities ("PPU") and those operating under non-fossil fuel operating licences ("IO Non-BBM") (see *Section 2.2.2.1 - Generation* for further details). These power plants generated 254.5 TWh of electricity in 2017.[11] The current power generation fuel mix includes coal (57.22%), gas (24.82%), oil (5.81%) and renewables (12.15 %) as in Figure 1.6.[12]

Figure 1.6 – Development of fuel mix for power generation



	2010	2011	2012	2013	2014	2015	2016	2017
Oil	22.00%	22.95%	14.97%	12.54%	11.81%	8.58%	6.96%	5.81%
Gas	25.00%	21.00%	23.41%	23.56%	24.07%	24.89%	25.88%	24.82%
Coal	38.00%	44.06%	50.27%	51.58%	52.87%	56.06%	54.70%	57.22%
Hydro	12.00%	6.80%	6.39%	7.73%	6.70%	5.93%	7.88%	7.06%
Geothermal + Other New and Renewable Energy ("NRE")	3.00%	5.20%	4.96%	4.58%	4.55%	4.54%	4.58%	5.09%

Source: LAKIN DJK 2017

10 LAKIN DJK 2017, p. 26
11 LAKIN DJK 2017, p. 34
12 LAKIN DJK 2017, p. 36

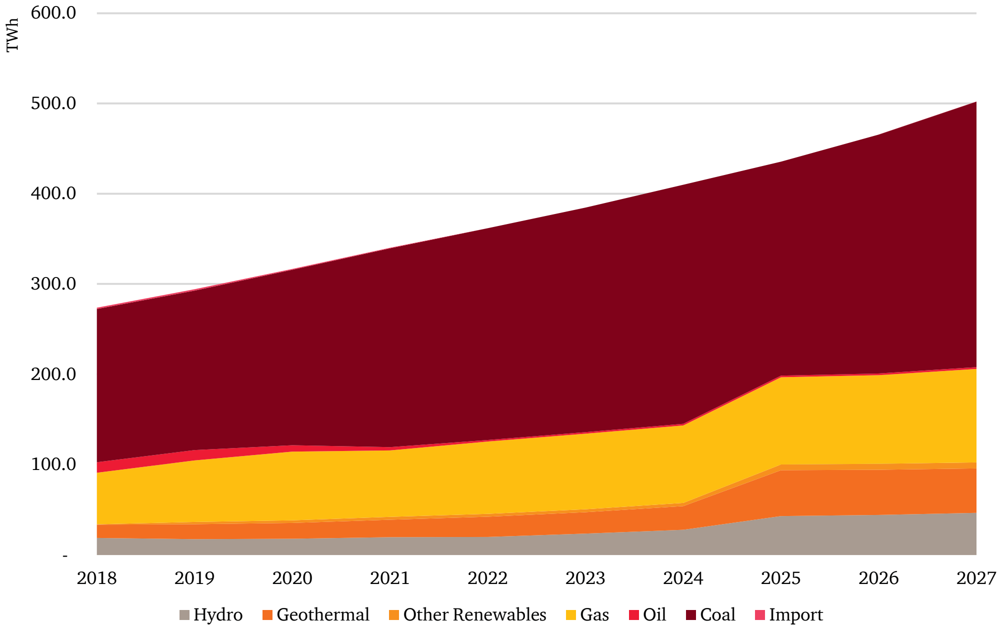
The significant role of fossil fuels reflects Indonesia's natural abundance of hydrocarbons as outlined in detail in *Section 4 - Conventional Energy*. Key factors and trends in the three major conventional energy sectors include the following:

- **Coal**: Coal has historically been, and remains, Indonesia's most important source of fuel for electricity and a driver for economic growth. Economic and logistical considerations (as well as significant available reserves) have led to coal's ongoing dominance as a low-cost fuel that is easy to extract and transport with existing infrastructure. In 2017, coal accounted for 57.2% of Indonesia's power generation fuel mix and coal mining made up 2.4% of Indonesia's total GDP. Indonesia's abundance of coal favours investments in coal-fired power plants. Based on the 2018 RUPTL coal-fired power plants will account for 37% of the increase in installed capacity by 2027 compared to 32% in the 2017 RUPTL.
- **Natural Gas**: Natural gas is relatively low-carbon (as compared to coal) and is generally medium-cost. Gas is therefore likely to remain a favoured fuel for at least the next decade especially given Indonesia's extensive gas reserves. While the electricity generated from natural gas in 2027 is expected to increase by over 80% from 2018 (in TWh terms) the share of gas in the energy mix in 2027 is expected to be only 20.6% representing a decrease from 24.8% of the energy mix in 2017. An oversupply of global and Asian (including Indonesian) Liquefied Natural Gas ("LNG") is likely to stimulate further consumption although the LNG market is expected to tighten over the next few years. Certainty over the upstream oil and gas investment climate and improved physical infrastructure (including pipelines and Floating Storage Regasification Units ("FSRUs")) as well as pricing for gas-for-power arrangements (currently under review again) are crucial to enabling a strong long-term role for gas in the Indonesian power generation mix.
- **Oil**: Crude oil has traditionally played a large role in Indonesia's energy supply including exports. However, Indonesia is now a net oil importer. Increasing oil prices have driven Indonesia's energy mix away from diesel power plants. PLN aims to significantly reduce the use of oil in Indonesia's future energy generation from 5.8% in 2017 to 0.4% by 2023.

Other forms of non-conventional fossil fuel energy, such as coalbed methane or coal gasification technologies, also exist and are being developed in Indonesia but are so far insignificant. We have not explored these in this Guide due to the limited current usage. For a full overview of the regulatory, tax and investment issues in the mining as well as the oil and gas sectors please see our separate Investment Guides.[13]

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

Figure 1.7 - 2018 – 2027 Indonesian electricity generation (in TWh)



Fuel Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hydro	19.0	17.6	18.0	19.8	20.0	23.7	28.0	43.1	44.4	46.7
Geothermal	14.7	16.6	17.5	19.3	22.4	23.6	26.2	50.8	50.0	49.2
Other Renewables	0.4	2.5	2.9	3.2	3.2	3.3	3.6	6.3	6.6	6.6
Gas (including LNG)	57.1	68.1	76.1	73.5	80 .0	83.7	85.7	96.6	98.1	103.5
Oil	11.6	11.4	7.1	3.6	1.7	1.7	1.8	1.8	1.9	2.0
Coal	169.6	176.5	194.2	220.1	234.5	248.6	264.6	236.8	264.4	293.9
Import	1.4	1.6	0.9	0.6	-	-	-	-	-	-
Total	**273.8**	**294.3**	**316.7**	**340.1**	**361.8**	**384.6**	**409.9**	**435.4**	**465.4**	**501.9**

Source: 2018 RUPTL

Indonesia has enormous potential in renewable resources as outlined in Table 1.1 below. The potential renewable energy resources are based on a technical assessment by the MoEMR only but do not necessarily consider the financial/economic viability of individual projects. However, Government Regulation ("GR") No. 79/2014 on the National Energy Policy (the "2014 NEP") requires that the development of renewable energy resources consider economic viability. The potential resource estimates in Table 1.1 also do not consider locational factors (i.e. as some renewable energy resources are located in areas with very low electricity 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	33 GW
Solar Photovoltaic ("PV")	208 GWp (4.80 kWh/m^2/day)
Wind Power	61 GW (3 – 6 m/s)
Ocean	18 GW

Source: Statistik EBTKE 2016, Direktorat Jendral Energi Baru dan Terbarukan dan Konservasi Energi ("Ditjen EBTKE") [2016 EBTKE Statistics issued by Directorate General of New and Renewable Energy and Energy Conservation ("DGNREEC")]

Renewable energy is nevertheless looking increasingly attractive in Indonesia not only to support environmental policy around CO_2 emissions and urban air pollution but also due to the improving cost profile and ability to be deployed in a more decentralised manner. According to the 2018 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, hydro accounted for 7.1% of national power generation with this expected to grow to 9.3% in 2027. Many prospective sites have good water flow although limitations on foreign ownership may hold back smaller projects (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 approval for at least 50 small hydro (≤ 10 Megawatt ("MW")) Power Purchase Agreements ("PPAs") with PLN at tariffs between IDR 780 and 1,050/kWh. Since then, approximately 38 small hydro projects have reported difficulties in reaching financial close as at the end of the first quarter of 2018.[14] In April 2018, IPP hydropower developers were invited by PLN to a general pre-qualification process for future hydropower projects with over 100 developers submitting applications to PLN.[15]
- **Solar PV**: Despite naturally high solar penetration across most parts of the country Solar PV deployment currently remains limited (estimated to be 109 MWp)[16]. The potential is estimated to be around 208 GWp.[17] There have been several revisions to the regulations underpinning Solar PV pricing and procurement over the past few years although the problematic regulations regarding local content remain (see *Section 2.2.3 - Local Content*). Based on Official Letter of the Minister of Energy and Mineral Resources No. 5827/23/MEM.I./2017 up to six Solar PV PPAs have been signed but, at the time of the writing, two out of the six were reported to be facing difficulties with reaching financial close as at the end of the first quarter of 2018. There is no further information regarding the 168 MW of solar PV tenders in Sumatera after pre-qualification was completed in the second-half of 2017. The tenders are understood to be waiting for administrative documents to be completed.[18]

14 Gatra, https://www.gatra.com/rubrik/ekonomi/324345-Asosiasi-Listrik:-Pemerintah-tidak-punya-visi-bangun-energi-efisien, accessed 25 June 2018

15 GBG Indonesia, http://www.gbgindonesia.com/en/main/legal_updates/indonesia_s_pln_invites_hydropower_developers_to_prequalify.php, accessed 2 July 2018

16 Rida Mulyana (Directorate General of DGNREEC) "Utilisation of Renewable Energy", presentation at the PetroGas Days UI. 16 March 2017; and LAKIN EBTKE 2017

17 Statistik EBTKE 2016 (DGNREEC 2016 Statistics), p. 16

18 Bisnis.com, http://sumatra.bisnis.com/read/20180515/451/794974/energi-baru-terbarukan-lelang-plts-tunggu-dokumen-administrasi, accessed 20 July 2018

- **Geothermal**: With Indonesia possessing the second-largest geothermal resource in the world the geothermal share of the fuel mix is expected to almost double from 5% in 2017 to 9.8% in 2027. A key strength of geothermal is its ability to provide base-load power offsetting one of the traditional weaknesses of renewable energy. However, there are only a limited number of concessions under development with PPA approval slow and Indonesian state-owned enterprises ("SOEs") playing a dominant role. Notwithstanding this, the Independent Power Producer ("IPP")-driven Sarulla project came online in March 2017 with Unit-1 (110 MW), followed by Unit-2 in October 2017 (110 MW) and Unit-3 in May 2018 (110 MW). There was also the Karaha geothermal power plant (30 MW) becoming operational in April 2018.[19] Along with hydropower, PLN also invited developers of geothermal power plants to a pre-qualification process in April 2018.
- **Bioenergy**: The bioenergy market consists of discrete segments such as agricultural/plantation biomass waste, Palm Oil Mill Effluent ("POME"), Municipal Solid Waste ("MSW") and biodiesel. The market largely consists of power plants with 10 MW or less of capacity. Significant potential remains with large amounts of 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. The recently issued Presidential Regulation ("PR") No. 35/2018 is the current reference for MSW PPAs. On 2 August 2017, PLN also signed at least four biomass and five biogas PPAs ≤ 10 MW at tariffs between IDR 890 and IDR 1,555/kWh. However it is reported that five Bioenergy PPAs have faced difficulties in financing their projects as of the first quarter of 2018.[20] 78 companies were nevertheless reported to have participated in the tender for waste-to-energy infrastructure in Tangerang while waste power plants of an aggregate 95 MW across Indonesia are yet to be awarded.[21]
- **Wind**: Historically wind has not played an important role in Indonesia's fuel mix. However, significant progress has been observed with UPC's 75 MW Sidrap wind farm in South Sulawesi becoming operational from March 2018, and being officially inaugurated by President Joko Widodo in July 2018.[22] The 72 MW Jeneponto wind farm in the same province is also expected to become operational in the near future.[23]

MoEMR Regulation No. 50/2017 regulates the tariff regimes for renewable electricity generation with tariffs still benchmarked to PLN's average electricity generation cost (*Biaya Pokok Pembangkitan* – "BPP"). As a result developers are still facing challenges regarding the viability of the new power plant projects although the severity of the impact depends on the geographical area.

19 DGNREEC, http://ebtke.esdm.go.id/post/2018/04/28/1948/indonesia.peringkat.2.produsen.listrik.panas.bumi.lampaui.filipina.?lang=en, accessed 08 June 2018
20 Gatra, https://www.gatra.com/rubrik/ekonomi/324345-Asosiasi-Listrik:-Pemerintah-tidak-punya-visi-bangun-energi-efisien, accessed 25 June 2018
21 PwC, https://www.pwc.com/id/en/media-centre/infrastructure-news/may-2018/78-companies-follow-tender-in-tangerang.html
22 Katadata, https://katadata.co.id/berita/2018/07/02/diresmikan-jokowi-pltb-sidrap-bisa-alirkan-listrik-ke-70000-rumah, accessed 19 July 2018
23 Tempo, https://bisnis.tempo.co/read/1102567/sudah-92-persen-pembangunan-pltb-tolo-1-rampung-agustus-2018, accessed 20 July 2018

Many factors support renewable deployment, including falling costs, national carbon emissions targets, the high cost of oil-based generation (especially in remote regions) and the regulatory and physical barriers to gas distribution. However, the lack of a bankable PPA has become a major concern. Of the 70 renewable power plant projects signed before the end of 2017, 55 projects have since experienced financing difficulties.[24] As of June 2018, 45 projects were reported to have made no progress towards financial close with only four projects having reached COD.[25] METI also stated that most of their members were unable to secure funding for new renewables projects under the new PPAs.[26]

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 Stipulations for Renewable Energy* for more information on MoEMR Regulation No. 50/2017.

1.3 *Electricity Tariffs*

Under Law No. 30/2009 (the “2009 Electricity Law”), 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 subsidised with IDR 415/kWh representing a price of less than a third of the average electricity supply cost of IDR 1,318/kWh in 2017.[27]

Prior to 2013, PLN’s revenue was dictated by regulated electricity prices with tariffs set by the Central Government and ultimately approved by Parliament. This was except for electricity prices in Batam which were approved by the Regional Government. Since price increases required 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 tariff 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.

24 Bisnis.com, http://industri.bisnis.com/read/20180111/44/725350/68-proyek-pembangkit-liatrik-energi-terbarukan-siap-dibangun, accessed 10 July 2018
25 Kontan, https://industri.kontan.co.id/news/pengembangan-45-pembangit-listrik-energi-terbarukan-mandek, accessed 10 July 2018
26 PwC “Alternating Currents: Indonesian Power Industry Survey”, July 2018, p. 25
27 PLN Annual Report 2017, p. 240

Table 1.2 - Average cost, average tariff, and subsidies

Year	Average Cost (IDR/kWh)	Average Tariff (IDR/kWh)	Subsidy (IDR Trillion)
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
2017	1,318	1,105	45.7

Source: 2017 PLN Statistics

The latest subsidy regulation was promulgated through Minister of Finance Regulation ("MoF Regulation") No. 44/2017 (as amended by MoF Regulation No. 162/2017) concerning the Procedures for the Provision, Calculation, Payment and Accountability for Electricity Subsidy. 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 automatic tariff adjustment mechanism or customers that are not charged by PLN (e.g. tenants in industrial estates). The amount of electricity subsidy is based on the MoEMR calculation which is proposed to the MoF for incorporation into the State Budget Plan (*Rencana Anggaran Pengeluaran and Belanja Negara* – RAPBN").

Starting in January 2017, the Government 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 for business customers, 6,600 VA up to >200 kVA for Government offices customers, >200 kVA for industrial customers as well as public street lighting and special services. Therefore, except for 450 VA and some 900 VA customers (which are not classified as high income households) all customers 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.

At the end of 2017, PLN served 67.5 million customers through a transmission network comprised of 48,901 kilometre circuits ("kmc") of transmission lines and 113,791 Megavolt Amperes ("MVA") of transmission transformer capacity. Given that close to 5% of the population of Indonesia is without access to electricity, and many of those who are connected suffer frequent supply interruptions, it is unsurprising that the expansion of power generation and T&D networks is both a top priority and a major challenge. According to the 2018 RUPTL, PLN projects electricity demand to grow at 6.9% p.a. until 2027 reaching a total of 434 TWh of electricity consumed in 2027. This is compared to 223 TWh in 2017. By 2024, the Government expects the entire population of Indonesia to have access to electricity.

Transmission network projects are generally implemented by PLN while transmission projects specifically related to individual Independent Power Producers ("IPP") are conducted by IPP developers in accordance with PLN's Request for Proposal ("RfP"). However, transmission projects may also be implemented by the private sector under certain business schemes such as Build-Lease-Transfer ("BLT") or power wheeling.

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

Region/Island	25-30 kV	70 kV	150 kV	275 kV	500 kV	Total
Sumatera	-	338	11,683	2,727	-	14,748
Java-Bali	97	3,035	14,584	-	5,074	22,790
Kalimantan	-	123	4,698	163	-	4,984
Sulawesi	4	596	4,495	-	-	5,095
Papua and Maluku	-	290	-	-	-	290
Nusa Tenggara	-	653	341	-	-	994
Total	**101**	**5,035**	**35,801**	**2,890**	**5,074**	**48,901**

Source: 2017 PLN Statistics

A summary of the sub-station transformer capacity for each significant island in Indonesia is as follows (in MVA):

Region/Island	<30 kV	70 kV	150 kV	275 kV	500 kV	Total
Sumatera	-	775	12,243	5,660	-	18,678
Java-Bali	-	2,841	53,159	-	30,014	86,014
Kalimantan	-	148	3,617	498	-	4,263
Sulawesi	30	825	2,830	90	-	3,775
Papua and Maluku	-	216	60	-	-	276
Nusa Tenggara	-	265	520	-	-	785
Total	**30**	**5,070**	**72,429**	**6,248**	**30,014**	**113,791**

Source: 2017 PLN Statistics

During 2017, PLN built 4,616 kms of additional transmission lines and 16,210 MVA of sub-station transformer capacity.[28] Based on the 2018 RUPTL Indonesia will need additional transmission lines of approximately 64,000 km by 2027 and sub-station transformer capacity of 151,000 MVA.[29] In connection with the delayed 35 GW Programme, plans are underway to add another 31,061 kmc of additional transmission lines and 70,645 MVA of sub-station capacity by 2019.

There are already limited cross-border transmission lines connecting Indonesia and other ASEAN countries as part of the ASEAN Grid programme. Please refer *Section 2.2.6 - Cross-Border Sale and Purchase* for a detailed explanation.

28 PLN Annual Report 2017, p. 59
29 2018 RUPTL, p. V-84

In 2017, the existing distribution network consisted of around 402,000 kmc of Medium Voltage cables, 627,000 kmc of Low Voltage cables and 60,000 MVA of transformer capacity with 472,000 transformers as follows:

Region/ Island	Medium voltage (in kmc)	Low voltage (in kmc)	Number of transformers (in Unit)	Transformer capacity (in MVA)
Sumatera	108,533	141,032	98,975	9,839
Java-Bali	199,204	390,120	287,313	42,094
Kalimantan	33,116	34,870	31,385	3,112
Sulawesi	36,072	35,122	36,585	3,206
Papua	5,346	8,465	3,570	411
Maluku	6,823	4,231	4,249	405
Nusa Tenggara	12,865	12,879	9,688	1,033
Total	**401,959**	**626,719**	**471,765**	**60,100**

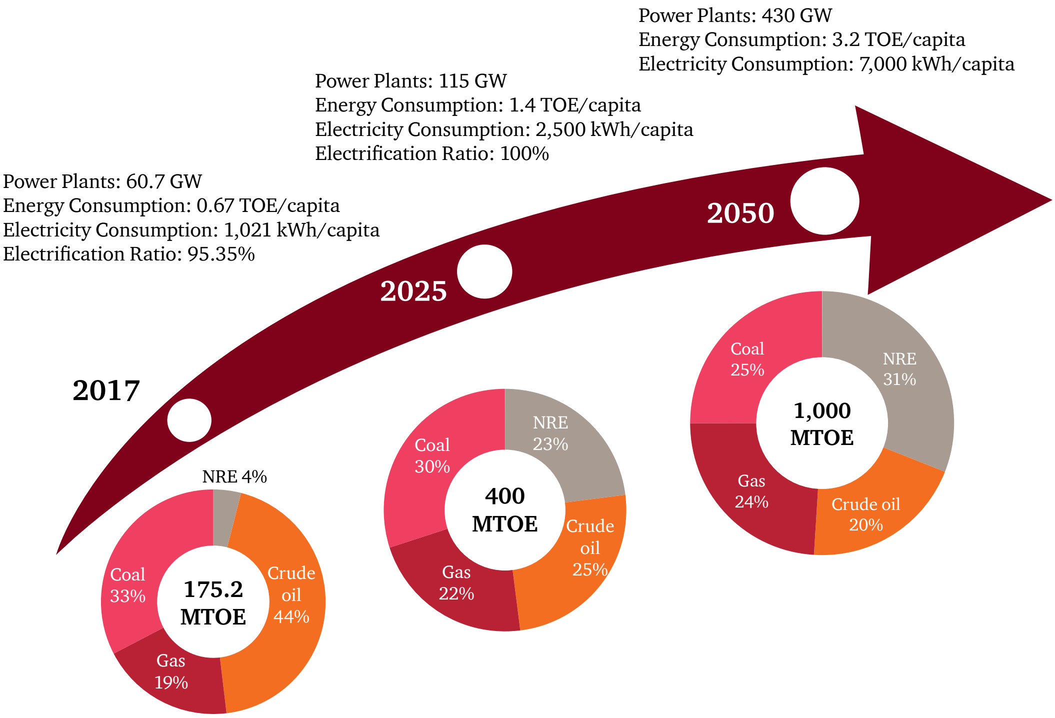
Source: 2017 PLN Statistics

The overall power network performance is designed to support the implementation of a Smart Grid system across Indonesia. Efficient energy planning, improved grid reliability and access, and developing a metering system and infrastructure are aspects that have been prioritised in the PLN Smart Grid Roadmap, which has commenced with the following pilot projects:

- Development of a Smart Grid in the Surya Cipta Sarana Industrial Zone, Karawang;
- Development of a Smart Grid for renewable energy in Sumba Island, East Nusa Tenggara; and
- Development of a Smart Grid with Advance Metering Infrastructure technology in a distribution area in Jakarta.

1.5 *Government Strategies, Policies and Plans for the Power Sector in Indonesia*

Renewables have increased in importance in recent years due to concerns over global warming and other environmental issues. Certain renewable technologies have also 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) 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 2018, PwC Analysis

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

- To reach installed capacity for power generation 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 the electricity subsidy in stages until the population's purchasing power can afford this without subsidy; and
f) Encourage domestic capability in order to execute geothermal exploration and support the power industry.

To support the new and renewable energy mix, and based on the 2014 NEP, the power generation energy mix should comprise approximately 25% of new and renewable energy, 50% coal, 24% gas and 1% diesel fuel by 2025.[30] In 2017, power generation from new and renewable energy was around 12%. Therefore achieving 25% by 2025 represents an ambitious target. Based on the 2018 RUPTL, PLN projects that involve power generation from renewables will amount to a maximum of 20.4% by 2027.[31] As such, it is likely the target prescribed in the 2014 NEP will not be achieved unless a new strategy is implemented.

With Law No. 30/2007 on Energy and the 2014 NEP, as targeted in GR No. 79/2014, in mind President Joko Widodo issued PR No. 22/2017 on the National General Energy Plan (*Rencana Umum Energi Nasional* - "RUEN") in March 2017. 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 the 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. The RUEN will be reviewed whenever there are changes to the fundamentals of NEP or strategic energy policies. Otherwise the RUEN is to be reviewed every five years.

A large number of regulatory, financial and practical barriers will need to be overcome for Indonesia's 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. Recent developments have shown that the regulations that were issued in 2017 are a major obstacle for the development of the renewables sector. In particular, the risk allocation principles in PPAs, restrictions on share transfers, and IPP tariffs have had a negative impact on investors' future plans. The changes in the regulations issued in 2017 could be seen as indicating a lack of clear regulatory objectives or processes for stakeholders. This could harm perceptions in the investment community as well as the Government's ability to develop much-needed electricity infrastructure to support economic growth. This is reflected in the recent PwC 2018 Indonesian Power Survey in which we noted a significant decrease in investor confidence in the Indonesian power industry in general, including renewables.[32]

30 The renewables target in the primary energy mix is 23%, which is not to be confused with the renewables target in the power generation fuel mix (25%)
31 2018 RUPTL, p. V-64
32 PwC "Alternating Currents: Indonesian Power Industry Survey", July 2018, p.14

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 as much as 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 being 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 to independently 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.[33] 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.

33 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.

1.7 *Stakeholders*

MoEMR

The MoEMR is charged with creating and implementing Indonesia's energy policy including the National Electricity General Plan (*Rencana Umum Ketenagalistrikan 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, the 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 the environment.

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

PLN

PLN is responsible for the majority of Indonesia's power generation with 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. This means that, if PLN is not supplying a particular area and there are no regionally-owned companies, private enterprises or cooperatives willing to supply then the Government can instruct PLN to ensure the supply of electricity.

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 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 2010, BKPM started issuing electricity supply business licences. From 2015, BKPM also acts as a "one-stop" integrated service for business start-up and licensing procedures as well as for facilitating foreign worker permits. BKPM also offers an Investor Relations Unit for providing information and dealing with enquiries from existing and potential investors. The Government recently introduced an online business licensing platform via the Online Single Submission ("OSS") System.

Please see the discussion in *Section 2.2.4 - IUPTL, Section 2.2.5 - Online Single Submission ("OSS") System* 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 together with the Coordinating Minister for Maritime Affairs. Other members of KPPIP include the Minister of Finance, the Minister of National Development Planning/ Bappenas, the Minister of Agrarian and Spatial Planning and the Minister of Environment and Forestry. KPPIP was established with the main objective of coordinating the decision-making process. KPPIP is the main point of contact for "de-bottlenecking" strategically important national 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 government support, providing technical guidance, evaluating the financing and maintaining investor relations. 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 under PPP scheme. 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 8 trillion in capital injected as at the end of 2017. For further details please see *Section 3.3.1 - IIGF – for PPPs*.

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 includes the Heads of the Associations of Geothermal, Hydro, Solar, Biofuel, Biomass, Biogas, Wind, Nuclear and Ocean Energy.

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 55.39 trillion by the end of 2017. PT SMI exists to help investors obtain domestic financing for the debt and equity funding of infrastructure development including power projects as well as to prepare projects under Project Development Facilities assigned by the Minister of Finance. PT SMI is backed by multilateral agencies including the World Bank. The total financing commitment of PT SMI at the end of 2017 was IDR 29 trillion with 32% 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. Its shareholders are 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*.

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, approves its annual budget and assesses the achievement of those targets.

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, the business environment and regulations.

The Indonesian Independent Power Producers Association *(Asosiasi Produsen 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 parties related to the activities of IPPs. APLSI's vision is to become an efficient and trustworthy association of IPPs in Indonesia and to make a contribution to the development of Indonesian IPPs at the international level.

Indonesian Geothermal Association ("INAGA")

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

Photo source: PwC

2 Legal and Regulatory Framework

2.1 *Introduction*

The power sector is regulated by the 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. This is as well as implementing regulations issued by the MoEMR, the MoF, the Minister of Industry, 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 Developments (the 2012 Land Acquisition Law) and its implementing regulation PR No. 71/2012 on the Implementation of Land Procurement for Public Interest Developments (as amended by PR Nos. 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 laws and regulations specific to 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 and RUEN (please refer to *Section 1.5 – Government Strategies, Policies and Plans for the Power Sector in Indonesia* for details of the RUEN) which are stipulated under GR No. 79/2014 and PR No. 22/2017 respectively. The RUKN was formulated in collaboration

Photo source: PT UPC Sidrap Bayu Energi

with the Government during the course of several Focus Group Discussions ("FGDs"). Based on 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 RUKN and RUKD. The RUPTL contains demand forecasts, future expansion plans, electricity production forecasts, fuel requirements and projects to be developed by PLN and IPP investors respectively. The procurement route for IPPs is also based on the RUPTL. As such, the RUPTL is an 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 supplies.

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. This is 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 out the *Wilayah Usaha* for the electricity supply business. According to MoEMR Regulation No. 28/2012 (as amended by MoEMR Regulation No. 7/2016) a *Wilayah Usaha* can be granted to parties as described above with the following conditions:

a) The area is not yet covered by an existing IUPTL holder; or

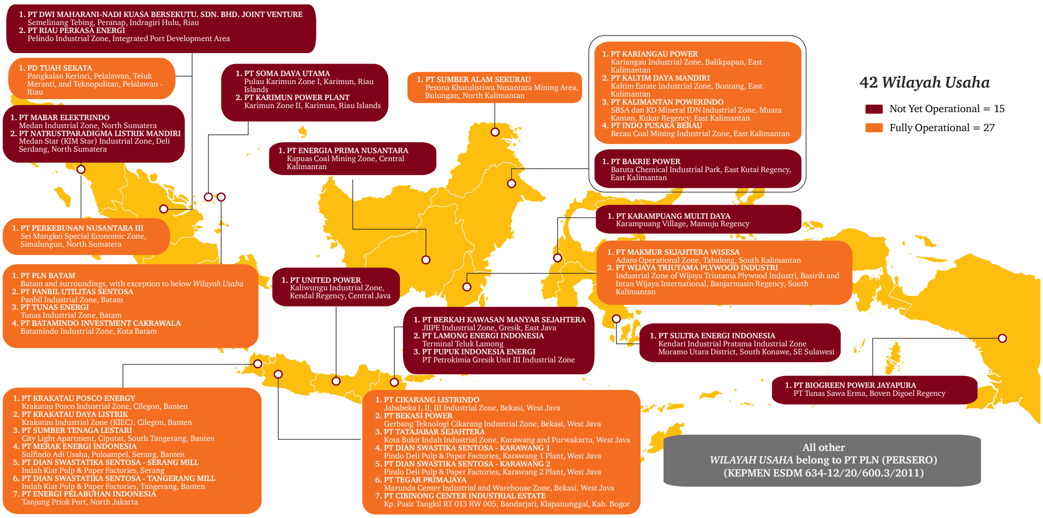
b) The existing IUPTL holder in the *Wilayah Usaha* is not able to provide a good and reliable electricity supply or electricity distribution network; or

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. This should be 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 with authority to issue recommendations where a *Wilayah Usaha* is within a single province. The DGE will assign a technical team to assess the technical feasibility of the request in order to determine whether the requested *Wilayah Usaha* will be granted.

At the end of 2017 the Government had issued 42 *Wilayah Usaha*, including the *Wilayah Usaha* of PLN, with a breakdown of 27 *Wilayah Usaha* already in operation and 15 *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 2017



Source: DGE; I Warsito, "The Availability of Reliable Electricity to Improve the Competitiveness of Industrial Area", 18th July 2018, p. 12.

2.2.2.1 Generation

PLN and IPPs

At the end of 2017 the total installed capacity was 60.7 GW divided between: PLN and its subsidiaries which accounted for 41.7 GW (69%); IPPs accounting for 14.2 GW (23%); PPUs, accounting for 2.4 GW (4%), and the remaining 2.4 GW (4%) belonging to the holders of non-fossil fuel operating licences (IO Non-BBM).[34] As such the majority of power-generating assets in Indonesia are controlled by PLN including its subsidiaries such as 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 of LKPP (*Lembaga Kebijakan Pengadaan Barang dan Jasa Pemerintah* - Government Procurement of Goods and Services Policy Board) No. 19/2015. For a detailed discussion of the IPP/PPP procurement process please see *Section 3.4 - Procurement Process*.

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).[35] PPUs with a capacity between 25-200 kVA must obtain approval from the relevant Minister, Governor or Mayor. 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 (which in practice is most likely to be PLN) or directly to end customers subject to the approval of the relevant Minister, Governor or Mayor. In cases where PPUs are producing power for their own use and selling directly to other users (e.g. industrial estate tenants) PPUs will need *Wilayah Usaha* and IUPTL permits in addition to an *Izin Operasi* in order to act as a seller of electricity.

MoEMR Regulation No. 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 annually to accommodate any changes 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) A Connection Charge: based on the existing Law and related ministerial regulations;
b) A Capacity Charge: calculated using the following formula: total power generated (MW) times 40 hours times electricity tariff;
c) An Energy Charge:
   - Normal Energy Charge: applies when PPUs normally operate in parallel systems;
   - Emergency Energy Charge: when an emergency situation occurs which results in PPUs using the electricity that is supplied by PLN.

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34 LAKIN DJK 2017, p. 26
35 PwC and GE Operations Indonesia ("GE"), Private Power Utilities: The Economic Benefits of Captive Power in Industrial Estates in Indonesia, 2016.

The regulation also provides that PLN can set the capacity charge without approval from the Minister of Energy and Mineral Resources. PLN can also apply a higher capacity charge subject to the approval of the Minister of Energy and Mineral Resources. Industry players have called for the MoEMR to clarify whether MoEMR Regulation No. 1/2017 applies to Solar PV Rooftops on which matter the MoEMR intends to issue an entirely new regulation.[36]

2.2.2.2 Transmission, Distribution and Retailing

The 2009 Electricity Law provides PLN with priority rights for conducting 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) allow for private participation in the supply of power for public use and for transmission and distribution. However, private sector participation is limited to the power generation sector. This should change following the issuance 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 on the detailed technical procedures and financial charges for T&D network access have yet to be released.

2.2.2.3 Electricity Support Business

The 2009 Electricity Law classifies electricity support businesses into Electricity-Supporting Service Business Licences and Electricity-Supporting Industry Business Licences.

Based on GR No. 62/2012 Electricity-Supporting Service Businesses cover 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 the use of electricity;
i) Certification of electricity equipment adequacy and the use of electricity;
j) Certification of electricity engineering competence; and
k) Businesses or other services directly related to the provision of electricity.

Entities involved in Electricity-Supporting Service Business must have an Electricity Supporting Services Business Licence (*Izin Usaha Jasa Penunjang Tenaga Listrik* – "IUJPTL").

Electricity-Supporting Industry Businesses involve the supporting industries for electricity equipment and for electricity utilisation.

36 MoEMR, https://www.esdm.go.id/en/media-center/news-archives/dukung-gerakan-sejuta-atap-kementerian-esdm-siapkan-regulasi-plts-atap, accessed 20 July 2018

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/M-IND/PER/3/2012 (as amended by MoI Regulation No. 5/M-IND/PER/2/2017) stipulates the minimum required percentage of local goods and services (by value) that are to be 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 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 local content (TKDN)
Coal-Fired	Up to 15 MW	67.95% for goods; 96.31% for services; and 70.79% for goods and services combined
	>15 to 25 MW	45.36% for goods; 91.99% for services; and 49.09% for goods and services combined
	> 25 to 100 MW	40.85% for goods; 88.07% for services; and 44.14% for goods and services combined
	> 100 to 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 to 50 MW	49.84% for goods; 55.54% for services; and 51.60% for goods and services combined
	> 50 to 150 MW	48.11% for goods; 51.10% for services; and 49.00% 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 to 10 MW	21.00% for goods; 82.30% for services; and 40.45% for goods and services combined
	> 10 to 60 MW	15.70% for goods; 74.10% for services; and 33.24% for goods and services combined
	> 60 to 110 MW	16.30% for goods; 60.10% for services; and 29.21% for goods and services combined
	Above 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 local content (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 to 100 MW per block	35.71% for goods; 71.53% for services; and 40.00% for goods and services combined
	> 100 to 300 MW per block	30.67% for goods; 71.53% for services; and 34.76% for goods and services combined
	Above 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 45.90% 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:

a) 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 should be undertaken and led by a national Engineering, Procurement and Construction ("EPC") company.

b) The development of power plants other than those mentioned above can be undertaken by a consortium of a foreign company and a local company.

Based on 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 should 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 power plants, main relay stations, and transmission/distribution networks are regulated by MoI Regulation No. 02/M-IND/PER/1/2014 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 licences 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 operating licence ("*Izin Operasi*") to supply electricity for own use (i.e. for PPUs) with electricity capacity of more than 200 kVA and 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.

As per June 2018, the authority to issue power-related licences which was previously delegated by MoEMR to BKPM is now temporarily under the Coordinating Ministry of Economic Affairs and performed via a platform referred to as Online Single Submission. Please see *Section 2.2.5 - Online Single Submission ("OSS") System* below on the explanation of OSS. These licences are:

a) An IUPTL;
b) *Izin Operasi*;
c) The determination of *Wilayah Usaha*;
d) An IUJPTL;
e) A cross-border power sale and purchase licence;
f) A permit for the utilisation of the power grid for telecommunications, multimedia and informatics;
g) A geothermal preliminary survey assignment; and
h) Geothermal licence ("*Izin Panas Bumi*").

2.2.5 Online Single Submission ("OSS") System

The Government recently issued GR No. 24/2018 on Electronically Integrated Business Licensing Services which introduces new business licensing procedures via the OSS System. This was launched on 9 July 2018.

The OSS System is an online business licensing platform intended to accelerate and simplify the process of obtaining business licences which can be accessed at anytime, from anywhere and by any business in Indonesia. The OSS System is currently operated and managed by a dedicated OSS Body under the supervision of the Coordinating Ministry for Economic Affairs until BKPM is ready to take over its management.

GR No. 24/2018 mandates that any existing or newly established businesses in Indonesia must obtain a Single Business Number (*Nomor Induk Berusaha* - "NIB") by registering under the OSS System (https://oss.go.id/oss/). The NIB is a mandatory requirement for any business to: (i) apply for new business licences and/or commercial/operational licences; or (ii) extend or amend existing business licences and/or commercial/operational licences through the OSS System.

During the registration process, in order to obtain an NIB, the investor must provide certain information in the OSS System including:
a) A deed of establishment and the approval from the Minister of Law and Human Rights for the business to operate in the form of a limited liability company;
b) The relevant business line;
c) The type of investment (in accordance with the Indonesian negative investment list);
d) The amount of the investment plan; and
e) Other investment information.

Any changes to the above information must be submitted to the OSS System in due course. Transitional rules apply to an existing investment company that currently holds:
a) An interim investment licence from BKPM (e.g. an in-principle licence or investment registration); or
b) A business licence from BKPM and/or other government institutions and wishes to, for example, expand its business or investments.

Any corporate actions undertaken by an investment company that involve the amendment of Articles of Association or corporate positions (e.g. mergers, acquisitions, transfers of shares etc.) will not be managed by the OSS System. To the extent required by law/regulations this can be done only after obtaining the required approvals from other relevant government authorities (e.g. the Ministry of Law and Human Rights). Business' information within the OSS System must however be updated by the relevant business after the completion of any such actions.

In order to establish a new foreign investment company, or conduct any corporate actions, care must be taken to see whether the establishment or the corporate actions are in line with the prevailing regulations (e.g. the Negative List of Investments). Any violations to the prevailing regulations may cause the business licence application to be rejected by the OSS System.

2.2.6 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 MoEMR.

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 the 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 892 GWh in 2017 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 in order to import hydro-generated power under a 20-year agreement between PLN and the Sarawak Energy Supply Corporation. The payment is based on usage for the first five years while the rest of the contract will see a fixed cost according to the contract. 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 time either party can buy or sell energy from this project. 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.[37]

The Sarawak-West Kalimantan link could be viewed as 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 the flexibility for systems operators to match supply and demand at the lowest possible cost, supporting further intermittent renewable deployment and increasing energy security. The 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.

In addition, a small cross-border transmission line connection has been built from Jayapura to the Papua New Guinea ("PNG") border in order to supply 2 MW of power (generated from diesel plants in Jayapura) to the Wutung Border Post. [38] PNG Power Ltd ("PPL") is awaiting approval to invest the estimated PGK 3.5 million (USD 1.1 million) that is required to construct the 42 km, 20 kV transmission line from Vanimo to Wutung.[39]

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

Interconnection transmission network	Earliest 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

37 MoEMR, https://www.esdm.go.id/id/media-center/arsip-berita/indonesia-malaysia-kerja-sama-perkuat-kelistrikan-di-perbatasan, accessed 9 September 2016

38 The National, https://www.thenational.com.pg/indonesia-set-to-provide-electricity-to-png-border/, accessed 20 July 2018

39 The National, https://www.thenational.com.pg/k1-5m-given-for-villages-to-get-power-from-indonesia/, accessed 20 July 2018

2.3 *Capacity Initiatives – 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 introduced FTP I for 10 GW of coal-fired power generation in 2006 and FTP II for a further 10 GW, coming largely from renewable energy projects, in 2010. The realisation of FTP I and II has not been very successful. After ten years FTP I is not yet 100% complete. FTP II has also not progressed as expected with various projects now integrated into the 35 GW Programme under President Joko Widodo's administration.[40]

Based on the experience and obstacles faced by FTP I and II PR No. 4/2016 (as amended by PR No. 14/2017) on the Acceleration of Power Infrastructure Development was issued in order to address the various problems affecting the development of power projects in Indonesia. This included a Government guarantee for the development of power projects which covers 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 for the power project. 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. It is at the discretion of PLN to propose the guarantee. Further, the proposed guarantee may therefore need to be included in the procurement documents.

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 guaranteed by the MoF. To obtain such a guarantee PLN's President Director also needs to request the guarantee from the MoF who 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).

40 Metro TV, http://ekonomi.metrotvnews.com/energi/4baoXWaK-pln-program-kelistrikan-ftp-1-sudah-menguntungkan, accessed 20 July 2018

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:

a) Fiscal incentives;
b) Licensing and non-licensing relief;
c) Feed-in tariffs for new and renewable energy sources;
d) The establishment of a separate business entity to generate energy from new and renewable sources for sale to PLN; and
e) 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 PR No. 4/2016 (as amended by PR No. 14/2017), the Government plans to develop a new and renewable energy aggregator to buy electricity generated from new and renewable sources and on-sell to PLN for specific subsidies. However, it is not clear when this new aggregator will be established nor 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 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 for 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

PR No. 4/2016 (as amended by PR No. 14/2017) provides that where PLN has to work with a foreign business entity priority shall be given to cooperation with foreign business entities owned by the related foreign Governments (i.e. a 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). This should also follow the shortest timeframes (currently the maximum time is set at 583 days – see the 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 not clear how effectively 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 where higher than the appraisal price, then PLN, a subsidiary of PLN or an IPP can rent or lease the land or cooperate with the landowners based on some other agreement.

When acquiring land for electricity infrastructure development that is controlled by 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 the information in coordination with the minister responsible for the environment and forestry. If the National Land Agency states that the public does not have the rights to the land located in the forest area then PLN, a subsidiary of PLN or an IPP can 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. This settlement should take into account their needs and the social impact. Settlements agreed will be regulated by a MoEMR 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/regionally-owned land.

As an amendment to PR No. 4/2016, PR No. 14/2017 also includes a provision that PLN must pay rent for the SOE/Regionally-owned entities-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 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). This is carried out 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 over 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 a 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 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 the 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 MoEMR Regulation No. 15/2016 (as amended by MoEMR Regulation No. 13/2017) concerning Three-Hours Licensing Services for Infrastructure in the 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 of the administrative and technical requirements within 60 days after the issuance of the IUPTLS. In the event that the company fails to meet these 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 this with the national PTSP as applicable.

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

As discussed in *Section 2.2.5 - Online Single Submission ("OSS") System*, the Government recently launched OSS system to simplify the process of obtaining licences. Please see *Section 2.2.5 - Online Single Submission ("OSS") System* for further discussion regarding the OSS system.

2.3.7 Spatial Plan (*Tata Ruang*)

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

a) 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 to be 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;

b) 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 the refusal by the Ministry of Forestry then the matter shall be settled through the use of a holding zone;[41]

c) Power infrastructure developments that utilise water, heat and wind, including transmission lines, are permitted in nature reserve areas and nature conservation areas.

2.4 *Regulation on PPAs*

In 2017 the MoEMR issued MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation Nos. 49/2017 and 10/2018) on the Principles of Power Purchase Agreements. The regulation outlines the contractual 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) A new penalty mechanisms.

Note that the regulation does not apply to intermittent renewables, small hydro (below 10 MW), biogas or MSW.

MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation Nos. 49/2017 and 10/2018) raises new concerns for investors with the key features as follows:

- **Risk Sharing and Allocation**

  PLN’s previous PPA model was successful in attracting private investment. However, MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation Nos. 49/2017 and 10/2018) adopts a major change to the risk sharing and allocation principles.

  Under the previous regulation force majeure risks were generally borne by the party most able to bear them generally meaning that IPPs were not subject to damages from events beyond their control. The new regulation however, appears to place PLN and IPPs in a risk sharing position if (say) a FM event arises from a natural disaster.

  Based on previous regulations and market precedents PLN bore the FM risk via Deemed Dispatch payments. PLN was also generally obliged to pay compensation to IPPs through termination payments if a FM event resulted in a long term interruption. However, under MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation No. 49/2017 and No. 10/2018) where a natural FM prevents PLN from taking power PLN is no longer required to make the Deemed Dispatch payments. As compensation the PPA may instead be extended by the length of time lost by the disaster and associated repairs. This may of course be problematic to lenders who require regular debt service payments from project cash flow.

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

Where a natural FM event results in a delay in COD the PPA may also be extended by the length of time lost by the disaster and repairs.

- **A New Regime on Penalties and Incentives**

  Under previous regulations and market precedents if an IPP fails to meet the plant's availability factor as set out in the PPA the IPP would be penalised through a revenue deduction aligned with the shortfall in the AF.

  However, the new regulation moves towards a strict "deliver-or-pay" scheme. For example, in the event that an IPP cannot meet its PPA obligations, there is a delay in the COD on account of IPP, or the IPP fails to meet the Availability, Capacity or Outage Factors then the IPP must pay a penalty proportionate to the costs borne by PLN in order to replace the unrequited supply.

  This stricter penalty regime should incentivise performance by IPPs although IPPs will also factor this risk into bid prices. Other penalties can apply to IPPs who fail to maintain certain technical performance standards such as:
  a) Heat rate;
  b) Reactive power within the interconnection system; and
  c) Frequency and ramp rate.

  Similarly PLN is required to pay a penalty for any failure of a power uptake on account of PLN (except under natural FM events mentioned above). Meanwhile, IPPs have the right to incentives if requested by PLN to reach COD early.

- **Applying the 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. That is, at the end of the contract period, the IPP's facilities shall be transferred to PLN. This implies that contract renewal will no longer be possible for IPPs. This is typically not material for a discounted cash flow analysis longer than 30 years and, in any case, most projects already effectively constitute BOOT arrangements (with the exception of some geothermal and hydro projects that follow the Build-Own-Operate ("BOO") scheme). However, the BOOT could create issues for some projects, such as biomass power plants, where the power assets are sometimes inseparable from the plantation assets including land. Developers are also not clear about the treatment of pre-existing assets under such BOOT arrangements.

- **Other Matters**

  MoEMR Regulation No. 10/2017 (as amended by MoEMR Regulation Nos. 49/2017 and 10/2018) provides that:

  a) 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 then the exchange rate shall refer to the Jakarta Interbank Spot Dollar Rate ("JISDOR"). This provision reflects BI Regulation 17/3/PBI/2015 which has already been implemented in practice on numerous power projects.

  b) Restriction of Ownership Transfer

  The regulation prohibits the transfer of the ownership rights of the project before reaching 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 an affiliate must be a Business Entity 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 is approved by PLN. In the case of post-COD ownership a shareholding transfer is also subject to PLN approval and must be reported to the Minister of Energy and Mineral Resources via the DGE.

c) Transitional Provisions

This regulation does not apply to projects that have 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 and social responsibility programme; and
d) Meeting certain environmental conservation obligations.

BKPM has been 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.

Since 2015, once the PT PMA Company has been established it must apply through BKPM's PTSP for an IUPTL and other licences (such as the permanent business licence and the in-principle licence).

Please refer to *Section 2.2.4 - IUPTL* and *Section 2.3.6 - Ease of Licensing* for detailed discussion on 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 of up to 49%;
c) Small geothermal power plants (≤ 10 MW) are open for foreign ownership of up to 67%;
d) Power plants with a capacity of more than 10 MW are open for foreign ownership of up to 95% or 100% for PPP projects;
e) Electrical power T&D is open for foreign ownership of up to 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 of up to 95%;
g) Construction and installation of high-/extra-high-voltage electric power utilisation is open for foreign ownership of up to 49%;
h) Construction and installation of low-/medium-voltage electric power utilisation is closed for foreign investment;
i) Examination and testing on installations of high-/extra-high-voltage electrical power supply or utilities are open for foreign ownership of up to 49%;
j) Examination and testing on installations of low-/medium-voltage electrical power utility installations are closed for foreign investment; and
k) Geothermal O&M services are open for foreign ownership of up to 90%, and for drilling and surveying services of up to 95%.

2.5.3 The 2009 Environment Law

Pursuant to Law No. 32/2009 and 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 environmental practices and secure environmental permits before they begin operations as follows:
a) Construction of transmission network – high-voltage air lines, high-voltage channel cables, high-voltage submarine cables > 150 kV;
b) Construction of diesel, gas-fired, coal-fired and combined cycle power plants ≥ 100 MW in one location;
c) Construction of geothermal power plants ≥ 55 MW;
d) 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;
e) Construction of waste power plants with methane harvesting process ≥ 30 MW; and
f) 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 being PR Nos. 40/2014, 99/2014, 30/2015 and 148/2015) 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, which repeal PR Nos. 36/2005 and 65/2006, set out a maximum timeframe for the four stages of land acquisition. These are planning, preparation, implementation and transfer of the acquired land, and 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 of IDR 16 trillion to buy land to support National Strategic Projects. The first phase of the LMAN is concentrated on toll roads with the upcoming phase allocated to ports, railways and dams. So far no energy-related projects have been included in LMAN's work plan.

Photo source:
PT UPC Sidrap Bayu Energi

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. This 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 and following discussions with the private sector. The media release refers to three categories of transaction as follows:

a) **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. In these cases a transition period of up to six months will be given;

b) **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. In these cases transactions in fixed-term contracts shall continue to be in the foreign currency, with the possibility of future amendment;

c) **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. In these cases 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.

Of interest is that PLN is still paying invoices denominated in USD. However, for recently signed PPAs with invoices denominated in USD PLN will pay the invoices in IDR which will be converted by SOE banks to USD when payment is transferred to the IPPs' bank accounts. PLN has signed tripartite agreements with SOE banks and IPPs to ensure that PLN does not violate the regulation requiring the use of IDR while at the same time does not violate its PPAs. Notwithstanding this, there is a concern from some IPPs as to whether this arrangement will continue for the entire term of their 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 Nos. 49/2017 and 10/2018) payments must now explicitly be made in IDR unless exempted by BI (see *Section 2.4 - Regulation on PPAs* for further details).

2.5.6 BI Regulation on Foreign Currency Transactions and 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. While banking institutions only have to report their foreign loans, non-banking financial institutions and non-financial institutions have to report every trade between citizens and non-citizens as well as the position and changes in Foreign Financial Assets and Liabilities, and their Foreign Loan plan up to realisation. The report must include an explanation and supporting data regarding the transaction, the entity that reports the transaction and/or the other entities involve in the transaction. This is mandatory for any business owned by the state including regionally-owned, private, personal and other enterprises. Further, the fourth quarter report needs to be verified by an independent public accountant. Failure to comply with the reporting obligations triggers an administrative sanction 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 of 25% of the negative difference between the foreign exchange assets and the 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 a "negative difference" of more than US$ 100,000 are required to fulfill the minimum hedging ratio;

b) Minimum liquidity ratio of 70% calculated by comparing the company's foreign exchange assets and foreign exchange liabilities due within three months from the end of the reporting quarter; and

c) A minimum credit rating of "BB-" or equivalent from a credit ratings agency recognised by BI.

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

On 3 August 2017 the MoEMR issued Regulation No. 48/2017 on the Supervision of Business Enterprises in the Energy and Mineral Resources Sector. The aim 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 this means that IPPs, which were primarily regulated by their PPA with PLN, will now be subject to greater reporting requirements. The regulation sets out provisions similar to those for geothermal developers. The details are as follows:

Share transfers or changes in shareholders

The transfer of shares in 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 has been authorised by the Minister of Law and Human Rights.

IUPTL Holders that sell electricity to PLN must not transfer shares until the power plant reaches COD. Transfers can be made prior to the COD only if to an affiliate of which more than 90% of the shares are owned by the Sponsor intending to transfer the shares. This is under the condition that such an affiliate must be a Business Entity one level below the transferor. The transfer must be approved by PLN.

The transfer of shares in a Geothermal Licence (i.e. *Izin Panas Bumi* or IPB) holder or a geothermal contractor under a Joint Operation Contract ("JOC") through the Indonesian Stock Exchange (presumably meaning via an Initial Public Offering) upon the completion of exploration must be approved by 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 of Energy and Mineral Resources.

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

Changes in the make-up 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 administrative documents and procedures for conducting both transfers of share and changes in corporate management.

Photo source: PT Adaro Power

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 not generally (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 60.7 GW. Certain IPPs, particularly in recent times, have also operated pursuant to a more general set of PPP arrangements.

The key 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, which contains general guidelines for PPP implementation, and LKPP Regulation No. 19/2015 which contains detailed procurement procedures for PPP Projects. The Government is in the process of amending LKPP Regulation No. 19/2015. The amendment is intended to improve the effectiveness of the PPP procurement for infrastructure 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

Photo source: PT Vale Indonesia Tbk

under renegotiated terms. When renegotiations were completed in 2003 most continuing IPP investors agreed to new PPAs which generally included lower tariffs than had initially been 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. However this generation was 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 an Umbrella Note of Mutual Understanding with the Japan Bank for International Cooperation ("JBIC") 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 were as follows:

a) The sectors covered were wider and included oil and gas infrastructure (e.g. refineries), urban infrastructure, industrial estates and social infrastructure (e.g. healthcare);
b) That SOEs or regionally owned enterprises could act as a Government Contracting Agency ("GCA");
c) The "bundling" of two or more PPP projects was permitted (i.e. the projects could be procured together, e.g. a power plant and related infrastructure);
d) That 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 being the "performance-based annuity scheme" was made available;
f) Projects developed through unsolicited bids were encouraged by providing compensation of:
   i) An additional 10% price preference in the bid evaluation;
   ii) The right to match a lower price bid by a competitor;
   iii) The purchase of 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, continued 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 was 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 paid to international organisations/consultants in assisting the project's preparation where 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 were set out in LKPP Regulation No. 19/2015 concerning Procedures for the 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 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 awarded in October 2011. The land acquisition process for this project was completed in late 2015 and the financial closing for this project was completed in June 2016. The construction of the power plant is ongoing with an expected COD of 2020.

There are no power plant projects in the 2018 PPP Book issued by Bappenas in the "ready to offer" or "under preparation" category but there are waste-to-energy and hydro projects in the "prospective prospects" category.

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 by MoEMR Regulation No. 40/2014 to 17.4 GW. These focus 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 superseded FTP II and all of the projects planned for completion between 2015 and 2019 have been rolled into the 35 GW 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.

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) the projects 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 detailed discussions please see *Section 3.7.2 - The 35 GW Power Development 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.	• Central Java 2 x 1,000 MW coal-fired power plant.

	Regulations	Guarantees	Examples
FTP II (superseded by 35 GW programme)	• 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.
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 Nos. 14/2017 and 30/2018), 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: The Use of Natural Gas for Power Plants; • MoEMR Regulation No. 50/2017: The Use of Renewable Energy for Electricity Power Supply. • MoF Regulation No. 173/2014: Government guarantee for IPPs and PLN obligations to IPPs to purchase power in accordance with the PPA.	• 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 the 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).

	Regulations	Guarantees	Examples
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. The aim of the IIGF 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 to 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. This was in the form of a joint guarantee facility from the IIGF and the MoF.

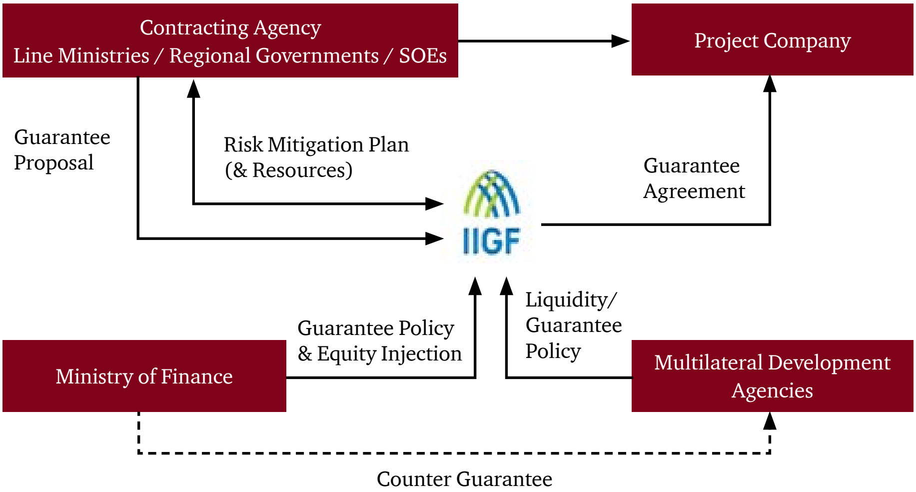
The IIGF will function as a "single window" for all requests for Government guarantees on PPP projects with the following objectives:

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 risks by ring-fencing Government obligations against guarantees.

The issuer of the Guarantee Agreement is the IIGF although the Multilateral Development Agency ("MDA") 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 (the 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. 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 a 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 a Region (Governor or Regent). This support 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 greater 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 be terminated 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 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 being 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 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 Government 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 follows MoEMR Regulation No. 1/2006 (as amended by MoEMR Regulation No. 4/2007) which generally runs on a competitive tender basis but sometimes by direct selection or direct appointment.[42]

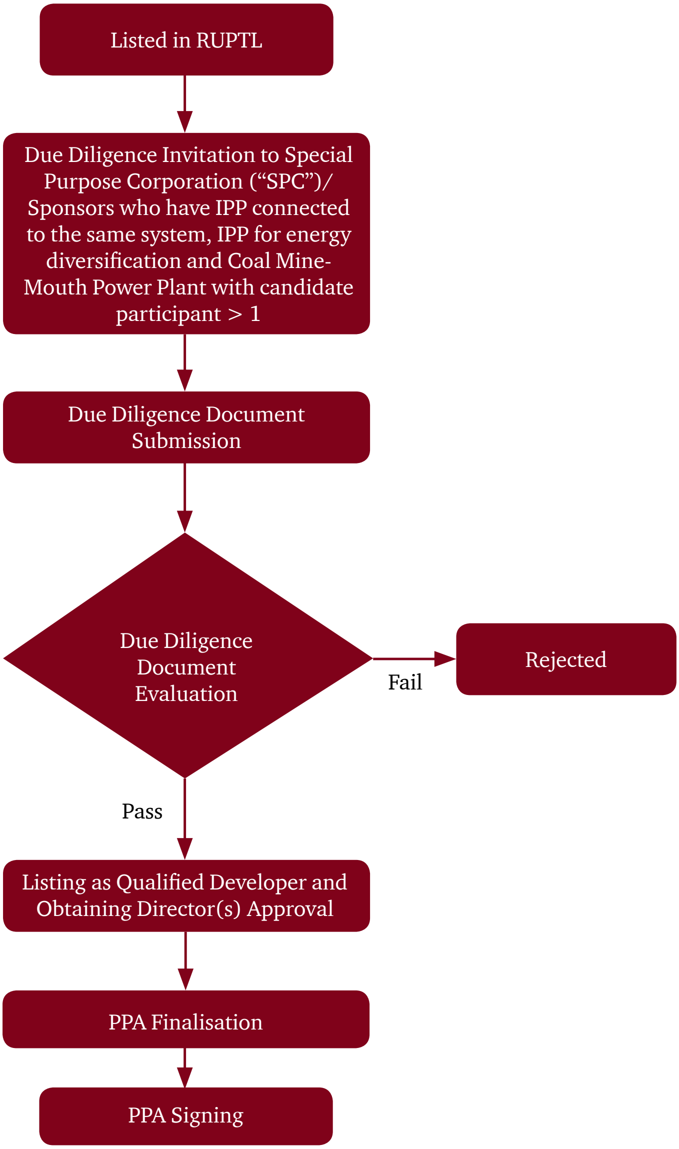
The key features of the procurement methods are as follows:

a) Open tender basis;
b) Direct selection 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 event that a project could otherwise be directly appointed but there is more than one bidder available; and
c) Direct appointment.

42 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. Direct selection from pre-qualification up to contract arrangement and finalisation is up to 150 days [43] and direct appointment can take a maximum of 100 days.

The procurement procedures for **direct selections** complying with MoEMR Regulation No. 1/2006 (as amended by MoEMR Regulation No. 4/2007) are as follows:



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

The procurement procedures for **direct appointments** complying with MoEMR Regulation No. 1/2006 (as amended by MoEMR Regulation No. 4/2007) are as follows:

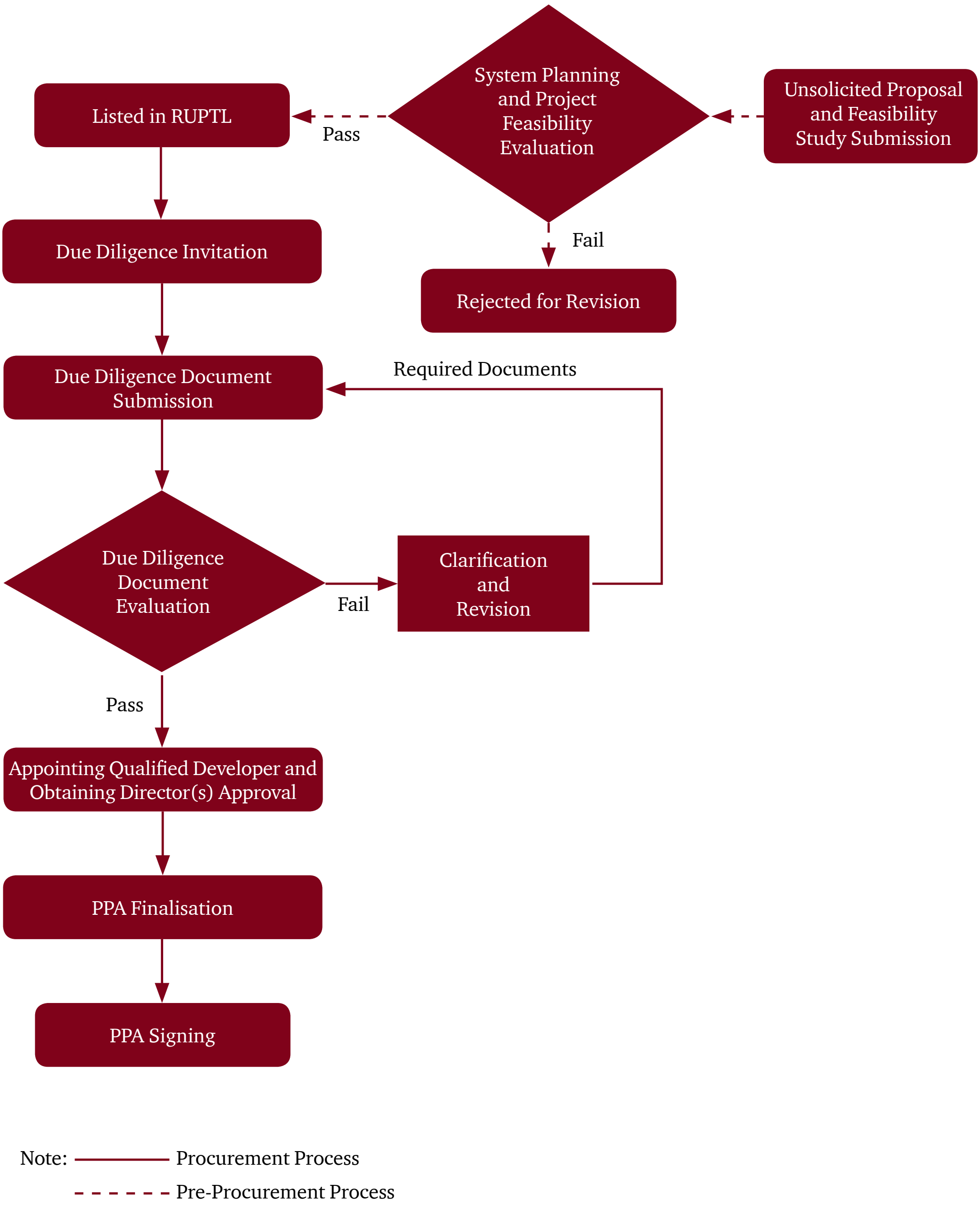


Photo source: PwC

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

MoEMR Regulation No. 1/2006 and its amendment 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 appointments and on the lowest price proposal submitted by participants for direct selection or through an open tender.

After the preferred bidder has been selected the process from the awarding of a tender to the COD of the project will involve the following:

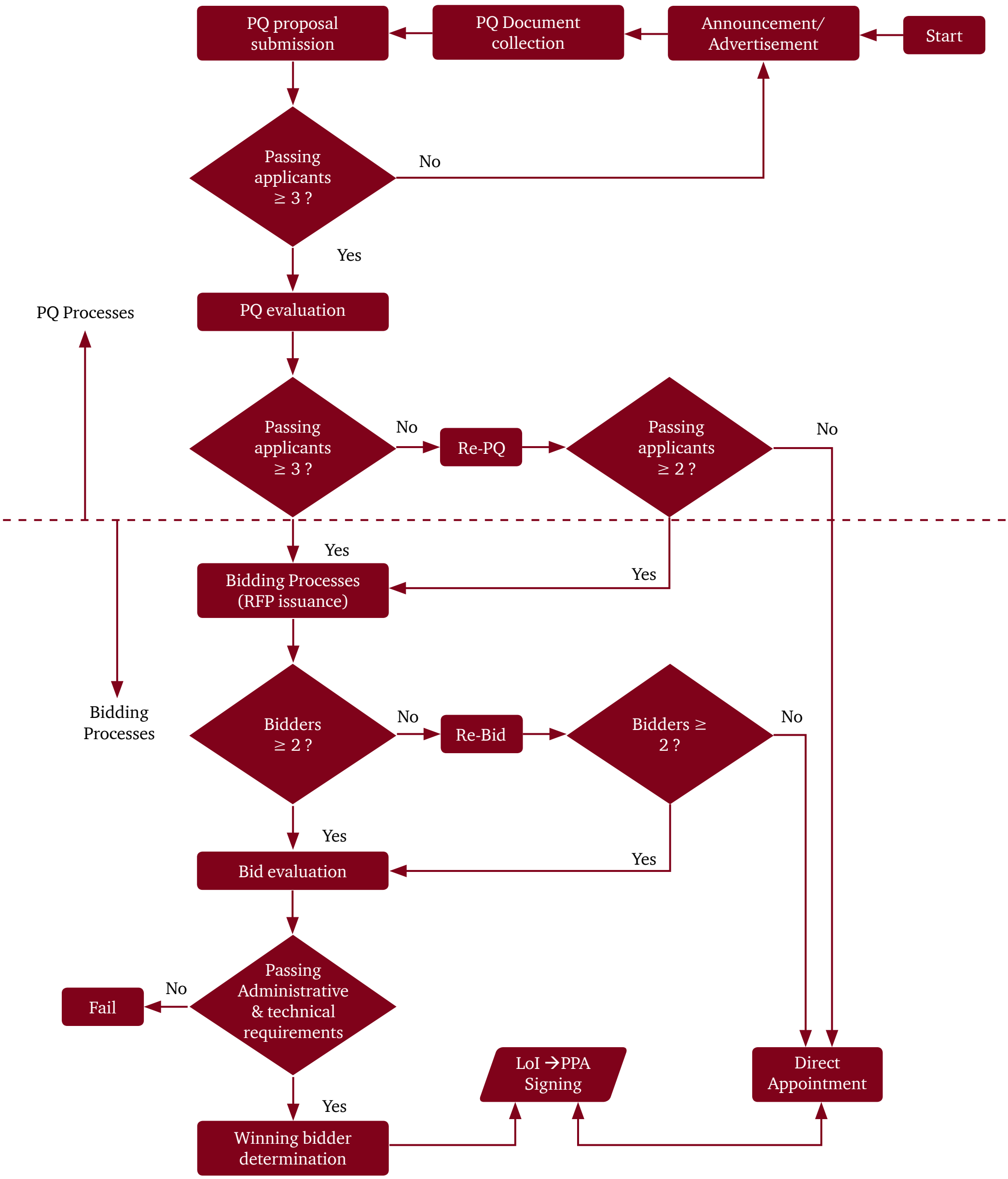
a) The issue of a Letter of Intent that contains the agreed terms and conditions, the agreed electricity tariff and the basic formula;

b) The signing of the PPA which requires multiple performance bonds covering the financing period, PLN's corporate approval, the MoEMR tariff approval and the establishment of a special-purpose company applying for a temporary business licence through 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, the 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.

The 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

In March 2018, PLN's Board of Directors issued a new policy based on Decree No. 0022P/DIR/2018 regarding power purchases from renewables as an implementing regulation of MoEMR Regulation No. 50/2017. This internal PLN's regulation aims to provide guidance for power purchases from IPPs' in order to equalise, simplify and accelerate the power purchase process. The content of this regulation includes:

a) The necessary documents and requirements for an IPP to qualify for the *Daftar Penyedia Terseleksi* ("DPT" – List of selected IPPs) and how the qualification will be applied;
b) The criteria for power purchases from renewables which includes the ability of the local grid to accept the renewable electricity supply, the BPP and/or the need to fulfill the power demand in the location with no other primary electricity source;
c) Additional criteria for specific power plants such as:
    i) For biogas power plants which require the IPP to have sufficient feedstock for operations over the entire PPA duration;
    ii) For waste-to-electricity power plants developed by IPPs which are determined by the Government or the local government; and
    iii) For geothermal IPPs which must hold a geothermal working area with proven reserves after exploration;
d) The mechanism of power purchase (either by election or direct assignment in PLN Central (*Pusat*) or PLN *Wilayah* (regional));
e) The price for the electricity from renewable sources;
f) Procurement bonds (bid bonds and performance bonds);
g) The PPA contract and duration (i.e. with a BOOT model for all renewables except from waste-to-electricity); and
h) The electrical grid construction based on business-to-business mechanism.

Based on this regulation the administration requirements for qualification consist of:

a) Holding a permit in accordance with the relevant line of industry based on the existing regulations;
b) Being in good standing;
c) Having the legal capacity to sign an agreement;
d) Not being monitored by a court, not being bankrupt, not having any business activity suspended and not having directors under criminal sanctions;
e) Not having directors or management that are on the list of blacklisted IPPs;
f) Having fulfilled tax obligations for the previous year proven by attaching a copy of the annual income tax return receipt for the previous year and a copy of tax payment slips for income tax or Value Added Tax ("VAT") for at least the last three months;
g) For IPPs in the form of a partnership the IPP must have a partnership cooperation agreement that accommodates the representations of the partnership and the entities that represent the partnership; and
h) For foreign companies that are assigned as IPPs these must follow the relevant permit regulations.

Meanwhile the technical requirements for qualification are as follows:
a) For power plants above 10 MW IPPs need to have experience in developing IPPs and/or as an EPC contractor and/or as an O&M contractor for related power plants;
b) Be capable of procuring the relevant facilities and equipment and the personnel necessary for work implementation including occupational health and safety;
c) For special/specific/high-technology work additional requirements (such as a specific equipment, specialists needed, or specific experience) can be added; and
d) Be able to meet the local content requirements as regulated by existing regulations.

The financial requirements include having sufficient financial capability and a certificate of financial support or reference letter from a bank. The financial capability is to be demonstrated by audited financial statements or a rating result/ranking from a credible financial rating institution.

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, the 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 service the 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. the ADB and the 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 the terms and conditions for any shareholder loans
PPA	IPP entity and PLN	Sets out the terms and conditions of power generation activity
EPC Agreement – Offshore	IPP entity, third-party contractors and/or affiliates	Sets out the 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 the 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 the 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	Covers the key aspects of project financing including: • Corporate Lending; • Export Credit Agencies; • Cash Waterfalls; • 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 a BOOT format);
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 and No. 10/2018) the maximum period of power plant operation 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) Tariffs and payments;
i) Government guarantees (if applicable);
j) Service performance standards;
k) Insurance arrangements;
l) Indemnification and liability arrangements;
m) Natural force majeure scenarios;
n) Settlements 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 make additional investments of around Rp 90 trillion (around USD 6.3 billion) in order to cover the construction of substations, transmission and distribution networks, along with operational costs in 2018.[44]

44 Metro TV, http://ekonomi.metrotvnews.com/energi/ob3Vn3JN-target-investasi-rp90-triliun-pln-bakal-lakukan-pinjaman-rp60-triliun accessed 11 July 2018

Based on the 2018 RUPTL IPPs may have access to power generation projects as follows:

Table 3.3 – Accessible IPPs for power generation for 2018-2027

	PLN	IPPs	Unallocated	Total
Coal	3,971	15,116	1,675	20,762
Coal Mine-Mouth	-	6,045	-	6,045
Geothermal	425	2,170	1,988	4,583
Gas/Combined Cycle	9,450	4,090	730	14,270
Hydro (including small hydro and pumped storage)	2,688	3,558	2,037	8,283
Others (including diesel, solar PV, biomass, etc.)	38	1,080	964	2,082
Total	**16,572**	**32,059**	**7,394**	**56,025**

Source: 2018 RUPTL

The 2018 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 2018 RUPTL should be at least 25% of the fuel mix by 2025. As projected in the 2018 RUPTL (see Table 3.4) the renewable power generation in 2025 will only be 23%. As the draft 2015 – 2034 RUKN requires a fuel mix of approximately 50% from coal, 24% from gas, 25% from renewables and 1% from diesel fuel this actually indicates a shift of focus back to coal powered generation.

Table 3.4 – Electricity fuel shares in the 2018 RUPTL

No	Fuel Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Hydropower	6.92%	5.98%	5.70%	5.82%	5.54%	6.17%	6.82%	9.91%	9.54%	9.30%
2	Geothermal	5.37%	5.62%	5.52%	5.67%	6.19%	6.15%	6.39%	11.66%	10.74%	9.80%
3	Other Renewables	0.15%	0.85%	0.91%	0.94%	0.89%	0.85%	0.86%	1.45%	1.42%	1.32%
4	Gas	20.84%	23.15%	24.02%	21.62%	22.12%	21.75%	20.92%	22.17%	21.08%	20.62%
5	Fossil Fuels	4.25%	3.88%	2.23%	1.07%	0.46%	0.45%	0.45%	0.42%	0.41%	0.40%
6	Coal	61.95%	59.99%	61.33%	64.70%	64.80%	64.63%	64.56%	54.39%	56.81%	58.56%
7	Import	0.52%	0.53%	0.29%	0.18%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

The 2018 RUPTL plans for the installation of additional power capacity of 56 GW compared to the 77.9 GW in the 2017 RUPTL. Lower electricity demand growth is the main reason for this reduction. Of the 21.9 GW reduction in plant capacity gas-fired power plants (including gas-machine and combined-cycle power plants) saw the largest cut of 10.1 GW. This represents a decrease in the predicted gas consumption for the power sector from over 3,300 billion British thermal units per day ("BBTUD") in 2026 to around 2,000 BBTUD in 2027.[45]

45 Katadata, https://katadata.co.id/berita/2018/04/13/kebutuhan-gas-pln-untuk-10-tahun-ke-depan-turun-dari-target-awal, accessed 24 May 2018

Table 3.5 – Comparison of power generation between 2017 RUPTL and 2018 RUPTL

Power Source	Allocated to PLN (MW)		Allocated to IPPs (MW)		Unallocated (MW)	
	2017 RUPTL	2018 RUPTL	2017 RUPTL	2018 RUPTL	2017 RUPTL	2018 RUPTL
Coal	6,064	3,971	23,881	21,161	1,990	1,675
Geothermal	490	425	4,405	2,170	1,395	1,988
Gas (and Combined Cycle)	10,191	9,450	6,293	4,090	7,905	730
Hydro (and Pumped Storage)	4,239	2,688	6,259	3,558	3,539	2,037
Others (including diesel, solar PV, biomass, etc.)	-	38	1,224	1,080	-	964
Total	**20,984**	**16,572**	**42,062**	**32,059**	**14,829**	**7,394**

In the 2018 RUPTL, for site selection purposes PLN will apply a "regional balance" principle in prioritising the availability or ease of supply of primary energy sources in any local area. Additionally, the 2018 RUPTL emphasises that power plants will be located closer to energy sources particularly in Sumatera, Kalimantan, Sulawesi and Papua. This is emphasised by PLN's plans to develop coal mine-mouth and gas wellhead-fired power plants.

Coal will continue to play a significant role in the development of power generation in Indonesia over the next ten years due to the relatively low costs of construction and operation. Coal mine-mouth power plants remain integral 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 gasification combined cycles or carbon capture and storage, have not been planned in the 2018 RUPTL as these are not commercially viable yet.

PLN also plans for the extensive use of LNG for gas-fired power plants. However, because of the relatively high cost of LNG (compared to pipeline gas), as well as the need for regasification, PLN plans to use LNG as a peak-load backup rather than for base-load power plants. This is particularly for the Java-Bali and Sumatera networks where the power grid has been established and more affordable power plants cover the base-load generation.

3.7.2 The 35 GW Power Development Programme

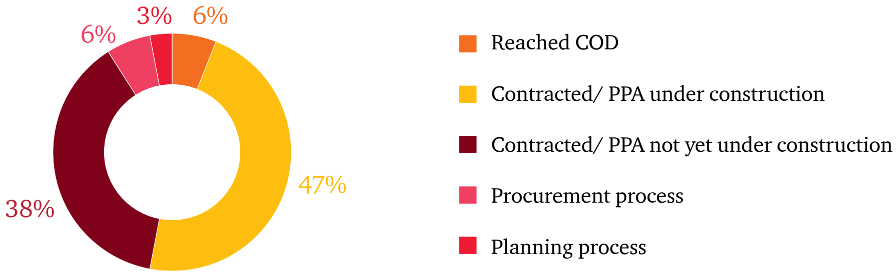
The 35 GW programme was launched in 2015. Since then the total capacity and its composition have undergone changes in the various versions of the RUPTL. The initial breakdown of the 35 GW Programme is outlined in the table below:

Development Scheme	Coal (GW)	Gas (GW)	Hydro (GW)	Geothermal (GW)	Other (GW)	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**

According to PLN progress of the 35 GW power development programme as of May 2018 is as follows:[46]

a) 6% (2,114 MW) of capacity has reached Commercial Operation Date;
b) 47% (16,687 MW) of capacity was in construction stage;
c) 38% (13,481 MW) of capacity had signed PPAs but had not reached commenced construction;
d) 6% (2,130 MW) was in procurement stage; and
e) 3% (1,007 MW) of capacity was in planning stage.

35 GW Power Plant Progress (MW)



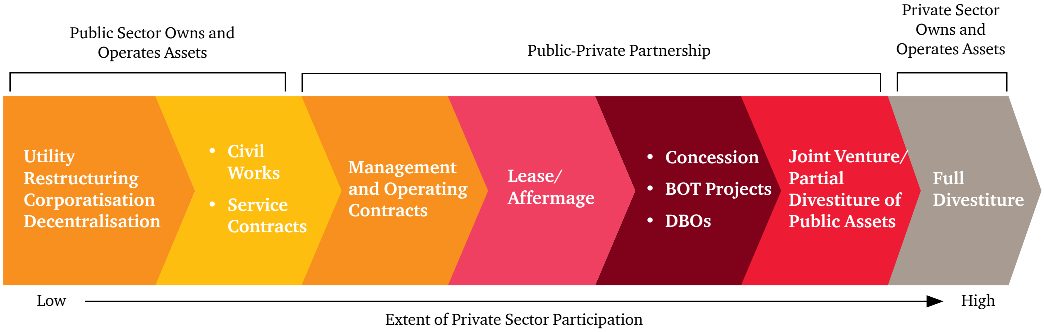
As such the 35 GW program has not progressed as planned with only around 2 GW worth of power plants having commenced operation. For further detail on the progress please see *Section 3.7.2 – The 35 GW Power Development Programme*. The lower than expected demand growth is cited as the main reason for this slow progress. This is reflected in the 2018 RUPTL which forecasts 6.9% annual electricity demand growth instead of 8.3% as in the 2017 RUPTL.

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 as well as variety in terms of the involvement of and risks borne by the private party. The terms of a PPP are typically set out in a contract or agreement which outlines the responsibilities of each party and allocate associated risks. The graph below highlights the spectrum of typical PPP agreements:[47]

46 PLN presentation in IPP Summit 17-18 July 2018
47 World Bank, https://ppp.worldbank.org/public-private-partnership/overview/what-are-public-private-partnerships, accessed 22 May 2016



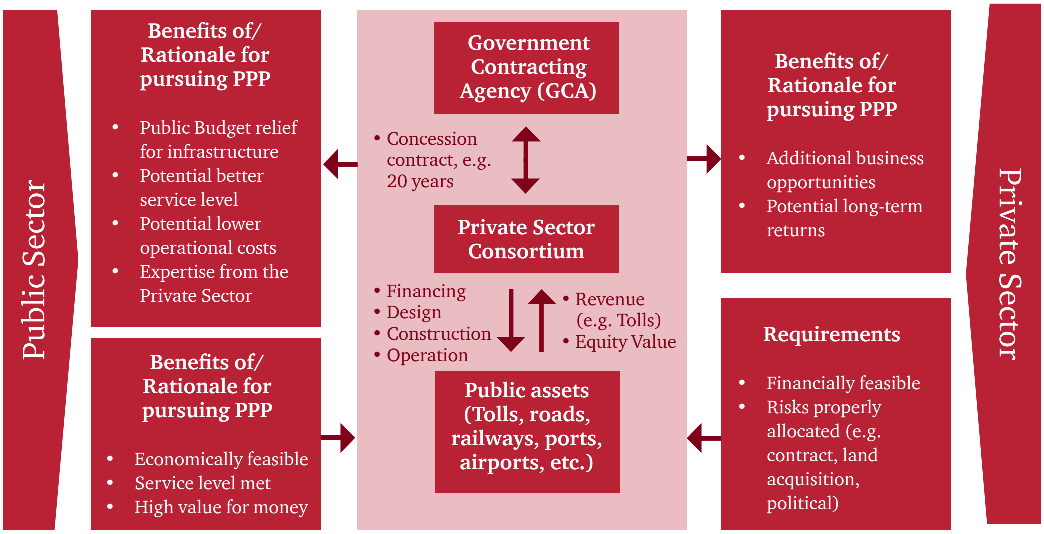
Source: World Bank

The variety of the arrangements provide options for structuring agreements that best fit the project, its associated risks and the nature of the investors. For instance leases and contracts have lower 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 telecoms and energy projects which have high potential returns. Greenfield agreements are by far the most utilised as 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.

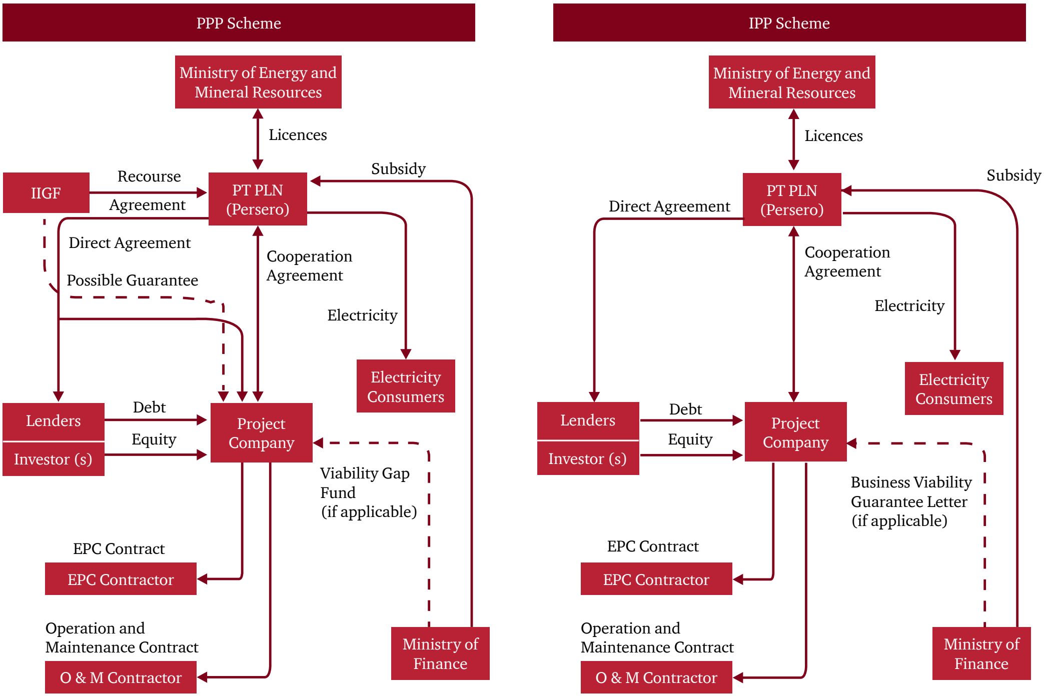
As discussed in Chapter 1 and earlier in this chapter Indonesia is building a significant amount of infrastructure which requires enormous investment that the Government cannot finance. As such, PPP arrangements represent a possible means of developing Indonesia's infrastructure. However, the meaning of a PPP in the Indonesian context is 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 as a PPP in Indonesia where it does not fall under the scope of the PPP regulation (PR No. 38/2015). This is because an IPP does not have any guarantees from the 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. The investors require that the projects be financially feasible and that the risks be manageable including contractual, 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 role undertaken by the private sector is largely only for generation where 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 Planned in Indonesia" report (the "PPP Handbook 2018"), no power projects are included. There are no power plant projects in the 2018 PPP Book issued by Bappenas in the "ready to offer" or "under preparation" category but there are waste-to-energy and hydro projects in the "prospective prospects" category.

LKPP Regulation No. 19/2015 regulates the Procedures for the 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 organisation, restrictions to prevent conflicts of interest, provisions of the procurement committee, and procurement of a business entity that can be done via auction or direct appointment, and the 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 regionally-owned enterprises, private business entities, and cooperative businesses to become involved in improving electrification in rural and remote areas by managing an area of business or *Wilayah Usaha*.

This regulation is motivated by concern over the 2,510 villages that do not have access to electricity across Indonesia. PLN has stated that it is possible to provide electricity to all of Indonesia by the end of 2018, by using the energy-efficient solar lamps that can last for three years to provide lighting while the permanent infrastructure for providing electricity to those villages is developed.[48]

Under MoEMR Regulation No. 38/2016, business entities must optimise the use of new local energy or renewable energy resources. In doing so those private investors may be given fiscal incentives 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 Businesses (*Usaha Penyediaan Tenaga Listrik* – "UPTL"). However, in the event that no business entity is interested the Governor may appoint regionally-owned enterprises to develop small-scale UPTLs.

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 subsidy funds are utilised the tariff follows the PLN average tariff for the 450 VA household customers. Business entities can propose subsidy funds to the Government based on certain criteria, i.e. fuel use realisation and plans, operational expenditure, losses, electricity generation costs, and expansion plans, which will be evaluated and determined by the DGE. On the other hand, where the electricity tariff does not utilise subsidy funds the tariff is determined by the Minister of Energy and Mineral Resources or the Governor based on their authority, along with the existing laws and regulations.

48 Katadata, https://katadata.co.id/berita/2018/03/06/pln-targetkan-seluruh-wilayah-indonesia-dapat-akses-listrik-tahun-ini accessed 20 June 2018

Photo source: PT Vale Indonesia Tbk

4 Conventional Energy

4.1 Introduction

Global primary energy consumption increased by an average of 2.2% per annum in 2017 which was higher than the ten-year average of 1.7%. This growth was led by natural gas and renewables and continued coal's decline in the energy mix. Oil remained the world's leading fuel accounting for over a third (34.2%) of global energy consumption and showing an increase in the global market share for the third year in a row. This follows a consistent 15-year decline from 1999-2014. Similar growth can be seen in natural gas, the consumption of which grew by 3%, which is the fastest since 2010. Despite a coal consumption increase of 1% its global share of primary energy market fell to 27.6% which is the lowest since 2004.[49]

Indonesia's primary energy supply increased by 24% from 1,011 million barrels of oil equivalent ("MMBOE") in 2007 to 1,250 MMBOE in 2016. Coal and oil remained Indonesia's leading sources of primary energy supply accounting for 24.4% and 33.2% respectively. Biomass and biofuel represented a further 19.9% followed by natural gas with 18.5%. Hydro accounted for 2.9% with the remaining 1.1% from geothermal.[50]

Indonesia's primary energy consumption also increased by 30%, from 920 MMBOE in 2007 to 1,199 MMBOE in 2017. Oil, coal and natural gas accounted for 44.1%, 32.6% and 19.2% of the final energy consumption respectively. The remaining consumption was accounted for by renewable energy consisting of hydropower and other renewables and accounting for 4% in total.[51] Overall, conventional energy (oil, coal, and gas) has continued to play a dominant role in Indonesia's energy mix.

49 BP Statistical Review of World Energy 2018, p. 2-9
50 2017 Handbook of Energy and Economic Statistics of Indonesia, p. 10-11
51 BP Statistical Review of World Energy 2018, p. 9

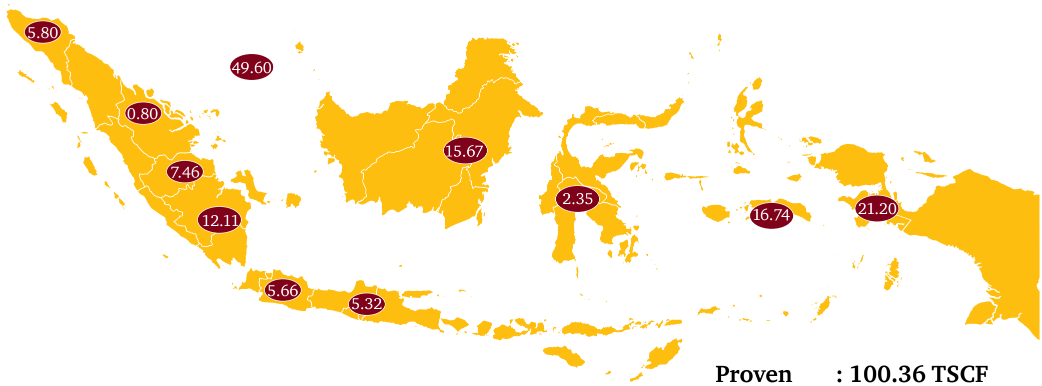
Photo source: PT Bhimasena Power Indonesia

4.2 Gas

4.2.1 Indonesian Gas Reserves, Consumption and Production

Indonesia has large natural gas reserves standing at around 142.71 trillion standard cubic feet ("TSCF") in 2017 (see Figure 4.1 below for more details).[52] The largest undeveloped gas reserves are located in the offshore East Natuna Block which holds approximately 49.6 TSCF. Other areas with high potential are West Papua and Maluku.[53] Assuming no new discoveries existing reserves would last around 50 years at the current rate of consumption.[54]

Figure 4.1 – Map of Indonesian gas reserves as of 1 January 2017



Source: LAKIN DJMGB 2017

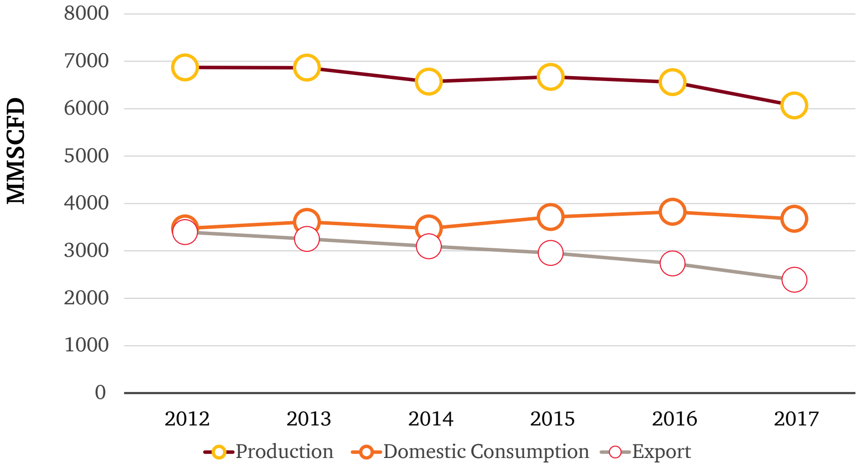
Despite crude oil traditionally playing a significant role in Indonesia's energy supply and exports Indonesia is now a net oil importer. Indonesia's oil and gas production has been dominated by gas in recent years with the production of natural gas accounting for approximately 59% of total oil and gas production as a whole. This is expected to reach 65% in 2020 and 80% in 2050 should Enhanced Oil Recovery (EOR) technology not be implemented in any upstream projects. This should still be 55% in 2050 even if EOR technology is implemented.[55]

Indonesia has experienced a gradually narrowing surplus of gas production over domestic consumption over the past five years (see Figure 4.2). Indonesia's oil and gas industry has been under pressure due to declines in oil and gas prices which have delayed field developments. Further, the difficulties associated with improving production in mature oil fields, the lack of exploration in the recent past and the unattractiveness of the fiscal regime are thought to be major factors in the overall gas production decrease since 2012.[56] For instance, this fell from 6,870 million standard cubic feet per day ("MMSCFD") ≈ 7,181 Billion British Thermal Units

52 Laporan Kinerja Direktorat Jenderal Minyak dan Gas Bumi 2017 ("LAKIN DJMGB 2017") [2017 Performance Report of Directorate General Oil and Gas], p. 53-54
53 LAKIN DJMGB 2017, p. 54
54 LAKIN DJMGB 2017, p. 57
55 Annual Report SKK Migas 2017 p. 38-39
56 Bisnis.com, http://industri.bisnis.com/read/20180411/44/783132/ini-penyebab-lifting-minyak-gas-bumi-kuartal-i2018-turun- accessed 13 June 2018

per Day ("BBTUD") in 2012 to 6,067 MMSCFD ≈ 6,342 BBTUD (an 11.7% decline) in 2017.[57] In contrast, domestic gas consumption in Indonesia has increased by more than 8% over the same period. As a result, over the same period, Indonesia's gas exports have declined by 31% in line with the Government's long-term plan to gradually decrease gas export volumes to zero by 2040.[58] This has resulted in Indonesia falling from the world's largest LNG exporter in 2005, to being the world's fifth-largest LNG exporter in 2017 behind Qatar, Australia, Malaysia and Nigeria.[59]

Figure 4.2 - Indonesian natural gas used for production, domestic consumption, and export (in MMSCFD) for 2012-2017



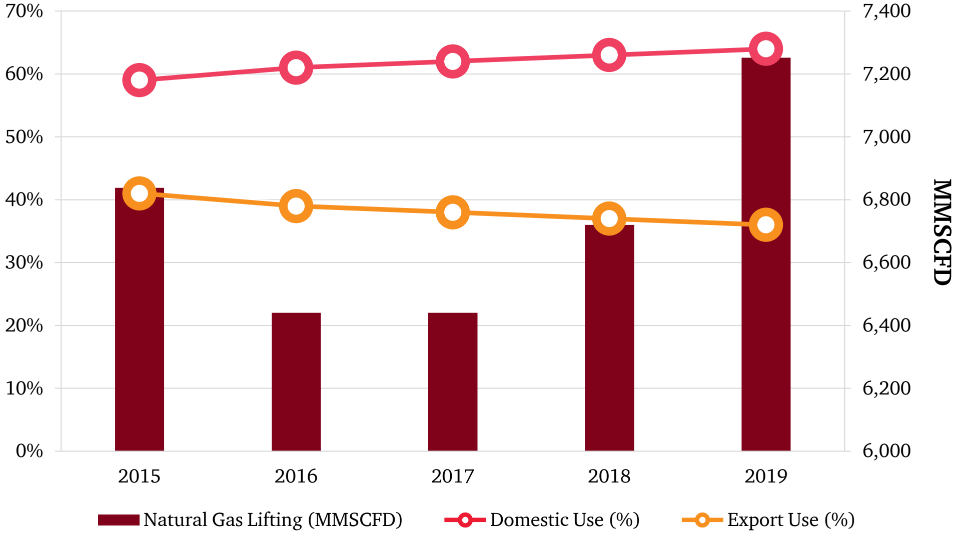
Source: LAKIN DJMGB 2017

Despite recent trends, 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 operations. These include the Indonesia Deep Water Project in Makassar Strait, East Kalimantan by Chevron Indonesia; the LNG Abadi Project in Arafura Sea, Maluku by INPEX; the LNG Jangkrik Project in Makassar Strait, East Kalimantan by ENI; the LNG Tangguh Train-3 Project in Bintuni,[60] West Papua by BP; and the Jambaran Tiung Biru Project in Bojonegoro, East Java by PT Pertamina EP Cepu. According to the 2018 RUPTL the LNG from Tangguh will strengthen the gas supplies for PLN's gas-fired power plants in Sumatera and Java through the Arun LNG terminal, the Nusantara Regas Floating Storage Regasification Unit ("FSRU"), and the planned Jawa-1 FSRU.[61] The latter is expected to supply natural gas to West Kalimantan as well as Java and Sumatera (including the Jawa-1 Combined Cycle, see *Section 4.2.3 - Current Installed Gas-Fired Power Plant Capacity and Government Plans*).

57 LAKIN DJMGB 2017, p. 68
58 Tempo, https://bisnis.tempo.co/read/691560/ekspor-migas-bakal-jadi-nol-persen-penuhi-pasar-domestik, accessed 9 September 2016
59 BP Statistical Review of World Energy 2018, p. 34
60 Katadata, https://katadata.co.id/berita/2017/02/28/bp-mulai-lakukan-konstruksi-awal-proyek-train-3, accessed 7 August 2018
61 2018 RUPTL, p. III-32

An increase in domestic gas demand, particularly for power generation, is projected over the period from 2018 to 2027. This expected increase is not as large as forecast in the 2017 RUPTL due to a number of delayed or cancelled gas power plant projects. However, the total gas required (including LNG) is still expected to significantly increase from 834 MMSCFD in 2017 to 1,921 MMSCFD in 2027 as a result of the plan for 14 GW of additional gas-fired power plants. This will contribute to the Government's target for domestic gas utilisation (See Figure 4.3 below).

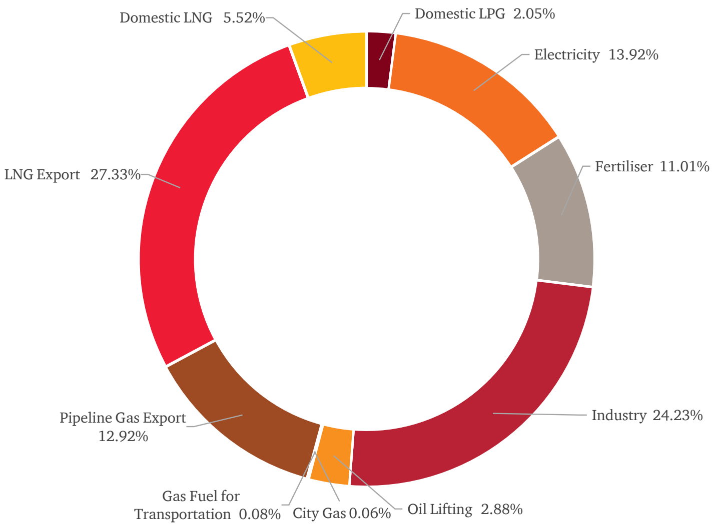
Figure 4.3 - Indonesian natural gas lifting (in MMSCFD) and utilisation targets for 2015 - 2019



Source: LAKIN DJMGB 2015

Indonesia's domestic natural gas consumption in 2017 was 3,675 MMSCFD. There were five major categories of gas users in 2017 being LNG for export, the power sector, the industrial sector, the fertiliser sector and gas pipeline exports. LNG exports accounted for more than a quarter of the total natural gas utilisation in Indonesia in 2017 (27.3%). Power, industrial, fertiliser and gas exports via pipelines then consumed approximately 13.9%, 24.2%, 11.0% and 12.9% of total Indonesian gas production (see Figure 4.4).

Figure 4.4 - Indonesian natural gas utilisation for 2017



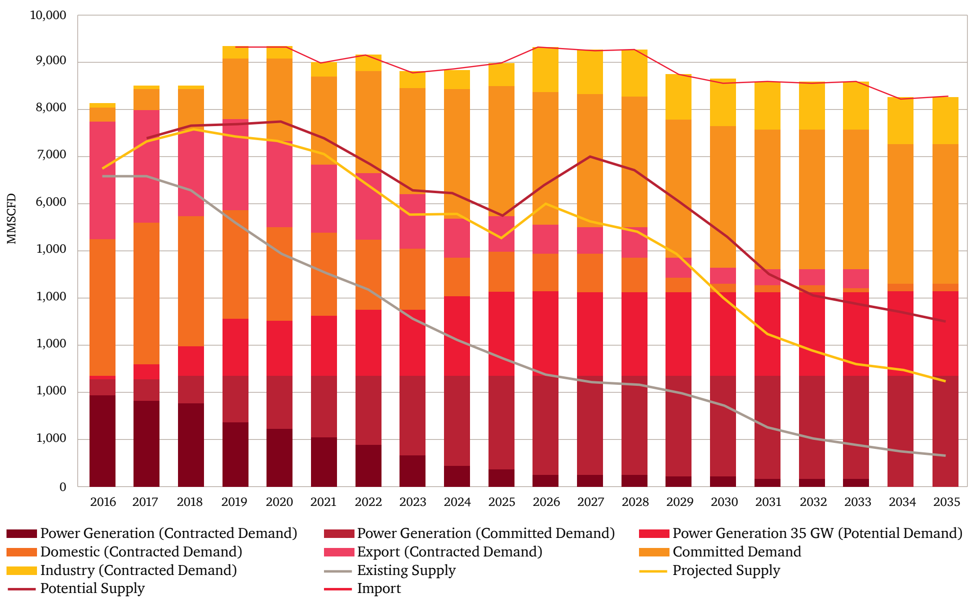
Source: Laporan Akuntabilitas Kinerja Instansi Pemerintah Kementerian Energi dan Sumber Daya Mineral 2017 ("LAKIP ESDM" 2017) [2017 Performance Report of MoEMR]

In anticipation of rising gas demand the Government initially planned to import LNG by 2019 as stated in the National Gas Balance 2014-2030 (updated to 2016-2035). However, the Government revised this plan in July 2017 following the increased domestic gas production and stated that no imported LNG was needed.[62] As most gas fields are located in remote areas far from buyers, including power plants, the MoEMR expects that there will be 20 excess consignments of LNG available in 2018 [63] with an update to the national natural gas balance in progress. The recent MoEMR Decree No. 1790 K/20/MEM/2018 also stated that the Minister of Energy and Mineral Resources is empowered to allocate some or all of the natural gas previously allocated to the power sector if it cannot be utilised by PLN or is not followed up with a natural gas purchase agreement within a year. The planned natural gas allocation for the power sector until 2027 is also included in this decree.

62 https://www.reuters.com/article/us-indonesia-gas-imports/indonesia-unlikely-to-need-imported-lng-until-2020-as-output-to-rise-idUSKBN19X0H5, accessed 6 December 2017

63 Katadata, https://katadata.co.id/berita/2018/03/21/arcandra-bantah-hitungan-wood-mackenzie-soal-surplus-lng-tahun-ini, accessed 26 July 2018

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

4.2.2 Prices and Regulation

Domestic pipeline gas prices in Indonesia (but not CNG) 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 which is formulated as cost plus an annual escalation (depending on the agreement). This means that the Indonesian gas pricing regime is not directly connected to oil price fluctuations (see Table 4.1). MoEMR Regulation No. 58/2017 stipulates a maximum gas price based on the gas cost, the IRR for gas infrastructure and the profit margin for the gas trader. The IRR for gas infrastructure is limited to 11% (or 12% for a company that develops gas infrastructure in an underdeveloped region) while the profit for gas trading is limited to 7%. It is nevertheless expected that negotiation will still play a major role in determining gas prices.

The pipeline gas price is composed of several components, including the upstream investment and operational costs, the contractor share and transportation costs (i.e. for transmission and distribution including VAT). As an illustration the upstream gas price for domestic pipelines (sold from contractors/oil and gas companies) in 2016 was an average of USD 5.9 per Million British thermal unit ("MMBtu") with a range of USD 3.63-8.24 per MMBtu. Gas transmission and distribution costs of USD 0.89 per MMBtu and USD 1.5 per MMBtu respectively were added.[64]

64 Bisnis.com, http://industri.bisnis.com/read/20170217/44/629688/begini-komponen-harga-gas-pipa-dan-lng-di-indonesia, accessed 6 December 2017

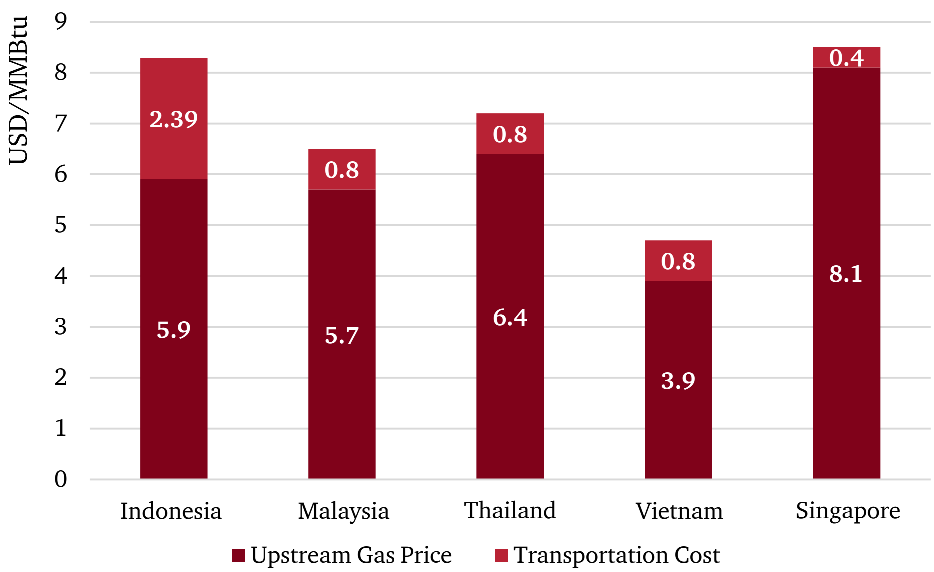
Table 4.1 – Gas price regimes in the region

	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, accessed 6 December 2017

The Indonesian non-LNG upstream gas price is considered to be competitive as compared to neighbouring countries. However, the Indonesian gas market experiences relatively expensive gas transportation (transmission and distribution) costs which impacts affordability for the buyer/end-user. Figure 4.6 shows a comparison of domestic pipeline gas prices in Southeast Asia before MoEMR Regulation No. 58/2017 was issued.

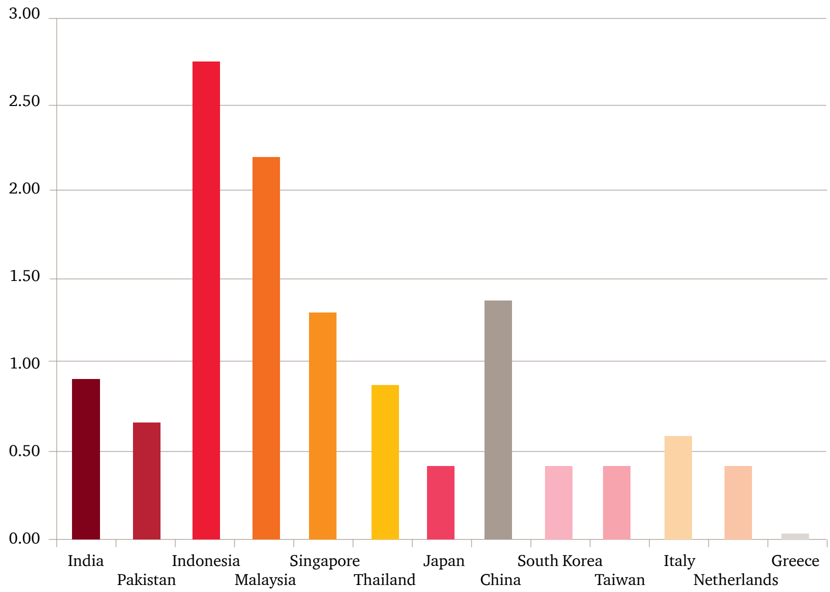
Figure 4.6 – Comparison of domestic pipeline gas prices in Southeast Asia



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 - and then transportation (transmission and distribution) costs. However, although Indonesia is an LNG exporter, it has the highest regasification costs in the world (Figure 4.7). Thus, despite large domestic gas reserves and competitive extraction costs Indonesia faces challenges regarding end-user gas prices.

Figure 4.7 – Comparison of regasification costs 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) and MoEMR Regulation No. 6/2016 on Provisions and Procedures on Determination of Allocation and Utilisation as well as the Price of Natural Gas (an amendment to MoEMR Regulation No. 37/2015). These set priorities as follows:

a) To support the Government's programme by providing gas for transportation, households and small users;
b) To support the national production of oil and gas;
c) To provide raw materials for fertiliser;
d) To support industries that utilise natural gas as a raw material;
e) To provide fuel to be used for electricity production; and
f) 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 such as PLN and its subsidiaries;
b) Regionally-owned enterprises located in oil and gas producing areas which hold IUPTLs;
c) State-owned enterprises in the oil and gas sector or regionally-owned enterprises located in 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 of their gas to IUPTL-holders then those entities may sell the excess to other business entities with marketing permits providing they meet the following requirements:

a) They own or control the 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, a raw material or for other purposes to meet domestic demand optimally. The revision of the decree was due to the Government 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. The Minister of Energy and Mineral Resources allows imports of natural gas in the event that domestic demand cannot be met.

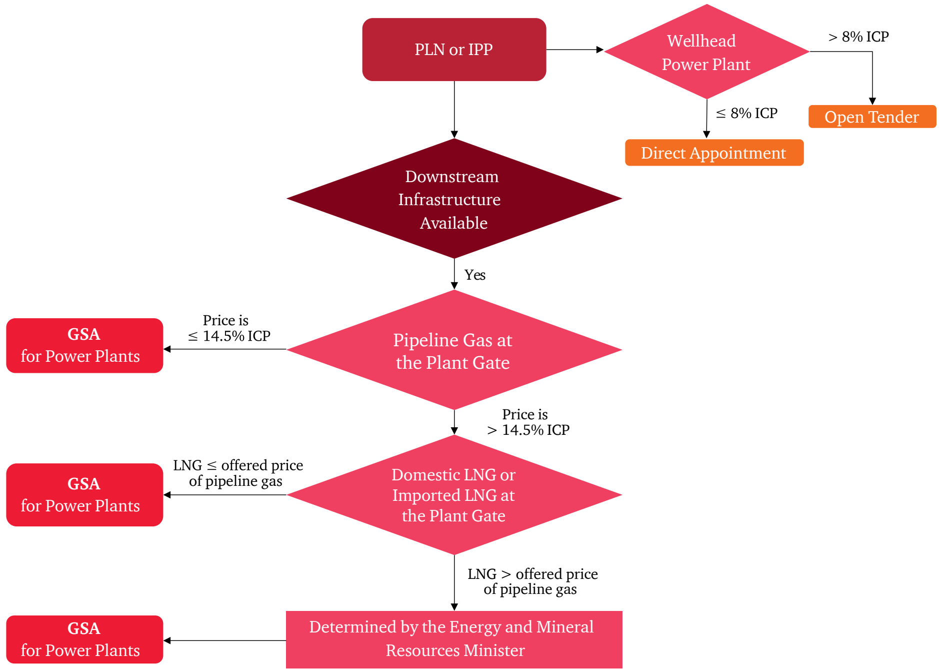
In May 2016, President Joko Widodo issued PR No. 40/2016 on Provisions for Natural Gas Prices which was intended to reduce gas prices to a maximum of USD 6 per MMBtu for certain industries such as those involved in fertilisers, petrochemicals, oleochemicals, steel, ceramics, glass and rubber gloves. PR No. 40/2016 was 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 the PT Petrokimia Gresik, PT Krakatau Steel, PT Pupuk Kujang, PT Pupuk Iskandar Muda and PT Pupuk Kaltim at USD 6 per MMBtu.[65] Further, the Minister of Energy and Mineral Resources 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 in February 2017. As a result, the gas for industrial users, which previously sold at USD 13.38 per MMBtu, was reduced to USD 9.95 per MMBtu.[66]

Additionally, and specifically for the power sector, in July 2017 the MoEMR issued MoEMR Regulation No. 45/2017 on the Use of Natural Gas for Power Plants. This regulation revoked 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 the importation of LNG are outlined in Figure 4.8 as follows:

65 DGOG, https://migas.esdm.go.id/post/read/pemerintah-putuskan-harga-gas-3-industri-maksimal-us$-6-per-mmbtu, accessed 6 December 2017

66 The Minister of Energy and Mineral Resources Decision No. 434/K/12/MEM/2017; MoEMR presentation at Forum Gas Nasional, 3 May 2017

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:

a) In the case of the utilisation of wellhead gas, if the price is ≤8% of ICP [67], the gas price can be based on direct appointment. If the price is >8% of ICP the gas price must be based on an open tender. The gas wellhead supply must also be sufficiently guaranteed. In the case that wellhead gas is used for power generation the Specific Fuel Consumption must be equal to HSD-equivalent 0.25 litres/kWh;
b) In the case that pipeline gas at the buyer's plant gate (power plant) is ≤14.5% of ICP, then PLN or an IPP can purchase;
c) In the case that pipeline gas at the buyer's plant gate (power plant) is >14.5% of ICP, then PLN or IPPs can choose to use either 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 being ready to be used by the power plant;
d) In the case that the domestic LNG price is equal to the imported LNG price the domestic LNG must be prioritised; and
e) In the case that the conditions above cannot be met the Minister will determine the provision of natural gas for power provision.

67 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)

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

Currently about 16.5 GW of gas-fired power plants (including combined-cycle) are installed and operated by PLN including plants in Belawan, Muara Karang, Priok, Cilegon, Muara Tawar, Tambak Lorok, North Bali and Gresik. In 2017, power generation from gas-fired power plants accounted for 24.8% of total generation. It is expected, as per the 2018 RUPTL, that the share of gas-fired power generation will be around 20.6% by 2027. This includes additional gas-fired power plant capacity of 14.3 GW which will increase the gas consumption of power plants by more than 80% in the next ten years.

Generally, PLN prioritises the use of pipeline gas for its gas-fired power plants. This especially for power plants that are “must-run” and bear a high electricity load such as Muara Karang, Priok and Muara Tawar. However, with the aim of enhancing gas supply security, PLN has started to use LNG as well due to the depletion of existing gas fields. Additionally, PLN is looking at the use of 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) and the need for regasification and other infrastructure. The LNG supplies for PLN currently come only from Bontang and Tangguh. In a few years supplies are expected to increase from Tangguh and Jambaran-Tiung Biru.

One of the largest planned gas-fired power plants is the Jawa 1 Combined-Cycle (2 x 880 MW). A consortium of Sojitz, Marubeni and Pertamina was awarded the tender and signed a PPA in January 2017 at a price of USD 5.5 cents/kWh. The Jawa 1 project will be developed in Cilamaya, West Java. Jawa 1 is the first gas-steam combined-cycle power plant in Asia and integrates an FSRU with a combined-cycle power plant. With a capacity of 2 x 880 MW the project will also be the largest gas combined-cycle power plant in Southeast Asia.[68] The gas for Jawa 1 is to be supplied by LNG Tangguh as PLN was reported to have agreed a gas price formula of 11.2% of ICP plus 0.4% for distribution costs.[69] The Jawa 1 Combined-Cycle project is expected to reach financial closing in September 2018.[70]

After the issuance of MoEMR Regulation No. 45/2017 PLN plans to build three FSRUs in Northern Sumatera, Muara Tawar Jakarta and Gorontalo [71] as well as five mini-LNGs in Papua.[72] This is part of PLN’s commitment to secure gas supply for IPP projects although the policy remains unclear for smaller gas-fired plant projects (see *Section 4.2.5 - Challenges*).

68 Pertamina, https://www.pertamina.com/id/news-room/news-release/bangun-proyek-pembangkit-listrik-tenaga-gas-terbesar-jawa-satu-power-mandatkan-kontrak-epc-berkisar-900-juta, accessed 26 June 2018

69 Rambu Energy, https://www.rambuenergy.com/2017/05/pln-bp-tangguh-reach-agreement-on-lng-price-for-pltgu-jawa-i-power-plant/, accessed 6 December 2017

70 The Jakarta Post, http://www.thejakartapost.com/news/2018/07/23/pertamina-edging-toward-closing-us1-44b-deal-for-java-1-power-plant.html, accessed 26 July 2018

71 Kompas, https://ekonomi.kompas.com/read/2017/09/12/180000626/bidik-bisnis-gas-bumi-pln-bakal-bangun-7-terminal-lng, accessed 4 June 2018

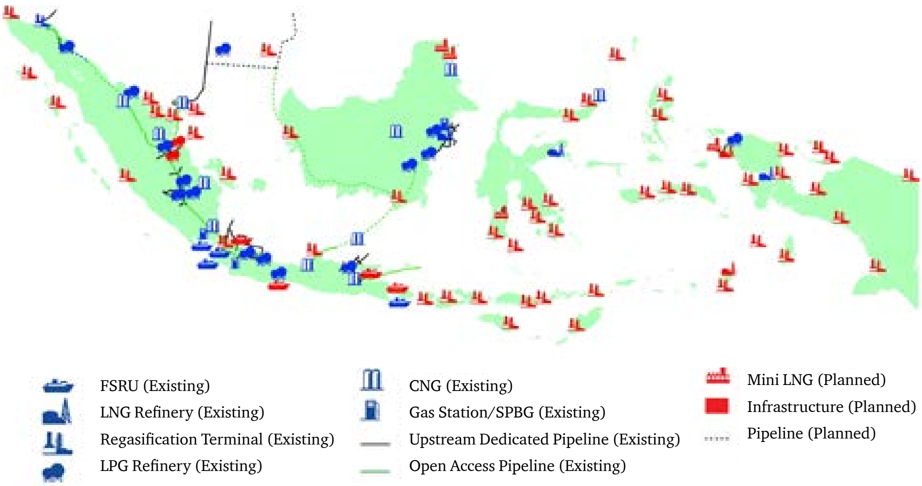
72 Rambu Energy, https://www.rambuenergy.com/2018/03/pln-to-auction-mini-lng-facilities-for-papua-this-year/, accessed 4 June 2018

In terms of the progress of the gas power plants the Senipah Combined-Cycle project reached financial close in October 2017 with the target COD being 24 months after the financial close.[73] The Jawa 2 Combined-Cycle project reached COD in August 2018.[74] The construction of the 40 MW Luwuk Gas Engine power plant has also started with the expected COD in 2019.[75] However, the procurement of many gas power plant projects has been delayed after the recent change to the 2018 RUPTL including the Jawa-3, Jawa-4 and Jawa-5 Combined-Cycle power plants.[76]

CNG was originally intended to optimise the potential of small-capacity and marginal gas fields by storing gas in advance for temporary use. However, over time PLN has utilised large-scale CNG to supply gas to some power plants especially those whose status has changed from baseloader to load-follower. CNG has been 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. This is estimated to require USD 48.2 billion of capital investment between 2016 and 2035 (see Figure 4.9 below). This includes the construction of gas pipelines of USD 12 billion, LNG refineries of USD 25.6 billion, gas stations (*Stasiun Pengisian Bahan Bakar Gas* -"SPBG") and CNGs of USD 1.93 billion, regasification facilities of USD 6.1 billion, gas network distribution facilities of USD 2.2 billion and LPG infrastructure of USD 400 million. Gas infrastructure is planned to be developed gradually. 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 expected to develop a gas-receiving terminal to support the 35 GW Programme.

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



Source: Neraca Gas Bumi Nasional 2016-2035

73 Kontan, https://industri.kontan.co.id/news/ipp-pltgu-senipah-telah-capai-financial-close, accessed 26 July 2018
74 Metro TV News, http://ekonomi.metrotvnews.com/energi/yKX93Y6N-pltgu-jawa-2-unit-2-siap-pasok-listrik-asian-games, accessed 8 August 2018
75 Coal Asia 30 June-30 July 2018, p. 56
76 Katadata, https://katadata.co.id/berita/2018/03/22/jonan-pangkas-rencana-pembangunan-pembangkit-listrik-tenaga-gas, accessed 3 July 2018

4.2.4 Opportunities

Based on the 2018 RUPTL the Government aims to keep the proportion of gas in the power generation mix at around 20.6% in 2027 down from 24.8% in 2017. There are several IPPs and captive power plants located near supporting infrastructure (natural gas plants, ports, etc.). Of the 14.3 GW of planned gas-fired power capacity 9.5 GW is to be developed by PLN, 4.1 GW by IPPs and 730 MW unallocated between IPPs and PLN.[77] These figures highlight the opportunities for the private sector.

The Government also plans to increase the growth of FSRUs across Indonesia. This is partly due to the costs of developing FSRUs which are significantly lower than a land-based terminals of comparable size and because generally FSRUs are quicker to develop than onshore regasification terminals.[78] Receiving terminals like these also present a private sector investment opportunity especially for captive power generation for Industrial Estates in coastal areas.

PLN now operates a policy of assigning large gas (and coal) power plant projects to its subsidiaries (PT Pembangkit Jawa Bali and PT Indonesia Power) who are then tasked to find private sector partners according to their own processes. A shortlist of gas-fired power plants recently advertised by PLN is set out below.

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

Gas-fired Power Plant Project	Capacity (MW)	Stage	PLN / IPP / Unallocated	Target PPA Date	Target FC Date	Construction Period (Months)	Target Project COD
Bali*	135	Planning	Unallocated	2019	2020	33	2022
CC Kalsel-1	100	Planning	Unallocated	2024	2025	24	2027
CC Kalbar Peaker-2	250	Planning	Unallocated	2023	2024	30	2027
CC/GE Lombok-1	100	Planning	Unallocated	2022	2023	24	2025
CC Sumbagut-1,3,4	800	Procurement	IPP	Dec-18	15-Jun-19	18	01-Dec-20
CC Jawa-3	800	Procurement	Unallocated	Nov-18	17-Jun-19	30	01-Dec-21
CC Riau-2	250	Planning and Procurement	IPP	2020	2021	30	2024
CC/GE Jawa Bali 3	500	Procurement	n/a	n/a	n/a	n/a	After 2027
CC/GE Jawa Bali 4	450	Procurement	n/a	n/a	n/a	n/a	After 2027
CC/GE Peaker Jawa Bali 2	1x500	Procurement	n/a	n/a	n/a	n/a	After 2027
GT/GE (Scattered) Belitung Peaker	1x40	Procurement	n/a	n/a	n/a	n/a	n/a
GT/GE (Scattered) TB. Karimun	1x10	Procurement	n/a	n/a	n/a	n/a	After 2027
GT/GE (Scattered) Tj. Pinang	1x50	Procurement	n/a	n/a	n/a	n/a	After 2027
CC Riau	275	Financing	IPP	n/a	Aug-18	36	Aug-21
CC Jawa-1	2x880	Financing	IPP	n/a	Sep-18	39	Mar-23

**Bali Power Plant can be either a gas-fired or a coal-fired power plant.*

Source: Suprapto, "IPP Outlook in Indonesia", PLN in IPP Summit, Jakarta, 18th July 2018; PLN presentation at UK Embassy export Credit Agency event, Jakarta, May 2018

77 2018 RUPTL, p. V-35

78 Philip Weems, "FSRUs: Looking back at the Evolution of the FSRU Market", December 2015. https://www.kslaw.com/blog-posts/fsrus-looking-back-at-the-evolution-of-the-fsru-market, accessed 26 June 2018

Since the revocation of MoEMR Regulation No. 3/2015 the pricing of power from gas-fired power plants has become unclear and will presumably be set by competitive bidding in Open Tenders for the plants mentioned above. However, in 2017 the MoEMR issued two regulations on gas pricing.

The first regulation deals with untapped gas resources at the gas wellhead. According to MoEMR Regulation No. 45/2017 on the Use of Natural Gas for Power Plants the gas supply from wellheads will be benchmarked to ICP with an 8% slope (see *Section 4.2.2 - Prices and Regulation*). The expectation is that this relatively cheap fuel pricing should result in a power price of around USD 3 cents/kWh.[79] There is some private sector interest in this structure. Recently, the Italian oil and gas company ENI which operates a concession in Muara Bakau (being the Jangkrik Complex Project - projected to be one of the largest deep water gas fields in Indonesia) announced that it was considering developing Indonesia's first offshore wellhead gas power plant. The location of the gas power plant would be in the Makassar Strait with a potential capacity of 400-500 MW.

The second regulation deals with the use of flared gas. Flared gas is gas produced through oil and gas exploration, production or processing activities. The gas is burned because it cannot be incorporated into the relevant production or processing facilities. There are at least 175 gas flaring chimneys in Indonesia 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 flared 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 flared gas is USD 0.35/MMBtu which should enable very cheap power.

4.2.5 Challenges

The lack of sufficient new infrastructure, and the aging existing infrastructure, are 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, an expansion of the pipeline network, as well as the development of FSRUs and LNG facilities, is required to support the distribution of gas. In September 2017, Keppel Offshore & Marine signed an agreement with Pavilion Energy and PLN to explore opportunities in developing small-scale LNG distribution in the western part of Indonesia.[80]

Gas, as component C (fuel) in a power plant PPA, is principally a pass-through cost to the IPP. In 2016, PLN announced that it will supply fuel for the gas-fired power plants of IPPs. However, PLN's policy on gas supply frequently changes. In practice, PLN supplies gas only for large-capacity power plant projects including Jawa-1. For smaller capacity projects, such as the Scattered Riau Gas Machine (180 MW) and the Pontianak Gas Machine (100 MW) plants, PLN is still relying on the private sector to supply gas.[81]

79 CNN Indonesia, https://www.cnnindonesia.com/ekonomi/20170202165427-85-190903/aturan-pltg-well-head-diklaim-sunat-biaya-listrik, accessed 9 December 2017
80 The Straits Times, https://www.straitstimes.com/business/companies-markets/keppel-om-pavilion-energy-and-indonesias-pln-to-cooperate-on-west, accessed 2 August 2018
81 Kontan, http://industri.kontan.co.id/news/pln-diminta-konsisten-soal-suplai-gas-pembangkit, accessed 9 December 2017

Additionally, the impact of the power sector being only fifth on the list of priority sectors for gas supply (see page 90) is yet to play out. So far however this has had not any obvious impact on IPPs.

4.3 Coal

4.3.1 Indonesian Resources, Consumption and Production

Coal has historically been, and still remains, Indonesia's most important source of fuel for electricity with Indonesia's abundance of coal resources favouring investment in coal-fired power plants. The high demand from China however spiked the coal price from the second half of 2017 with the Indonesian coal reference price (*Harga Batubara Acuan* – "HBA") in the first seven months of 2018 being no lower than USD 89.53/tonne (in April 2018).

In the long term, world coal production is expected to remain at between 9 to 10 billion tons p.a. from 2015 to 2040 as reduced consumption in China and the U.S.A. is offset by growth from India. China's reduction is linked to the implementation of policies addressing air pollution and climate change.[82] As a share of the energy mix coal is likely to fall over the long term as natural gas and renewables increase their presence.[83]

In Indonesia, as indicated coal remains the most important sources of fuel for electricity. Coal mining also plays a significant role in the Indonesian economy contributing 2.4% to GDP in 2017.[84] According to the BP Statistical Review of World Energy 2018 Indonesia sits in tenth place in terms of proven coal reserves with 2.2% of global coal reserves. Approximately 92% of Indonesia's coal reserves consist of cheaper, lower-quality coal (medium rank) with a calorific value of less than 6,100 kcal/kg.[85] This type of coal is generally competitively priced on the international market.

The three largest provinces for 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 a few large producers and many small players that own coal mines and concessions (mainly in Sumatera and Kalimantan). In 2017, Indonesia had coal resources of 127 billion tonnes mainly located in Kalimantan (75.8 billion tonnes), Sumatera (50.8 billion tonnes) and other regions (0.4 billion tonnes). In 2017, coal reserves amounted to 26.8 billion tonnes. Most of South Sumatera's coal reserves and resources are low-rank coal and mostly used for power generation. It is however generally not feasible to transport low-rank coal unless the coal price is significantly higher than average.

82 U.S. Energy Information Administration, International Energy Outlook 2017 Powerpoint slide, slide 63-64
83 PwC, Mine 2017
84 Bank Indonesia, Statistics of Indonesian Economic and Finance ("SEKI"), www.bi.go.id/en/statistik/metadata/seki
85 LAKIN Minerba 2016

Table 4.3 – Coal resources and reserves by province as of November 2017

No.	Island	Province	Resources (Millions of Tonnes)					Reserves (Millions of Tonnes)		
			Hypothetical	Inferred	Indicated	Measured	Total	Probable	Proven	Total
1	Java	Banten	5.47	38.98	28.45	25.10	98.00	0.00	0.00	0.00
2		Central Java	0.00	0.82	0.00	0.00	0.82	0.00	0.00	0.00
3		East Java	0.00	0.08	0.00	0.00	0.08	0.00	0.00	0.00
4	Sumatera	Aceh	0.00	423.65	163.70	662.93	1.250.28	95.30	321.38	416.68
5		North Sumatera	0.00	7.00	1.84	25.75	34.59	0.00	0.00	0.00
6		Riau	3.86	325.77	855.29	758.58	1.943.50	86.28	498.64	584.92
7		West Sumatera	21.09	510.09	135.35	180.90	847.43	6.54	67.00	73.54
8		Jambi	138.75	1.327.29	1.039.93	1.233.15	3.739.12	664.70	479.47	1.144.17
9		Bengkulu	0.00	79.78	132.95	80.22	292.95	9.74	84.56	94.30
10		South Sumatera	3.322.74	12.801.94	13.050.17	13.338.60	42.513.45	5.535.12	3.418.31	8.953.43
11		Lampung	0.00	122.95	8.21	4.47	135.63	11.74	0.00	11.74
12	Kalimantan	West Kalimantan	2.26	483.94	6.85	4.70	497.75	0.00	0.00	0.00
13		Central Kalimantan	22.54	4.905.16	2.456.75	2.458.43	9.842.88	935.25	1.278.07	2.213.32
14		South Kalimantan	0.00	6.205.47	4.833.71	7.095.33	18.134.51	1.875.42	2.555.18	4.430.60
15		East Kalimantan	916.10	13.324.71	13.934.20	16.388.84	44.563.85	2.823.18	5.055.02	7.878.20
16		North Kalimantan	25.79	867.59	672.44	1.167.50	2.733.32	501.48	538.66	1.040.14
17	Sulawesi	West Sulawesi	8.13	15.13	0.78	0.16	24.20	0.00	0.00	0.00
18		South Sulawesi	10.66	48.81	128.90	53.09	241.46	0.06	0.06	0.12
19		Southeast Sulawesi	0.64	0.00	0.00	0.00	0.64	0.00	0.00	0.00
20		Central Sulawesi	0.52	1.98	0.00	0.00	2.50	0.00	0.00	0.00
21	Maluku	North Maluku	8.22	0.00	0.00	0.00	8.22	0.00	0.00	0.00
22	Papua	West Papua	93.66	32.82	0.00	0.00	126.48	0.00	0.00	0.00
23		Papua	7.20	2.16	0.00	0.00	9.36	0.00	0.00	0.00
Total			**4.587.63**	**41.526.12**	**37.449.52**	**43.477.75**	**127.041.02**	**12.544.81**	**14.296.35**	**26.841.16**

Source: LAKIN Minerba 2017

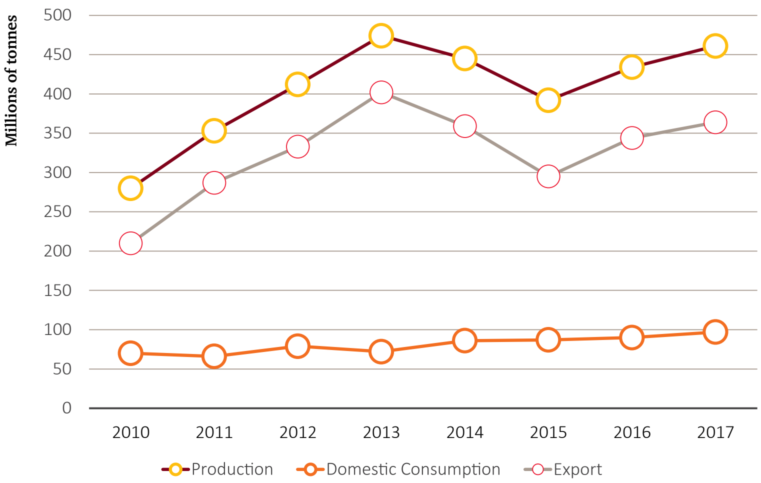
As the world's fifth-largest coal producer [86] Indonesia is also the world's largest thermal coal exporter or the second largest when metallurgical coal is taken into account.[87] Indonesia's coal production increased to 461 million tonnes in 2017 which was up from 434 million tonnes in 2016. Before 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 400 million tonnes by 2019 –

86 BP Statistical Review of World Energy 2018, p. 38
87 Greg Evans, Minerals Council of Australia, The outlook for coal exports and domestic electricity demand/supply, February 2018. http://www.businesschamber.com.au/NSWBC/media/Hunter/Presentations/G-Evans-Hunter-Valley-Chamber-Business-lunch-presentation-on-23-Feb-2018.pdf, accessed 05 June 2018

so that 60% of production would be consumed domestically.[88] It is unclear if this plan will still be implemented after rising coal prices boosted coal production and the IDR is under pressure from a current account perspective.

In 2017, Indonesia exported 364 million tonnes of coal (see Figure 4.10) generating USD 20.4 billion in export earnings. [89] The main export destinations have historically been China, India, Japan and South Korea although other countries such as Malaysia and Philippines are emerging markets.

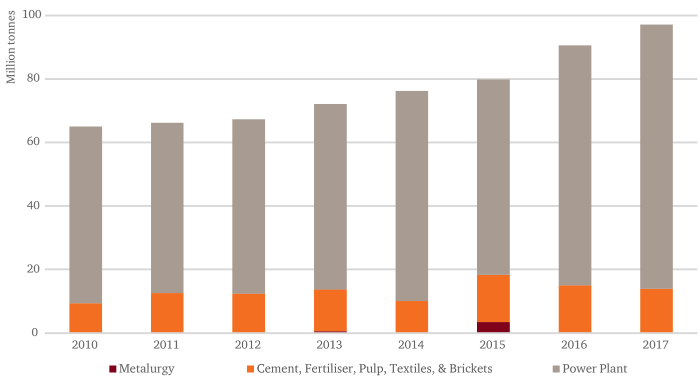
Figure 4.10 – Indonesian coal production and consumption for 2010-2017



Source: Asosiasi Pertambangan Batubara Indonesia ("APBI") [Indonesian Coal Mining Association]

In recent years Indonesia's domestic coal consumption has increased by almost 50% from 65 million tonnes in 2010 to 97 million tonnes in 2017 mainly due to increased demand from coal-fired power plants (see Figure 4.11). Based on the 2018 RUPTL coal-fired power plants are expected to consume 96 and 162 million tonnes of coal by 2019 and 2027 respectively.

Figure 4.11 – Domestic coal consumption consumer breakdown 2010 - 2017



Source: LAKIP ESDM 2017

88 Rencana Strategis ("RENSTRA") Kementerian ESDM ("KESDM")2015-2019 [2015-2019 MoEMR Strategic Plan], p. 85-87
89 Bank Indonesia, Statistics of Indonesian Economic and Finance ("SEKI"), www.bi.go.id/en/statistik/metadata/seki

4.3.2 Prices and Regulations

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

MoEMR Regulation No. 9/2016, which was partially amended by MoEMR Regulation No. 24/2016, provides the legal basis for defining mine-mouth power coal supply arrangement as follows:

a) The coal to be used is economically feasible for utilisation in a mine-mouth power project;
b) The availability of the coal supply is guaranteed by the coal mining company throughout the operation of the plant;
c) The power plant is no more than 20 km from the location of the coal mine; and
d) The coal price does not include transportation costs except from mine location to the power plant's stockpile.

In addition, a mine-mouth coal supplier or an 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 Batubar*a - "PKP2B"). Crucially, the new tariffs may not be as attractive as the previous regime in many cases.

The key features of the regulation are stated in Table 4.6 and Figure 4.12 as follows:

Table 4.6 – Summary of 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 determined by 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

The electrical power purchasing price is set under the assumption that the plant has an 80% Capacity Factor and the PPA follows a BOOT scheme.

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

a) In the event of power purchases resulting from the expansion of a power plant in the same location then the procurement method can follow direct appointment but with a lower benchmark price (as above);

b) In the event of power purchases resulting from the expansion of a power plant in a different location but in the same power system then the procurement method can follow direct selection but with a lower benchmark price (as above).

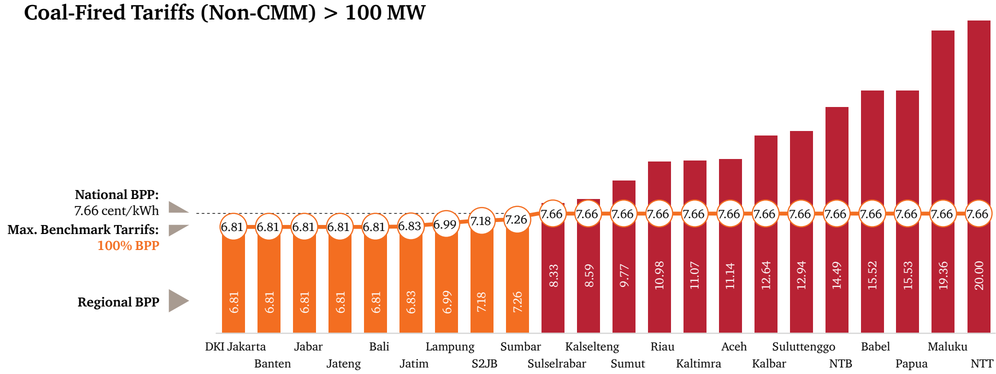
The procurement of CMM power plants can be through direct appointment.

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

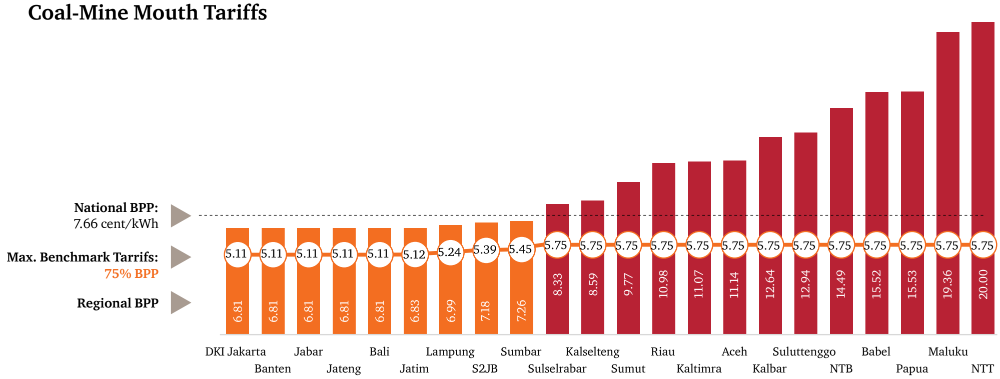
The new maximum benchmark price for coal-fired power plant projects ranges at between USD cents 6.81-7.26/kWh for any region where the Regional BPP ≤ National BPP such as in Java, Bali, the Southern part of Sumatera and West Sumatera. The new maximum benchmark price follows the national BPP (USD cent 7.66/kWh) in the case of coal-fired plants with a capacity higher than 100 MW if they are installed in any region where the Regional BPP > National BPP (see Figure 4.12 below). Additionally, and 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.

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

Coal-Fired Tariffs (Non-CMM) > 100 MW



Coal-Mine Mouth Tariffs



Source: Ignasius Jonan (Minister of Energy and Mineral Resources), "Electricity Generation Cost in 2017", 20 March 2018

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

In recent years the global coal price had fallen resulting in a sharply declining Indonesian coal reference price (*Harga Batubara Acuan* - "HBA"). This resulted in a decrease in coal production in Indonesia as small-scale miners suspended operations and big players took steps to protect margins. The Indonesian coal reference price declined by 58.3% from USD 127.05/tonne in February 2011 to USD 53/tonne in July 2016. However, coal prices began a strong rally coinciding with Chinese consumption policies and the overall demand for coal. The first quarter of 2018 saw rises in the coal price following cold weather, limited hydro power and natural gas shortages in China. Demand then decreased after the Chinese winter passed.[90] However, as Chinese steel mills were expected to replenish stockpiles following the increase in steel production [91] the coal price climbed again in the second quarter of 2018. As of mid-2018, the coal price remained high by historic standards (Figure 4.13).

Figure 4.13 - Indonesian coal price for the periods January 2010 – July 2018

Source: MoEMR, GEM Commodities, World Bank, Bloomberg

The benchmark price for coal sales, specifically steam (thermal) coal, is regulated by MoEMR Regulation No. 7/2017 (as amended by MoEMR Regulation No. 44/2017 and No. 19/2018) which revoked 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*"). This is except for coal for domestic consumption where the price is determined by the Minister of Energy and Mineral Resources as per MoEMR Regulation No. 19/2018. The HPB is determined based on a number of factors including the HBA and individual coal quality characteristics (i.e. calorific value, moisture content, sulphur

90 World Bank, Commodity Markets Outlook April 2018, http://pubdocs.worldbank.org/en/271041524326092667/CMO-April-2018-Full-Report.pdf, accessed 6 June 2018
91 Mining.com, http://www.mining.com/web/chinas-steelmaking-raw-materials-extend-gains-firm-demand-outlook/, accessed 6 June 2018

content and ash content). The HBA is calculated according to the average coal prices in the local and international market indexes including 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 MoEMR each month.

The HPB is used as the basis for most IPP contracts. The HPB 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 used for stipulating the price of coal in a sales contract is based on a formula of 50% (fifty percent) of the HBA in the month of contract signing plus 30% (thirty percent) of the HBA 1 (one) month prior to contract signing plus 20% (twenty percent) of HBA 2 (two) months prior to contract signing. For sales to domestic end-users the HBA used in the contract can be reviewed every 3 (three) months at the earliest. While the regulation refers to HBA the actual reference used in the contract should probably be HPB.

For CMM plants 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. This is 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.[92]

In March 2018, the MoEMR issued Decree No. 1395/K/30/MEM/2018 which caps the price of coal sales to power plants (both PLN and IPPs) to USD70/tonne for the first 100 million tonnes sold each year. This should apply to nearly all of the coal sales agreements in 2018 and 2019 considering the annual coal purchases by PLN and IPPs in 2017 were slightly below 100 million tonnes. Producers that meet these DMO requirements will be eligible to have their approved production volumes increased by 10%. This regulation is only applied when the HBA surpasses USD 70/tonne otherwise the HBA will remain the reference price for coal sales agreements in the power sector.

The application across different coal specifications is as follows:

a) For high quality coal (>GAR 6,322 kcal/kg, max. TM 8%, S_2 0.8 and Ash 15%) the price is simply capped at USD70/tonne;
b) For lower quality coal where the HBA is more than or equal to USD70/tonne the contract price will be USD70/tonne with appropriate price adjustments being made for the specification of the delivered coal as compared to the specification of the HBA benchmark coal. These adjustments will be governed by a standard formula.

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

In 2017, power generation from coal-fired power plants accounted for 58% of total generation. The share of coal in the energy mix is planned to decrease to 54% by 2025 in order to align with the target NEP energy mix in 2025. PLN plans to triple energy production from renewable from 30.9 GWh in 2017 to around 100 GWh in 2025 (see Figure 1.7 and Table 3.4).[93]

92 Coal Asia, 25 June-25 July 2016, p. 54
93 2018 RUPTL, p. V-63

As discussed in *Section 3.7.1 - IPP Opportunities and Challenges* coal is likely to 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 26.8 GW of coal-based power generation planned in the 2018 RUPTL regular coal-fired power plants account for 20.8 GW while CMM power plants account for 6 GW. Of the regular coal-fired power plants about 4 GW of coal-fired power plants are planned to be developed by PLN while another 15.1 GW are to be developed by IPPs. The remaining 1.7 GW projects are unallocated. Of the CMM power plants the entire 6 GW of capacity has been allocated to IPPs.[94] These figures indicate that there are significant opportunities in Indonesia for the private sector.

A shortlist of plants recently advertised by PLN is set out below.

Table 4.5 – Procurement and financing of coal-fired and coal mine-mouth power plants in 2018

Coal-fired Power Plant Project	Capacity (MW)	Stage	PLN / IPP / Unallocated	Target PPA Date	Target FC Date	Construction Period (Months)	Target Project COD
Bali*	135	Planning	Unallocated	2019	2020	33	2022
Banten	660	Planning	Unallocated	2021	2022	45	2026
Jawa-5 (FTP2)	1 x 1,000	Planning	IPP	Dec-18	22-Jun-19	45	01-Dec-22
Kalbar-3	200	Planning	Unallocated	2020	2021	36	2024
Kalbar-4	2 x 100	Planning	Unallocated	2024	2025	39	2028
Sumsel Mine-Mouth (Expansion)	1 x 350	Planning	IPP	Nov-18	18-Nov-19	45	01-Aug-23
Jambi-2 Mine-Mouth	2 x 300	Procurement	IPP	Jun-18	17-Dec-18	39	01-Mar-22
Sumbagsel-1 Mine-Mouth	300	Procurement	IPP	Nov-18	18-Nov-19	38	01-Jan-23
Kaltimra Mine-Mouth	2 x 200	Procurement	n/a	2024	2025	39	2028
Sulbagut 3	2 x 50	Procurement	IPP	2020	2021	36	2024
Sumsel-6B Mine-Mouth	300	Procurement	IPP	2022	2023	36	2026
Sumut-2	2 x 300	Financing	IPP	n/a	Dec-18	36	Dec-21
Jambi-1 Mine-Mouth	2 x 300	Financing	IPP	n/a	Dec-18	45	Sep-22
Sumsel-6 Mine-Mouth	1 x 300	Financing	IPP	n/a	Apr-21	38	Jun-24
Jawa 9 & 10	2 x 1,000	Financing	IPP	n/a	Sep-19	54	Mar-24
Kaltim-3 Mine-Mouth	2 x 100	Financing	IPP	n/a	Mar-21	36	Mar-24

94 2018 RUPTL, p. V-35

Coal-fired Power Plant Project	Capacity (MW)	Stage	PLN / IPP / Unallocated	Target PPA Date	Target FC Date	Construction Period (Months)	Target Project COD
Kaltim-5 Mine-Mouth	2 x 100	Financing	IPP	n/a	Mar-20	36	Mar-23
Kalbar-2	2 x 100	Financing	IPP	n/a	Mar-19	36	Mar-22
Kalselteng-3 Mine-Mouth	2 x 100	Financing	IPP	n/a	Sep-21	36	Jun-24
Kalselteng-4 Mine-Mouth	2 x 100	Financing	IPP	n/a	Sep-22	36	Jun-25
Kalselteng-5 Mine-Mouth	2 x 100	Financing	IPP	n/a	Sep-24	36	Jun-27
Kaltim-6 Mine-Mouth	1 x 200	Financing	n/a	n/a	Jun-26	36	Jun-29
Sulut-3	2 x 50	Financing	IPP	n/a	Jan-19	27	Apr-21
Meulaboh (Nagan Raya) #3,4	2 x 200	Financing	IPP	n/a	Oct-18	42	Dec-21
Banyuasin Mine-Mouth	2 x 125	Financing	IPP	n/a	Dec-18	36	Dec-21
Sumsel-8 Mine-Mouth	2 x 600	Financing	IPP	n/a	Jun-18	45	Mar-23
Jawa-3 (FTP2)	2 x 660	Financing	IPP	n/a	Jul-20	54	Jan-25

**Bali Power Plant can be either a gas-fired or a coal-fired power plant.*

Source: Suprapto, "IPP Outlook in Indonesia", PLN in IPP Summit, Jakarta, 18th July 2018

PLN noted that there are about 2.55 GW of coal-fired power plants in the planning stage including the 1.2 GW of unallocated coal-fired power plants and 1.7 GW of coal-fired power plants in the procurement stage. There are over 7.1 GW of plants in the financing stage many of which are joint ventures between the private sector and a PLN subsidiary (with PLN remaining the off-taker, see Table 4.5 above).

PLN signed a PPA with the 250 MW Banyuasin and the 300 MW Sumbagsel-1 CMM power plants at the end of May 2018. These were stalled due to the protracted negotiations over power tariffs and the verification of the coal mine's "clean and clear" status. An additional four 200 MW CMM power plants in West, South, Central and East Kalimantan are also expected to be signed in September 2018. PLN has also started construction of the 100 MW Sulsel Barru-2 coal-fired power plant with a target COD of 2021.[95] On the IPP side PT Huadian Bukit Asam Power recently signed a USD 1.26 billion loan to help finance the planned Sumsel-8 CMM power plant (2x620 MW) with estimated investment of USD 1.68 billion. The Sumsel-8 CMM power plant has an expected COD of 2021 (for Unit I) and 2022 (for Unit II).[96]

95 Coal Asia, 30 June-30 July 2018, p. 56-57
96 Coal Asia, 29 May-25 June 2018, p. 45

4.3.5 Challenges

Indonesia has large geological reserves of coal. However, coal transport infrastructure still contributes significantly to Free On Board ("FOB") coal prices in many areas. Efficient solutions such as railways (which have 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 a committed to renewing Mining Business Licences (*Izin Usaha Pertambangan* – "IUP") or PKP2B as part of this.

Compared to the benchmark price stipulated in MoEMR Regulation No. 3/2015 the price for coal-generated power as stated in MoEMR Regulation No. 19/2017 is generally lower. From the Government's standpoint it is expected that the regional BPPs may be more effective under the new regulation which could drive greater competition on electrical power prices. Seemingly, what drove the MoEMR to implement this regulation was the goal of reducing 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 particularly if the profitability for coal-fired and CMM power plants is reduced.

4.4 Oil

In 2017 Indonesia's total crude oil production amounted to 0.8 million barrels per day or around 87% of its 2008 production.[97] Meanwhile, between 2007 and 2017 Indonesia's total oil consumption grew at an average rate of 2.4% annually to 1.68 million barrels per day resulting in Indonesia being a net oil importer.[98] However, most oil is consumed by the transportation sector rather than in power generation. At the current rate of consumption Indonesian oil reserves are expected to be exhausted in 24 years.[99]

In terms of the power sector oil contributes a relatively insignificant share. Generally, PLN uses oil to provide electricity in rural or isolated grid areas. In the 2018 RUPTL PLN plans to reduce the use of oil from the predicted 4.2% in 2018 to 0.4% by 2025 (see Figure 1.7). This is motivated by efforts to reduce the BPP and increase efficiency.

However, in regard to captive generation facilities oil (diesel) is also used by non-electrified communities in rural and remote areas as well as the industrial sector. For industries this has been caused by a surge in demand for electricity in front of capacity growth. As a result PLN has sometimes been forced to implement blackouts in some provinces. Thus, many industries operate their own backup diesel generators.[100] Some players are attempting to hybridise diesel with renewables although none have reached COD yet.

97 SKK Migas, http://skkmigas.go.id/publikasi/infografis/lifting-minyak-dan-kondensat, accessed 13 August 2018
98 BP Statistical Review of World Energy 2018, p. 17
99 LAKIN DJMGB 2017, p. 57
100 PwC, Oil and GE Operations Indonesia ("GE"), Private Power Utilities: The Economic Benefits of Captive Power in Industrial Estates in Indonesia, 2016, p. 18

Photo source: PT Adaro Power

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 underinvestment Indonesia's production of renewable energy remains modest although utility-scale deployment of wind and solar PV picked up in 2017.

Indonesia's primary objectives in expanding its use of renewable energy are 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 areas without grid access such as in rural, remote and border areas, and on islands. This is with a target to achieve a 97% electrification rate by 2019; and
c) To contribute towards GHG emissions targets and encourage the green economy in line with the Government's desire to cut GHG emissions by 29% by 2030.

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

a) Energy sources already being widely used in commercial operations (e.g. geothermal, hydro and biomass);
b) Energy sources being developed commercially but with some residual concerns over the regulatory and commercial aspects (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 as including liquefied coal, coalbed methane, gasified coal, nuclear energy and hydrogen. Renewable energy sources are defined as including geothermal resources, hydropower, bioenergy,

Photo source: PwC

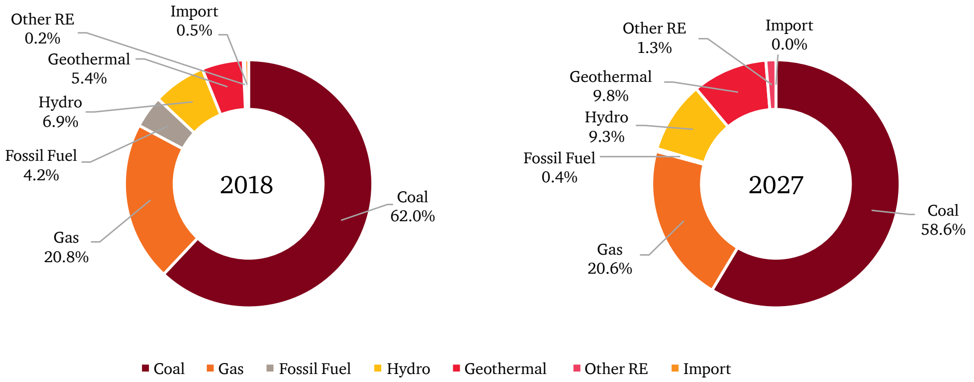
solar, wind and ocean energy. The composition of the 23% target consists of 10% bioenergy, 7% geothermal, 3% hydropower and 3% other new and renewable energy. In terms of the power sector the renewables' share reached 12.52% in November 2017 thereby exceeding the 2017 target of 11.96%. Hydropower (7.27%) and geothermal (5%) are the dominant renewables sources with other renewables contributing 0.25% in the power sector.[101] However, achieving the NEP target of a 23% renewable energy share by 2025 will be challenging given the small quota under the 35 GW Programme (*see Section 3.7.2 – The 35 GW Power Development Programme*) and with the recent 2018 RUPTL focus on coal power plants.

With regard to the regulatory framework tariffs and pricing are among the most sensitive issues in renewable energy investment and development. Until 2016 the regulations 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 given 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 Regulation No. 12/2017 (as amended by MoEMR Regulation No. 43/2017), alleviated some of these concerns mainly through increasing some tariffs or providing more flexibility for many provinces especially in Java and Sumatera. Please see *Section 5.9 - New Tariff Stipulations for Renewable Energy* for more information on tariffs or renewable tariffs.

5.2 *Renewable Energy in RUPTL*

Despite the potential issues in Indonesia's renewable energy sector from an investment perspective, particularly concerning new power purchase tariffs, both PLN and the MoEMR remain optimistic about renewable energy development. In the 2018 RUPTL the target for renewable energy deployment in the fuel mix increased from 12.5% in 2018 to 20.4% by 2027 which will mainly be supported by geothermal energy (9.8%) and hydropower for (9.3%) (see Figure 5.1).

Figure 5.1 – Fuel mix projection in the electricity sector as in the 2018 RUPTL



Source: 2018 RUPTL

101 MoEMR, https://www.esdm.go.id/en/media-center/news-archives/realisasi-2017-bauran-energi-terbarukan-pada-pembangkit-listrik-meningkat, accessed 31 July 2018

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 towards the geothermal resource to repeat the process. Indonesia is geothermal-rich being situated on the world's most active volcanic fault (the Ring of Fire). Additionally, Indonesia lies between two of the Earth's major active tectonic plates (the Pacific and the 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 plants and 1,600 times less than oil-fired 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 of over 80% worldwide. Some plants have surpassed the capacity factor of 90% which is higher even than fossil fired resources.[102]

Indonesia's geothermal potential is about 28,508 MW (Table 5.1) across 342 locations and represents the second largest geothermal resource in the world being 28% of total global resources.[103]

Table 5.1 – Resources, reserves and installed capacity of Indonesian geothermal as of May 2018

No	Island	No. of Locations	Potential Energy (MW)					Total - MW	Installed Capacity - MW
			Resources		Reserves				
			Speculative	Hypothetical	Possible	Probable	Proven		
1	Sumatera	98	2,817	1,917	5,065	930	917	11,646	562
2	Java	73	1,410	1,689	3,949	1,373	1,865	10,286	1,254
3	Bali	6	70	22	122	110	30	354	-
4	Nusa Tenggara	28	225	395	901	-	15	1,536	12.5
5	Kalimantan	14	152	17	13	-	-	182	-
6	Sulawesi	87	1,308	325	1,248	80	140	3,101	120
7	Maluku	33	560	91	677	-	-	1,328	-
8	Papua	3	75	-	-	-	-	75	-
Total		342	6,617	4,456	11,975	2,493	2,967	28,508	1,948.5
			11,073		17,435				

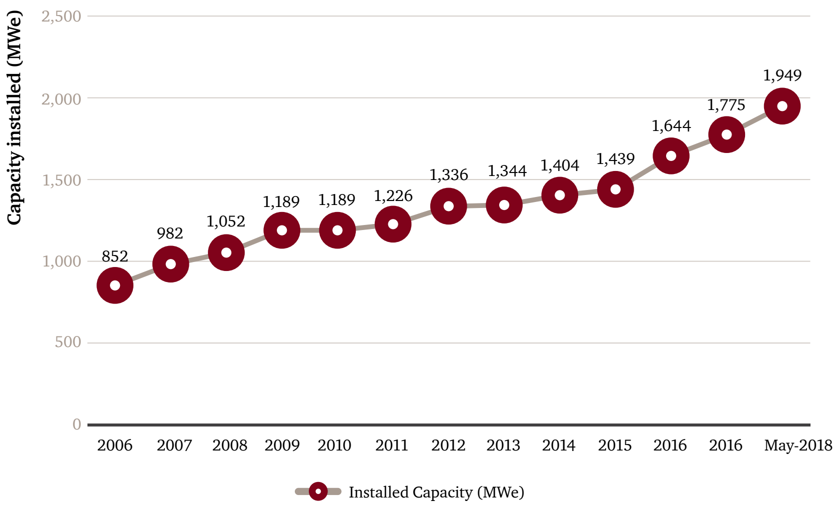
Source: DGNREEC, "Doing Business in Geothermal", June 2018

The geographical location of geothermal resources across Indonesia 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 slow. The growth of geothermal energy in Indonesia is presented in Figure 5.2. To date there are only eleven working areas (or concessions) operating and despite the Government having identified 75 potential working areas. Currently the total installed capacity is 1,949 MW (see Table 5.2 for the operating working areas) equivalent to only 6.8% of the total estimated resources.

102 International Renewable Energy Agency, Geothermal Power Technology Brief p. 2 and p. 21, 2017 http://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Aug/IRENA_Geothermal_Power_2017.pdf, accessed 8 June 2018

103 RENSTRA KESDM 2015-2019, p. 70

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



Source: DGNREEC, "Doing Business in Geothermal", June 2018

Table 5.2 – Installed geothermal capacity by the licence holder and developer as of March 2018

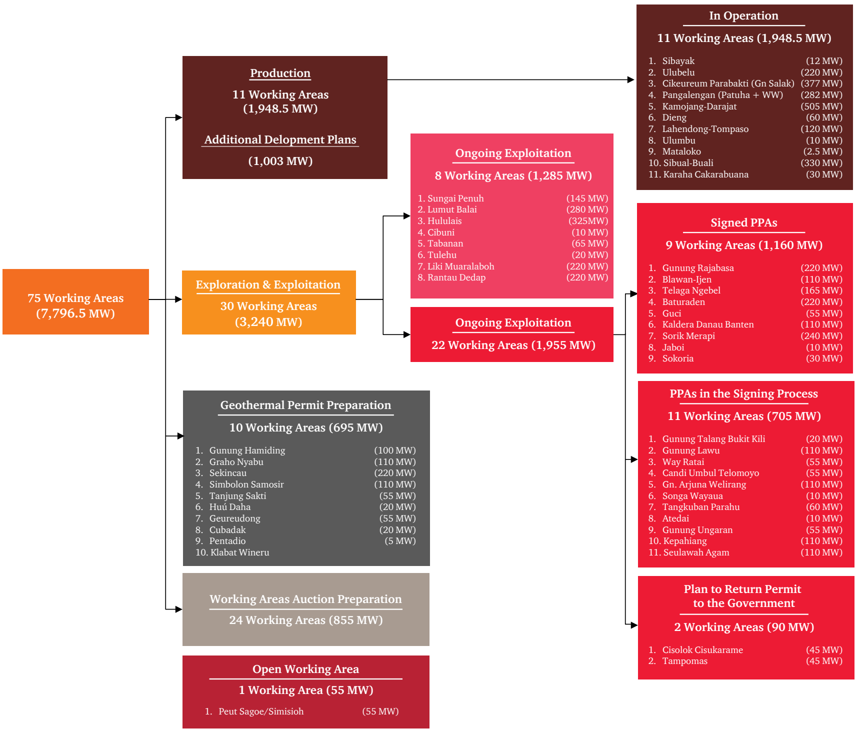
No	Geothermal Working Area Location	Licence Holder	Developer	Power Plant	Turbine Capacity (MW)	Installed Capacity (MW)
1	Sibayak – Sinabung, North Sumatera	PT Pertamina Geothermal Energy ("PGE")	PGE	Sibayak	2 x 5 1 x 2	12.0
2	Cibeureum – Parabakti, West Java	PGE	JOC - Star Energy Geothermal Salak, Ltd. (formerly Chevron Geothermal Salak, Ltd.)	Salak	3 x 60 3 x 65.67	377.0
3	Pangalengan, West Java	PGE	JOC – Star Energy Geothermal Wayang Windu, Ltd	Wayang Windu	1 x 110 1 x 117	227.0
	Pangalengan, West Java	PT Geo Dipa Energi "GDE")	GDE	Patuha	1 x 55	55.0
4	Kamojang – Darajat, West Java	PGE	PGE	Kamojang	1 x 30 2 x 55 1 x 60 1 x 35	235.0
	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	270.0
5	Dataran Tinggi Dieng, Central Java	GDE	GDE	Dieng	1 x 60	60.0
6	Lahendong – Tompaso, North Sulawesi	PGE	PGE	Lahendong	6 x 20	120.0

No	Geothermal Working Area Location	Licence Holder	Developer	Power Plant	Turbine Capacity (MW)	Installed Capacity (MW)
7	Way Panas, Lampung	PGE	PGE	Ulubelu	4 x 55	220.0
8	Ulumbu, NTT	PT PLN Geothermal ("PLN G")	PLN G	Ulumbu	4 x 2.5	10.0
9	Mataloko, NTT	PLN G	PLN G	Mataloko	1 x 2.5	2.5
10	Sibual-buali, North Sumatera	PGE	Sarulla Operation Ltd	Sarulla	3 x 110	330.0
11	Tasikmalaya, West Java	PGE	PGE	Karaha Bodas	1 x 30	30.0
Total Installed Capacity (MW)						1,948.5

Source: DGNREEC, "Doing Business in Geothermal", June 2018

As of June 2018, 65 *Wilayah Kerja Panas Bumi* (geothermal working areas – "WKP") and 10 *Wilayah Penugasan Survey Pendahuluan dan Eksplorasi* (preliminary survey and exploration areas – "WPSPE") have been stipulated by the Government. This comprises 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 10 working areas identified after the issuance of Law No. 21/2014. Further, there is one open working area for which the survey has not yet been conducted (see Figure 5.3).

Figure 5.3 – The status of the 75 geothermal working areas as of June 2018



Source: DGNREEC, "Doing Business in Geothermal", June 2018

In February 2017, the Government issued a new regulation on geothermal development being 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"),[104] research institute or 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 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.

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 for conducting the PSP is limited to one year with an option to extend by up to six months.

Alternatively, the Minister of Energy and Mineral Resources could 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 which 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 perform/drill at least one exploration well in order to obtain an estimation of the 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 an auction mechanism.

A Business Entity that is assigned to conduct a PSPE will hold the right to obtain fiscal facilities and have an obligation to an Exploration Commitment of 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. A Business Entity assigned a PSPE will have first rank order when entering the tender process for the assigned working area.[105]

5.3.1 Recent Trends in Geothermal Development in Indonesia

Under its five-year plan for 2015-2019 the Government indicated that it would like to achieve 3,200 MW of installed geothermal capacity by 2019.[106] However, according to the 2018 RUPTL PLN has indicated that by 2019 Indonesia is expected to only achieve 2,219 MW of installed geothermal capacity.

104 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.

105 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)

106 RENSTRA KESDM 2015-2019, p. 91

PLN also plans that, by 2027, Indonesia should have an additional 4,583 MW of installed geothermal capacity. If so the total installed capacity will be 6,432 MW at the end of 2027. The projects are listed in Table 5.3 as follows:

Table 5.3. List of geothermal project development plans for the period 2018-2027

Geothermal Project Name	Power System Region	Project Developers	Plan of COD and Installed Capacity										
			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Remarks
Sarulla I	Sumbagut	IPP	110										
Sorik Marapi			40		50	50	50	50					
Spread geothermal power plants		Unallocated						55	140				Additional Plan
Hululais	Sumbagselteng	PLN			55	55							
Sungai Penuh										110			
Lumut Balai		IPP	55	55									
Muara Laboh				80						140			
Rantau Dedap					86					134			
Rajabasa										220			
Spread geothermal power plants		Unallocated						290	55				
Tangkuban Perahu-Ciater	Jawa-Bali	PLN						20	40				
Ungaran										55			
Patuha		IPP					55						
Ijen						55	55						
Wilis/Ngebel						55				55			
Cibuni							10						
Wayang Windu										120			
Dieng							55						
Baturaden/Slamet							50			170			
Guci									55				
Rawa Dano							110						
Dieng Binary					10								
Dieng Small Scale				10									
Spread geothermal power plants									55	40			Additional Plan
Spread geothermal power plants		Unallocated								1,428			Additional Plan
Lahendong 7	Sulbagut	IPP								20			Additional Plan
Lahendong 8										20			Additional Plan
Tulehu	Ambon	PLN			20								
Total			**205**	**145**	**221**	**215**	**385**	**415**	**345**	**2,512**	**0**	**0**	

Source: 2018 RUPTL

In March 2017, the Sarulla Geothermal Project in Sibual-Buali, North Sumatera reached the COD for the first Unit-1 of 110 MW capacity being also the first greenfield Indonesian geothermal project financed on a limited recourse basis since the Wayang Windu project in 1997. The Sarulla Geothermal Project is designed to have 330 MW capacity in total with the 110 MW Unit-II becoming operational from October 2017 [107] and the 110 MW Unit-III becoming operational from May 2018.[108]

107 Petrominer, https://petrominer.com/pltp-sarulla-unit-2-mulai-beroperasi/, accessed 20 June 2017
108 EMR, https://www.esdm.go.id/en/media-center/news-archives/pltp-sarulla-beroperasi-penuh-kapasitas-pembangkit-terpasang-menjadi-19485-mw, accessed 31 July 2018

The 30 MW Karaha Bodas Unit 1 also reached COD in April 2018 which, together with Sarulla, makes Indonesia the second biggest geothermal power producer. Three more geothermal power plants – the 30 MW Sorik Marapi-1, the 55 MW Lumut Balai-1, and the 5 MW Sokoria-1 – are expected to reach COD before the end of 2018.[109]

However, despite the ambitious targets and encouraging results the Government continues to struggle in attracting investment in geothermal exploration. In 2015-2016 the MoEMR failed to find participants at several geothermal auctions (i.e. the Danau Ranau, Marana, Gunung Galunggung, Gunung Wilis, and Gunung Ciremai working areas).

In March 2017, PLN requested the Government to assign it the operation of fourteen geothermal areas with a total capacity of 1,100 MW while looking for joint venture partners to assist with the requested geothermal blocks.[110] This resulted in six geothermal working areas being explored with joint funding from PLN and SMI and with the target of obtaining an additional of 160 MW geothermal capacity.[111] As of March 2018 PLN was still considering partners after being assigned eight geothermal working areas with a total capacity of 337.5 MW on the understanding that PLN retains the majority stake.[112] It is noted that Aboitiz power withdrew from the joint venture with Medco on the Ijen geothermal project in early January 2017, and that Chevron recently sold its stakes in the Salak (377 MW) and Darajat (270 MW) Geothermal Projects to Star Energy. These transaction have made Star Energy the largest geothermal company in Indonesia since April 2017. PLN has also invited investors to prequalify as geothermal power plant developers in Indonesia. Requirements include that the participants be able to demonstrate successful experience in a geothermal resource study of 10 MW or above, well drilling and testing in an oil and gas or geothermal projects, and management of geothermal reservoirs of 10 MW or above.

There are five WKPs and five WPSPEs to be tendered in 2018. Another five WKPs will be directly assigned. PLN is expected to receive three WKPs with the other two WKPs to be assigned to PGE. This represents a continuation of a trend starting in 2016 of geothermal projects to be assigned to SOEs.

109 DGNREEC, http://ebtke.esdm.go.id/post/2018/04/28/1948/indonesia.peringkat.2.produsen.listrik.panas.bumi.lampaui.filipina, accessed 8 June 2018
110 CNN Indonesia, https://www.cnnindonesia.com/ekonomi/20170329183015-92-203516/garap-14-wilayah-panas-bumi-pln-tagih-penugasan-pemerintah, accessed 20 June 2018
111 Okezone, https://economy.okezone.com/read/2017/09/13/320/1774948/didanai-smi-pln-eksplorasi-6-wilayah-kerja-panas-bumi-senilai-rp8-triliun, accessed 20 June 2018
112 Bisnis.com, http://industri.bisnis.com/read/20180320/44/752097/pln-berencana-gandeng-mitra-kelola-panas-bumi, accessed 8 June 2018

Table 5.4 – List of geothermal working area offerings in 2018

Working Area	Province	Estimated Resource (MW)	Capacity Development Plan (MW)	Status
Gunung Endut	Banten	180	40	Will be tendered as WKP in 2018
Lainea	Southeast Sulawesi	66	20	Will be tendered as WKP in 2018
Sembalun	West Nusa Tenggara	100	20	Will be tendered as WKP in 2018
Sumani	West Sumatera	100	20	Will be tendered as WKP in 2018
Wapsalit	Maluku	70	5	Will be tendered as WKP in 2018
Danau Ranau	South Sumatera, Lampung	210	40	Will be assigned to PLN in 2018
Gunung Sirung	East Nusa Tenggara	152	5	Will be assigned to PLN in 2018
Oka Ile Ange	East Nusa Tenggara	50	10	Will be assigned to PLN in 2018
Gunung Ciremai	West Java	150	110	Will be assigned to PGE in 2018
Kotamobagu	North Sulawesi	410	80	Will be assigned to PGE in 2018
Cubadak	West Sumatera	20	N/A	Will be tendered as WPSPE in 2018
Geureudong	Aceh	55	N/A	Will be tendered as WPSPE in 2018
Hu'u Daha	West Nusa Tenggara	20	N/A	Will be tendered as WPSPE in 2018
Klabat Wineru	North Sulawesi	N/A	N/A	Will be tendered as WPSPE in 2018
Pentadio	Gorontalo	5	N/A	Will be tendered as WPSPE in 2018

Source: DGNREEC, "Doing Business in Geothermal", June 2018; PwC Analysis

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

To expedite the utilisation of geothermal energy, on 17 September 2014, the Government issued Law No. 21/2014 on Geothermal (the "2014 Geothermal Law"). Under the 2014 Geothermal Law geothermal operations were classified as being either for "direct use" (e.g. hot springs) or indirect use (i.e. electricity generation). Only the Central Government can now 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 was 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 mining activities these working areas were restricted under the Forestry Law.

The 2014 Geothermal Law requires Geothermal Licence holders to provide a "production bonus" to the Regional Government covering the permit holder's working area. This will be a specified percentage of the gross revenue arising from the date of commercial operation 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 evaluates the qualification of the Business Entity based on its administrative criteria, financial strength and performance. The second stage evaluates the "geothermal development proposal" and exploration commitment of the Business Entity the results of which are 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 followed by exploitation and production activities for a maximum period of 30 years.

For the working areas based on a PSPE, GR No. 7/2017 provides 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 SOE (as a competitor in the tender). A Business Entity that has performed a PSPE and participated in the assigned working area tender shall be treated as the first-ranked participant (prioritised) in the tender while any SOE shall be second-ranked.

In order to determine the 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 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 the relevant 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 reserves the right to conduct direct appointments even of a private Business Entity. This is allowable in the event that there is only one participant even after the tender is repeated.

In 2018, the MoEMR issued MoEMR Regulation No. 37/2018 with more detail on the tendering process for geothermal working areas (including PSPE working areas), the direct selection process, the granting of the IPB and the assignment of certain working areas to SOEs with geothermal activities or BLUs.

5.3.4 Challenges for Geothermal Development

Geothermal investment is characterised by a long lead time for commercial operations and project financing which is only 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 Government 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 by providing high-quality information about greenfield geothermal sites, verified by reputable international institutions, to investors during the tendering process for new work areas.

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 the MoF issued 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.[113] The MoF has also stipulated that PT SMI should leverage the funds with sources from the private sector or international multilateral agencies.

To expedite the implementation and disbursement of the GSF the Minister of Finance issued MoF Regulation No. 62/2017 on Fund Management and Infrastructure Financing for Geothermal. Based on the MoF Regulation the Government, through SMI, provides funding for geothermal infrastructure. The funds may be used for:

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 under the corporate business framework of PT SMI. Meanwhile, PT SMI will provide geothermal data and information acting as the Government representative on the basis of a special assignment from the Minister of Finance. For exploration activities the provision of funds is expected to significantly reduce risks for developers thereby attracting greater 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.

The GSF disbursed for the first time when six geothermal working areas were assigned to PLN in September 2017 with three working areas in East Nusa Tenggara and the rest being in West Java, Central Sulawesi and North Maluku.[114] In March 2018, PLN issued a plan to create a new subsidiary in the gas and geothermal sector stating that the Government will support up to half of the funding using a low-interest foreign loans through SMI.[115]

113 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

114 Media Indonesia, http://mediaindonesia.com/read/detail/122220-pln-dapat-geothermal-fund-untuk-6-wkp, accessed 28 June 2018

115 Berita Satu, http://id.beritasatu.com/energy/pln-bakal-bentuk-anak-usaha-panas-bumi/173711 accessed 28 June 2018

In addition to the GSF-allocated from the state budget (IDR 3 trillion) the Government has sought financial support from the World Bank under the Geothermal Energy Upstream Development Project ("GEUDP"). Similar to the GSF the GEUDP also applies a revolving fund scheme.[116]

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 to finance exploration activities. 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.[117]

The Government has decided that the GSF and the GEUDP funding schemes will be available for several geothermal working areas including Waisano and Inelika in East Nusa Tenggara, and Jailolo in North Maluku.[118] In June 2018 the World Bank indicated that the preparation for infrastructure development and drilling for the first sub-project in Waisano was ongoing. However the Environmental and Social Management Plan (ESMP) and the Abbreviated Land Acquisition and Resettlement Action Plan have yet to be finalised. The other two projects are being considered for drilling depending on the decision of the Project Joint Committee.[119]

Other 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 utility-style economic returns, where 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) including preliminary surveys, exploration and test drilling;
e) The poor quality of data provided on working areas prior to tender rounds;
f) Limited infrastructure (e.g. ports and roads) particularly in rural and remote areas which makes for difficult access and logistics at some sites and which may require the developer to fund infrastructure (e.g. access roads); and
g) Long lead times from exploration to production (generally of seven to eight years).

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 pursuing large projects the approach is less likely to lead to 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 through drilling insurance, direct grants or the use of revolving funds.

116 DGNREEC, http://www.ebtke.esdm.go.id/post/2017/04/18/1629/percepat.pengembangan.panas.bumi.pemerintah.luncurkan.5.upaya.terobosan, accessed 6 December 2017
117 World Bank, http://www.worldbank.org/en/news/press-release/2017/02/09/world-bank-approves-5525-million-grant-to-help-develop-geothermal-power-in-indonesia, accessed 6 December 2017
118 Jawa Pos, "Tugaskan BUMN Garap Panas Bumi", Jawa Pos, 20 April 2017
119 World Bank, http://documents.worldbank.org/curated/en/815851529573453241/pdf/Disclosable-Version-of-the-ISR-Indonesia-Geothermal-Energy-Upstream-Development-Project-P155047-Sequence-No-04.pdf, accessed 28 June 2018

With regard to the geothermal tariff MoEMR 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, provides that the tariffs for renewable energy projects, including geothermal, should follow the Regional BPP as benchmarks or be based on B2B negotiations. Please see *Section 5.9 - New Tariff Stipulations for Renewable Energy* for further discussion.

As per 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 with "proven reserves" after exploration. This obviously raises the risks for geothermal investment noting the following factors:

a) That geothermal projects have long lead times;
b) That BPP values change annually;
c) That this regulation will lead investors to incure capital expenditure without knowing for sure the tariff and commitment of PLN to purchase the electricity.

It is likely that investors can negotiate a Heads of Agreement ("HoA") with PLN, as a preliminary substitute for a PPA, prior to exploration. However, a HoA is not a binding contract meaning it may not effectively mitigate the 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 the most robust and mature of the renewable technologies. Until 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 across the country with substantial potential for large-scale projects in the middle and eastern parts 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 Hydropower Development in Indonesia conducted by Nippon Koei in 2011 found total hydropower potential of 26,321 MW. Based on economic, social and environmental considerations realistically only 8 GW of additional hydropower is likely to be built (i.e. in addition to the existing 10,294 MW of projects in operation, under construction or being planned). The list of prioritised hydropower projects in the 2018 RUPTL is on Table 5.5 as follows:

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
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	Sinamar-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: 2018 RUPTL

5.4.1 Large-scale Hydropower

As part of the 35 GW programme and the regular PLN 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) and Malea (2 x 45 MW). The Power Construction Corporation of China signed a Memorandum of Understanding ("MoU") with PT Indonesian Kayan Hydropower in April 2018 to jointly build five hydropower plants with a total capacity of 9,000 MW and a total investment of USD 17.8 billion in North Kalimantan.[120] Terregra Asia Energy, a company with a focus on hydropower and solar power, also conducted an IPO in May 2017 to increase their capital for land procurement and project development as well as operational capital.[121]

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 the Asahan 3 (2 x 87 MW) project. However, on 2 May 2017 the World Bank cancelled funds worth USD 596 million for the Upper Cisokan pumped-storage plant after the construction was delayed due to the need to agree with the contractor the terms for reconstructing the damaged access road.[122] PLN stated that the funds needed for this USD 800 million project will come from loans and internal funds with the power plant scheduled to reach COD by 2024 or 2025.[123]

There are also construction projects under PLN's regular programme namely Masang 2 (55 MW) and Jatigede (2 x 55 MW). The latter has been delayed for more than 50 years (it was originally planned in 1963) due to disputes over land compensation and the resettlement of local people. The Government only started the first inundation for the Jatigede Dam in August 2015. This will later be augmented with a 2 x 55 MW hydropower system.

Based on the 2018 RUPTL some major hydro projects, such as the Seko-1 (480 MW) and Kaltara-2 (300 MW) projects, as well as the lower priority hydropower candidates in Bonto Batu (100 MW), Kluet-1 (180 MW), and Lasolo (145 MW) have been delayed until after 2027 or included in the list of projects for potential development. The RUPTL 2018 notes that most of the delayed hydropower projects are in Sumatera and Sulawesi although the RUPTL 2018 also mentions the need to add 400 MW of hydropower projects in Sulawesi in order to meet the energy mix target in 2025.[124]

The Ministry of Public Works and People's Housing (the "MoPW") reported its intention to incentivise the private sector to utilise existing dams for hydropower. This targets 18 dams operated by the MoPW including those at Jatigede (West Java), Lodoyo (East Java), Berjaya (Riau), and Jatibarang (Central Java). Together with PLN the MoPW would like to calculate the potential electricity generation from the 18 dams. In May 2017, the MoPW issued MoPW Regulation No. 9/PRT/M/2017 concerning 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). This requires hydropower and solar power business entities to follow pre-qualification and selection processes should they need to lease infrastructure relating to water resources.

120 The Jakarta Post, http://www.thejakartapost.com/news/2018/04/19/powerchina-to-build-hydropower-plants-for-17-8-billion.html, accessed 10 June 2018
121 Metro TV, http://ekonomi.metrotvnews.com/bursa/JKRynx3k-resmi-ipo-saham-terregra-asia-energy-naik-60-poin, accessed 10 June 2018
122 World Bank. World Bank Implementation Status & Results Report on Upper Cisokan PST Project (P112158), 2017
123 The Jakarta Post, http://www.thejakartapost.com/news/2018/06/13/cisokan-hydropower-plant-project-needs-800m-in-investment.html, accessed 1 August 2018
124 2018 RUPTL, p. V-1 to V-11

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 the historical issuance of water permits by regional/local Governments;
c) Environmental, resettlement and flora and fauna issues; and
d) Permits for forest use.

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 Stipulations 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 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 can become attractive renewable energy projects for investors.[125] SHP uses mature technology compared to some other small-scale renewables.

In May 2017, the state-owned construction company PT Brantas Abipraya (Persero) officially launched the commercial operation of a 3.2 MW Padang Guci SHP located in Bengkulu. Separately, in Sumatera PLN signed a PPA with PT Dwi Jaya Makmur for an SHP project of PLTM Semendo for 9 MW and 23 Memoranda of Understanding ("MoUs") for SHP project developments in Sumatera totalling 150 MW.[126]

On 2 August and 8 September 2017, PLN signed PPAs for 50 SHP projects totalling 292 MW. However, 38 PPAs have reported difficulties in financing with PLN reportedly being ready to cancel the PPAs if financial closing was not reached within 12 months of the PPAs being signed. To help resolve the issue the MoEMR is reported to be lobbying *Otoritas Jasa Keuangan* (the Financial Services Authority – "OJK") to facilitate these PPAs through a green financing program that requires banking institutions to support the funding of renewable energy.[127] However, industry associations report that financing difficulties have arisen due to the "unbankability" of the PPAs and associated commercial issues.

Prequalifications for hydro projects, in accordance to MoEMR Regulation No. 50/2017, were held in April 2018 during which PLN stated that interested parties must show that they have a feasibility study and foreign interested parties must be partnered with a local developer.[128] The results regarding which hydropower developers have passed the pre-qualification in order to be included on the list of PLN's selected providers was unavailable at the time of writing.

125 DGNREEC, http://ebtke.esdm.go.id/post/2016/01/08/1077/175.permohonan.pembangunan.pltmh.dengan.investasi.rp1094.triliun, accessed 6 December 2017

126 Detik, https://finance.detik.com/energi/d-3505816/pln-teken-kerja-sama-pengadaan-listrik-sumatera-283-mw, accessed 6 December 2017

127 Katadata, https://katadata.co.id/berita/2018/04/27/kementerian-esdm-lobi-ojk-fasilitasi-pendanaan-energi-terbarukan, accessed 1 August 2018

128 GBG Indonesia, http://www.gbgindonesia.com/en/main/legal_updates/indonesia_s_pln_invites_hydropower_developers_to_prequalify.php, accessed 2 July 2018

Further challenges to 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 limitations on foreign investment with micro power plants (<1 MW) closed for foreign investment and small power plants (1– 10 MW) open for foreign ownership of up to only 49%;
b) The need to invest in transmission lines from the SHP site to the interconnection point if existing 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 SHPs, generally will not have a take-or pay provisions meaning also that off-take risk is 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 and is likely to require substantial collateral from the Sponsors;
e) The quality of hydrological data;
f) The unclear status of water concessions/permits held by private companies;
g) The 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.

5.5 Bioenergy

Bioenergy refers to energy produced from biomass or biogas to generate electricity and heat or to produce liquid fuels (e.g. biodiesel or bioethanol) for transport use. Biomass is organic matter derived from recently living plants or animals and includes agricultural products, forestry products, municipal and other waste. Biogas refers to the gases that are produced from 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 essentially two processes for generating electricity being biological and thermal. The biological process uses anaerobic digestion technology where feedstock is decomposed by microorganisms to produce methane (CH_4) gas (biogas) that is combusted for power generation. This process requires feedstock with a high organic content (e.g. POME, vegetables, food or agro waste). Alternatively the thermal process mainly uses technologies of incineration or gasification. Incineration technology requires a high calorific value and low moisture (dry) content feedstock (e.g. paper, plastics, wood, textiles, etc.) which are commonly shredded or pelletised. The feedstock is combusted to provide heat that flows to a boiler producing steam that is used to turn the turbine and generate electricity. Meanwhile, gasification feedstock is subject to partial combustion in the event of a limited supply of oxygen so as to produce synthetic natural gas ("syngas") that is used to generate electricity.

Based on several estimates the potential of bioenergy in Indonesia is estimated to be 32.6 GW with 1.8 GW of currently installed capacity (Table 5.7).[129] Most of this capacity is off-grid. To date the capacity of bioenergy power plants connected to PLN's electricity grid is only around 131.4 MW (see Table 5.8). Upon the inauguration of the Asian Agri POME Biogas Plant in early 2016 the DGNREEC indicated that by 2018 the Government would oblige companies to utilise any associated waste for power generation. The intent is to encourage the conversion of waste-to-energy but with the additional benefit of avoiding the release of climate change-causing methane gas. The Government plans further growth in biogas and biomass plants albeit being more private-sector driven. This will help support 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
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

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
2	PT Listrindo Kencana	2006	IPP	Bangka	Palm Waste	5
3	PT Growth Sumatera 1	2006	Excess Power	North Sumatera	Palm Waste	9
4	PT Indah Kiat Pulp & Paper	2006	Excess Power	Riau	Palm Waste	3
5	PT Belitung Energy	2010	IPP	Belitung	Palm Waste	7
6	PT Growth Sumatera 2	2010	Excess Power	North Sumatera	Palm Waste	10
7	PT Navigat Organic	2011	IPP	Bali	MSW	2
8	PT Navigat Organic	2011	IPP	Bekasi	MSW	12
9	PT Growth Asia	2012	Excess Power	North Sumatera	Palm Waste	10
10	PT Navigat Organic	2012	IPP	Bekasi	MSW	2
11	Harkat Sejahtera	2013	Excess Power	North Sumatera	Palm Waste	10
12	Rimba Palma	2013	Excess Power	Jambi	Palm Waste	10
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

129 RENSTRA EBTKE 2015-2019, p. 36

No.	Company	COD	Type of Contract	Location	Type of Bioenergy	Contract (MW)
16	Sumber Organik	2015	IPP	Surabaya	MSW	1.6
17	Meskom Agro Sarimas	2015	Excess Power	Riau	Palm Waste	10
18	Maju Aneka Sawit	2015	Excess Power	South Kalimantan	POME	1
19	Sukajadi Sawit	2015	Excess Power	South Kalimantan	POME	2.4
20	Mutiara Bunda	2015	Excess Power	South Sumatera	POME	2
21	Sampurna	2016	Excess Power	South Sumatera	POME	2
22	PT Riau Prima Energy	2016	Excess Power	Riau	Biomass	15
23	PTPN III	2016	Excess Power	North Sumatera	Palm Waste	1.8
24	Siringo-ringo	2016	Excess Power	North Sumatera	POME	1
					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 the Sei Mangkei Special Economic Zone, North Sumatera which has biogas-to-electricity potential of 1.6 MW including a tenant as the off-taker. This facility is targeted to reach COD before 2020.

In August 2017, PLN signed four biomass and five biogas PPAs ≤ 10 MW following the 19 MoUs for bioenergy power plants signed in March 2017 and a PPA for a 9 MW biogas power plant signed with PT Mitra Puding Mas in May 2017. Five of the PPAs signed are reported to have encountered difficulties in financing with one reported to have reached COD.[130] A 2.2 MW biogas power plant also reached COD in January 2018 with 700 kW used for self-consumption by PT Inti Indosawit Subur.[131] A 700 kW bamboo-based biomass power plant is expected to reach COD in September in Mentawai, West Sumatera.[132]

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) Various permits and licensing issues (e.g. land, water, environmental) and clarity at the regional level on the associated fees and processes;
e) The availability of regional EPC contractors with relevant experience and skills; and
f) The availability of spare parts and after-sales service.

5.5.1 Municipal Waste-to-Energy

Noting the increase in waste, the limited waste treatment capacity and the stresses on most landfill facility areas "municipal waste-to-energy" is being looked at as a solution for waste management which remains a significant problem in many cities in Indonesia. Similar to bioenergy, the feedstock used is municipal waste. However, in the Indonesian context the application of these technologies is not straightforward. The waste produced in Indonesia is typically mixed and unsorted with organic and non-organic waste as well wet and dry garbage. Additional effort is needed to manage this. Unsorted waste can be fed directly into an incinerator but the high moisture content reduces the thermal efficiency needed for complete combustion. The potential of municipal solid waste for the production of electricity in selected cities/ regencies in Indonesia is set out in Table 5.9.

Table 5.9 – 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

130 Gatra, https://www.gatra.com/rubrik/ekonomi/324345-Asosiasi-Listrik:-Pemerintah-tidak-punya-visi-bangun-energi-efisien, accessed 25 June 2018
131 Kompas, https://ekonomi.kompas.com/read/2018/01/24/111024626/menteri-esdm-resmikan-pembangkit-listrik-tenaga-biogas-di-tungkal-ulu, accessed 19 July 2018
132 Metro TV, http://news.metrotvnews.com/read/2018/06/30/895083/bambu-di-mentawai-dapat-alirkan-listrik-untuk-ribuan-rumah, accessed 1 August 2018

Province	Municipal Waste Availability (Tonne/Year)	Total Techno-Eco Potential (MW)
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	13.1
Bali	370,752	23.65
NTB	148,543	8.87
East Java	1,237,010	77.89
NTT	15,046	0.9
North Sulawesi	66,704	3.99
Gorontalo	16,973	1.01
South Sulawesi	182,500	11.9
West Papua	10,494	0.63
Total	**8,707,437**	**535.72**

Source: 2016 EBTKE Statistics

The Government has continued efforts to develop municipal waste-to-energy to overcome the city waste problem and to provide clean energy. The Strategic Plan of the MoEMR focuses on the construction of municipal waste-to-energy power plants funded by the State budget. With this in mind on 16 April 2018 President Joko Widodo issued PR No. 35/2018 on The Acceleration of Municipal Waste-to-Energy Power Plant Development and revoked the previous PR No. 18/2016. The Government named twelve cities for pilot projects of thermal municipal waste-to-energy development being Jakarta, Bandung, Tangerang, Semarang, Surabaya, Solo, Makassar, South Tangerang, Bekasi, Denpasar, Palembang and Manado. PR No. 35/2018 also regulates the feed-in tariff for municipal waste-to-energy power plants so as to provide certainty on revenue from the sale of electricity. Where a plant produces less than 20 MW the project will receive USD 13.35 cent/kWh. Higher capacity waste power plants that are connected to a high or medium voltage grid will receive USD 14.54 cent/kWh reduced by 0.076 and multiplied by the capacity of the power plant. If a subsidy from the Central Government is required the subsidy is capped at IDR 500,000 per ton of waste. The subsidy from the Central Government must be proposed by the Minister of Environment and Forestry to the Minister of Finance in accordance with the relevant regulations.

In its implementation, the President instructed the regional mayors to assign regionally-owned enterprises, or to appoint private business entities, in order to undertake the project development. This regulation also obliges PT PLN to sign PPAs for the aforementioned 12 municipal waste-to-energy projects. However, negative sentiment regarding technological challenges (e.g. selection of incineration technology) and concerns over environmental pollution remain. The previously issued PR No. 18/2016 was challenged by a number of environmental activists in the Supreme Court in early 2017 which consequently revoked the regulation. However, the Government continued to develop the municipal waste-to-energy plan despite the court ruling. The Government believes this is the most effective way to solve the waste problem in big cities in Indonesia.[133] A similar problem is seen in PR No. 35/2018 with non-governmental organisations highlighting issues regarding the unclear standards involving environment-friendly technology, high capital, O&M expenditure and the potential influence on general health and the environment.[134]

Table 5.10 – Status of Waste-to-Energy projects - July 2018

City	Status
Jakarta	Contract award negotiations
Tangerang	Tender preparation
Bandung (West Java)	Tender preparation
Semarang	Pre-feasibility study development
Solo	Approval procedure for tipping fee and PPA
Surabaya	Gas landfill construction
Makassar	Pre-feasibility study development
Denpasar	Pre-feasibility study development
Palembang	Under discussion of tipping fee

Source: PwC Analysis

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

a) Delays in securing the PPA (PT PLN) and off-take arrangements for electricity from the processing of MSW;
b) The insufficiency of feed-in tariffs for MSW WTE projects and the uncertainty of funding commitments from the Provincial/Municipal Governments;
c) Concerns from Regional Governments over the management of and responsibility for the implementation of waste-to-energy plants due to a lack of experience at the Regional Government level regarding waste-to-energy and a lack of knowledge of power purchase mechanisms;
d) The negative sentiment from the local community over public health and safety issues;
e) The socio-economic concerns over the livelihoods of 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 recent PR No. 35/2018 also set new tariffs for municipal waste-to-energy projects. Please see *Section 5.9 - New Tariff Stipulations for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

133 The Jakarta Post, 17 January 2017, “Govt sticks with incinerator plan despite court ruling
134 WALHI, https://walhi.or.id/perpres-no-35-2018-tentang-pltsa-pemaksaan-teknologi-mahal-dan-tidak-berkelanjutan/, accessed 1 August 2018

5.6 Solar PV

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

With an average daily insolation of approximately 4.8kWh/m^2 [135] Indonesia is estimated to have around 208 GWp for solar power-based electricity.[136] The level of insolation varies across the Indonesian archipelago (see Table 5.11) but is regarded as offering good potential by international standards and to represent a viable source of power for remote areas or island locations that are off-grid.

Table 5.11 – Solar energy potential in Indonesia

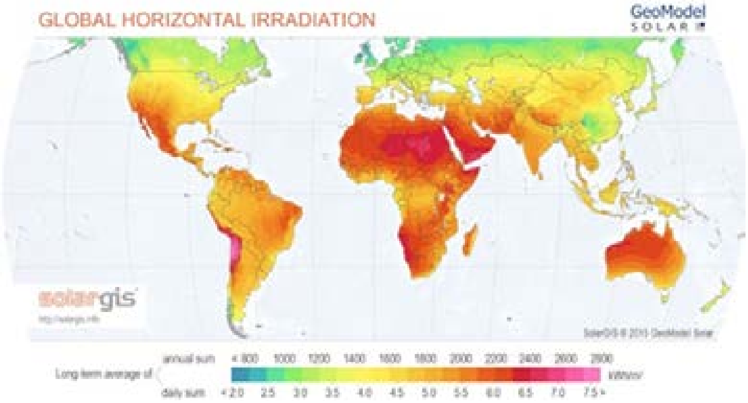
No.	Regency/City Location	Province	Geographic Position	Average Irradiation (kWh/m2/day)
1	Banda Aceh	Nanggroe Aceh Darussalam	4°15'N;96 °52'E	4.10
2	Palembang	South Sumatera	3°10'S;104°42'E	4.95
3	Menggala	Lampung	4°28'S; 105°17' E	5.23
4	Jakarta	DKI Jakarta	6°11'S;106°SE	4.19
5	Bandung	West Java	6°56'S;107°38'E	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 EBTKE Statistics

135 2014 EBKTE Statistics, p. 82
136 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 installed solar capacity was about 109 MW [137] with the dominant portion being off-grid. PLN plans to develop centralised or concentrated solar PV farms in hybrid mode with other electricity generation sources being adjusted to each region including diesel power plants.[138] Indonesia had previously planned to increase 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
Construction of solar power plants (MW)	9.8	15.2	26.5	61.4	80.3
- Solar non-state budget (MW)	-	5	15	50	70
- Solar state budget - MoEMR (MW)	2.8	3	4	3.5	2
- Solar special allocation fund (MW)	7	7.2	7.5	7.9	8.3
Installed capacity – end of year (MW)	76.9	92.1	118.6	180	260.3

Source: RENSTRA KESDM 2015-2019

In April 2017, President Joko Widodo released PR No. 47/2017 on the 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. PR No. 47/2017 is implemented through MoEMR Regulation No. 33/2017 (as amended by MoEMR Regulation No. 5/2018) on Guidelines for Energy Saving Solar Lamp Provisions for Unelectrified Communities. The intended beneficiaries are communities not connected to traditional electricity supplies and who are situated in border, lagging or isolated areas, and/or outer islands. These programmes also represent a means of allocating funding from the reduction in the electricity subsidy so as to help ensure equality of energy access across Indonesia.[139]

137 Rida Mulyana (DGNREEEC), “Utilisation of Renewable Energy”, Presentation at the PetroGas Days UI, 16 March 2017 in the PetroGas Days UI and LAKIN EBTKE 2017
138 2018 RUPTL, p. III-14
139 MoEMR, https://www.esdm.go.id/id/media-center/arsip-berita/permen-esdm-nomor-38-tahun-2016-upaya-pemenuhan-kelistrikan-daerah-terpencil, accessed 6 December 2017

In September 2017, *Gerakan Nasional Sejuta Listrik Surya Atap* (the Solar Rooftop Electricity National Movement) declared a target of 1 GWp of installed rooftop solar PV capacity before 2020. This movement aims to develop a competitive PV industry, to increase public participation in reducing both greenhouse gases and the threat of climate change, and to accelerate the construction of PV on the rooftops of residential areas, public facilities, government offices, commercial buildings and industrial areas.[140]

In November 2017, Masdar signed a project development agreement with PT PJB for the Cirata 200 MW floating solar PV power plant.[141] PT PLN also signed two letters of intents ("LoI") to build solar farms in Bali. A consortium of Equis Energy Indonesia (now Vena Energy)[142] and PT Infrastruktur Terbarukan Fortuna will work on the Bali-1 50 MW solar farm in Kubu Regency while Akuo Energy Indonesia Ltd. will work on the Bali-2 50 MW solar farm in Jembrana Regency. Each project is valued at USD 91.6 million.[143] However, it has been reported that the letters of intent have been cancelled and the projects are being re-tendered. The 168 MW of solar PV projects in Sumatera also show no signs of progressing beyond pre-qualification as the administrative documents for the tender was still uncompleted in May 2018.[144]

Of the five PPAs and six MoUs signed in 2017, the Jakabaring PV project reached COD in June 2018 to support an Asian Games venue.[145] In May 2018, the Asian Development Bank announced financing for the PV projects of Equis (in consortium with PT Infrastruktur Terbarukan Fortuna) being one 21 MW Solar PV Power Plant in North Sulawesi and three 7 MW Solar PV Power Plant in Lombok.[146] The 10 MW Solar PV project in Gorontalo by PT Quantum Energi also entered construction in 2018 and is expected to reach COD before the end of the year. Some players are attempting to hybridise Solar PV with other energy sources. This includes PT Sumberdaya Sewatama which is currently developing 150 MW of hybrid power plants from solar energy combined with diesel or gas in multiple locations after an MoU was signed in 2017.

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 ideally 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;
d) Access to human resources/expertise with experience in Solar PV technology compounded by stringent local content requirements (see *Section 2.2.3 - Local Content*);
e) Limited technical experience within PLN's teams in relation to understanding the implications of solar deployment for grid stability and how to manage risks.

140 DGNREEC, http://ebtke.esdm.go.id/post/2017/09/14/1747/gerakan.nasional.sejuta.surya.atap.menuju.gigawatt.fotovoltaik.di.indonesia, accessed 7 August 2018
141 Masdar, http://www.masdar.ae/en/media/detail/pt-pembangkitan-jawa-bali-and-masdar-sign-pda-for-200mw-floating-solar-pv-p, accessed 11 June 2018
142 https://www.dealstreetasia.com/stories/after-acquisition-by-gip-equis-energy-rebrands-to-vena-energy-97156/, accessed 8 August 2018
143 Media Indonesia, http://mediaindonesia.com/read/detail/136030-pln-gandeng-prancis-bangun-pembangkit-tenaga-angin-senilai-rp4-53-triliun, accessed 28 June 2018
144 Bisnis.com, http://sumatra.bisnis.com/read/20180515/451/794974/energi-baru-terbarukan-lelang-plts-tunggu-dokumen-administrasi, accessed 20 July 2018
145 Tempo, https://tekno.tempo.co/read/1102540/asian-games-plts-2-mw-beroperasi-di-jakabaring, accessed 1 August 2018
146 Asian Development Bank, https://www.adb.org/news/adb-finances-first-ever-utility-scale-solar-pv-plants-indonesia-160-million-renewables-deal, accessed 8 August 2018

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 Stipulations 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 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 resource assessments and research for 153 sites is as follows (see Table 5.12):

Table 5.12 – 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 indicate that wind potential in Indonesia is as high as 61 GW.[147] However, the Asian Development Bank has wind potential figures for Indonesia that might be no higher than 9.3 GW.[148] It should also be noted that the areas in Indonesia with the most wind (i.e. Eastern Indonesia) are also the least populated and have limited transmission infrastructure. Recently, in collaboration with the MoEMR, the Danish Embassy in Indonesia through its Environmental Support Program funded the development of a wind map across Indonesia. The 3 km resolution wind map is now accessible to the public (http://indonesia.windprospecting.com/).

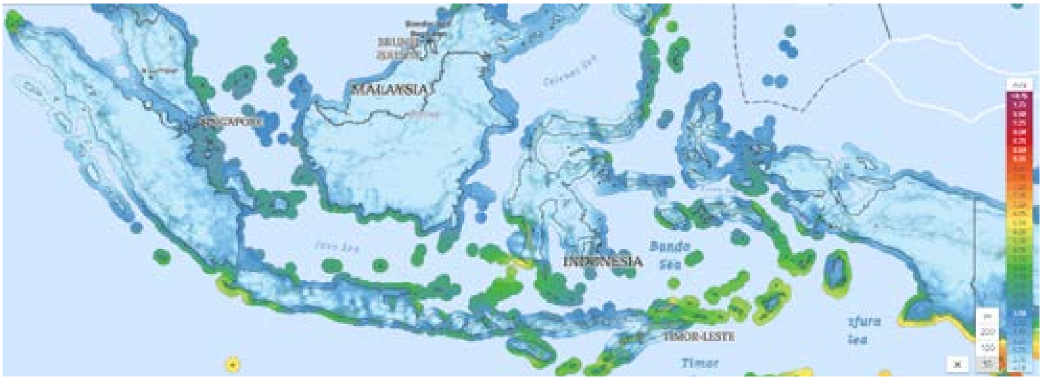
147 Rida Mulyana (Director General of DGNREEC), "Utilisation of Renewable Energy", presentation at the PetroGas Days UI, 16 March 2017

148 Asia Development Bank 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

Figure 5.6 – Indonesia wind power density in height of 50 meters

Source: Global wind atlas, accessed 31 August 2018

Figure 5.7 – Indonesia wind speed in height of 50 meters



Source: Global wind atlas, accessed 31 August 2018

The locations showing the greatest 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

The planned development of wind energy by the MoEMR is modest when compared to a number of private-sector developments. This is shown in the Government's plan for 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 including operational efficiency and the wide and established utilisation in other countries have nevertheless attracted interest in Indonesian wind energy investment.

Additionally, an initial study by the Agency for Assessment and Application of Technology (BPPT)-Wind Hybrid Power Generation (WHyPGen) in Java and Sulawesi indicated wind energy potential of around 970 MW distributed across the following locations including the Sidrap and Jeneponto projects that are currently being developed (see Table 5.13):

Table 5.13 – BPPT and WHyPGen wind energy assessment studies in Java and Sulawesi

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

Source: BPPT-WHyPGen

The total installed wind farm capacity in mid-2018 was around 77.4 MW including the recently commissioned 75-MW Sidrap wind farm owned by UPC Renewables.[149] Aside from the Sidrap wind farm UPC Renewables signed a Memorandum of Understanding ("MoU") with PLN in March 2017 to develop a hybrid power plant consisting of wind and Solar PV/small hydropower in Maluku's Selayar Island.[150] The operational Sidrap wind farm has itself far exceeded the Government's plan in RENSTRA KESDM 2015-2019.

Another wind farm is currently being developed by Equis Energy (now Vena Energy) in Jeneponto, South Sulawesi and is expected to follow the Sidrap wind farm in reaching COD this year. The consortium of PACE Energy and PT Juvisk Tri Swarna signed an LoI with PLN in December 2017 to develop a 70 MW wind farm in Tanah Laut, South Kalimantan along with Akuo Energy Indonesia Ltd. and the consortium of Equis Energy Indonesia.[151] However, this LoI has been cancelled and the project is being re-tendered.

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;
c) Concerns over the 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 need for imports of overseas equipment manufactured;
g) The need for greater collaboration between all stakeholders including the Government, PLN and investors; and
h) The limited technical experience within PLN's team in relation to understanding the implications of wind deployment on 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 Stipulations for Renewable Energy* for an explanation of the new tariff stipulations and mechanism.

149 UPC Renewables, http://www.upcrenewables.com/konsorsium-bayu-energi-siap-bangun-pltb-sidrap-fase-ii/, accessed 11 June 2018
150 Detik, https://finance.detik.com/energi/d-3459737/pln-teken-10-kontrak-energi-terbarukan, accessed 9 December 2017
151 Media Indonesia, http://mediaindonesia.com/read/detail/136030-pln-gandeng-prancis-bangun-pembangkit-tenaga-angin-senilai-rp4-53-triliun, accessed 28 June 2018

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 and 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 this 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 the coastal straits.[152] As an archipelagic state consisting of islands and straits the potential of ocean energy in Indonesia is thought to be 17.9 GW.[153] Studies carried out by the MoEMR with foreign donors have identified that the areas with most potential are Kelang in Maluku (500 MW), the Alas Strait (9 MW) and the Larantuka Strait (3 MW). However, especially for Kelang local demand is very low meaning that only 3.2 MW could probably be developed.[154]

In 2015, the MoEMR indicated that Indonesia would encourage the use of the energy potential of the sea as part of the Government's marine development policy.[155] The MoEMR's plan is that 1 MW of ocean energy pilot plants should be ready by 2019.[156]

SBS International Ltd. has also attempted to harvest power from the ocean with its Nautilus tidal-stream project which started in 2013. This project is designed to deliver 150 MW of power in 3 phases. As of July 2018, this project had finished its feasibility study and was in pre-PPA development stage. An MoU with PT Indonesia Power was signed in January 2018.

It was also reported that the Indonesian and Dutch Government will work together to develop tidal energy in the Larantuka strait. In April 2018, a feasibility study was conducted for this project and involved an 810-meter Pancasila-Palmerah bridge connecting Flores, Adonara Island and East Nusa Tenggara with turbines installed under the bridge to generate electricity from ocean currents.[157] This sea current turbine power plant capacity is expected to reach 30 MW. An MoU with PLN was signed in February 2018. The project will be developed to accommodate 90 to 115 MW of installed capacity for the second phase.[158] The project was awarded to Tidal Bridge Indonesia – a joint venture between the construction engineering company Strukton International, private equity firm Dutch Expansion Capital, and PT PJB. The shares of Strukton in Tidal Bridge BV were transferred in May 2018 to BAM International BV, a Dutch construction engineering company.[159]

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152 DGNREEC, http://ebtke.esdm.go.id/post/2016/04/14/1188/potensi.energi.laut.indonesia.menjanjikan, accessed 11 June 2018
153 Rida Mulyana (Director General of DGNREEC), "Utilisation of Renewable Energy", presentation at the PetroGas Days UI, 16 March 2017
154 Agence Française de Développement. Tidal Energy Project in Indonesia., January 2017
155 The Jakarta Post, "Govt looks to ocean wave power plants", 3 June 2015
156 RENSTRA KESDM 2015-2019, p. 137
157 DGNREEC, http://ebtke.esdm.go.id/post/2018/04/02/1924/menteri.esdm.tinjau.lokasi.pembangunan.pembangkit.listrik.arus.laut.di.selat.larantuka, accessed 11 June 2018
158 Rambu Energy, https://www.rambuenergy.com/2018/04/indonesia-to-build-world-first-tidal-bridge-in-larantuka-east-flores/, accessed 29 June 2018
159 Bam, https://www.bam.com/en/press/press-releases/2018/5/bam-announces-acquisition-of-struktons-share-in-tidal-bridge-from, accessed 1 August 2018

Wello Oy, a Finland-based wave energy converter also announced that it will provide a 10 MW marine and hydrokinetic energy park at Nusa Penida Island, Bali following a request of Gapura Energi Utama. Delivery is expected to take place after the permitting process is finalised at the end of 2018.[160]

An Indonesian Ocean Energy Association also exists and in 2013 a draft road map for ocean energy regulation was released. 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. 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) The geographical distances including the logistics of locations and the absence of infrastructure; and
c) The need to better understand 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.

5.9 New Tariff Stipulations for Renewable Energy

In late January 2017, the MoEMR issued MoEMR Regulation No. 12/2017 on the Utilisation of Renewable Energy Resources for Electricity. The regulation was amended by MoEMR Regulation No. 43/2017 in July 2017 which changed some points regarding 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 via MoEMR Regulation No. 50/2017.

MoEMR Regulation No. 50/2017 provides new mechanisms for determining 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 of a PPA which reimburses investors for transmission line spending from the power plant to the PLN grid is to be conducted through B2B negotiations between PLN and IPPs. The key features of MoEMR Regulation No. 50/2017 (Table 5.14) are as follows:

160 https://www.hydroworld.com/articles/2018/01/indonesia-continues-marine-and-hydrokinetic-energy-development-with-10-mw-park-in-bali.html, accessed 22 June 2018

Table 5.14 – Salient features and explanation of MoEMR Regulation No. 50/2017

Items	Description	Ref.
Key Features	• 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. • 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	• Covers hydro that is based on waterflow/fall or on the utilisation of a multi-purpose dam/irrigation channels. • 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 and Biogas	• Biomass and biogas projects can only be with IPPs that have sufficient feedstock for the entire operational period and must be conducted through the direct selection mechanism.	Articles 8, 9
Municipal Waste-to-Energy	• Municipal waste-to-energy technologies include: a) Sanitary landfill; b) Anaerobic digestion; and c) Thermochemical technology. • IPPs may receive additional facilities and incentives according to current Laws and Regulations.	Article 10
Geothermal	• The purchase of electricity from geothermal sources must be with IPPs that have working areas with "proven reserves" after exploration.	Article 11
Tariff for Renewable Electricity	• The tariff 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 see Table 5.19 below.	Articles 5, 6, 7, 8, 9, 10, 11,12
BOOT	• The BOOT scheme is applied to all projects except waste-to-energy.	Articles 7, 11
Local Components	• 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; and c) Provide standard documents on the procurement and the PPA model. • The IPP selected on a renewable energy project is obligated to complete construction in accordance with the PPA. Any delay in construction is subject to sanctions and/or penalties as set out in the PPA.	Articles 14, 16, 17, 18
Transitional Provisions	• IPPs working on renewables projects with signed PPAs must comply with the existing PPAs. • IPPs that have not signed PPAs shall comply with MoEMR Regulation No. 50/2017. • IPPs appointed as geothermal tender winners, and SoEs that have been assigned for geothermal development, shall comply with the previous Regulation No. 17/2014. • IPPs that have obtained tariff approval from the Minister based on MoEMR Regulation No. 12/2017 (as amended by MoMR Regulation No. 43/2017), but have not yet signed PPAs, shall comply with MoEMR Regulation No. 12/2017. • The ongoing Solar PV quota capacity tender shall continue and must comply with MoEMR Regulation No. 50/2017.	Articles 19, 20, 21, 22, 23, 24

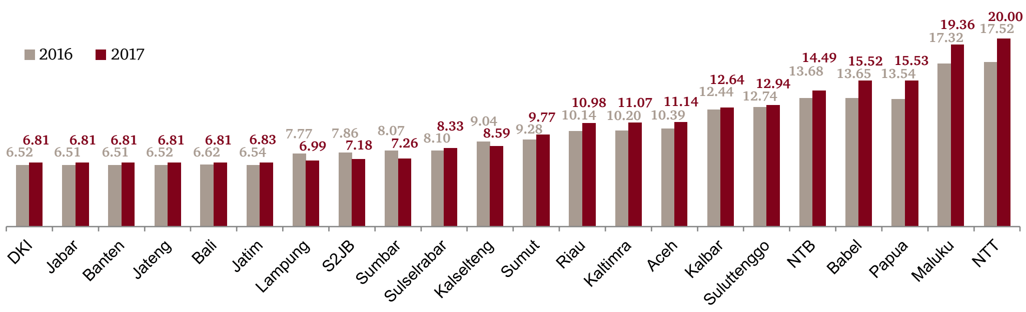
Table 5.15. – Tariff stipulation based on MoEMR Regulation No. 50/2017

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

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

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 the 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. However, based on PR No. 35/2018, specific to waste-to-energy, local government can assign developers from the regional-state-owned-enterprises (Badan Usaha Milik Daerah - "BUMD") or hold an open tender for private sector. Should the private sector is not interested and the BUMD is considered incapable, the Minister of Energy and Mineral Resources can assign the waste-to-energy power plant to a state-owned enterprise based on the recommendation from the local government.*

The new regulation represents a move back to 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 to them that their target tariff will change due to BPP updates (perhaps even annually, as shown by the difference of BPP in 2016 and 2017 below).



Source: MoEMR Regulation no. 1772 K/20/MEM/2018

For Solar PV, wind, biomass, biogas and ocean energy where the Regional BPP exceeds the National BPP then the maximum benchmark tariffs are 85% of Regional BPP. B2B tariffs will be used in the event that the Regional BPP is less than or equal to National BPP.

For hydropower, geothermal and municipal waste-to-energy where the Regional BPP exceeds the National BPP then the maximum benchmark tariff is the Regional BPP. For Sumatera, Java and Bali or other places where the Regional BPP is less than or equal to the National BPP the tariff shall be conducted based on B2B negotiations between IPPs and PLN. This raises questions regarding projects located in Sumatera, Java or Bali which have a Regional BPP exceeding the National BPP (e.g. North Sumatera where the Regional BPP is USD 9.77 cents/kWh). The MoEMR appeared to prioritise certain regions over the Regional BPP. For example, the price for North Sumatera shall be based on B2B negotiations rather than benchmarking against the Regional BPP (see Table 5.15).

The recently issued PR No. 35/2018 stipulates a separate price of electricity from waste-to-energy power plants while MoEMR Regulation No. 50/2017 also stipulates tariffs based on either BPP or B2B negotiations.[161] It remains untested as to whether PLN will accept tariffs based on PR No. 35/2018 which are higher than those in MoEMR Regulation No. 50/2017.

These provisions arguably provide an incentive for PLN to sign PPAs and provides clear pricing benchmarks (at least in the case where Regional BPP exceeds the National BPP). However, compared to the previous regulations (i.e. MoEMR Regulation No. 19/2015, No. 19/2016, and No. 21/2016 which all were revoked by MoEMR Regulation No. 9/2018) the new tariffs are generally lower and so are likely to lead to a decrease in investment returns. In cases 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 developments. Mandating that tariff negotiations can only be conducted for projects only with “proven reserves” (i.e. 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*).

161 DGE, “Principles of Regulation Nos. 45/2017, 49/2017, and 50/2017”, Coffee Morning Session with DGE, 10 August 2017

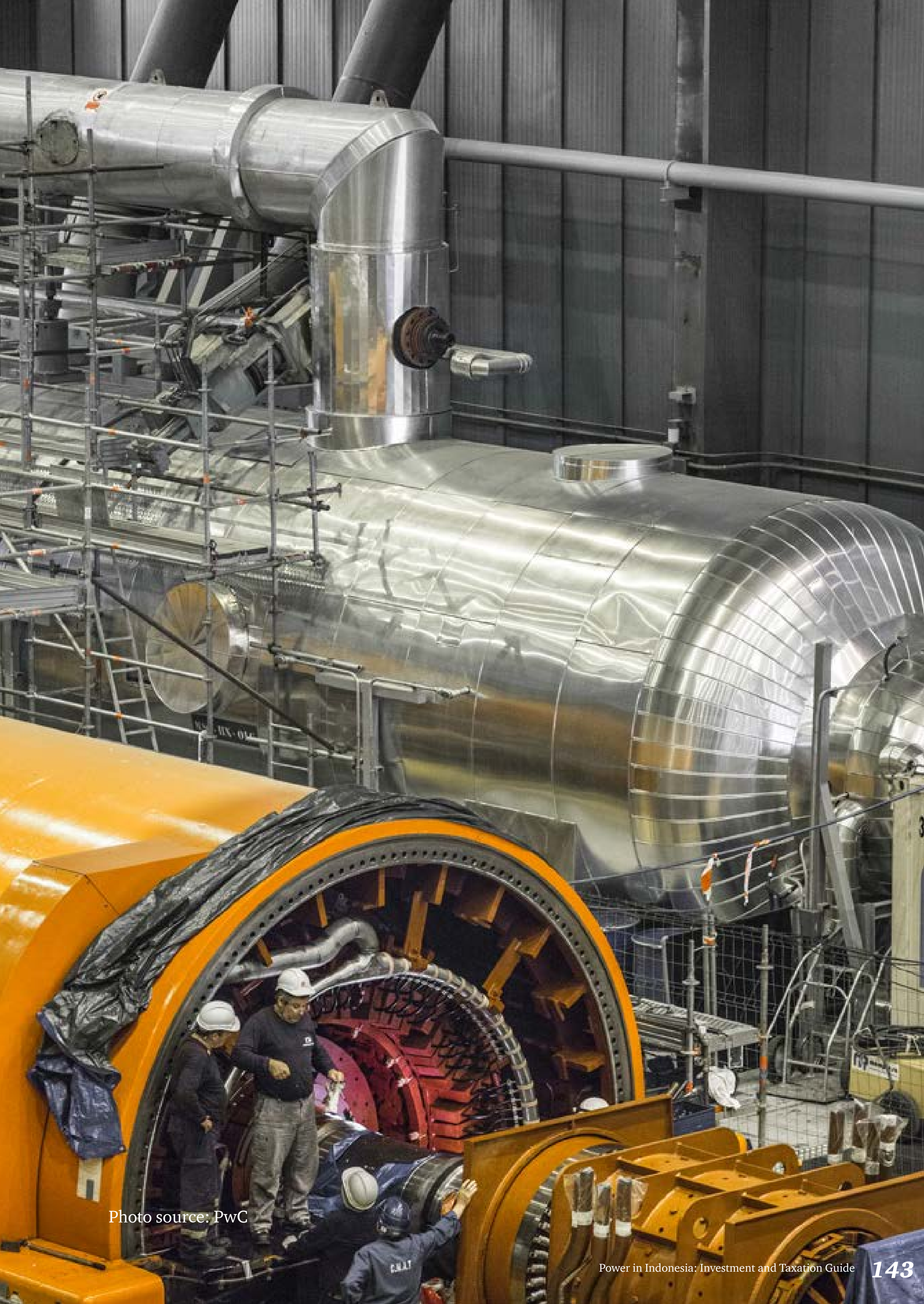


Photo source: PwC

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 sector 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.

Photo source: PwC

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 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) Uncertain 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.

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 either 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 is 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 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 due to 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 for purchasing, installing and constructing an asset. This generally extends to interest incurred during the construction period where that interest is construction-related.

Photo source: PT Adaro Power

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 the 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. Assets attached to the ground and which cannot be moved without being dismantled are generally treated as buildings. Uncertainty can exist in regard to 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. MoF 169 provides an exemption from the DER rules for certain industries, including for those involved in "infrastructure", albeit without an "infrastructure" definition. Formal implementing regulations on the DER were issued in late 2017 but still did not clarify which industries were considered to be infrastructure.

   The tax authorities nevertheless seem to be of the view that "infrastructure" should follow the definition set out in Presidential Regulation No. 38/2015 pertaining to public-private partnerships. This definition extends to IPP activity. Further, in 2018, the revised "tax holiday" rules (see Section 6.4.4 below) included "economic infrastructure" as an industry that would be eligible for the incentive. A related BKPM regulation indicated that power infrastructure should be covered by this definition.

g) *Payments of non-cash employment benefits*: see 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%).

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.

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 entitlement (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 that are 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. 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 any "founder" shareholders must also pay tax at 0.5% of the market price of their shares upon listing. If not paid, founders are taxed on any gains arising upon subsequent sales under the normal tax 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. This is provided that such a person 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 (including expatriates).

The Social Security Agency or *Badan Penyelenggara Jaminan Sosial* ("BPJS") scheme replaced the former Jamsostek scheme (which generally did not apply to expatriates) from 1 January and July 2015 for local employees and expatriates.

Photo source: PT UPC Sidrap Bayu Energi

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; b) Old age savings; c) Death insurance; d) Pension.	0.24% - 1.74% 3.70% 0.30% 2.00%	 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%

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.

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 (including 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).

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. 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 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 from 1 January 2016, VAT registration was made mandatory for IPPs even though electricity supplies remained VAT-exempt. As a result, IPPs are required to issue VAT invoices on their electricity deliveries with the VAT invoices stamped 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 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).

Photo source: PwC

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 private vehicles and above	
			0.5% – 1% for public vehicles	
			0.1% – 0.2% for 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 title transfer or above	
			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 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 the extent to which the tax arrangements might be ultimately impacted by the introduction of ISAK 8 or ISAK 16. See discussion of Accounting Consideration in *Section 7.1 - Accounting for Conventional Power Generation* for further detail.

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 for 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 (noting that the 4:1 DER would be unlikely to apply-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% of the 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 the 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. The JoC 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 results in an "assume to discharge" position for the Contractor in relation to other tax obligations. This includes with respect to 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 the 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 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) which provides Income Tax incentives as follows:
   - 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 which 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 which provides an Import VAT exemption facility for geothermal projects in both the exploration and exploitation phases; and

d) MoF Regulation No. 21/2010 which provides an Article 22 exemption for imports by IPPs involved in renewable energy.

6.4.5 Pioneer Industry - Tax Holiday

On 4 April 2018, the Minister of Finance issued Regulation No.35/PMK.010/2018 ("PMK-35") dealing with the revised Tax Holiday arrangements for investors in "Pioneer Industries". PMK-35 revokes MoF Regulation No.159/PMK.010/2015 as amended by MoF Regulation No.103/PMK.010/2016.

PMK-35 allows for a "holiday" from the payment of Corporate Income Tax ("CIT") for a period of up to 20 years for businesses in Pioneer Industries. These industries extend to a number of key sectors of relevance to investors in the electricity development space.

On 30 May 2018, the Capital Investment Board (*Badan Koordinasi Penanaman Modal* – "BKPM") issued Regulation No.5/2018 ("BKPM-5") to more formally identify businesses entitled to the PMK-35 concession.

Of particular relevance to readers of this Guide is that the "Pioneer Industry" classifications now formally extend to "economic infrastructure" with the relevant KBLI covering "road infrastructure" and "electricity infrastructure". This would appear therefore to mean that a high percentage of investment in the power generation sector will, in principle at least, attract this tax concession.

Interestingly PMK-35 also indicates that even investments not falling within the formal classifications may still be approved should the investment fulfil the remaining requirements.

Among the other major policy developments set out in PMK-35 are that:
a) The new minimum capital investment threshold has been reduced to IDR 500 billion (approx. US$35mn);
b) There is no longer a requirement for the investment to be via a new entity;
c) There is no longer a requirement for a percentage of the proposed investment to be pledged as a guarantee of investment realisation;
d) There is clarity that the incentive period starts from the fiscal year in which commercial production commences.

The new holiday periods, with a comparison to the prior positions, can be summarised as follows:

<table>
<tr><th>Provision</th><th>Old (PMK 103)</th><th colspan="4">New (PMK 35)</th></tr>
<tr><td>Applicants</td><td>New Indonesian entities only</td><td colspan="4">Any new "investment"</td></tr>
<tr><td>Reduction of CIT - %</td><td>10 – 100%</td><td colspan="4">100% (single rate to nil)</td></tr>
<tr><td rowspan="6">Period of reduction</td><td rowspan="6">• 5 – 15 years
• can be extended to 20 years</td><th>No.</th><th>Period (Years)</th><th>Investment (in IDR)</th><th>US$ mn (approx.)*</th></tr>
<tr><td>1</td><td>5</td><td>500 bn up to < 1 T</td><td>35 - 70</td></tr>
<tr><td>2</td><td>7</td><td>1 T up to < 5 T</td><td>70 - 350</td></tr>
<tr><td>3</td><td>10</td><td>5 T up to < 15 T</td><td>350 - 1050</td></tr>
<tr><td>4</td><td>15</td><td>15 T up to < 30 T</td><td>1050 - 2100</td></tr>
<tr><td>5</td><td>20</td><td>≥ 30 T</td><td>>2100</td></tr>
<tr><td>Transition</td><td>Not available</td><td colspan="4">50% CIT reduction for the next 2 years</td></tr>
</table>

**US$1:IDR14,500*

The updated application features include:

a) That an applicant can apply for the incentive:
   i) at the time of application for capital investment registration; or
   ii) within 1 year after the issuance of capital investment registration;

b) That, whilst a new entity is not required, the applicant should nevertheless be Indonesian incorporated (albeit with no limitation on the date of incorporation);

c) That, once a complete application has been received, BKPM is required to forward a (qualifying) proposal to the Minister of Finance for approval within 3 working days. The Minister of Finance should then decide on any application within 5 working days;

d) That BKPM can submit recommendations to the Minister of Finance up until 3 April 2023;

e) That the applicant should never have had a previous Tax Holiday application granted or rejected by the Minister of Finance;

f) That the investment is still required to satisfy the "debt to equity ratio" leverage limitations set out in MoF Regulation No.169/PMK.010/2015 (see *Section 6.2.1 - Income Tax* above); and

g) That any domestic shareholders of the applicant must obtain a "tax clearance letter" (confirming the status of their tax compliance) from the Director General of Tax.

In general the new Tax Holiday framework represents a significant improvement on the prior rules. This is in line with the Government's aim of spurring investment in infrastructure and other capital intensive industries more generally and (presumably) in the power generation sector in particular. This is noting that many IPP projects should qualify for at least a partial tax holiday and so greatly improve cash flow economics.

Enjoyment of the incentive remains of course subject to the review of any of the key qualification criteria (e.g. realisation of the committed investment threshold, actual investment alignment with the relevant industry classification, etc.). This review is made pursuant to an Indonesian Tax Office ("ITO") field audit carried out on a post Minister of Finance approval basis. If the ITO determines that any of the qualifying requirements have not been satisfied then the Tax Holiday period can be amended or revoked with any taxes not paid as a result of the non-compliance then becoming payable with penalties. This aspect will arguably need to be managed carefully.

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 an 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.

Photo source: PT Vale Indonesia Tbk

PSAKs in relation to arrangements that may contain a lease will change further after the issuance of PSAK 73. Please 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*.

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 "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.


Photo source: PwC

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 in order 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. A 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 conclusions as to 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 therefore they must follow the provisions of the PSAKs.

POJK No. 6/2017 is applied prospectively, starting on 1 January 2017, and it can be adopted 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.

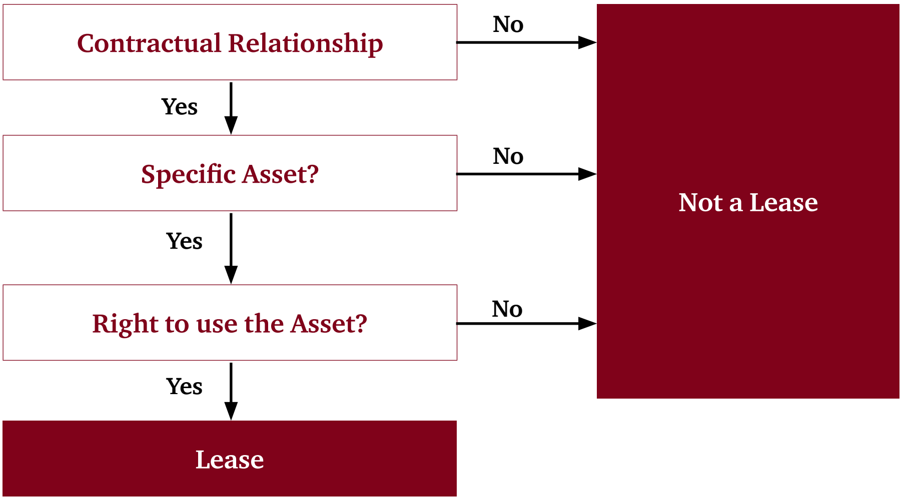
It is not entirely clear how POJK No. 6/2017 will be applied in a group situation, where a listed parent entity (an Issuer) controls a privately owned IPP that signs a PPA with PLN. As it is currently written, it does not appear that the temporary exemption is applicable to the group, unless the parent 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.

Photo source: PT Pertamina (Persero)

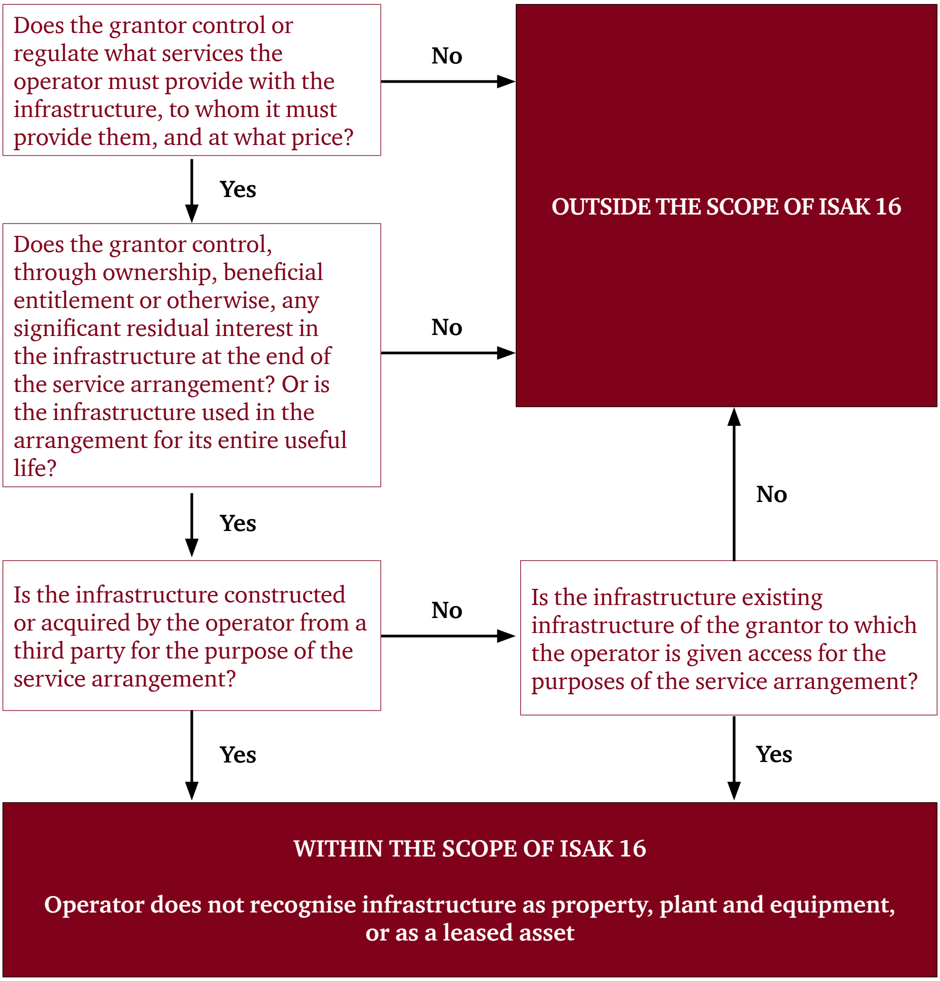
7.1.4 Application of accounting standards

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*.

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 relating 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*.

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 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 for 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 is 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".[162] 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".[163]

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.

162 https://www.pwc.com/id/en/publications/assets/assurance/acs/ifrs-and-indonesia-gaap-ifas-2016-r1.pdf
163 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 the customer), and to 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 it 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 for obtaining a PPA. PSAK 72 allows power companies to capitalise certain costs of obtaining a contract, which may include the commission fees payable to agents for obtaining 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 to be 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"), returns 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 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 a technical update is 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 mainly 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.

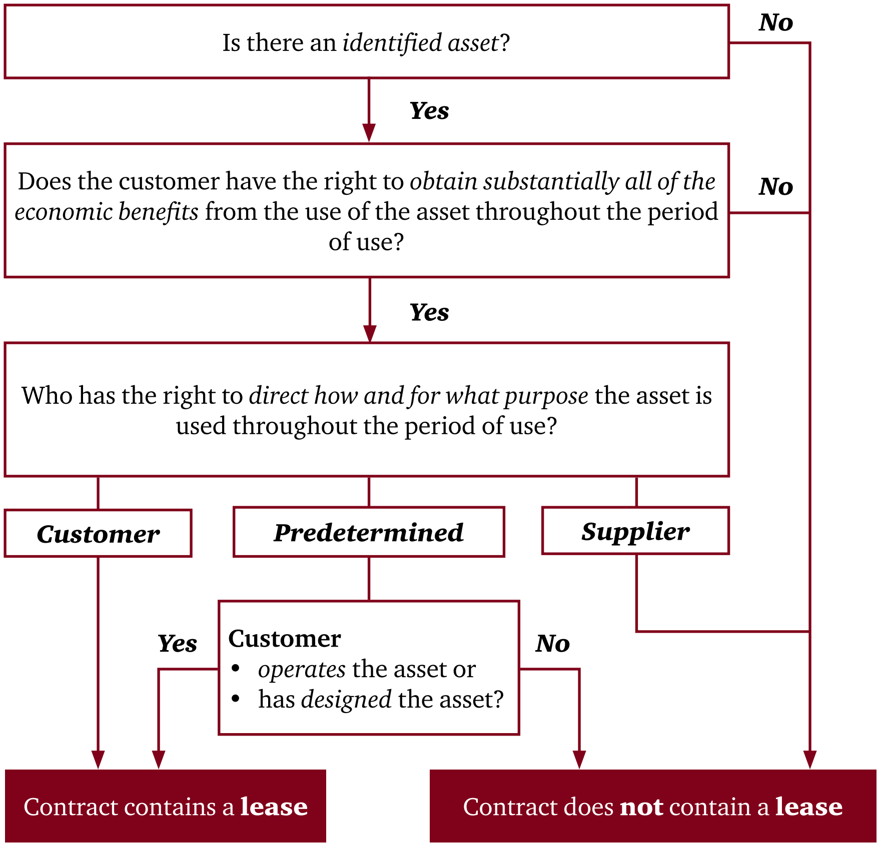
The key question to address, therefore, is which party (that is, the customer or the supplier) has the right to direct how and for what purpose an identified asset is used throughout the contract period. PSAK 73 gives several examples of relevant decision-making rights:

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 are independently exclusive, meaning there is no threshold for determining 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 in order to determine whether a lease element is embedded in the contract. We have analysed each 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.

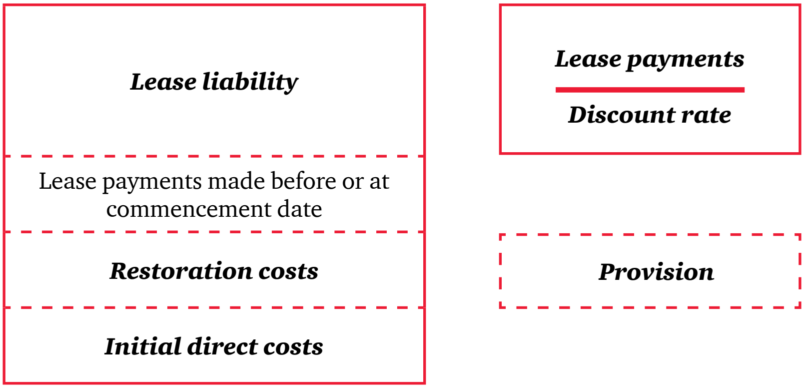
Customer's rights	Supplier's rights	Conclusion
Example 2 The customer has the right to obtain substantially all of the economic benefits from the use of the identified power plant over the 20-year period of use. The contract sets out the quantity and timing of power that the power plant will produce 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.

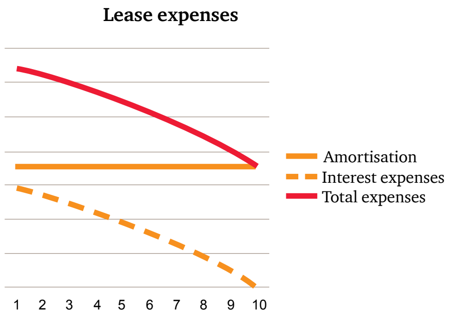


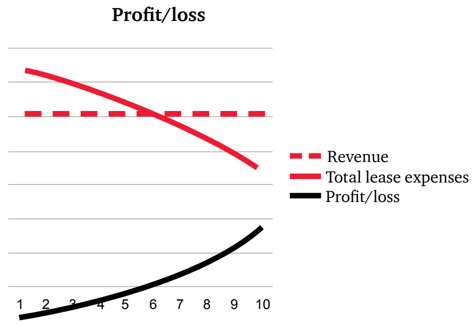
The effect of this approach is a substantial increase in the amount of capitalised financial liabilities and assets for entities that have entered into significant lease contracts that are currently classified as operating leases.

Subsequent measurement

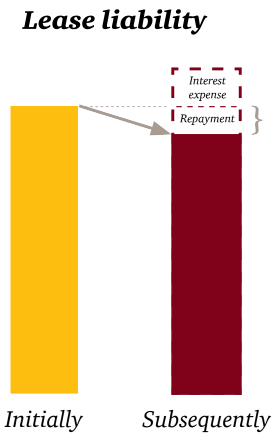
The lease liability is measured in subsequent periods using the effective interest rate method. The right-of-use asset is depreciated in accordance with the requirements in IAS 16, "Property, Plant and Equipment", which will result in depreciation on a straight-line basis or another systematic basis that is more representative of the pattern through which the entity expects to consume the right-of-use asset.

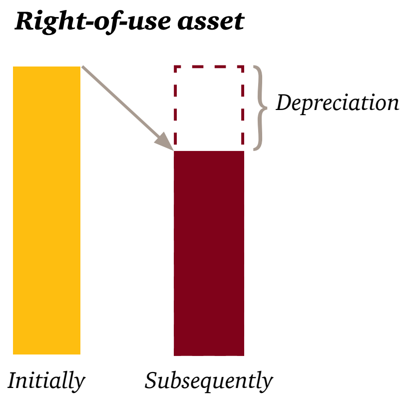
The combination of the straight-line depreciation of the right-of-use asset and the effective interest rate method applied to the lease liability results in a decreasing total lease expense throughout the lease term. This effect is sometimes referred to as *frontloading*.





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.





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.
EBITDA	This will increase because of the removal of lease payments that were previously presented as operating expenses under PSAK 30.

Indicator	Impact from PSAK 73
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 relating 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


Photo source: PwC

Tax Incentives: Comparison for Conventional and Renewable Power Plants

Regulations	Incentives	Conventional				Renewable			
		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 meet 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 at the 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

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 and accounting assumptions; • Site and land acquisition (regional land and building taxes); • Forestry borrow and 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/CERs.
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 Licences; and • Recharging of pre-incorporation spending.	• Licensing clarification (KBLI).
Ownership of Infrastructure	• Mine-Mouth or captive plants; • Transfer of distribution facilities – land and 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.

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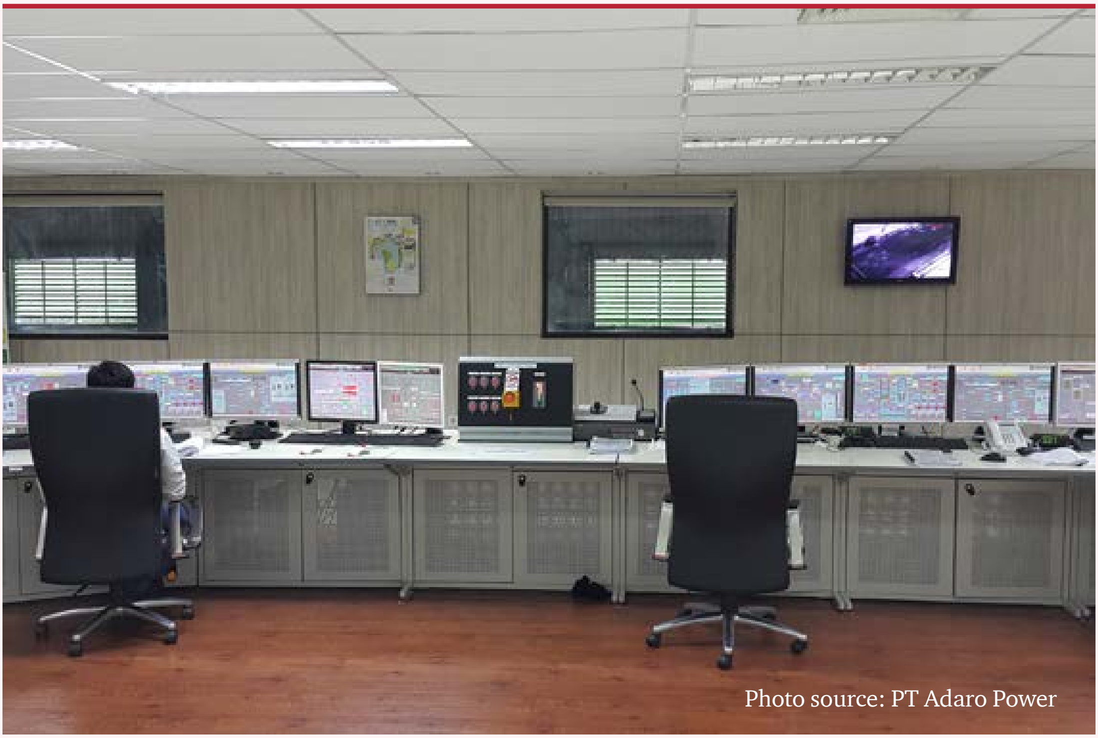

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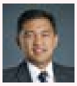

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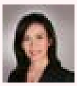

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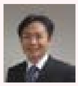

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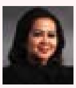

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Acknowledgements

We would like to convey our sincere thanks to all of the contributors for their efforts in supporting the preparation of this publication.

Photographic contributions

We gratefully acknowledge and thank the following companies that have provided photographs for inclusion in this publication (in alphabetical order):

PT Adaro Energy Tbk.
PT Adaro Power
PT Bhimasena Power Indonesia
PT Vale Indonesia Tbk.
PT Pertamina (Persero)
PT UPC Sidrap Bayu Energi

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