Oil and Gas in Indonesia

Investment, taxation and regulatory guide

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Photo source: PwC

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Glossary

Term	Definition
AFE	Authorisation for Expenditure
AKM	Asap Kido Merah
APBN	Anggaran Pendapatan dan Belanja Negara (State Budget)
ASC	Accounting Standard Codification
ATIGA	ASEAN Trade in Goods Agreement
BBC	Bare-boat charter
bbl	Barrel
BBTUD	British Thermal Units per Day
Bcm	Billion Cubic Metres
BI	Bank Indonesia
BiK	Benefits in Kind
BKPM	*Badan Koordinasi Penanaman Modal* (Indonesia's Investment Coordinating Board)
BOPD	Barrels of Oil per Day
BP Migas	*Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (Oil and Gas Upstream Business Activities Operational Agency), now SKK Migas
BPH Migas	*Badan Pengatur Hilir Minyak dan Gas Bumi* (Oil and Gas Downstream Regulatory Agency)
BPKP	*Badan Pengawasan Keuangan dan Pembangunan* (the Financial and Development Supervision Agency)
BPMA	*Badan Pengelola Migas Aceh* (Special Oil and Gas Regulatory Body of Aceh)
BPR	Branch Profit Remittance
BPT	Branch Profits Tax (i.e. on BPRs)
BSCF	Billion Standard Cubic Feet
BSCFD	Billion Standard Cubic Feet per Day
BUMD	*Badan Usaha Milik Daerah* (Regionally Owned Business Enterprise established by the Regional Government)
BUK Migas	*Badan Usaha Khusus Minyak dan Gas Bumi* (Oil and Gas Special Executive Agency)
CBM	Coal Bed Methane
CCS/CCUS	Carbon Capture & Storage/Carbon Capture Utilisation & Storage
CD	Community Development
CITR	Corporate Income Tax Return
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CoD	Certificate of Domicile
COP	Conference of Parties
COVID-19	Coronavirus Disease of 2019
C&D Tax	Corporate and Dividend Tax
DEN	*Dewan Energi Nasional* (National Energy Council)
DGB	Directorate General of Budget
DGoCE	Directorate General of Customs and Excise

Term	Definition
DGoG	Directorate General of Oil and Gas
DGT	Directorate General of Taxes
DHE	*Devisa Hasil Ekspor* (Foreign Exchange Proceeds from Export)
DMO	Domestic Market Obligation
DPR	*Dewan Perwakilan Rakyat* (House of Representatives)
EGR	Enhanced Gas Recovery
EIT	Employee Income Tax
EOR	Enhanced Oil Recovery
ESG	Environmental, Social and Governance
EV	Electric Vehicle
E&P	Exploration and Production
FCR	Foreign Exchange Report
FDC	Foreign-owned Drilling Company
FMR	Financial Monthly Report
FMV	Fair Market Value
FPS	Floating Production System
FPSO/FSO	Floating Production Storage and Offload (vessel)/Floating Storage and Offload (vessel)
FPU	Floating Production Unit
FQR	Financial Quarterly Report
FSRU	Floating Storage Regasification Unit
FSU	Floating Storage Unit
FTP	First Tranche Petroleum
FTZ	Free Trade Zone
GAAP	Generally Accepted Accounting Principles
GDP	Gross Domestic Product
GFMR	Global Flaring and Methane Reduction
the Government	Government of Indonesia
GHG	Greenhouse Gas
GR	*Peraturan Pemerintah* (Government Regulation)
GS	Gross Split
GW	Gigawatts
G&G	Geological and Geophysical
HPP	*Harmonisasi Peraturan Pajak* (the Harmonisation of Tax Regulations)
HS	Harmonised System
IAS	International Accounting Standards
ICP	Indonesian Crude Price
IDR	Indonesian Rupiah
IDD	Indonesia Deepwater Development
IFAS	Indonesian Financial Accounting Standards
IFRS	International Financial Reporting Standards
JETP	Just Energy Transition Partnership

Term	Definition
JOA/JOB	Joint Operation Agreement/Joint Operating Body
KBLI	*Klasifikasi Baku Lapangan Usaha Indonesia* (Indonesian Standard Industry Classification)
KEK	*Kawasan Ekonomi Khusus* (Special Economic Zone)
Km^2	Square Kilometre
LDAR	Leak Detection and Repair
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LST	Luxury-goods Sales Tax
MBOE	Thousand Barrels of Oil Equivalent
MBOEPD	Thousand Barrels of Oil Equivalent per Day
MBOPD	Thousand Barrels of Oil per Day
MIGAS	*Minyak Bumi dan Gas Alam* (Oil and Natural Gas)
MMBOE	Million Barrels of Oil Equivalent
MMBOPD	Million Barrels of Oil per Day
MMBtu	Million British thermal units
MMSCFD	Million standard cubic feet per day
MMTPA	Million Metric Tonnes per Annum
MoEMR	Ministry of Energy and Mineral Resources
MoF	Ministry of Finance
MTPA	Million Tonnes per Annum
NBV	Net Book Value
NDC	Nationally Determined Contributions
NJOP	*Nilai Jual Objek Pajak* (Tax Object Selling Value)
NO_x	Nitrogen Oxides
NPWP	*Nomor Pokok Wajib Pajak* (Taxpayer Identification Number)
OECD	Organisation for Economic Co-operation and Development
OGCI	Oil and Gas Climate Initiative
OPEC	Organisation of Petroleum Exporting Countries
OSS	Online Single Submission
O&G	Oil and Gas
PBB	*Pajak Bumi dan Bangunan* (Land and Building Tax)
PBI	*Peraturan Bank Indonesia* (Bank Indonesia Regulation)
PCO	Parent Company Overhead
PE	Permanent Establishment
Perppu	*Peraturan Pemerintah Pengganti Undang-Undang*
Pertagas	PT Pertamina Gas
PGN	PT Perusahaan Gas Negara (State Gas Company)
PHE	PT Pertamina Hulu Energi
PHR	PT Pertamina Hulu Rokan
PIS	Placed Into Service
PMA	*Penanaman Modal Asing* (Foreign Investment Company)

Term	Definition
PMK	*Peraturan Menteri Keuangan Republik Indonesia* (Minister of Finance Regulation)
PoD	Plan of Development
POME	Palm Oil Mill Effluent
PPnBM	*Pajak Penjualan Barang Mewah* (Sales Tax on Luxury Goods)
PP&E	Property, Plant & Equipment
PSC	*Kontrak Kerja Sama - KKS* (Production Sharing Contract, one of the types of Joint Cooperation Contracts)
PSN	*Proyek Strategis Nasional* (National Strategic Projects)
PT	*Perseroan Terbatas* (Limited Liability Company)
PTK	*Pedoman Tata Kerja* (Standard Operating Procedure)
PwC	PwC Indonesia, or the PwC global network of firms, as the context requires
RDMP	Refinery Development Master Plan
RPT	Risk Participation Transaction
RPTKA	*Rencana Penggunaan Tenaga Kerja Asing* (Foreign Manpower Employment Plan)
RTO	Regional Tax Office
RUKN	*Rencana Umum Ketenagalistrikan Nasional* (National Electricity Master Plan)
SAF	Sustainable Aviation Fuel
SA-VAT	Self-assessed VAT
SDA	*Sumber Daya Alam* (Natural Resources)
SE	*Surat Edaran* (Circular Letter)
SFAS	Statement of Financial Accounting Standards
SKK Migas	*Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (Special Task Force for Upstream Oil and Gas Business Activities)
SKB	*Surat Keterangan Bebas* (Tax Exemption Declaration Letter)
SKFP GS	*Surat Keterangan Fasilitas Perpajakan GS* (GS Tax Facilities Letter)
SKUP	*Surat Kemampuan Usaha Penunjang* (Supporting Business Capacity Certificate)
SOE	*Badan Usaha Milik Negara - BUMN* (State-Owned Enterprise)
SPOP	*Surat Pemberitahuan Objek Pajak* (Notification of PBB Objects)
SPPT	*Surat Pemberitahuan Pajak Terutang* (Official Tax Payable Notification)
SSP	*Surat Setoran Pajak* (Tax Payment Slip)
Tcf	Trillion Cubic Feet
TKDN	*Tingkat Komponen Dalam Negeri* (Local Content Level)
UCO	Used Cooking Oil
UK	United Kingdom
UoP	Units of Production
US	United States
USD	US Dollar
US GAAP	Generally Accepted Accounting Principles (in the United States)
VAT	Value Added Tax
WAP	Weighted Average Price
WHT	Withholding Tax
WP&B	Work Program & Budget

Foreword

Welcome to the 14th edition of PwC Indonesia's Oil and Gas in Indonesia—Investment, taxation and regulatory guide. In recent years, the macroeconomic landscape has rapidly transformed, with sustainability becoming a central focus. This shift presents a challenge, as many countries continue to depend heavily on fossil fuels for their energy needs and daily necessities, including petrochemical products. Recognising the need to balance sustainability with the demand for energy and petrochemical products, the investment climate for oil and gas has become increasingly crucial. In response, the Indonesian government has introduced alternative solutions, such as establishing a carbon credit market to promote emission offsetting. Additionally, there is a growing emphasis on Carbon Capture and Storage (CCS) as a key solution, given Indonesia's significant potential in this area. These initiatives align with the Government's broader focus on energy transition, aiming to balance energy demand with economic growth and the country's commitment to achieving net-zero emissions by 2060.

This edition of the Guide focuses on updating readers on the latest tax, regulatory and commercial changes since our previous edition, with an additional focus on the energy transition in Indonesia.

This publication serves as a general investment and taxation guide for all stakeholders interested in Indonesia's oil and gas sector. We have aimed to create a resource that is useful for existing investors, potential investors and anyone with a general interest in the status of this vital sector of the Indonesian economy.

This publication is organised into chapters that encompass the following overarching subjects:

1. Industry overview;
2. Energy transition;
3. Regulatory framework;
4. Upstream sector;
5. Gross Split Production Sharing Contracts (GS PSCs);
6. Downstream sector; and
7. Service providers.

As the global energy landscape continues to evolve, Indonesia's oil and gas industry finds itself at a critical juncture. The world's shift towards a more sustainable and low-carbon future presents both risks and opportunities for the industry. Balancing the ongoing decline in oil and gas production with the need for more sustainable practices poses a key challenge that requires attention.

To tackle this challenge, SKK Migas has launched a comprehensive Indonesia Oil and Gas Strategic Plan, known as IOG 4.0. This ambitious initiative aims to achieve a production target of one million barrels of oil per day (BOPD) and 12 billion standard cubic feet of gas per day (BSCFD) by 2030. The plan is supported by low-carbon initiatives, including new regulations, energy management, zero flaring, reduction of fugitive emissions, reforestation and the implementation of CCS and Carbon Capture, Utilisation and Storage (CCUS) technologies.

This Guide examines various facets of the ongoing energy transition, from the evolving global energy landscape to the policy frameworks and regulatory measures shaping the industry's future. It also explores the potential of renewable energy sources, such as solar and wind and their integration into the existing oil and gas infrastructure. Additionally, the Guide highlights the importance of energy efficiency and its role in reducing carbon emissions.

Another area highlighted in this Guide is the development of CCS technologies. CCS has emerged as a promising solution for mitigating carbon emissions from fossil fuel-based industries, including oil and gas. By capturing carbon dioxide (CO_2) emissions and storing them underground, CCS can significantly reduce the industry's carbon footprint and contribute to global efforts to combat climate change.

The Government has shown its support for the implementation of CCS/CCUS activities, through Minister of Energy and Mineral Resources (MoEMR) Regulation No. 2/2023 issued in March 2023 and Presidential Regulation No. 14/2024 issued in January 2024. These regulations outline processes for project approval, monitoring, reporting and verification. They also allow for carbon credit monetisation to fund these projects.

This publication aims to support investors in navigating the Indonesian oil and gas investment climate and to foster growth in the industry. Readers should note that the regulatory content in this publication was current as of 28 February 2025. While every effort has been made to ensure that all information was accurate at the time of publication, many of the topics discussed are subject to interpretation, and regulations are continuously changing. As such, this publication should only be viewed as a general guidebook and not as a substitute for up to date professional advice. For further guidance on investment opportunities in the Indonesian oil and gas sector, we recommend reaching out to PwC's oil and gas specialists (as listed in the Appendices).

We hope that you find this publication interesting and useful, and we wish all readers success with their endeavours in the Indonesian oil and gas sector.

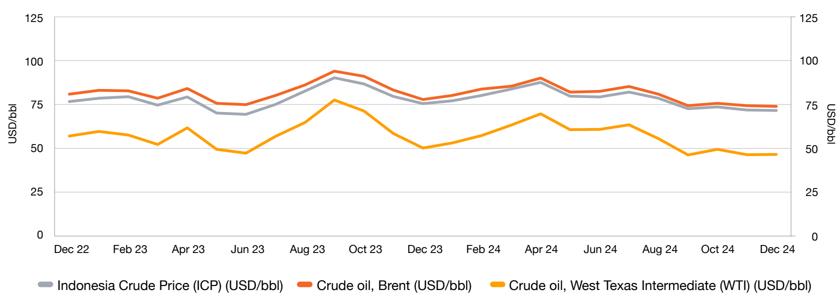
1 Industry overview

1.1 Global oil and gas overview

As the world navigates the transition to cleaner energy amidst ongoing economic challenges, the global oil and gas market has experienced significant volatility. Geopolitical tensions caused short-term spikes in oil prices, with a notable increase in April 2024 and another surge in early October 2024, when prices rose to USD81 per barrel. However, by mid-October, prices retreated due to concerns over oil oversupply, weak economic growth in China, and reduced risks to Middle Eastern oil infrastructure.

Despite this volatility, oil prices generally trended downwards. Brent crude, for example, decreased from USD83 per barrel in 2023 to USD81 per barrel in 2024, with projections indicating a further decline to an average of USD73 per barrel in 2025. This downward trend was attributed to reduced global oil consumption, diversification of supply with increased contributions from non-Organisation of the Petroleum Exporting Countries Plus (OPEC+) producers and OPEC+'s strategy of maintaining spare production capacity.

Oil prices 2023-2024

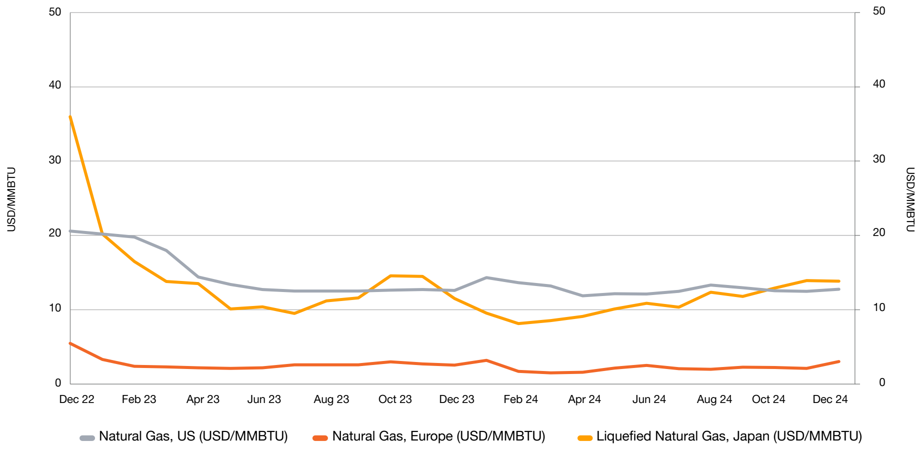


Source: MoEMR, World Bank, "Pink Commodity Sheet", 2025

In 2024, natural gas prices exhibited varied trends across different markets. In Europe, prices notably declined in the first quarter, from USD11.5/Million British Thermal Units (MMBTU) in the fourth quarter of 2023 to USD8.8/MMBTU in the first quarter of 2024, due to reduced demand and high inventory levels. Similarly, the United States (US) price fell from USD2.7/MMBTU in the fourth quarter of 2023 to USD2.1/MMBTU in the first quarter of 2024, driven by strong domestic production and milder winter temperatures reducing demand. Conversely, Japan experienced a rise in Liquefied Natural Gas (LNG) prices from USD12.9/MMBTU in the fourth quarter of 2023 to USD13.7/MMBTU in the first quarter of 2024, impacted by oil-indexed LNG contracts and increased import demand from China, which emerged as the largest LNG importer in 2023[1].

By the third quarter of 2024, the US price remained steady at USD2.1/MMBTU, supported by strong domestic production amid geopolitical tensions like the ongoing Russia-Ukraine conflict. Meanwhile, Japan's LNG prices increased by 7.2%, reaching USD12.9/MMBTU in the third quarter of 2024. The European price rose by 15%, climbing to USD11.5/MMBTU in the third quarter as Europe faced intensified global competition for LNG imports. Below is a summary of these natural gas price trends from 2023 to 2024[2].

Gas prices 2023-2024



Source: World Bank, "Pink Commodity Sheet", 2025

Oil supply-demand

In 2023, global oil production reached over 96 million barrels of oil per day (MMBOPD), illustrating industry resilience. The US maintained its position as the largest oil producer with an 8% increase, driven by technological advancements and supportive policies. In contrast, Russia's output declined by over 1% due to sanctions. Southern and Central America saw the highest regional growth at 11%, while China's production rose by 2%, contributing 57% of Asia Pacific's output.

In early 2024, global oil supply dynamics shifted. By the end of 2023, supply hit 102.9 MMBOPD in the fourth quarter. However, it decreased to 101.7 MMBOPD in the first quarter of 2024, due to OPEC+ production cuts, biofuel declines, and North American weather disruptions. US production faced a January dip of 540,000 barrels per day but recovered by March. Despite these disruptions, weak demand growth helped absorb the supply cuts, maintaining stable stock levels. OPEC+ saw minimal production changes, with Russia redirecting exports to India and China[2]. In the second quarter, supply fluctuated, dipping in April due to Canadian maintenance and OPEC+ cuts[4], then recovering to 102.9 MMBOPD by June[5].

In the second half of 2024, oil supply continued to rise, reaching 103.2 MMBOPD in the third quarter[6,7,8]. This increase was driven by gains in advanced economies and Latin America. However, OPEC+ members faced challenges, with Libya's output dropping by 25% due to a production crisis and Russia's declining exports. In the final quarter, oil supply averaged 103.3 MMBOPD[9,10,11]. By December, supply rose slightly to 103.5 MMBOPD, supported by increased output from OPEC+ African producers[11].

Looking ahead, US production is expected to grow by 0.6 MMBOPD annually in 2024 and 2025. In 2025, smaller producers like Kazakhstan, Norway and African countries are also expected to increase output[8]. OPEC+ decided to extend voluntary cuts by three months and extend the ramp-up period by nine months to September 2026. This decision significantly reduced the potential for a supply surplus in the following year. Despite some OPEC+ overproduction, non-OPEC+ growth suggests a well-supplied market in 2025[10]. These trends underscored the complex interplay of factors shaping the global oil market, with regional production shifts and strategic decisions by OPEC+ playing key roles.

On the demand side, in 2023, global oil consumption surpassed 100 million barrels per day for the first time, reflecting increased energy demand as economies recovered from COVID-19 disruptions. Key petroleum products like gasoline, diesel, and kerosene saw consumption levels return to or exceed those of 2019, underscoring oil's crucial role in global economic activities. Gasoline consumption increased to 25 MMBOPD, reflecting a resurgence in travel and business activities. Similarly, diesel consumption rose to 28 MMBOPD, highlighting the overall recovery in economic operations. Kerosene, primarily used in aviation, increased to 1.3 MMBOPD but had not fully reached its 2019 peak, highlighting ongoing challenges in air travel recovery[3]. These trends reveal the complex dynamics of oil consumption across regions and sectors.

Then, in late 2023 and early 2024, global oil demand slowed after a period of strong post-pandemic growth. A key player in the global oil consumption landscape is China, which in 2023 emerged as a significant driver of increased demand. China's oil demand grew by 12% year-over-year, driven by increased naphtha usage for petrochemical production, contributing significantly to global consumption despite stagnant demand in advanced economies. Demand also rose in

East Asia and Pacific countries, South Asia (notably India), and Latin America (notably Brazil), but fell in the Middle East. Brazil, China, India, Indonesia and Saudi Arabia accounted for about three-fourths of the global growth, while advanced economies saw a slight decline[1].

By late 2024, global oil demand growth was lower than the previous year, notably in China, due to subdued industrial growth and increased adoption of electric vehicles. Growth decelerated in Latin America but increased in East Asia and the Pacific (excluding China), the Middle East and North Africa and South Asia. Demand stalled in Europe and Central Asia and decreased in Sub-Saharan Africa. Emerging markets are expected to drive demand growth, as advanced economies stagnate or decline[2].

In conclusion, while global oil supply is stabilising, with contributions from both OPEC+ and non-OPEC+ countries, global demand is shifting towards emerging markets. These dynamics illustrate the ongoing changes in the global oil landscape, influenced by geopolitical, economic and technological factors.

Gas supply-demand

In parallel, the global natural gas supply landscape in 2023 underwent significant changes. Despite geopolitical and market disruptions, overall gas supplies remained stable, largely due to increased LNG production. This increase was crucial in balancing the decline in Russian piped gas exports as Europe and the rest of the world adjusted to reduced supplies[1].

By 2024, the LNG and natural gas markets faced challenges, with LNG supply growing by only 2.5%, markedly below historical averages. This slowdown was mainly due to project delays and difficulties in securing feed gas in regions such as Angola, Egypt and Trinidad and Tobago. However, the industry anticipated stronger supply growth of around 5% in 2025, driven by large projects, especially in North America, where the US, Canada and Mexico aim to significantly enhance their export capabilities[12]. During the first three quarters of 2024, global LNG supply increased by just 2% year-on-year, highlighting supply chain vulnerabilities[13]. Meanwhile, China and India saw over 10% increases in LNG imports to meet their rising demands. Looking ahead, North America, Africa and Asia were expected to be key contributors to LNG supply growth in 2025, although Africa faced investment and production challenges[14].

In 2024, US natural gas production initially declined due to low prices but began recovering by mid-year as prices stabilised, a trend expected to continue into 2025 with the support of new LNG projects. The Middle East showed moderate growth, while Africa struggled with investment and production stability, with Egypt shifting from a net exporter to a net importer[12]. New LNG capacity from the US and Africa, including projects like Freeport LNG, Plaquemines LNG Phase 1 and the Tortue FLNG plant off West Africa, is set to alter the supply landscape[14]. The expiration of the Russian gas transit contract through Ukraine at the end of 2024 was significant, as it was assumed that Russian deliveries would only cease in 2025, potentially forcing Europe to increase LNG imports amidst ongoing geopolitical tensions[12]. By 2025, Africa was expected to play a more significant role in the LNG market, despite challenges in Egypt and Nigeria[12]. Global gas markets were also expected to see an increase in low-emissions gas supply by 2027, driven by policy support in Europe and North America, aligning with environmental goals[13].

Meanwhile, global gas demand stagnated with a modest increase of 0.5% in 2023 after a decline the previous year. This stabilisation was primarily driven by the Asia Pacific region, particularly China and India, where demand grew in the power and industrial sectors. The Asia Pacific region saw an almost 2% rise in gas demand, largely due to a 7% growth in China and India[3]. In contrast, Europe's demand fell to its lowest since 1996. The decline in Europe resulted from reduced electricity use, a shift towards renewable energy, improved efficiency, policy measures and mild winters[1]. Europe experienced a significant 7% drop in natural gas demand, reaching its lowest point since 1994, accompanied by reduced production in Norway, the UK and the Netherlands. The Russian Federation's share of EU gas imports significantly declined from 43% in 2021 to 14% in 2023, placing it behind Norway and the US[3].

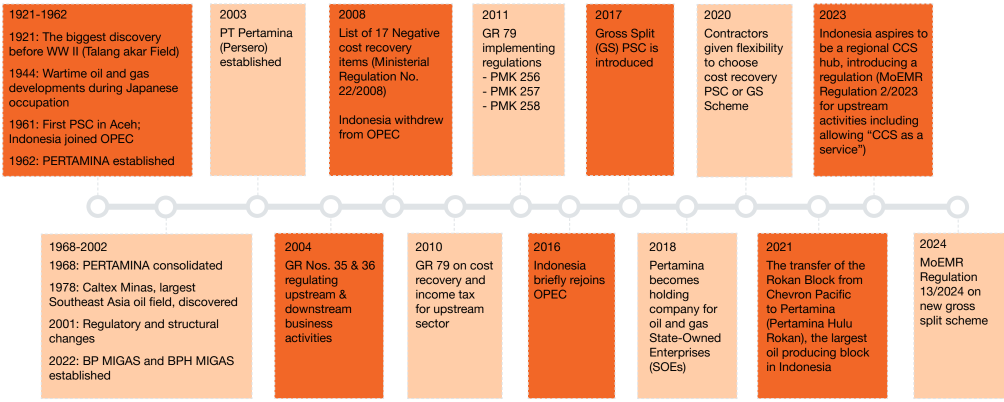
Throughout 2024, global natural gas demand reached unprecedented levels, driven by economic growth in Asian markets, particularly China and India which led the surge and accounted for over 40% of the increase. North America's demand saw moderate growth, mainly driven by the power sector, with seasonal weather variations affecting gas usage while South America increased gas-fired power generation due to droughts[12]. By the first three quarters of 2024, natural gas demand had grown by 2.8%, with the Asia-Pacific region contributing 60% of this growth. China's consumption rose significantly, boosted by government initiatives for energy security and carbon reduction (as part of its ongoing transition away from coal), while India, Japan and South Korea also saw robust growth. Meanwhile, Europe's gas consumption continued to decline due to reduced heating needs and increased output from renewable and nuclear energy sources. North America's gas consumption increased by 1.5%, driven by low prices and demand from the power sector[2].

COP 29: Implications on the future of oil and gas markets

As the world navigated energy dynamics, the 29th United Nations Climate Change Conference (COP29) discussions became pivotal, focusing on the transition from fossil fuels to clean energy, significantly impacting future oil and gas markets. Although there were few new announcements on phasing out fossil fuels, a coalition of 25 countries and the EU committed to no new unabated coal power. Despite no new members joining the Beyond Oil and Gas Alliance, a global pledge was made to deploy 1,500 gigawatts (GW) of energy storage and upgrade grids by 2030 to support renewable expansion. The commitment to promoting green-energy zones and corridors underscored the shift towards efficient renewable energy distribution, as did the hydrogen declaration aimed at boosting renewable hydrogen production. Methane emissions were addressed, with over 30 countries setting reduction targets, and the US introduced a methane fee for oil and gas producers. These discussions mark a pivotal moment for the oil and gas industry as it faces increased regulatory scrutiny and a clear shift towards sustainable energy practices[15], subject to ongoing changes in the US arising from policies of the new Trump administration, which withdrew from the COP mechanism.

1.2 Indonesian context

Significant events in the history of Indonesia's oil and gas sector



Historical overview of oil and gas in Indonesia

Indonesia's oil and gas industry has a rich history, tracing back to its first oil discovery in North Sumatra in 1885. The country advanced its industry by signing its first Production Sharing Contract (PSC) in 1961 and joining OPEC, although it suspended its membership in 2009 due to declining production levels[16].

Recent developments have significantly impacted the sector. In 2020, the introduction of MoEMR Regulation No. 12/2020 allowed investors to choose between the traditional cost-recovery PSC and the newer Gross Split (GS) system, reigniting interest in the sector. This regulation was amended to MoEMR Regulation No. 13/2024 in 2024. By 2021, 17 contractors were operating under the GS system. After a pause due to COVID-19, oil and gas auctions resumed, including tenders for regions like South Coastal Plain and Pekanbaru (CPP), Sumbagsel, Rangkas and Liman[17]. Additionally, the Rokan PSC was transferred from PT Chevron Pacific Indonesia to PT Pertamina Hulu Rokan (PHR) in August 2021[18].

In 2022, the Government issued Government Regulation in lieu of Law No. 2 of 2022, which was later enacted as Law No. 6/2023, (thereby repealing Law No. 11/2020) aimed at improving the investment environment by enhancing business activities, employment, research and innovation, and economic zones.

In 2023, Indonesia made regulatory advancements aimed at becoming a regional hub for CCS with the introduction of MoEMR Regulation No. 2/2023. This regulation promotes collaboration in upstream oil and gas activities and introduces a “CCS as a service” business model. It proposes developing multi-user CCS hubs and outlined procedures for carbon capture, utilisation and storage. Economic aspects are considered by classifying CCS costs as operational expenses and exploring revenue through carbon trading or reimbursement. Additionally, the regulation requires downstream entities to obtain specific licences to monetise injection and storage services, demonstrating Indonesia's commitment to environmental sustainability and innovation.

There are several potential CCS/CCUS projects at various stages of development as follows:

Table 1.1 - CCS/CCUS projects in Indonesia

CCS/CCUS Blocks	Parties
CCS Sakakemang	Repsol Sakakemang
CCS/CCUS area SLO (Rokan Block)	PT Pertamina Hulu Rokan & Mitsui
CCUS Gemah (CO2)	PetroChina International Jabung
CCUS to Methanol RU V Balikpapan	PT Pertamina (Persero)
CCS/CCUS South Natuna Sea Block B	Medco E&P Natuna
CCS Corridor	Medco E&P Grissik
Bioenergy with Carbon Capture and Storage (BECCS South Sumatera)	PT Pertamina (Persero), Japan Petroleum Exploration, Marubeni
CCUS Jatibarang	PT Pertamina EP
CCUS/Enhanced Oil Recovery Sukowati	PT Pertamina EP
CCUS/Enhanced Gas Recovery Gundih	PT Pertamina EP Cepu
CCS Donggi - Matindok	PT Pertamina EP, PT Pupuk Indonesia, Mitsubishi
CCS Tambora - Nilam	PT Pertamina Hulu Energi Mahakam
CCS Sunda Asri	PT Pertamina Hulu Energi Offshore Southeast Sumatra (OSES) & ExxonMobil
CCS Abadi Masela	Inpex Masela
CCUS/Enhanced Gas Recovery Ubadari	BP Tangguh

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In 2023, the National Energy Council (*Dewan Energy Council* - DEN) outlined Indonesia's plan to transition from fossil fuels to clean energy, emphasising carbon emission reductions through specific subsidies and policies. The "Indonesia Energy Outlook 2023" presented two future scenarios for energy development:

1. Hymne Scenario: This scenario assumes a continuation of current trends, with a 4.6% annual increase in energy demand over the next decade. While fossil fuels remain dominant, there is a gradual shift towards renewable sources like biofuels and solar power, indicating a slower transition.
2. Mars Scenario: This scenario targets Indonesia's modernisation by 2045 and achieving Net Zero Emissions by 2060, with a 3.5% annual growth in energy demand due to improved efficiency. It emphasises a rapid increase in renewable energy use, including solar, biofuels, nuclear and hydrogen, especially in transportation, to substantially reduce reliance on fossil fuels and create a cleaner energy mix[19].

The year 2023 also marked a significant achievement for the upstream oil and gas industry with two major discoveries: Layaran-1 in the South Andaman Block, boasting 6 trillion cubic feet (Tcf) of reserves, and Geng North-1 in the North Ganal Block, with 5 Tcf[20]. These discoveries underscore the promising potential of Indonesia's natural gas resources, reinforcing its strategic position in the global energy market.

Photo source: PwC

Furthermore, Indonesia made significant progress in its major oil and gas projects, particularly with the Abadi LNG and Tangguh Train-3 developments. The Abadi LNG project is central to Indonesia's future energy strategy, with production set to begin by 2030[21]. Meanwhile, Tangguh Train-3 began operations in 2023, significantly enhancing Indonesia's LNG production capacity. As one of the five National Strategic Projects (*Proyek Strategis Nasional* - PSNs), it is operated by BP Berau Ltd. and was inaugurated by the President on 24 November 2023[20]. The LNG produced from Tangguh Train-3 is purchased by PLN and Kansai Electric[22].

In 2023, six projects successfully commenced operations, increasing production capacity by 4,900 barrels of oil per day (BOPD) and 306 million standard cubic feet per day (MMSCFD) of gas. These projects are detailed in Table 1.2 - List of oil and gas onstream projects in 2023 below.

Table 1.2 - List of oil and gas onstream projects in 2023

Project name	Company	Location	Objective	Facility/Scope	Onstream date
SP Jatisari	PT Pertamina EP	Subang Field, Jatiasri Complex, Subang Regency	Develop oil and gas from Talang Akar reservoir	Collection station: 3400 barrels of liquid per day (BLPD), 16 MMSCFD	September, 2023
LTRO-1B	PT Medco E&P Grissik	Rawa Field Corridor, South Sumatra	Maintain gas production via low-pressure compression	Low-pressure compression system: 45 MMSCFD	July, 2023
Gajah Baru Production Facility Platform (GBFCP)	Premier Oil Natuna Sea B.V.	GBFCP	Reduce arrival pressure at the Gajah Baru Central Processing Platform (GBCPP) facility	Compressor re-wheeling and modifications	December, 2023
Field Development Optimisation (Optimasi Pengembangan Lapangan - OPL) Bronang Gas	PT Medco E&P Natuna	Natuna	Add production wells and modify facilities	Install 14" pipeline, modify control and monitoring systems	First gas: September, 2023
YY Project	PHE ONWJ	Offshore Northwest Java	Reactivate YYA Platform and install subsea pipeline	2,000 BOPD, 1 MMSCFD capacity	August, 2023
MAC Project	Husky-CNOOC Madura Ltd.	Madura Strait	Produce gas from Globigerina Limestone reservoir	MAC Platform and subsea pipeline, MOPU rental	September, 2023

Source: SKK Migas, "SKK Migas 2023 Annual Report", 2024

Highlight on recent oil and gas developments in Indonesia

In 2024, Indonesia's upstream oil and gas sector remained optimistic, driven by oil and gas discoveries in 2023 and 2024, despite a reduction in oil and gas working areas from 170 in 2023 to 166 in 2024[23]. A significant milestone was reached with the discovery of substantial natural gas potential at the Tangkulo-1 deepwater well in the South Andaman Block[24].

Additionally, Pertamina's subsidiaries made four discoveries in this period. PHR identified a new oil and gas source through the drilling of the Astrea-1 Exploration Well, with a potential production of 3,000 BOPD[25] and Pinang East-1, with a production capacity of 2.53 million barrels of oil equivalent (MMBOE)[26]. PT Pertamina EP also successfully discovered an oil and gas resource with a potential of 40 MMBOE in the Julang Emas well[27]. PT Pertamina Hulu Energi (PHE) made a major discovery at the Tedong-001 Structure, uncovering reserves of 875.47 billion cubic feet (Bcf) of gas[28].

Under the new administration of President Prabowo Subianto, Indonesia is prioritising oil and gas for domestic energy needs while transitioning to energy self-sufficiency and renewable energy[29]. The Government envisions the phase-out of coal and fossil fuel power plants within 15 years while developing 75 GW of renewable energy[30]. This strategic shift has prompted some companies to invest in cleaner alternatives. Despite the beginnings of a focus on transition to renewable energy, Indonesia spent about IDR450 trillion on importing oil and gas, including Liquefied Petroleum Gas (LPG), significantly affecting its trade balance. Balancing these costs with renewable energy initiatives continues to be a major challenge[31].

In 2024, four PSNs remained under development: the Ubadari Field Development for the CCUS and Compression (UCC) Project in West Papua, the Abadi Field in Maluku, the Indonesia Deepwater Development (IDD) and Geng North in East Kalimantan and the Asap Kido Merah (AKM) Project in West Papua. The key projects under development in 2024 are as follows:

1. **Tangguh Ubadari Field Development, CCUS and UCC Project in West Papua - BP Berau Ltd:**
   This project integrates Indonesia's first large-scale CCUS system, initially sequestering about 15 million tonnes of carbon dioxide (CO_2). The Final Investment Decision (FID) was made on the USD7 billion which has the potential to unlock around 3 tcf of additional gas resources in Indonesia[33]. The Engineering, Procurement, Construction and Installation (EPCI) contract was awarded to Saipem and its partner PT Meindo Elang Indah, along with JGC Holdings Corporation through PT JGC[34].

2. **Abadi Project – Inpex Masela Ltd:**
   This project promises substantial energy outputs. The field is set to produce LNG with a capacity of 9.5 million tonnes per annum (MTPA) and piped gas at 150 MMSCFD[21]. Phase one of the CCS Study is underway, and the CO_2 Injection Pipeline Study was nearing completion in 2024[32].

3. **Indonesia Deepwater Development (IDD) and Geng North Project – Eni Rapak Deepwater Ltd., ENI Ganal Deepwater Ltd., ENI Makassar Ltd:**
   Eni received approval for the Plan of Development (POD) for the Geng North, Gehem, Gendalo and Gandang fields. These developments form a new production hub, the Northern Hub, in the Kutei Basin. Eni also secures a 20-year extension for the IDD licences, Ganal and Rapak. Eni plans to enhance gas and condensate production in East Kalimantan, targeting both domestic and international markets. The project utilises existing facilities like the Bontang LNG Plant and the Jangkrik Floating Production Unit (FPU) and includes a new Floating Production Storage and Offloading (FPSO) unit for production and storage. The Gendalo and Gandang development aims to prolong the gas production plateau of the Jangkrik FPU[35].

Photo source: PwC

4. **Asap Kido Merah (AKM) Project – Genting Oil Kasuri Ltd:**
   The Asap Kido Merah (AKM) Field Project by Genting Oil Kasuri Ltd. aims to extract 2,244.45 billion standard cubic feet (BSCF) of gas (2,213.61 BSCF for sales) and 5.4 million stock tank barrels (MMSTB) of condensate. Operations are scheduled to begin in late 2025 to support domestic energy needs and provide raw materials for ammonia and urea production. The project supports the growth of eastern Indonesia's first petrochemical industry by supplying gas to Pupuk Kaltim and advancing regional oil and gas development[20]. In June 2024, the Engineering Procurement and Construction (EPC) process was in progress. The Floating LNG (FLNG) construction is expected to start in the fourth quarter of 2025[32].

In early 2024, Indonesia's oil and gas sector reached some milestones. In March 2024, Natuna Pte. Ltd. received approval for its Revised POD I. The Ande-Ande Lumut (AAL) Oil Field is anticipated to produce approximately 20,000 BOPD significantly enhancing the country's national oil production targets[36].

In mid-2024, the MoEMR signed the 30-year cooperation contract with Petronas E&P Bobara Sdn. Bhd for the Bobara Block in the third phase of the 2023 working area auction[37].

Saka Energi Indonesia (PGN Saka), through its subsidiary, PT Saka Ketapang Perdana and Petronas Carigali Ketapang II Ltd., extended their production sharing contract for 20 years beyond its original 2028 expiry[38].

In September 2024, the MoEMR announced the winners of phase one of the 2024 oil and gas working area bidding involving three areas: Central Andaman, Amanah and Melati. Three blocks were offered under the direct offer tender. The Central Andaman area was awarded to Premier Oil South Andaman Limited and Mubadala Energy Holdings Limited. The Amanah block was awarded to PT Medco Energi Linggau, PT Sele Raya and KUFPEC Regional Ventures (Indonesia) Limited, while the Melati block located in Sulawesi was awarded to a consortium of PHE, Sinopec International Energy Investment Holdings and KUFPEC Regional Ventures (Indonesia) Limited[39].

In 2024, 12 out of the targeted 15 oil and gas projects had commenced operations. These projects are anticipated to contribute or maintain a production capacity of approximately 36,237 BOPD and 300 MMSCFD of gas[40]. The list can be seen in Table 1.3 below.

Table 1.3 - List of gas onstream projects in 2024

No	Name	Gas Production Cap. (MMSCFD)	Operator	Onstream
1	SWPG Debottlenecking	8	Pertamina Hulu Mahakam (PHM)	Apr 2024
2	Bekapai Artificial Lift	12	PHM	May 2024
3	Peciko 88	16	PHM	Jun 2024
4	Compressor Facility South Sembakung	22	Joint Operation Body Pertamina-Medco E&P (JOB PMEP) Simenggaris	Jun 2024
5	Anoa Futher Compression Project (AFCP)	117	Premier Oil Natuna Sea BV	Jun 2024
6	Dayung Facility Optimisation	40	Medco Grissik	Jun 2024
7	The CO_2 and DHU Project at the Karang Baru Field	5	Pertamina EP	Jul 2024
8	Akatara Gas Plant	25	Jadestone Energy	Jun 2024[41]
9	West Belut	55	Medco Natuna	Sep 2024

Source: SKK Migas, "Hingga September 2024 Sebanyak 12 Proyek Hulu Migas Sudah Onstream", 2024

Table 1.4 - List of oil onstream projects in 2024

No	Name	Oil Production Cap. (BOPD)	Operator	Onstream
1	Field Development Optimisation (*Optimasi Pengembangan Lapangan* - OPL) Main	1,893	Pertamina Hulu Energi Offshore Northwest Java (PHE ONWJ)	May 2024
2	Flowline ASDJ-116X	94	Pertamina Hulu Energi (PHE) Ogan Komering	Jun 2024
3	Banyu Urip Infill Clastic	33,000	ExxonMobil Cepu Ltd.	Aug 2024

Source: SKK Migas, "Hingga September 2024 Sebanyak 12 Proyek Hulu Migas Sudah Onstream", 2024

SKK Migas is focused on operationalising three upcoming key upstream oil and gas projects to enhance energy production and security. Notably, the Forel Bronang Medco Natuna Project is set to produce 10,000 barrels of oil per day and 43 MMSCFD[40]. In late 2024, the Indonesian government announced plans to offer 60 oil and gas blocks to investors over the next four years. This includes 14 potential working areas over the period 2024 to 2028[42].

In 2025, PC North Madura II Ltd., a subsidiary of PETRONAS, secured approval for the FID for the development of the Hidayah field, located in the North Madura II Working Area, East Java, Indonesia. The Hidayah field was targeted to be onstream in the first quarter of 2027, with an aim to produce oil reserves amounting to 88.55 MMSTB[43].

SKK Migas also identified 15 upstream oil and gas projects that will begin operations in 2025, as follows:

Table 1.5 – List of oil onstream projects in 2025

No	Name	Oil Production Cap. (BOPD)	Operator	Onstream
1	Terubuk	6,654	Medco EP Natuna	Q2 2025
2	Balam GS Upgrade	35,000	PHR	Q1 2025
3	CEOR Minas	3,000	PHR	Q4 2025
4	NDO A14 Stage-2	6,723	PHR	Q2 2025
5	Akasia Bagus Stage-1	9,000	PHR	Q2 2025
6	OPL Rama	739	PHE OSES	Q2 2025

Source: House of Representatives (DPR), “Hearing Meeting of the House of Representatives Commission XII with the Head of SKK Migas regarding the Progress and Evaluation of Program Implementation up to the 3rd Quarter of Fiscal Year 2024, strategic programs for Fiscal Year 2025”, 2024

Table 1.6 – List of gas onstream projects in 2025

No	Name	Gas Production Cap. (MMSCFD)	Operator	Onstream
1	Bentu Production Line	8	PT. Energi Mega Persada (EMP) Bentu	Q2 2025
2	A-24	6.7	Premier Oil Natuna Sea BV	Q3 2025
3	OPL Les	15	PHE ONWJ	Q4 2025
4	Letang Tengah Rawa Expansion	70	Medco EP Grissik Ltd.	Q1 2025
5	Suban Future Facility Optimisation	400	Medco EP Grissik Ltd.	Q4 2025
6	South Senoro	110	JOB Pertamina-Medco E&P Tomori Sulawesi	Q4 2025
7	Sisi Nubl AOI 1,3,5	120	PHM	Q4 2025
8	Karamba	7	PT Indo Sino Oil and Gas (ISOG)	Q4 2025
9	Bangkudulis (Rental EPF)	6	PT. Pertamina EP (KSO)	Q1 2025

Source: House of Representatives (DPR), “Hearing Meeting of the House of Representatives Commission XII with the Head of SKK Migas regarding the Progress and Evaluation of Program Implementation up to the 3rd Quarter of Fiscal Year 2024, strategic programs for Fiscal Year 2025”, 2024

New measures to improve upstream sector

The Government of Indonesia and SKK Migas introduced new policies aimed at optimising upstream operations. MoEMR Decision No. 110/2024 was introduced to reactivate idle oil fields. The Government inventoried these fields to explore reactivation with existing contractors or collaboration with technology providers to establish new working areas. Alternatively, idle fields could be returned to the Government for future auctions or alternative uses.

Additionally, a new gross split scheme was introduced under MoEMR Regulation No. 13/2024, revising the framework for Gross-split Profit-sharing Contracts (GS-PSCs) and replacing MoEMR No. 8/2017 and parts of MoEMR Regulation No. 23/2021. It allows parties to switch between the GS-PSC systems to improve efficiency, reduce bureaucracy, and offer contractors a more favourable base split. Additionally, MoEMR Decision No. 230/2024 provides guidelines for these changes, highlighting Indonesia's effort to a more streamlined, contractor-friendly oil and gas industry.

The new gross split scheme was applied in the contract for the Central Andaman Block operated by Harbour Energy Central Andaman Ltd. in December 2024.

A preliminary analysis on the impact of MoEMR Regulation 13/2024 is discussed further in Chapter 3.

1.3 Resources, reserves and production

Resources

There are 128 oil and gas basins identified in Indonesia. Up to June 2024, 20 basins are in the production stage, while eight have been drilled but are not yet producing. Additionally, 19 basins show indications of hydrocarbons, 13 have been identified as dry holes and 68 basins remain unexplored[32].

The MoEMR has touted the substantial potential in the Western Indonesia Area Phase 2 (*Indonesia Bagian Barat Tahap 2* - IBB 2). It is estimated to hold over 4.3 billion barrels of oil equivalent (BBOE), with significant potential concentrated in the East Natuna Basin, the Makassar Strait Basin, the Southeast Java Basin and the Barito Basin[44].

To further enhance oil and gas production, various strategies were implemented. By June 2024, domestic and international companies had drilled a total of 17 exploration wells, a significant increase from the seven wells drilled during the same period in 2023, as reported by SKK Migas[32]. Additionally, Indonesia welcomed the addition of several resources in 2024, with four ongoing PSNs and several strategic onstream oil and gas projects set for 2024 and 2025.

In May 2024, a significant gas discovery was announced by SKK Migas and Mubadala Energy in the South Andaman Block offshore northern Sumatra, Indonesia. The Tangkulo-1 deepwater well, operated by Mubadala, revealed an 80-metre gas column

Photo source: PwC

with a flow capacity of 47 MMSCFD of gas and 1,300 barrels of condensate, increasing the block's potential reserves to 8 Tcf[24].

Jindi South Jambi B discovered hydrocarbon gas through re-entry exploration and retesting of the Bungin-1 well in Bengku Village, Batanghari Regency, Jambi Province. Jindi South Jambi continued the re-entry, employing Surface Well Test and Slickline methods, resulting in a production of 9.45 MMSCFD[45].

Pertamina subsidiaries made notable advancements in oil and natural gas exploration and management in early 2024. Pertamina EP launched significant drilling operations in central and eastern Indonesia, starting with the Julang Emas (JLE-01) project in Banggai, Central Sulawesi, in January 2024. This onshore drilling was part of a wider exploration effort in Central Sulawesi, aimed at assessing potential oil and gas resources, with an estimated yield of approximately 40 MMBOE from two target formations[27].

In March 2024, PHR conducted drilling at Pinang East-1 in the Rokan Block, identifying contingent oil resources of 2.53 MMBOE. Then, in July 2024, PHR's efforts led to the discovery of a new oil and gas source through the Astrea-1 Exploration Well in Tanah Putih District, Rokan Hilir Regency, Riau, with a potential production capacity of up to 3,000 BOPD[26].

Later in the year, PHE had success with the Tedong-001 Structure, uncovering natural gas reserves of 875.47 Bcf equivalent to 151.13 MMBOE[28].

Reserves

In 2023, the Energy Institute reported that the country had proven oil reserves of 2.4 billion barrels and proven gas reserves of 44.2 Tcf. As a result, Indonesia became the fourth-largest holder of natural gas reserves in the Asia Pacific region, trailing only China, Australia and India[3].

According to the MoEMR, Indonesia experienced a reduction in proven oil and gas reserves, from 2.41 billion barrels in 2023 to 2.29 billion barrels in 2024 and proven gas reserves from 35.3 trillion cubic feet (Tcf) to 33.8 Tcf[46].

The reserve status in 2024 is set out in Table 1.7 below.

Table 1.7 – Key indicators - Indonesia's oil and gas industry

Indicator	2018	2019	2020	2021	2022	2023	2024
Reserves							
Oil (Million Barrels)	7,512	3,770	4,170	3,950	4,171	4,703	4,312
Proven	3,154	2,480	2,440	2,245	2,271	2,413	2,288
Potential	4,358	1,290	1,730	1,700	1,900	2,290	2,024
Natural Gas (TCF)	135.55	77.29	62.39	60.61	54.83	54.76	51.98
Proven	96.06	49.74	43.57	41.62	36.34	35.30	33.84
Potential	39.49	27.55	18.82	18.99	18.49	19.46	18.14
Production							
Crude oil (MBOPD)	772	745	708	659	612	606	580
Natural gas (MMSCFD)	7,764	7,235	6,665	6,668	6,492	6,636	6,802
New contracts signed	11	6	0	2	5	13	4

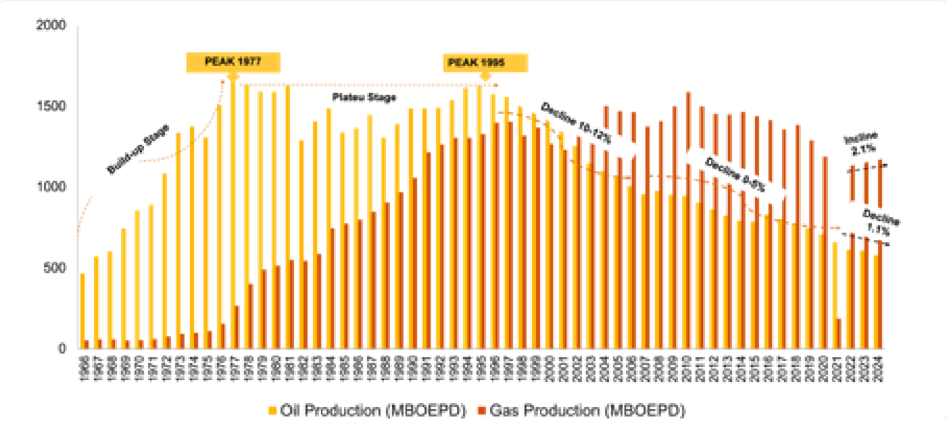
Sources:
Reserves of oil and gas are obtained from Directorate General of Oil and Gas (DGoG), MoEMR
2018-2023 Gas Oil Production: SKK Migas, “SKK Migas 2023 Annual Report”, 2024
2024 Oil and Gas Production: MoEMR, "Performance of the Energy and Mineral Resources Sector in 2024", 2024
New Contracts Signed 2018 - 2023: DGoG, "Statistik Migas Semester 1 2024", 2024
New Contracts Signed 2024: DGoG, "Performance Report of the Directorate General of Oil and Gas for the year 2024", 2024

Production

Despite several noteworthy discoveries between 2023 and 2024, oil production in Indonesia continued to decline, dropping from 606 thousand barrels of oil per day (MBOPD) in 2023[47] to 580 MBOPD in 2024[48]. This downward trend is primarily attributed to the diminishing output from many ageing wells and the challenge of technical factors such as unplanned shutdowns in various oil and gas working areas, posing a significant challenge to efforts aimed at boosting production[49].

Indonesia's gas lifting performance exceeded expectations, achieving 6,802 MMSCFD[50], which surpassed the State Budget (APBN) target of 5,785 MMSCFD, with increases from several PSCs, including BP Berau Ltd., Medco E&P Grissik Ltd. and PT Pertamina EP[51]. In September 2024, national gas production set a record, climbing to 7,399 MMSCFD[52]. The oil and gas production profile in Indonesia is presented as follows:

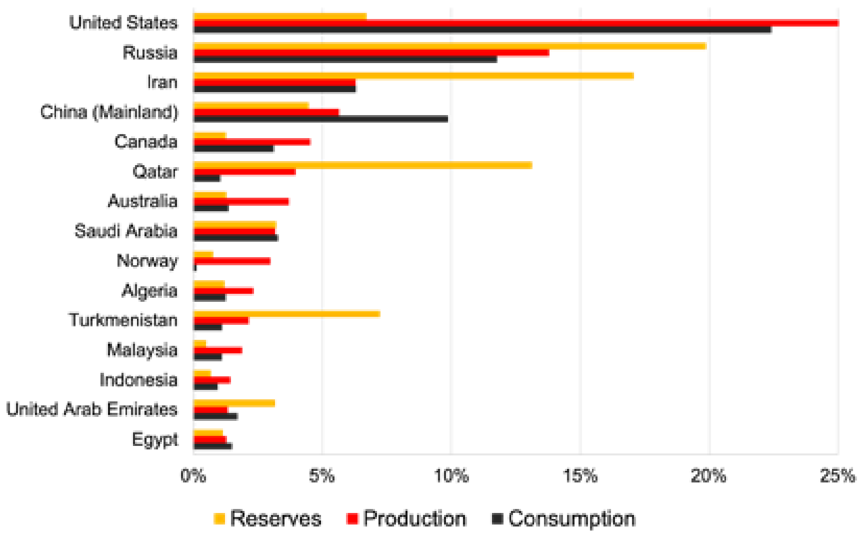
Indonesian oil and gas production profile



Source: SKK Migas, “SKK Migas 2023 Annual Report”, 2024

This resulted in Indonesia retaining 13th position globally in terms of gas production, the same rank as the previous year, with a total output of 61.49 billion cubic metres (Bcm), equivalent to 2.17 Tcf. On the consumption front, Indonesia ranked 25th globally, with a consumption volume of 39.12 Bcm (equivalent to 1.38 Tcf)[53], as shown below:

Share world gas 2024 - rank based on 2024 production

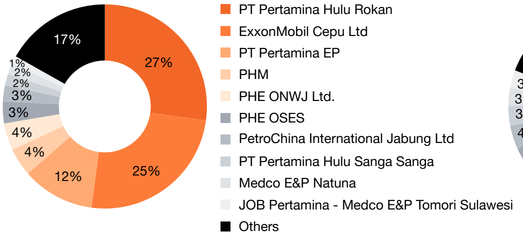


Sources:
Reserve: Global Energy Monitor (GEM), “LNG Terminals 2024”, 2024
Production & Consumption: BMI (Fitch Solution), “BMI Data Tools -- Production, Consumption”, 2024

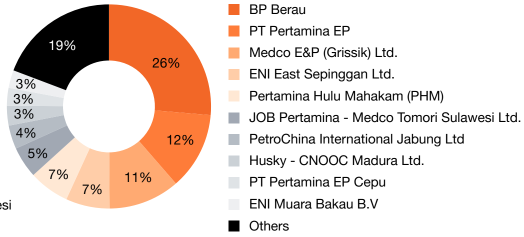
Pertamina entities contributed approximately 50% of Indonesia's oil and gas production[54]. The major crude oil and natural gas producers, as PSC operators, as of 2024 were as follows.

Indonesia's Major oil and gas producers 2024

Oil producers 2024



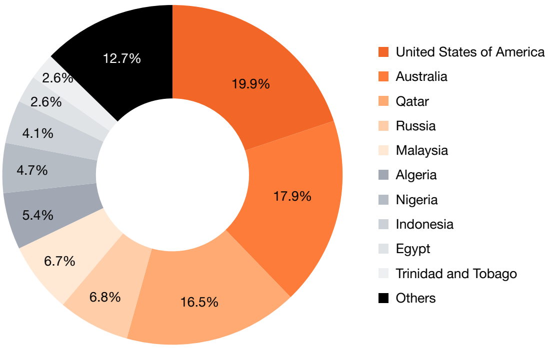
Gas producers 2024



Source: Directorate General of Oil and Gas (DGoG), "Statistik Migas Semester I 2024", 2024.

LNG plays a crucial role in Indonesia's energy sector. However, the country's global standing in LNG exports has slipped. In 2024, Indonesia became the eighth-largest LNG exporter, down from sixth place in 2023, with a capacity of 19.2 million metric tonnes per anum (MMTPA). It ranked behind the United States, Australia, Qatar, Russia, Malaysia, Algeria and Nigeria[55]. Notably, Malaysia and Nigeria have recently expanded their LNG export capacities, further impacting Indonesia's position[56]. This trend is likely to continue with Indonesia looking to utilise more LNG production domestically.

World's top LNG exporters 2024



Source: Global Energy Monitor (GEM), 2024

Indonesia's LNG liquefaction and regasification capacities are presented below:

Table 1.8 - List of Indonesian LNG liquefaction plants

Location	Project	Capacity (MMTPA)	Operator
East Kalimantan	Bontang	22.5	PT Badak LNG
West Papua	Tangguh	11.4	BP Tangguh LNG
Central Sulawesi	Donggi Senoro	2	PT Donggi Senoro LNG

Sources:
DGoG, "Statistik Migas Semester I 2024", 2024
Inpex, "Abadi LNG Project.", 2023

Table 1.9 - List of Indonesian LNG regasification terminals

Location	Project	Capacity (MMSCFD)	Operator
West Java	Nusantara Regas Satu	500	PT Nusantara Regas
West Java	Jawa Satu	300	PT Jawa Satu Power
Aceh	Arun Regas	405	PT Pertamina Gas
South Sumatera	Lampung LNG	240	PT PGN LNG
Bali	Tanjung Benoa LNG	50	PT Pelindo Energi Logistik

Sources:
DGoG, "Statistik Migas Semester I 2024", 2024
Pertamina, Perta Arun Gas, ."Bisnis Kami", Accessed in 2025,
Jawa Satu Power, "Project Highlights", Accessed in 2025

Further strategy to improve Reserve Replacement Ratio (RRR)

In response to rising energy demands, SKK Migas in 2024 developed a roadmap for the 2035 Strategic Plan (*Rencana Strategis* - Renstra), aiming to achieve production of 1 MMBOPD oil and 12 billion standard cubic feet per day (BSCFD) natural gas by 2035, an increase of more than 70% on 2024 production levels. SKK Migas's 2035 strategy focuses on several key areas, including exploration-led growth, the operationalisation of Enhanced Oil Recovery (EOR) and the development of more efficient work processes, however, implementing the roadmap has not been easy due to various global and domestic challenges[57].

Exploration activities experienced growth in 2024, particularly with a substantial increase in 2D seismic surveys, which expanded from 25 kilometres in the first half of 2023 to 2,609 kilometres in the first half of 2024. Similarly, 3D seismic operations expanded from 429 to 3,593 square kilometres. The drilling of exploration wells also increased from seven to 17, while development wells rose from 354 to 358 (refer to Table 1.10 Key indicators - Indonesia's oil and gas industry exploration activities below).

Table 1.10 - Key indicators - Indonesia's oil and gas industry exploration activities

		H1 2023 realisation	H1 2024 target	H1 2024 Realisation	% H1 2023 vs H1 2024	% of H1 2024 target
2D seismic	Km	25	3,029	2,609	10436%	86%
3D seismic	Km^2	429	4,612	3,593	838%	78%
Development wells	Wells	354	446	358	101%	80%
Exploration wells drilling	Wells	7	21	17	243%	81%
Workover wells	Wells	397	456	489	123%	107%
Well service activity	Activity	16,577	17,849	17,941	108%	101%
Well service activity	Activity	30,229	33,182	33,412	110.5%	101%

Sources:
SKK Migas, "Press Conference for Performance of Upstream Oil and Gas for the First Semester of 2024", 2024
SKK Migas, "SKK Migas Press Conference on the Performance for the First Half of 2023", 2023
SKK Migas, "Buletin Migas Edition 120 July 2023", 2023

In addition to efforts to augment production from active blocks, the Government prioritised the reactivation of idle wells and fields. It had established criteria for fields inactive for two years or with undeveloped plans. Contractors were afforded the opportunity to optimise these idle areas through various strategies, including self-operation or collaboration, the assumption of management by another contractor, or returning them to the state for re-auction[58].

The Government and industry players focused on adopting new technologies to enhance oil and gas production in Indonesia, including applying Sinopec's production enhancement technology across five Pertamina fields Rantau, Tanjung, Pamusian, Jirak and Zulu[59]. Meanwhile, Pertamina advanced its EOR initiatives in the Rokan Block, focusing on steam flooding in the North Duri Development (NDD) A14 field. This field marked a new steam flood area development following Pertamina's takeover of the Rokan Working Area. The first stage of the project involved drilling 68 wells, including 47 production wells, 15 steam injector wells and 6 observation wells, with total estimated reserves of approximately 6.74 million barrels of oil (MMBO)[60].

Regulatory improvements were made, such as refining the GS-PSC under MoEMR Regulation No. 13/2024, to attract investment, offering an alternative to the existing PSC cost recovery scheme[61]. Furthermore, the Government also streamlined permit requirements, reducing them from approximately 320 to 140 to facilitate investment[62].

In unconventional oil and gas efforts, PHR continued its initiative following the Gulamo exploration well in 2023 by drilling Unconventional Oil and Gas (*Migas Non Konvensional* - MNK) in the Kelok DET-1 well in February 2024[63]. By October, progress in the MNK project was reported, with successful fracturing in the Gulamo DET-1 well, with initial hydrocarbon flowback tests indicating promising signs of oil and gas flow[64].

1.4 Downstream sector

Demand

Crude oil remained in high demand in Indonesia. This was evident from the importation of crude oil and natural gas, which reached 52,144 tonnes in 2023[65] and increased to 53,745 tonnes in 2024[66]. The oil and gas trade balance deficit increased to USD1.76 billion in December 2024, driven by a significant rise in oil and gas imports, totalling 5,213 thousand tonnes, which outpaced the growth in exports[67]. Indonesia is actively working to optimise the use of its domestic natural gas resources. In 2024, domestic gas utilisation reached 3,881 billion British thermal units per day (BBTUD) equivalent to 3,743 MMSCFD. Compared to 2023, this figure increased from 3,757 BBTUD, which is equivalent to 3,623 MMSCFD. This domestic utilisation level in 2024 is approximately 55% of the natural gas production[68].

In terms of biofuel, Indonesia considered raising the biodiesel blend rate from 35% to 40% in 2025, aiming to save IDR147.5 trillion in foreign exchange and reduce CO_2 emissions by 41.46 million tonnes[69]. The actual biodiesel production in 2024 reached 13.15 million kilolitres, which was 116.4% of the target of 11.3 million kilolitres[68]. In recent years, Indonesia has intensified its efforts to utilise Used Cooking Oil (UCO) as a biodiesel feedstock[70]. With the B40 implementation, efforts to use UCO as a biodiesel feedstock increased, leading to stricter export regulations on UCO and palm residues to secure domestic supplies[71].

UCO is also prioritised for Sustainable Aviation Fuel (SAF) from 2027, with a 2025-29 action plan focusing on demand, supply and enablers, including SAF certification and pilot agreements for international flights[72].

Indonesia's future energy landscape, as outlined in the Pertamina Energy Outlook 2023, sees oil demand peaking before declining due to vehicle electrification. Gas is seen as a transitional fuel, crucial for industries and a potential coal replacement, but its role is expected to decrease with the rise of renewables. Strategic planning and infrastructure are deemed necessary for Indonesia's green energy transition[73].

Refinery and midstream Infrastructure

Indonesia's refining industry is controlled by Pertamina, through Kilang Pertamina International (KPI), with a total refining capacity of 1.05 MBOPD from the Dumai, Plaju, Cilacap, Balikpapan, Balongan and Kasim refineries[74]. With capacity expansion, Pertamina has reached 1.15 MPBOPD refinery capacity[85]. Pertamina aims to expand refining capacity to 2.0 MMBOPD through the Refinery Development Master Plan (RDMP), upgrading existing facilities and establishing new refineries in Cilacap, Dumai, Balongan and Balikpapan, with the addition of Grass Root Refinery (GRR) projects in Tuban and Bontang[75]. Key recently completed projects included the increase of Balongan's capacity to 150 MBOPD in 2023[74], and the expansion of RDMP Balikpapan's capacity to 360 MBOPD, completed in 2024[76]. The RDMP Balikpapan project had progressed to 92.42% completion, with the target for finishing set for September 2025.

The completion in 2024 involved accelerating the scope of the secondary process unit Residual Fluid Catalytic Cracking (RFCC). The additional production post-revamp and RFCC unit of RDMP Balikpapan included an increase in fuel products (20 MBOPD of gasoline and 40 MBOPD of diesel) and LPG (300 thousand tonnes per annum)[85].

In 2024, refinery intake volume produced 323 million barrels. The volume intake was targeted to increase by 3% in 2025, reaching 334 million barrels. In the Strategic Work Programme 2025, KPI is expected to pursue expansion and upgrading projects of the existing refineries and maintain higher operating rates to maximise refinery production for the domestic market. Pertamina has routinely carried out refinery upgrades and developments over the past ten years for several projects, such as upgrading projects (the Platformer Dumai, RDMP Balongan and RDMP Cilacap), alongside green projects (Blue Sky Project Cilacap and Green Refinery Cilacap 1) and a petrochemical project (Revamp TPPI Tuban)[85].

The Strategic Work Programme also aimed to optimise feedstock procurement and refinery product sales, alongside efforts to improve refinery yield, which reached 83% in 2024. Additionally, it included the completion and development of refinery projects such as RDMP Balikpapan, Green Refinery, and Petrochemical. The crude oil requirements for Pertamina's refineries reached 300 million barrels per year in 2024. KPI endeavoured to maximise the absorption of domestic crude, with 60% (181 million barrels) sourced domestically. The remainder was met through imports, specifically for certain refineries such as Cilacap, Balikpapan and Balongan, with imported supplies accounting for 40% (119 million barrels)[85].

Refinery-petrochemical integration in Indonesia has been limited to a select number of facilities. The Cilacap refinery stands out as the only one capable of producing value-added chemical products such as olefins, propylene, and aromatics[77]. Additionally, Cilacap is unique in developing renewable feedstocks based on Refined Bleached Deodorised Palm Kernel Oil (RBDPKO), Refined Bleached Deodorized Palm Oil (RBDPO), and Fatty Acid Methyl Esters (FAME), which are processed into biofuels like Hydrogenated Vegetable Oil (HVO), Biosolar and SAF. To support the B40 biodiesel programme, two Pertamina refineries, Plaju and Kasim, are utilised for blending FAME with diesel[85]. The TPPI condensate refinery in Tuban is integrated with aromatics plants, and the Tuban project is focused on producing ethylene and polymers[77].

Indonesia's fragmented gas pipeline network is operated by PT Pertamina Gas and PT Perusahaan Gas Negara[78]. Indonesia had extended pipeline natural gas exports to Singapore until 2028 and exported about 600 MMSCFD of natural gas annually via undersea pipelines to Singapore and Malaysia from gas fields in South Sumatra and West Natuna[77]. Pipeline gas exports to Singapore are projected to rise in 2026 when the Mako gas field in the West Natuna Sea commences production[79]. Indonesia has also commenced the second phase of the Cirebon – Semarang (Cisem) natural gas transmission pipeline project. It aims to connect existing gas transmission networks from East Java to Sumatra, including the Gresik-Semarang and the South Sumatra to West Java networks, with future plans for a pipeline from Dumai to Sei Mangkei in Sumatra[80].

1.5 Contribution to the economy

Dynamics in fuel and gas demand

Indonesia's heavy reliance on imported fuels and crude oil continues to pose significant risks to its energy security due to fluctuating global prices. As the country transitions away from coal to achieve its net-zero emissions target by 2060, its dependence on natural gas is increasing, while renewables are developed. This shift is reflected in the Government's plan to boost gas-fired electricity generation by 21% by 2034, adding 15 GW of new capacity[81].

Fitch predicted that Indonesia's fuel consumption will grow at an average annual rate of 2% from 2024 to 2026, down from a previous 3% forecast, due to government initiatives to promote sustainable energy. These initiatives includes boosting natural gas supplies and cutting fuel subsidies, aiming for cleaner energy and less reliance on fossil fuels. Diesel consumption is expected to fall as it is replaced with natural gas and biofuels in power and industrial sectors. Despite these changes, gasoline demand is expected to stay resilient due to increasing car ownership. LPG demand has slowed due to greater use of electricity and natural gas for cooking, with expanded gas infrastructure likely to further limit LPG use. This is aligned with the Government's efforts to modernise and diversify energy sources for sustainability[82].

Economic impact of oil and gas

In 2024, Indonesia's energy subsidy landscape evolved as the Government sought to balance economic growth with social welfare. The Ministry of Finance (MoF) reported that energy subsidy realisation reached IDR177.6 trillion, an increase from the previous year but still below the target of IDR186.9 trillion. The largest component of this subsidy was for 3 kg LPG canisters, amounting to IDR80.21 trillion or 45.2% of the total energy subsidy expenditure. This represented an 8.0% rise from the previous year, with an estimated output of 7.9 million metric tonnes. Subsidies for fuel in 2024 amounted to IDR21.6 trillion, accounting for 12.5% of the total energy subsidy. This included a diesel subsidy of IDR17.1 trillion and a kerosene subsidy of IDR4.5 trillion, reflecting a 1.4% increase from the previous year for kerosene. Overall, subsidies for fuel and 3 kg LPG canisters rose from IDR95.6 trillion in 2023 to IDR101.8 trillion in 2024[83].

Looking ahead to 2025, the Indonesian government has set an energy subsidy budget of IDR197.75 trillion, representing an 11.34% increase from the 2024 realisation. This budget marks a shift from the previous years of 2023 and 2024, where the largest portion of subsidies was allocated to 3 kg LPG. In 2025, the largest subsidy allocation is for electricity at IDR89.76 trillion, making up 45.38% of the total energy subsidy budget. The 3 kg LPG subsidy is set at IDR82.95 trillion, accounting for 41.38% of the total, while the fuel subsidy comprises 12.67% of the total energy subsidy budget[83].

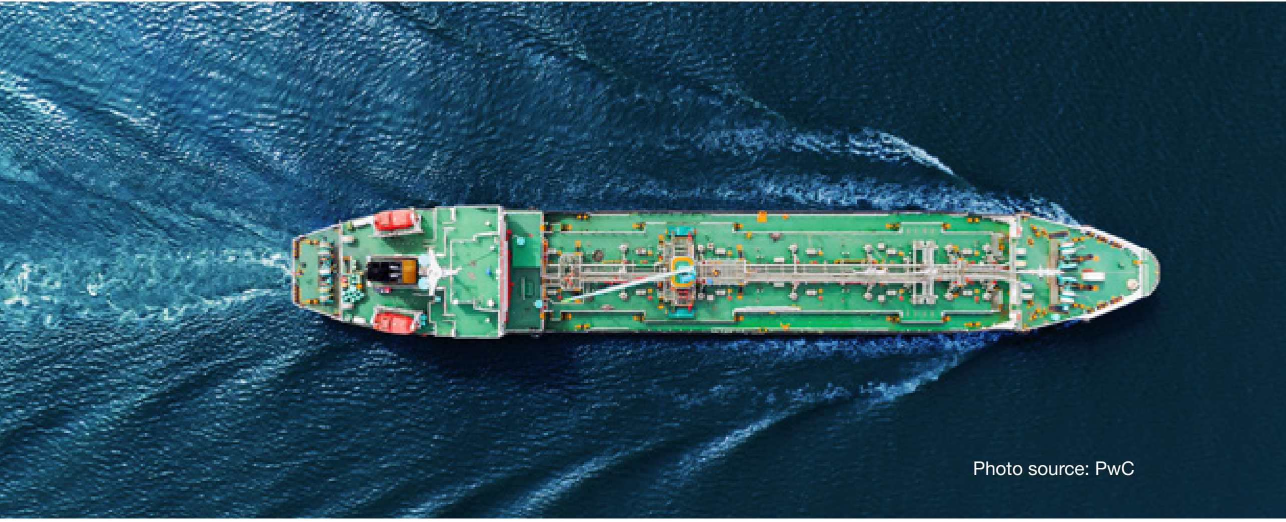
Despite increased subsidies, Non-Tax State Revenue from the oil and gas sub-sector decreased, reaching IDR111 trillion in 2024[68] compared to IDR117 trillion in 2023, but still 101% of the target set at IDR110.15 trillion[84] (refer to Table 1.11 – State budget below).

Table 1.11 - State budget

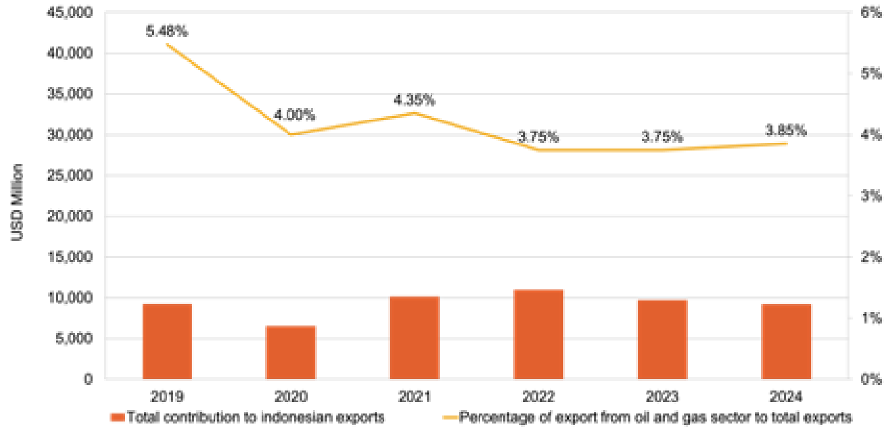
Year	Total state revenue (IDR trillion)	Oil and gas revenue (IDR trillion)	% of contribution from oil and gas
2019	1,959	127	6.49%
2020	1,699	69	4.07%
2021	1,736	95	5.47%
2022	1,846	149	8.05%
2023	2,462	117	4.75%
2024	2,843	111	3.90%

Sources:
MoF, “APBN 2024: Fondasi Kokoh untuk Menghadapi Ketidakpastian Global Sekaligus Mendukung Agenda Pembangunan Nasional”, 2025
MoEMR, “Kinerja Sektor ESDM 2024: Lampaui Target, Penuhi Kebutuhan Domestik, dan Tingkatkan Ketahanan Energi”, 2025

The export revenue from oil and gas grew slightly to 3.85% of total exports in 2024, up from 3.75% in 2023 (refer to figure: Oil and gas exports as a % of total Indonesian exports). Concurrently, the contribution of the oil and gas industry to Gross Domestic Product (GDP) saw another decline from 2.49% in 2023 to 2.38% in 2024 (refer to figure; Oil and gas products as a % of total Indonesian GDP).

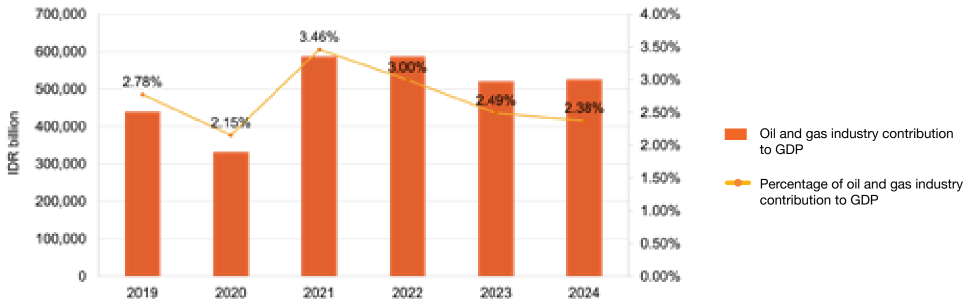


Oil and gas exports as a % of total Indonesian exports



Source: Bank Indonesia (BI), “Indonesian Economic and Financial Statistics (SEKI)”, 2025

Oil and gas products as a % of total Indonesian GDP



Source: Bank Indonesia (BI), “Indonesian Economic and Financial Statistics (SEKI)”, 2025

Investment in oil and gas

The DGoG reported that investment in Indonesia's upstream oil and gas sector reached USD15.33 billion in 2024, marking an 18% increase from the 2023 realisation of USD12.91 billion. This uptick reflects growing investor confidence in Indonesia's oil and gas potential, reflecting a positive outlook amidst the complexities of its evolving international engagements[46].

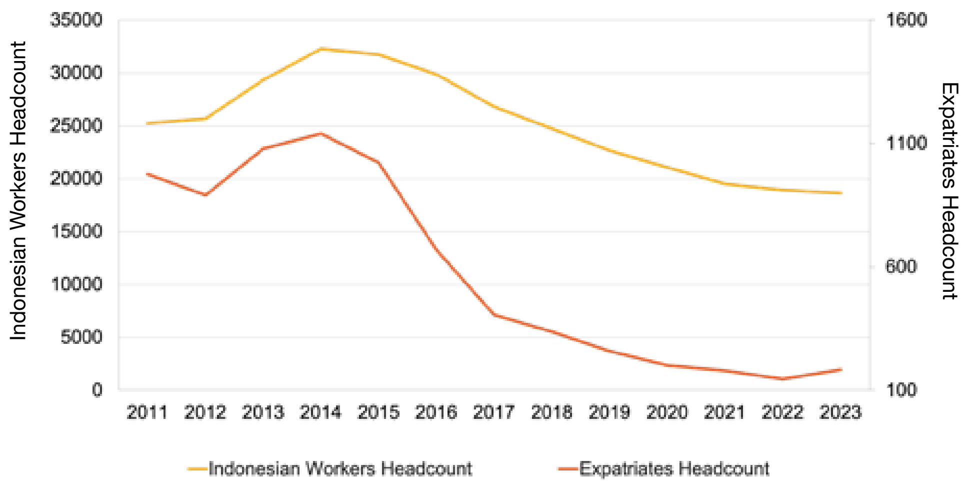
Table 1.12 - Upstream oil and gas investment (in million USD)

Type of operation	2019	2020	2021	2022	2023	2024
Exploration	591	445	613	698	1,041	1,393
Administration	924	718	773	830	663	897
Development	1,733	1,691	1,449	2,707	2,630	3,152
Production	8,621	7,617	8,059	8,087	8,575	9,893
Total expenditure	**11,869**	**10,472**	**10,894**	**12,322**	**12,908**	**15,334**

Sources: 2019 - 2024: DGoG, “Performance Report of the Directorate General of Oil and Gas for the year 2024”, 2024

According to the latest report from SKK Migas, the total workforce of PSC contractors is expected to reach 18,810 employees, comprising 18,627 Indonesian workers and 183 expatriates. From 2015 to 2022, the use of labour in Indonesia has steadily declined due to ongoing efficiency programmes implemented by PSC contractors. However, the number of foreign workers has increased slightly due to the execution of several oil and gas projects as set out in the figure below, although still less than 1% of the total workforce[20].

Indonesian workers and expatriates headcount in oil and gas



Source: SKK Migas, “SKK Migas 2023 Annual Report”, 2024

2 The role of oil and gas in energy transition (2025 edition)

2.1 Introduction

Sustainability in oil and gas is complex, yet full of opportunities due to the realities of sustainable transformation and the evolving oil and gas landscape. While, oil demand has been growing, the implementation of net-zero strategies could reduce demand going forward. In this market, the companies capable of producing oil at a lower price with a lower overall carbon intensity will have an advantage. However, the companies that are late to transformation, will need to pivot. Recent developments have shown that companies are adapting by shifting to green electrons (renewables) or green molecules (biofuels, hydrogen and carbon capture).

Companies face challenges in internalising the cost of unsustainable practices. However, changing shareholder agendas, regulatory environment, and consumer preferences are driving the shift in corporate priorities. Data gaps make decision-making even harder, but new standards like International Financial Reporting Standards (IFRS) S1 and S2 are driving progress. These standards contribute to the broader effort of integrating financial factors into sustainability reporting, enhancing quality and consistency across international borders, and providing better comparability, transparency and reliability for investors and other stakeholders.

Moreover, scaling biofuels requires the appropriate environment (feedstock availability, socio-ecological safeguards, policy framework, etc.). Some regions such as East Asia, are at a greater advantage compared to Southeast Asia, where overall growth is below the projections of net-zero pathways. Therefore, practical solutions matter in this context to develop the proper strategy and execution for energy transition.

Indonesia's energy sector is undergoing a transformative phase to balance the global energy trilemma: ensuring energy security, fostering economic development and achieving decarbonisation. International commitments such as the Paris Agreement and Indonesia's Long-Term Strategy for Low Carbon and Climate Resilience (LTS-LCCR) underscore the urgency of this transition. These agreements necessitate significant reductions in greenhouse gas (GHG) emissions, which directly affect the oil and gas (O&G) sector's operational landscape as one of the major emission contributors. Many sectors (from transportation to industry), traditionally reliant on fossil fuel extraction and processing, now face pressures to decarbonise while ensuring energy affordability and reliability. In fact, oil and gas remain pivotal as transition fuels, particularly natural gas, which supports renewable energy integration and smooths the transition pathway[86]. As Indonesia aims to achieve net-zero emissions by 2060, the O&G industry's role extends beyond production to include investments in low-carbon technologies and infrastructure that align with international decarbonisation objectives[87]. Low-carbon solutions such as Carbon Capture, Utilisation and Storage (CCUS), the development of new sources like hydrogen, higher bioenergy (either mixed, biomethane or equivalent), electricity-based solutions such as electric vehicles, and energy efficiency measures are all part of this effort. Indonesia strives to maintain energy security and economic growth while progressively reducing its carbon footprint. In the end, the O&G sector remains integral to Indonesia's growth and decarbonisation journey.

The transition from traditional fossil fuels to low-carbon energy solutions is a crucial component of the global initiative to reduce greenhouse gas emissions and address climate change. Several promising technologies are currently under development and are being scaled up at the national and global levels, including Carbon Capture and Storage/Carbon Capture, Utilisation and Storage (CCS/CCUS), hydrogen, biomethane, alternative electrification, and flexible gas power. Despite the fact that low-carbon technology can be an alternative, the O&G sector recognises this as an opportunity for transition due to its similar characteristics.

Among other low-carbon technologies, CCS/CCUS is regarded as a key set of technologies for mitigating emissions in the sectors that are challenging to decarbonise, such as O&G, heavy industry and fossil-fuel-based power generation. Reducing emissions from cement, iron, steel and chemical production (which contributed approximately 23% of Indonesia's carbon dioxide (CO_2) emissions in 2021[88]) is likely to be most effectively achieved by retrofitting industrial plants with carbon capture systems. The CCS/CCUS process generally involves four main steps: 1) capturing CO_2 emissions from industrial facilities, fossil-fuel power plants, or directly from the atmosphere; 2) transporting the captured CO_2 to locations for utilisation or storage via ships, trucks or pipelines; 3) utilising the captured CO_2 in the production of goods or services; and 4) permanently storing the CO_2 in geological formations, either onshore or offshore.

As a low-carbon fuel, hydrogen is emerging as a vital component in achieving net-zero emissions, serving as a versatile energy carrier with significant potential to decarbonise various sectors, including power generation, heating, heavy industry and transportation. There are primarily three types of hydrogen: 1) green hydrogen, produced by renewable energy sources; 2) blue hydrogen, generated by splitting natural gas into hydrogen and CO_2 with the integration of CCS/CCUS technologies; and 3) grey hydrogen, similar to blue hydrogen but without use of CCS/CCUS technology. Green and blue hydrogen, in particular, can help decarbonise Indonesia's power generation, transport (light- and heavy-duty vehicles, ships, trains and airplanes) and heavy industry, such as steel, pulp, cement and chemicals.

Biomethane, also known as Renewable Natural Gas (RNG), is a sustainable and renewable energy source (produced from organic materials like manure, agricultural residues, sewage sludge, and food waste) via either anaerobic digestion or gasification. Due to its identical characteristic to fossil-based natural gas, biomethane can be used in electricity generation, industrial applications and powering vehicles like cars, buses, and trucks, thereby reducing emissions.

Electrification involves the use of electricity generated from low-carbon sources to replace fossil fuels in various applications, such as transportation and heating. The shift from fossil fuels to electrification is a crucial step in fostering energy transition and achieving Indonesia's net zero target. The electrification of the transport sector via Electric Vehicles (EVs) for individual and public transport use replaces the traditional internal combustion engine vehicles, thereby reducing emissions associated with transportation.

Flexible gas power is a technology that is designed to quickly adjust its output to balance the variability of electricity supply and demand in a system that has high penetration of intermittent sources such as wind and solar. Flexible gas power can play a key role in stabilising Indonesia's energy grid amid the expansion of renewables. As more wind and solar power are integrated into the grid, this technology provides the necessary backup to ensure reliability when wind and solar power are not producing electricity due to their intermittent nature.

2.2 Oil and gas in the energy transition

2.2.1 The climate ambitions of Indonesia toward decarbonisation

Indonesia remains one of the most fossil fuel-dependent economies, with fossil fuels accounting for more than 80% of its energy supply in 2023[89]. O&G alone contributes 47% of the national energy mix as of 2023[90]. Petroleum products (gasoline and diesel) remain the predominant source in the transport sector, constituting 99.86% of energy consumption in transport[91].

While Indonesia has committed to achieving net-zero emissions by 2060, significant structural challenges remain, including heavy reliance on coal for baseload power and petroleum for transport, subsidies for fossil fuels, the slow pace of transition/ integration, and the financial burden of energy transition investments. The urgency of Indonesia's energy transition is underscored by its ambitious climate targets. Under its Long-Term Strategy for Low Carbon and Climate Resilience (LTS-LCCR), Indonesia aims to reach a renewable energy share of 23% by 2025 and progressively increase it to 31% by 2030 before achieving full decarbonisation in the power sector by 2050[92]. However, the pace of renewable energy development remains below expectations, with actual renewable energy deployment reaching only 13.4% of the energy mix as of 2023, far short of the interim targets set under the National Energy Policy (*Kebijakan Energi Nasional* - KEN)[93].

To support its energy transition, Indonesia has aligned its policies with international commitments, particularly under the Paris Agreement and the Just Energy Transition Partnership (JETP). The JETP, launched at the G20 Summit in Bali (2022), sets a roadmap for decarbonising Indonesia's electricity sector, with a goal of capping power sector emissions at 250 million tonnes of carbon dioxide ($MtCO_2$) by 2030 and achieving net-zero emissions in the sector by 2050[94]. This transition requires extensive investment in grid modernisation, renewable energy capacity expansion and energy storage solutions. The JETP roadmap estimates that Indonesia will require USD42 billion in cumulative grid infrastructure investments by 2040, with an additional USD9 billion needed for distribution networks[95]. To attract private sector participation, the Government has introduced incentives for Foreign Direct Investment (FDI) in renewable energy, but regulatory uncertainties and slow bureaucratic approvals continue to deter investors. In 2023, Indonesia secured USD3.6 billion in FDI for renewable energy projects, yet this remains far below the USD25 billion required annually to meet JETP targets[96].

The 2024 National Electricity Plan (*Rencana Umum Ketenagalistrikan Nasional* - RUKN) roadmap outlines the need for 6,000 kilometres (km) of new transmission lines by 2030, increasing to 15,000 km by 2040, to facilitate the integration of intermittent renewable energy sources such as solar and wind power[97]. Furthermore, the Government has projected USD97.1 billion in energy transition investments between 2023 and 2030, increasing to USD580.3 billion by 2050, to finance the shift towards clean energy[98].

The National Long-Term Development Plan/*Rencana Pembangunan Jangka Panjang Nasional* (RPJPN), governed by Law No. 59 of 2024, outlines the future energy landscape and underpins the energy transition as a part of economic transformation. The policy direction for implementing a green economy in Indonesia is based on the execution of low-carbon development. Hence, the energy transition, as part of economic transformation, is directed towards the utilisation of clean, efficient and renewable energy through the accelerated use of low carbon technology like CCS/CCUS, nuclear and renewable energy sources such as bioenergy, geothermal, hydro, solar and wind. The CCS/CCUS pilot implementation starts in 2024-2029, and will expand to other hard-to-abate sectors between 2030-2045. The low-carbon hydrogen use will be expanded to transport and industry by 2030-2045. This includes the gradual retirement of coal-fired power plants, the development of infrastructure and technology, the increase in quality energy consumption, the development of electrical grids and the acceleration of the use of clean energy vehicles.

In conclusion, Indonesia's energy transition is a complex, multi-faceted process requiring coordinated policy action, significant financial investments, and robust infrastructure development. The Government's alignment of the 2024 RUKN policies with the JETP roadmap provides a clear framework for balancing economic growth with emissions reduction targets. However, achieving these ambitions will depend on accelerating renewable energy deployment, modernising the national grid, and mobilising private sector investment. While progress is being made, the scale of the transition necessitates sustained policy support, international cooperation and financial commitment to ensure a secure, sustainable and inclusive energy future for Indonesia.

2.2.2 Opportunities and challenges in integrating sustainability within the oil and gas industry in Indonesia

To mitigate long-term emissions, Indonesia is actively developing alternative low-carbon solutions within the O&G sectors, such as CCS/CCUS, hydrogen, biomethane, LNG, flexible gas and electrification on the demand side.

The oil and gas industry has an array of opportunities that Indonesia can maximise. The adoption of Environmental, Social and Governance (ESG) principles presents significant opportunities for both the government and private sector companies operating within Indonesia's oil and gas industry. In particular, implementing ESG practices can help the nation attract foreign investment, as global investors are increasingly prioritising sustainability criteria[99].

The journey to ESG implementation in Indonesia's oil and gas sector brings forth challenges from various aspects. From the regulatory side, there is an ever-evolving nature of both local and international regulations that requires businesses to constantly adapt their processes. Environmental challenges can also financially burden companies as the oil and gas industry is implicated in emissions and even deforestation. Financially, the initial expenses of integrating ESG indicators can be large, necessitating a significant capital outlay with potential long-term rewards. There is not a one-size-fits-all solution to the negative ESG implications from the oil and gas industry[100], but robust ESG frameworks can help in strengthening and diversifying economic growth, transitioning to sustainable energy sources as well as enhancing energy security.

2.2.3 CCS/CCUS in Indonesia's energy transition

Indonesia is rapidly advancing its CCS/CCUS initiatives, recognising the technology as an essential component of its long-term decarbonisation strategy. With vast offshore storage potential and increasing regulatory support, Indonesia boasts a substantial carbon storage capacity of approximately 577.6 gigatonnes of CO_2[101]. The implementation of CCS/CCUS in Indonesia has the potential to cut emissions by up to 190 million tonnes of CO_2 annually by 2060, with fully operational storage sites in Sumatra, Java, Kalimantan and Sulawesi[102]. This includes the integration of CCS with non-oil and gas sectors, such as cement and steel production, petrochemicals, and low-emission hydrogen and ammonia production from 2030 onward. This capacity is predominantly concentrated in saline aquifers and inactive oil and gas fields.

The Government has reinforced its commitment through Ministerial Regulation No. 2/2023 and Presidential Regulation No. 14/2024, which provide the legal framework for CCS projects, investment incentives, and international collaboration. Presidential Regulation No. 14/2024 facilitates domestic and cross-border CO_2 trade, transport, and storage. MoEMR Regulation No. 2/2023, alongside SKK Migas Directive (PTK 070), provides guidelines for the development and implementation of CCS/CCUS in the oil and gas sectors. MoEMR Regulation No. 16/2024 governs carbon storage activities within designated carbon storage permit areas.

The Tangguh Ubadari CCS/CCUS and Compression (UCC) Project, led by BP Berau and its partners, is Indonesia's first large-scale CCS/CCUS project. Approved in November 2024, the USD7 billion project integrates Enhanced Gas Recovery (EGR) technology with CCS/CCUS infrastructure, enabling the storage of 15 million tonnes of CO_2 over its initial phase[103]. The initiative involves the development of three offshore injection wells, a dedicated offshore CO_2 injection platform, and a pipeline network to transport captured CO_2 to geological storage sites. The project aligns with Indonesia's strategy to decarbonise its LNG industry, particularly as Tangguh LNG accounts for nearly 40% of Indonesia's total LNG exports. The project also supports Indonesia's Nationally Determined Contributions (NDCs), which target a 29% reduction in emissions by 2030 without international assistance, and up to 41% with external support.

Another significant development is the Masela Abadi LNG CCS Integration project, spearheaded by Inpex Corporation. The Masela field, located in the Arafura Sea, is one of Indonesia's largest undeveloped gas reserves, estimated to hold 10.7 trillion cubic feet (Tcf) of recoverable gas[104]. The updated development plan, approved in 2023, mandates the incorporation of CCS/CCUS infrastructure, ensuring that emissions from LNG liquefaction are captured and permanently sequestered. The project is projected to store over 3.5 million tonnes of CO_2 annually, reinforcing Indonesia's commitment to aligning LNG production with low-carbon objectives[105].

Beyond these two projects, 15 CCS/CCUS projects are currently in the study or preparation phase, spanning from the west to the east of Indonesia[106]. These projects include:

- Tangguh EGR/CCUS (discussed earlier)
- Abadi CCS (discussed earlier)
- Sukowati CCUS/EOR
- Gundih CCUS/EGR
- Pilot Test CO_2 Huff and Puff at Jatibarang
- Ramba CCUS/EOR
- CO_2 Huff and Puff at Gemah
- Sakakemang CCS
- Arun CCS
- Central Sumatra Basin CCS/CCUS Hubs
- Kutai Basin CCS Hub
- Asri Basin CCS/CCUS Hubs
- CCU to Methanol at RU V Balikpapan
- East Kalimantan CCS/CCUS Study
- Blue Ammonia + CCS at Donggi Matindok

The Government of Indonesia has estimated that the cost of injecting CO_2 for storage projects is substantial, as per Table 2.1:

Table 2.1 - Cost, volume and investment for CCS projects in Indonesia

CCS Projects	Cost (per tonne of CO_2)	Volume (tonnes of CO_2 per year)	Investment cost (USD)
Natural Gas Purification, Gundih, East Java	USD43-53	0.3 million	105 million
LNG Production, Bintuni, West Papua	USD33	2.5-3.3 million	948 million
LNG Production, Masela, East Nusa Tenggara	USD26	3.5 million	1.4 billion
Coal Gasification to DME, Tanjung Enim, South Sumatra	USD50-55	3 million	1.6 billion

Source: MoEMR, “Menteri Arifin Beber Tantangan CCS/CCUS”, 2024.

These projects represent significant investments in carbon capture and storage, highlighting Indonesia’s commitment to reducing emissions and becoming a leading CCS/CCUS hub. Indonesia has also outlined a national vision to become a regional CCS hub, with plans to import CO_2 from Asia-Pacific countries such as Japan and Singapore, leveraging an estimated 400 gigatonnes (Gt) of CO_2 storage capacity in offshore basins. This initiative is backed by international agreements and collaborations to facilitate cross-border CO_2 storage solutions. The Natuna Basin and East Kalimantan Basin have been identified as priority sites for cross-border CCS projects, particularly in collaboration with Singapore and Malaysia. In February 2024, the

ASEAN Council on Petroleum (ASCOPE) endorsed Indonesia's CCS/CCUS roadmap, which includes pilot projects for cross-border CO_2 transport and storage, aiming to position Indonesia as a key service provider for regional carbon storage solutions[107].

Indonesia can gain valuable insights into best practices for large-scale CCS deployment from other countries like Norway and China. The Sleipner Gas Field in Norway, operated by Equinor, has been storing approximately 1 million tonnes of CO_2 annually since 1996[108]. As the world's first commercial CCS project, Sleipner has demonstrated the viability of offshore geological storage, providing key data on long-term CO_2 containment, monitoring, and verification techniques. Its success has influenced regulatory frameworks globally, including Indonesia's recent CCS policies. China has also made significant strides in CCS/CCUS development, with Sinopec's Qilu-Shengli CCS/CCUS project capturing 1 million tonnes of CO_2 per year for Enhanced Oil Recovery (EOR)[109]. The project serves as a benchmark for integrating CCS/CCUS with hydrocarbon production, highlighting how carbon capture can be commercially viable while supporting emissions reduction targets.

2.2.4 Alternative fuels

Hydrogen developments in the oil and gas sector to support transition

Indonesia is integrating hydrogen into its oil and gas sector to accelerate its energy transition and enhance energy security. Currently, 1.75 million metric tonnes of hydrogen are consumed annually, primarily in fertiliser production, ammonia synthesis and oil refining[110]. The National Hydrogen Strategy, launched in December 2023, prioritises green hydrogen from renewables and blue hydrogen via CCUS to position Indonesia as a key regional producer and exporter[111].

Pertamina is leading Indonesia's hydrogen development, identifying 17 potential production sites. Its Ulubelu Green Hydrogen Facility in Lampung will generate 100 kilograms of hydrogen per day using geothermal power[112]. Additionally, Pertamina and Hyundai are developing Indonesia's first hydrogen refuelling station in Jakarta, aiming to support hydrogen-powered transport[113]. To scale up hydrogen deployment, Indonesia is targeting USD25.2 billion in private investment by 2060[114].

On a larger scale, Sembcorp Utilities and *Perusahaan Listrik Negara* (PLN) are constructing a green hydrogen facility in Sumatra, capable of producing 100,000 tonnes per year. This will be Southeast Asia's largest facility, targeting exports to Singapore via subsea pipeline[115]. By 2040, hydrogen demand in Indonesia could reach 8 million metric tonnes per year, requiring 220 terawatt-hours (TWh) of electricity by 2060, which is nearly Indonesia's current total power demand.

However, high production costs, infrastructure gaps and regulatory uncertainties remain key challenges. Strategic incentives and global partnerships will be critical in establishing a viable commercial hydrogen market, ensuring Indonesia's competitiveness in the global energy transition.

LNG and flexible gas power for grid stability and backup supply

LNG serves as a transitional "bridge fuel" between conventional, high-emission fossil fuels and cleaner energy sources, thereby playing a vital role in the energy transition. In its liquefied form, LNG has a lower carbon emission profile compared to other fossil fuels, such as coal and oil. The combustion of LNG results in reduced emissions of carbon dioxide (CO_2) and pollutants like nitrogen oxides (NOx) and sulfur dioxide (SO_2). Replacing higher-emission fossil fuels with LNG in industrial applications, electricity generation, and hydrogen production leads to a significant and immediate reduction in carbon intensity. For instance, regional industrial parks that are powered by coal, and have resulted in a huge increase in Indonesia's coal-fired power fleet, can reduce their carbon intensity by utilising a captive Combined Cycle Gas Turbine (CCGT) fuelled by LNG.

The use of LNG in industrial applications, combined with the installation of CCS/CCUS system, can also significantly reduce the carbon footprint of heavy industries. Historically, the potential for carbon capture at stages such as gas extraction, liquefaction and combustion was largely theoretical and not scalable. However, an increasing number of large-scale carbon capture projects attached to gas-based energy systems are being implemented globally, demonstrating the possibility of effectively capturing carbon emissions and storing them underground. Therefore, LNG has the potential to be a critical intermediary in reducing global greenhouse gas emissions and even catalysing innovation for CCS/CCUS while meeting energy demands.

Flexible gas power refers to gas-fired power plants engineered with rapid start-up and shutdown capabilities, which enable them to effectively complement intermittent renewable energy sources such as solar and wind. These plants can swiftly adjust their output to accommodate fluctuations in demand, thereby enhancing grid stability. By serving as a reliable backup for renewable power generation, LNG-fired power plants can ensure a continuous electricity supply during periods of low renewable generation, thereby mitigating the intermittency challenges typically associated with renewable energy sources[116].

Expanding gasification and bio-CNG to replace diesel in transport and industry (de-dieselisation)

Expanding gasification and bio-Compressed Natural Gas (CNG) to replace diesel in transport and industry sectors offers significant environmental and economic benefits. Bio-CNG, derived from upgraded biogas, is a cost-effective and cleaner alternative to diesel, producing lower CO_2 emissions and less particulate matter. Despite challenges in transporting and supplying Compressed Natural Gas (CNG), these technologies play a vital role in transitioning away from diesel, enhancing energy security, and supporting renewable energy integration.

The National Energy Plan (RUEN) targets 489.8 million m³ of biogas in the national energy mix by 2025, with 143.4 million m³ realised in 2023, leaving a gap of 346.4 million m³. Ensuring feedstock sustainability, limited infrastructure and distribution networks and higher production costs compared to fossil fuels are significant challenges. Developing bioenergy strategies for agro-industry and supporting PLN's de-dieselisation plan with bioenergy technologies are key to achieving national energy targets and promoting sustainable economic growth. For example, gasification can decarbonise the steel industry by producing syngas from biomass, which can be used in direct reduced iron processes, significantly lowering carbon emissions. Meanwhile, bio-CNG is particularly beneficial for the transport sector, offering a cleaner and cost-effective alternative to diesel.

In general, syngas burns cleaner than diesel, resulting in significantly lower emissions of pollutants such as particulate matter, nitrogen oxides (NOx), and sulfur oxides (SOx). This helps industries reduce their environmental footprint and comply with stricter environmental regulations. Syngas is generally used for four industrial applications: as fuel gas to fire boilers or turbines in power cycles, as feedstock for production of synthetic fuels such as gasoline, as feedstock for hydrogen production, and also as feedstock for methanol synthesis as well as production of various chemical products.

CNG is generally cheaper than diesel and offers comparable fuel consumption, making it a practical choice for reducing lifecycle emissions. However, transporting and supplying CNG can be challenging and costly, especially across borders. Despite these challenges, CNG and gasification technologies offer flexibility and play a vital role in transitioning away from diesel, enhancing energy security, and supporting renewable energy integration.

Biofuel expansion supports the energy transition

Indonesia’s growing commitment to biofuels has positioned Palm Oil Mill Effluent (POME) as a crucial feedstock for renewable energy production. With an annual palm oil output exceeding 126 million tonnes of fresh fruit bunches, Indonesia generates over 60 million cubic metres of POME[117]. Historically considered an industrial waste product, POME is now being repurposed for biogas, bio-CNG and biodiesel, significantly reducing methane emissions and enhancing domestic energy security. The Indonesian government has recognised the strategic role of POME in supporting the national de-dieselisation agenda, particularly in the transport and industrial sectors[118].

Indonesia has been progressively increasing its blending mandates from B20 to B30 and is now targeting B40 and B50. Pertamina, the state-owned energy company, has played a pivotal role in scaling up biodiesel adoption by incorporating POME-derived feedstock and used cooking oil into its production mix[119]. The National Energy Policy aims for a B40 mandate by 2025, with road tests confirming its feasibility for transport, mining, and maritime applications. Concurrently, Indonesia is advancing bioethanol production, primarily from sugarcane and cassava, with the aim of integrating ethanol into gasoline blends to further displace fossil fuel consumption[120].

Pertamina has initiated large-scale procurement of used cooking oil for biofuel production, reducing reliance on crude palm oil while promoting circular economy principles. In parallel, the private sector has been instrumental in expanding bioethanol refining capacity, with companies like PT Astra Agro Lestari exploring palm oil waste as a bioethanol feedstock[121]. The Government has tightened export controls on POME to ensure sufficient domestic supply for biodiesel and bioethanol production[122].

Beyond liquid biofuels, POME-derived biogas and bio-CNG are emerging as viable diesel substitutes, particularly in heavy transport and industrial applications. Indonesia's gasification roadmap includes large-scale deployment of bio-CNG for trucking fleets and industrial heating. PTPN III, in collaboration with PGN and Japanese investors, is developing a POME-based biomethane production facility, with a focus on reducing the carbon footprint of logistics and manufacturing[123]. This initiative aligns with Indonesia's ambition to decarbonise hard-to-abate sectors while maximising the utilisation of existing palm oil industry byproducts.

Photo source: PT Medco Energi Internasional Tbk

Indonesia's biofuel expansion is supported by robust policies, offering incentives for biodiesel, bioethanol and bio-CNG producers. However, challenges remain, including feedstock sustainability, infrastructure limitations and higher production costs compared to conventional fossil fuels. To address these issues, the Government is incentivising investment in biofuel refineries, advanced biogas plants and POME-to-energy projects through various fiscal and non-fiscal measures[124].

For investors, Indonesia's growing biofuel sector presents opportunities across feedstock processing, technology development, and fuel distribution networks. Companies with expertise in biorefining and gasification technologies stand to benefit from the country's accelerated shift towards cleaner energy alternatives. As the nation moves towards its 2060 Net Zero target, POME-derived fuels will play an increasingly critical role in displacing fossil fuels, ensuring energy security and meeting climate commitments.

Sustainable aviation fuels progress in Indonesia

Indonesia is advancing the development of Sustainable Aviation Fuel (SAF) as part of its broader decarbonisation strategy, particularly in the transport sector. The aviation industry remains a significant contributor to GHG emissions, and Indonesia's commitment to net-zero emissions by 2060 has necessitated urgent measures to reduce its aviation-related carbon footprint. SAF, produced from bio-based feedstocks such as Used Cooking Oil (UCO), Palm Fatty Acid Distillate (PFAD), and other renewable sources, is seen as a key solution for achieving emission reductions while maintaining the growth of air travel.

The SAF Action Plan, unveiled by the Ministry of Maritime Affairs and Investment during the Bali International Airshow in September 2024, mandates a gradual SAF blending requirement for international flights departing from Indonesia. The regulation sets an initial 1% SAF blend in 2027, increasing progressively to 2.5% by 2030, 12.5% by 2040, 30% by 2050 and ultimately reaching 50% by 2060[125]. The policy aligns with global efforts led by the International Civil Aviation Organization (ICAO) and the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), positioning Indonesia as a regional leader in sustainable aviation fuel adoption[126].

To support SAF production, Indonesia is leveraging its vast bioenergy potential. PT Kilang Pertamina Internasional (KPI) is leading the country's SAF development efforts, with a target to produce 300,000 kilolitres annually at its Balikpapan refinery by 2026 (Pertamina, 2024). The facility will use Hydroprocessed Esters and Fatty Acids (HEFA) technology, converting UCO and PFAD into jet fuel-compatible SAF. This initiative complements the SAF pilot production trials conducted in 2023, which successfully tested a 2.4% biofuel blend in jet fuel for domestic flights operated by Garuda Indonesia[127].

Indonesia's bio-based SAF feedstock potential is estimated at 13.1 million kilolitres per year, supported by the country's palm oil industry and emerging alternative sources such as seaweed, coconut oil and rice dregs[128]. However, several challenges remain, including high production costs, limited refinery capacity and the need for dedicated SAF supply chain infrastructure. To address these issues, the Government is exploring incentives, including tax reductions and preferential financing schemes, to attract private-sector investment and scale up SAF production.

Recognising the need for international collaboration, Pertamina has entered a strategic partnership with Airbus to assess SAF development potential in Indonesia. The partnership aims to evaluate feedstock availability, production feasibility, and commercial deployment to support SAF adoption across Southeast Asia. This aligns with global trends, where major aviation and energy companies are accelerating SAF investments, such as Porsche and Siemens Energy's e-fuel project in Chile and Saudi Aramco's synthetic fuel refineries in Japan[129].

The development of SAF in Indonesia represents a crucial step towards reducing aviation emissions, enhancing energy security and positioning the country as a key player in Asia's sustainable aviation fuel market. With regulatory mandates, growing industrial partnerships and expanding biofuel infrastructure, Indonesia is well-positioned to scale up SAF production and integrate it into both domestic and international aviation networks.

2.2.5 Challenges for oil and gas

Electric vehicles disrupting oil and gas demand

The global automotive industry is undergoing a profound transformation as electrification gains momentum, driven by decarbonisation imperatives and advancements in battery technology. According to the International Energy Agency (IEA), global EV sales reached a record 14 million units in 2023, accounting for 18% of total car sales, with China, the European Union and the United States leading the transition[130]. Projections indicate that by 2030, more than 60% of new car sales in China and Europe will be electric, significantly reducing reliance on petroleum-based fuels[168]. While fossil fuel-based vehicles continue to dominate global on-the-road transportation, EVs are gradually reshaping mobility trends. This shift is particularly significant in Indonesia, where transportation accounts for around 36.74% of total energy consumption, making it a critical sector for energy transition efforts[131].

Indonesia's EV adoption has been comparatively slower than in leading global markets but is accelerating due to government incentives and increasing private sector investments. As of mid-2024, the country had 1,810 public EV charging stations (SPKLUs) across 1,306 locations, with projections to reach 48,118 SPKLUs by 2030[132]. This expansion is essential to support the national target of having 2 million electric cars and 13 million electric motorcycles on the roads by 2030[133].

The two-wheeler segment is expected to drive the majority of EV adoption due to its affordability and widespread use in Indonesia's urban mobility landscape. Government incentives have reduced the upfront cost of electric motorcycles, accelerating their adoption among ride-hailing companies and logistics providers[134]. Gojek and Grab, Indonesia's largest ride-hailing firms, have already committed to transitioning their fleets to electric motorcycles, further catalysing market growth.

Several international manufacturers, including those from China (such as BYD and Wuling), South Korea (Hyundai, in partnership with LG Energy Solution), and Vietnam (VinFast), are actively developing their EV supply chains in Indonesia.

BYD is investing approximately USD1.3 billion to establish an EV manufacturing plant in West Java, aiming for an annual production capacity of 150,000 units, with operations anticipated to commence in 2026[135]. Wuling and Hyundai have initiated their EV manufacturing operations earlier, with commissioning starting in 2017 and 2022, respectively. Wuling achieved a significant milestone by producing 160,000 EV units at its Cikarang facility in 2024, while Hyundai expanded its production capacity from 150,000 units to 250,000 units following an additional investment of USD1.55 billion in 2022[136]. Meanwhile, VinFast has invested around USD200 million to establish its EV assembly plant in Subang, with an anticipated annual production capacity of 50,000 units[137].

Hyundai is also extending its EV supply chain to include battery manufacturing facilities. In collaboration with LG Energy Solution, Hyundai commenced the construction of a USD1.1 billion battery plant in 2021[138]. The Hyundai-LG battery facility began commercial production in 2024, with an expected annual output of 10 gigawatt-hours (GWh) of battery cells, sufficient to power over 150,000 EVs[139]. Wuling is following Hyundai's lead in building a comprehensive EV supply chain by investing in its battery manufacturing facility, although its production capacity remains undisclosed[140].

The expansion of EV charging infrastructure is critical for mass adoption. PLN, Indonesia's state-owned electricity company, is leading the deployment with fast-charging networks in collaboration with private firms. By 2025, PLN aims to establish 9,287 charging stations across Indonesia, facilitating longer-range EV travel and improving charging convenience[141]. Additionally, the integration of battery-swapping stations, pioneered by companies such as Pertamina and Oyika, is emerging as an alternative solution to address charging time constraints[169]. Currently, the expansion of charging infrastructure can be integrated with the oil and gas stations, but it could replace them if electric vehicles become the major fleets on the road. Looking ahead, the declining cost of EV batteries and the expansion of charging infrastructure are expected to accelerate adoption rates. By 2035, EVs could account for 50% of new vehicle sales in Indonesia, significantly reducing fuel consumption and emissions from the transport sector[142].

This shift will directly impact Indonesia's O&G industry, necessitating further investments in alternative energy solutions, including hydrogen fuel cells and renewable energy integration, while at the same time, reducing import requirements and rebalancing Indonesia's domestic supply-demand equation.

The transition to EVs is not limited to passenger vehicles. Indonesia is also investing in electric buses and trucks to decarbonise public and commercial transportation. TransJakarta, the capital's public bus operator, has pledged to convert its entire fleet to electric buses by 2030, with initial deployments reaching 100 units in 2024[170]. In the logistics sector, companies such as Bluebird and DHL are integrating electric delivery vans to reduce emissions from last-mile delivery operations[143].

The ongoing transformation of Indonesia's transport sector underscores the broader energy transition underway. As EV adoption scales, O&G companies will need to adapt their strategies to remain competitive in a decarbonising world. By investing in EV-related infrastructure, battery supply chains, and sustainable mobility solutions, they can position themselves as key players in Indonesia's low-carbon future.

Recognising the long-term implications of EV adoption, major O&G companies in Indonesia are diversifying their business models. Pertamina, for example, has committed USD5 billion to develop an EV battery ecosystem, encompassing nickel processing, battery production and charging infrastructure development[144].

For O&G companies, this transition poses both risks and opportunities. While gasoline and diesel demand will continue in the medium term, companies are increasingly investing in alternative energy solutions, including EV infrastructure and battery technologies. ExxonMobil, for example, has initiated lithium extraction projects in the United States, positioning itself as a key supplier for the EV industry[145]. Similarly, Shell has expanded its EV charging network to over 70,000 charging points globally, aligning with the shift towards electrification[146].

Investment in low-carbon O&G technologies and O&G's contribution in financing the net zero transition

To navigate the structural decline in fossil fuel demand, oil and gas companies are increasingly diversifying their investment portfolios to include low-carbon technologies. The Oil and Gas Climate Initiative (OGCI) reported that its 12 member companies, including BP, Shell and TotalEnergies, have collectively invested nearly USD100 billion in low-carbon projects since 2017[147]. In 2023 alone, OGCI members allocated USD29.7 billion to low-carbon investments, representing a 15% increase from the previous year, underscoring the sector's commitment to decarbonisation[148]. The primary areas of investment include:

- CCS/CCUS: As of 2023, over 41 large-scale CCS/CCUS projects are currently in operation worldwide, with a combined CO_2 storage capacity exceeding 49 million tonnes per annum (MTPA)[149]. The OGCI aims to scale CCS/CCUS deployment to capture 1 gigatonne of CO_2 captured annually by 2030, a significant step towards meeting global net-zero targets[150]. In Indonesia, key projects such as the Tangguh LNG CCS/CCUS and the Masela Abadi LNG CCS/CCUS initiatives are positioning the country as a regional CCS/CCUS hub.
- Hydrogen: Investment in hydrogen-related infrastructure has surged, with total announced investments through 2030 for hydrogen projects expected to range from USD435 billion to USD570 billion[151]. Indonesia's hydrogen sector

has seen significant development, including the Papua Blue Ammonia project (875,000 tonnes per annum)[152] and PLN's pilot green hydrogen plants designed to support industrial decarbonisation and grid balancing.

- Biofuels and biomethane: Biofuels are emerging as a critical alternative to conventional hydrocarbons, especially in sectors where direct electrification remains challenging. Investment in bio-CNG and biomethane has accelerated, with projects such as PT AEP Group's biomethane production supporting industrial decarbonisation in Indonesia. On a global scale, the advanced biofuels market (including sustainable aviation fuel and renewable diesel) is projected to grow at a Compound Annual Growth Rate (CAGR) of 11.3% through 2030, driven by policy incentives and rising demand for cleaner transportation fuels[153].

Companies are committing to net-zero emissions by 2050 and making significant renewable energy investments. Despite mixed outcomes, these investments are driven by growing customer demand for cleaner energy and stronger regulatory incentives. Capital markets are valuing firms aligned with the energy transition more highly, although major O&G companies heavily invested in low-carbon markets have yet to see significant valuation increases. Companies like Shell, BP and Chevron are at the forefront, investing billions in solar, wind, hydrogen technologies, and EV charging infrastructure. Shell aims to operate 500,000 EV charging points by 2025[154], while BP plans to build 20 gigawatts of renewable energy capacity by 2025 and 50 gigawatts by 2030[155]. Chevron has allocated USD10 billion for lower carbon projects through 2028, focusing on emissions reduction and new technologies like carbon capture and hydrogen fuel cells[156].

O&G companies are increasingly channeling their revenues into renewable energy projects and state energy programs to meet global decarbonisation targets. Major national and international oil companies have set ambitious goals for net-zero emissions by 2050 and are making substantial investments in renewable energy.

In Indonesia, several leading O&G companies are actively investing in renewable energy to align with national energy transition goals. Pertamina, through its subsidiary Pertamina New & Renewable Energy (PNRE), has committed to achieving net-zero emissions by 2060 with significant investments in geothermal, solar photovoltaic (PV) and bioenergy projects[157]. MedcoEnergi, via Medco Power Indonesia, is developing a 2 × 25 MW solar PV plant in Bali and expanding its geothermal portfolio[158]. Indika Energy aims to generate 50% of its revenue from non-coal businesses by 2025, focusing on solar projects and electric mobility[159]. Multinational companies like TotalEnergies are also enhancing Indonesia's renewable capacity through large-scale solar installations. These efforts support the national Just Energy Transition Partnership (JETP) target of net-zero emissions in the power sector by 2050, with a 44% renewable energy share by 2030[160].

Photo source: bp Indonesia

Beyond direct investments, O&G companies are collaborating with other industries to adopt technologies like battery storage and off-grid solar systems to reduce emissions. In Indonesia, such partnerships have been initiated to supply cleaner energy to remote areas and industrial zones. Internationally, examples like Imperial Oil's partnership with Enel X demonstrate the global trend of cross-sector collaborations to cut on-site emissions. These initiatives are supported by government programmes that provide funding and technical assistance for sustainable energy projects. By adopting innovative technologies and fostering industry collaborations, O&G companies aim to enhance energy security, reduce carbon footprints, and accelerate the transition to cleaner energy sources.

Figure 2.1 - Energy transition initiatives of global oil and gas players

Global Energy Companies	Net Zero Target		GHG emission reduction target			Technology Initiatives	
	2050	2060	2025	2030	2050	Technology	Projects
TotalEnergies		Scope 1&2			40% all scopes 80% Methane	CCS/CCUS, Gas, Solar, Wind, Hydro, Green hydrogen for aviation fuel (SAF)	Solar PV (Adani, Sun Power, Haze), Hydropower (SN Power), Wind (Total Eren, Seagreen), Hydrogen (Airliquide), CCS (TLCS)
bp		Scope 1-3	20%		50% Methane	Energy efficiency, Solar, Wind and Methane measurement	Bioenergy (Archea, GETEC, Bunge Bionenergia), Solar (Lightsource, AREH), Wind (Equinor), EV
Shell	Scope 1-3				Reduce net carbon emisison intensity by 100%	Energy efficiency, Solar, Wind, Flaring reduction and CCS/CCUS	Solar PV (Solanergi, Clean Tech, Green Star), Wind (EOLFI, Savion), Biogas (Nature Energy), Energy Management (MP2 energy, Next Krafwerke)
ExxonMobil		Scope 1&2		20-30% All scopes 70-80% Methane		Energy efficiency, Solar, Wind, Flaring reduction and CCS/CCUS	Wind (Materia), Biofuel (Biojet AS, Global Clean Energy, Pioneer), CCS (Denbury)

Source: PwC Analysis from companies' sustainability report, decarbonisation report and energy transition report/roadmap

2.3 The future of oil and gas in a decarbonised world

The evolution of business models in a low-carbon economy

The global energy transition is compelling O&G companies to fundamentally transform their business models. Mounting regulatory pressures, shifting investor sentiment and the imperative for decarbonisation have necessitated a move away from extraction-focused operations towards diversified, technology-driven energy services. Companies are now redefining themselves as integrated energy providers, balancing hydrocarbons with renewables, carbon management, and sustainable fuels. In Indonesia, this transformation is accelerated by state-led policies, international financing agreements and evolving corporate strategies, reinforcing the country's role as a key player in Southeast Asia's low-carbon future.

The transition towards integrated energy providers is evident in corporate strategies prioritising renewables, energy storage, and electrification services. ExxonMobil's Low Carbon Solutions Division is actively developing carbon capture, utilisation, and storage (CCUS) hubs, including the Baytown CCS/CCUS project in Texas, targeting 50 million tonnes of CO_2 storage annually by 2030[161]. TotalEnergies and Airbus have partnered to expand SAF production, with TotalEnergies now supplying over 50% of Airbus' SAF requirements in Europe, reducing lifecycle emissions by up to 90%[162]. In line with this global trend, Cepsa has rebranded as Moeve, selling 70% of its oil assets while investing EUR3 billion in green hydrogen infrastructure, positioning renewables as the majority of its revenue source by 2030[163]. The transition is also reflected in Woodside Energy's USD2.35 billion acquisition of a low-carbon ammonia production facility in Texas, underscoring a shift towards lower-emission fuels[164].

Indonesia is following a similar trajectory, leveraging international financing and strategic partnerships to drive its energy transition. The Just Energy Transition Partnership (JETP), a USD20 billion initiative, is designed to reduce Indonesia's electricity sector emissions to net-zero by 2050, with a targeted emissions peak by 2030. In parallel, Chevron and Pertamina's lower-carbon business collaboration includes geothermal expansion, nature-based carbon offsets, and CCS/CCUS projects, further reinforcing Indonesia's leadership in Southeast Asia's energy transition[165]. The country is also positioning itself as a key renewable energy exporter, with Singapore committing USD20 billion to import an additional 1.4 GW of low-carbon electricity from Indonesia, primarily generated from solar and geothermal power[166].

As part of this transformation, O&G companies are diversifying into new energy markets, including biofuels, carbon management and electric mobility infrastructure. The expansion into lithium and battery storage is gaining traction, with ExxonMobil investing in Direct Lithium Extraction (DLE) in Arkansas, securing a role in the electric vehicle battery supply chain[167].

Similarly, Indonesia is leveraging its geothermal and solar resources to supply clean electricity to Singapore, with investments exceeding USD20 billion in grid interconnections and large-scale renewables. Indonesia is also exploring the creation of regional CCS/CCUS hubs in the Natuna Basin, aiming to facilitate cross-border CO_2 storage projects with Malaysia and Singapore.

Given the current market challenges in the Bio-CNG sector, Indonesia needs the implementation of a suitable business model that attracts key stakeholders, fosters partnerships, shares risk appropriately and creates a win-win structure. Shared Risk-Return (SRR) based business models led by public and private entities are emerging as a strategy to accelerate bio-CNG deployment. These models involve guarantees for financial risks, public investment in early-stage infrastructure, and the creation of replicable investment templates to attract private capital into bio-CNG markets.

Despite these ambitious efforts, structural and economic challenges persist in the shift towards low-carbon business models. High capital expenditures remain a major hurdle, particularly for CCS/CCUS and hydrogen infrastructure, requiring subsidies, carbon pricing and blended finance mechanisms. Regulatory uncertainty, especially regarding shifting policy incentives in key markets like the US and EU, impacts investment planning for projects relying on tax credits. Additionally, supply chain constraints for critical minerals such as lithium and nickel pose challenges for Indonesia's growing electric vehicle and battery sectors, necessitating the development of resilient supply chains and strategic trade partnerships.

The evolution of business models in Indonesia's O&G sector reflects a broader global trend, where companies are transitioning from fossil fuel dependency towards diversified, technology-driven energy portfolios. These shifts underscore the growing importance of carbon capture, sustainable fuels, and grid-scale energy solutions in ensuring long-term energy security.

2.4 Tax considerations for carbon reduction activities

With the growing focus on climate change and carbon emissions, companies (including PSC contractors) are increasingly taking steps to reduce or offset their carbon emissions. This has led to a rise in demand for carbon trading, which allows entities to offset all or part of the emissions generated by their operations or value chain.

Various arrangements for producing trading carbon units have emerged, and understanding their terms, conditions, rights and obligations can create complexities and challenges, including for taxation.

The tax regulatory framework has yet to stipulate specific tax treatments for carbon trading and carbon project development. Current tax regulations relevant to carbon emissions only address the imposition of Carbon Tax, for which the application has been deferred at the time of writing.

Following are several tax considerations which entities may need to think about pertaining to carbon:

Carbon Tax (implementation deferred)

Carbon Tax is imposed on carbon emissions that negatively impact the environment. Carbon Tax can be imposed on individuals or entities that:

a. carry out activities that emit a certain level of carbon; and/or
b. purchase goods containing carbon.

Emitting a certain level of carbon emissions is subject to the Carbon Tax at the rate of the lesser of:

a. the carbon credit price in the domestic carbon market per kg carbon dioxide equivalent (CO_2e); or
b. IDR30/kg CO_2e.

Carbon emitters are required to record the carbon emission activities, and self-remit and report the Carbon Tax on an annual basis.

The purchase of carbon content goods (not yet implemented at this stage) could also be subject to the Carbon Tax upon the purchase. The Carbon Tax is to be collected by the seller (appointed as a Carbon Tax collector). The Carbon Tax collector is required to record the relevant sales, pay and report the Carbon Tax on a monthly basis.

Carbon trading for voluntary market

When dealing with tax implications related to the voluntary market, entities, depending on whether they act as buyers (i.e. companies that purchase carbon credits for their own use or for resale) or project developers (i.e. companies that produce credits through projects that reduce greenhouse gas emissions or improve carbon sequestration activities), need to consider the following:

Photo source: PwC

A. Buyers perspective

Corporate Income Tax (CIT)	When purchasing carbon credits, it is important to note that the tax regulations are silent on the characteristics of spending related to carbon credit/unit. Therefore, the accounting treatment should be followed. The accounting position is critical and hence should be firmed up and supportable. Tax implications should be assessed once the accounting position is determined (see below). Depending on the accounting treatment of the carbon unit purchased (see below), buyers should consider the following tax considerations: a. whether the carbon unit fulfils the 3M principle and whether sufficient commercial justifications and/or supporting documents are available (as deduction); b. understand the valuation method and determine whether any fiscal correction is required (as inventory); and c. determine the tax amortisation method and useful life (as intangible assets). Overall, any differences between accounting and tax treatments should be properly monitored/identified, as fiscal corrections may need to be made. Proper assessment is needed as to whether the obligation associated with the liability is deductible.
Value-added Tax (VAT)	Below are some general VAT requirements for crediting Input VAT (not exhaustive) related to the purchase of a carbon unit: a. The buyer should be registered as a VAT-able entrepreneur and deliver non-exempted VAT-able goods and/or services; b. Input VAT is related to the procurement of goods and/or services which directly relates to the buyer's business activities (e.g. production, management and distribution, marketing); and c. the relevant VAT invoice should meet formal requirements. The above tax consideration is valid only with the assumption that the VAT is indeed charged by the Project Developer (see below Project Developer analysis). If VAT is charged, the buyer should be aware that creditability of input VAT is contingent on certain conditions (see above), including whether the associated purchase of the carbon unit is directly related to the business. This is not a straightforward analysis. For example: carbon unit purchased/consumed as part of production versus those used for commitment/disclosure purposes may have different implications. If VAT is not creditable, it would be deductible and claimed either directly or over time – subject to the classification of expenses (see our explanation on CIT aspect above).

B. Project developer perspective

CIT	•	When developing carbon projects, the project developer should consider the following tax consequences at the pre-production/development stage (not exhaustive): a. the decision to expense or capitalise should generally follow accounting standards. Note that taxation does not recognise immateriality levels for direct expenses, as may usually be adopted for accounting for practical reasons; b. tax grouping and the approach to depreciation or amortisation should follow tax rules. This includes the timing to start depreciation or amortisation; c. arguably deduction via depreciation or amortisation should still be applicable for tax, irrespective of whether accounting treats the project assets as financial assets (e.g. under lease or concession accounting); d. if the carbon unit is considered to be a "byproduct", the method of allocating depreciation expense of the same production assets should be considered (i.e. between the energy and carbon unit/produced).
	•	At the commerciality stage, the tax considerations may include the timing difference when revenue is recognised for accounting (eg. possibly upon sale or post-sale if a future obligation exists) vs. tax (typically upon sale). If a timing difference exists, it should lead to a fiscal adjustment.
	•	At the time of writing, tax incentives for nature-based solution projects are not yet available (although tax holidays/allowances are available for certain industries e.g. renewable power and geothermal). If a tax incentive is granted, it may impact the tax treatment described above.
VAT	•	At the time of writing, the sale of carbon units to overseas buyers is not yet allowed. Hence, relevant VAT consideration on the domestic sale of carbon units includes the following (not exhaustive): a. the VAT Law is currently silent on the treatment of carbon units. The VAT Law only stipulates that securities (i.e. *surat berharga*) are not VAT-able objects. The fact that carbon units are considered as "*efek*" under Law No. 4/2023 could therefore influence the VAT analysis. Based on the above, detailed assessment must then be performed to determine whether the definition/nature of securities (i.e. *surat berharga*) under the VAT Law is identical to the term "*efek*" under Law No. 4/2023 (being used to include carbon unit); b. if the "*efek*" is not considered as securities for VAT purposes, then the carbon unit should be considered VAT-able objects. Otherwise, they would not be subject to VAT. The practical application of VAT should also be considered, as carbon units are currently traded via the IDX; c. for the input VAT incurred by the project developer, the treatment would be contingent on the taxability of the carbon unit (from a VAT perspective), i.e.: i. if the carbon unit is VATable: The input VAT should generally be creditable; or ii. if the carbon unit is non-VATable: The input VAT should generally be deductible.

Aside from the CIT and VAT considerations above, the project developer would also need to consider the regional tax and non-tax state revenue aspects relevant to the carbon project.

Please note that comments outlined above are the tax considerations for the voluntary market. Tax consequences for the mandatory market may not necessarily be similar to those of the voluntary market.

Readers are encouraged to reach out to our PwC Contacts for any questions/issues that they may have regarding the above matter, as this is a developing area.

3 Regulatory framework

3.1 Oil and gas Law No. 22/2001

Law No. 6 of 2023 on the Stipulation of Government Regulation in Lieu of Law No. 2 of 2022 on Job Creation

On 30 December 2022, the President of the Republic of Indonesia signed Government Regulation in Lieu of Law No. 2 of 2022 on Job Creation (Perppu No. 2). Perppu No. 2 revoked and completely replaced Law No. 11 of 2020 concerning Job Creation (Law No. 11/2020), which had previously declared legally defective and conditionally unconstitutional by the Indonesia Constitutional Court, as per Constitutional Court Decision No. 91/PUU-XVIII/2020 (MK-91 Decision), due to its issuance without a proper formality process. On 31 March 2023, Indonesia's House of Representatives approved the Perppu No. 2 into law as Law No. 6/2023 (the Job Creation Law).

In general, the provisions stipulated in the Job Creation Law are not substantially different from those in Law No. 11/2020. The Job Creation Law essentially amends several laws, including the oil and gas law, namely Law No. 22 dated 23 November 2001 (Law No. 22). The laws amended by the Job Creation Law relating to the oil and gas sector and mentioned in this guide are:

1. Law No. 22;
2. Investment Law No. 25/2007 (Law No. 25/2007);
3. Company Law No. 40/2007 (Law No. 40/2007);
4. Environment Law No. 32/2009 (Law No. 32);
5. Forestry Law No. 41/1999, as amended by Law No. 19/2004 and Law No. 18/2013 (Law No. 41);
6. Shipping Law No. 17/2008 as amended by Law No. 66/2024.

For ease of reference, the above-mentioned regulations will be referred to throughout this guide with the understanding that they have been amended by the Job Creation Law.

The law regulating oil and gas activities is governed by Law No. 22. The objectives of Law No. 22, as stated in Article 3, are to:

a. guarantee effective, efficient, highly competitive and sustainable exploration and exploitation of oil and gas;
b. assure accountable processing, transport, storage and commercial businesses through fair and transparent business competition;
c. guarantee the efficient and effective supply of oil and gas as a source of energy and to meet domestic needs;
d. promote national capacity;
e. increase state income; and
f. enhance public welfare and prosperity equitably, while maintaining the conservation of the environment.

In recent years, particularly following the Constitutional Court's decision in 2012 to disband the upstream regulator BP Migas (*Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi*), there has been an expectation that Law No. 22 would be further amended. A draft amendment to Law No. 22 was made available to the public in 2023.

The draft law reaffirms that Indonesia's oil and gas resources are national assets under state control. The Central Government is designated as the holder of all mining authority and is tasked with establishing a “special executive agency”, which will be a state-owned enterprise (*Badan Usaha Khusus Minyak dan Gas Bumi* - BUK Migas). BUK Migas will be authorised by the state to conduct business activities in the upstream (independently and/or through a cooperation with contractors) and downstream sectors.

Whilst Law No. 22 specifies a maximum of 25% Domestic Market Obligation (DMO) for both oil and gas, the draft law maintains the same DMO percentage.

The draft law, although still under review, appears to emphasise reinforcing state control over oil and gas resources. While it does not represent a major shift, there is a noticeable focus on enhancing state authority. In practical terms, these proposed changes – especially the relaxation of contractual terms - may raise concerns among investors. Currently, there is no updated version of the revised Law No. 22 available, so it is crucial to closely monitor the progress of the draft law. Moreover, the draft revision is only included in the medium-term national legislation programme for the next five years and is not part of this year's priority national legislation programme.

3.1.1 Control of upstream and downstream activities

Law No. 22 stipulates that oil and gas, being strategic and non-renewable natural resources within the Indonesian mining territory, are national assets under state control. This state control is exercised by the Central Government through oil and gas activities in Indonesia. Law No. 22 differentiates between upstream business activities - encompassing exploration and exploitation - and downstream business activities, which include processing, transport, storage and commerce.

According to Article 6 of Law No. 22, upstream activities are managed through Joint Cooperation Contracts (JCCs), predominantly Production Sharing Contracts (PSCs), between the Business Entities/ Permanent Establishments (PEs) and the executing agency (SKK Migas). Meanwhile, Article 7 of Law No. 22 specifies that downstream activities are governed through the business licenses issued by the regulatory agency (*Badan Pengatur Hilir Minyak dan Gas Bumi* – BPH Migas).

SKK Migas and BPH Migas oversee upstream and downstream activities, respectively, to ensure:

a. the conservation of resources and reserves;
b. the management of oil and gas data;
c. the application of good technical norms;
d. the quality of processed products;
e. workplace safety and security;
f. appropriate environmental management to prevent environmental damage;

g. the prioritisation of local manpower, goods and services and domestic engineering capacities;
h. the development of local communities; and
i. the development and application of oil and gas technology.

Both upstream and downstream business activities may be carried out by State-Owned Enterprises (SOEs), regional administration-owned companies, cooperatives, small-scale businesses, or private-business entities. Upstream business activities may also involve branches of foreign incorporated enterprises as PEs.

However, upstream entities are prohibited from engaging in downstream activities and vice versa, as stated in Article 10, except where an upstream entity is required to construct transport, storage or processing facilities or conduct other downstream activities integral to supporting its exploitation activities (Article 1).

3.1.2 GR-79 on cost recovery and income tax for the oil and gas sector

Government Regulation (GR) No. 79 (GR-79), issued on 20 December 2010, established the initial legal framework for cost recovery and tax arrangements in the upstream oil and gas sector in Indonesia. Although numerous implementing regulations have been issued since its promulgation, some remain pending, highlighting ongoing evolution in this sector.

In response to feedback from the upstream industry regarding the application of GR-79, the Government enacted GR No. 27 (GR-27) on 19 June 2017 and GR No. 93 on 31 August 2021 (GR- 93). Among other provisions, these amendments address the income tax treatment related to the transfer of participating interests. A critical aspect for investors and operators involved in these transactions. The key provisions of GR-79, as well as the subsequent changes/amendments made by GR-27 and GR-93 are discussed in Section 4.4.2.

3.1.3 Minister of Energy and Mineral Resources Regulation No. 13/2024 on GS PSCs

In an effort to incentivise exploration and exploitation activities, the Indonesian Government introduced a "Gross Production Split" (GS PSC) model for conducting upstream business activities through MoEMR Regulation No. 8/2017. However, this regulation was revoked and replaced by MoEMR Regulation No. 13/2024.

The key change introduced by MoEMR Regulation No. 13/2024 is giving the oil and gas companies in the new tender for cooperation contracts the flexibility to choose between GS PSC and the cost recovery PSC models for their contracts.

As the successor to the previous regulation, MoEMR Regulation No. 13/2024 provides detailed governance on the implementation of GS PSCs, it also includes transitional provisions addressing the possible conversion of PSCs from cost recovery to GS PSC or vice versa.

Further details on the GS PSC model and its implications are elaborated in Chapter 5.

3.1.4 Restrictions on foreign workers

Currently, by the revocation of Regulation No. 31/2013 by the enactment of MoEMR Regulation No. 6/2018, there is no particular position that is closed to expatriates, unless such activities are restricted under general manpower regulations (e.g. human resource director, occupational safety specialist, job analyst, etc.).

3.1.5 Local content requirements

Law No. 22 requires that the Business Entities or PEs involved in oil and gas activities prioritise the use of local manpower, domestic goods, services and engineering and design capabilities in a transparent and competitive manner.

To implement this obligation, the MoEMR issued Regulation No. 15/2013 on the Use of Domestic Products for Upstream Business of Oil and Natural Gas Businesses. The regulation specifies that all procurement activities must align with the Domestic Product Appreciation Book (*Buku Apresiasi Produk Dalam Negeri* - APDN Book) published by the MoEMR. The APDN Book categorises goods and/or services as mandatory, maximised or empowered for the use of domestic products.

The calculation of the Local Content (*Tingkat Komponen Dalam Negeri* - TKDN) is determined as follows:

a. For goods, the TKDN is calculated based on the ratio of domestic components to the total costs of finished goods;
b. For services, it is calculated based on the ratio of domestic service costs to the total costs of services; and
c. For a combination of goods and services, the TKDN is determined by the ratio of the total domestic components costs to the total combined costs of goods and services.

In addition, the TKDN value is influenced by the status of the goods and/or services' providers, categorised by the MoEMR as follows: (i) a domestic company (owned at least 50% by an Indonesian entity(s)); (ii) a national company (owned 50% or more by foreign entities); and (iii) a foreign company. Furthermore, the requirement on TKDN is regulated under SKK Migas Work Guidelines (*Pedoman Tata Kerja* - PTK) No. PTK 007 concerning Procurement Guidelines for Goods or Services.

3.1.6 Licences

Business licensing in the oil and gas sector is primarily governed by GR No. 5/2021 (GR-5), which serves as the implementing regulation for Law No. 22/2001 (as amended by the Job Creation Law). GR-5 introduces a risk-based Business Licensing framework, where the level of risk associated with business activities determines the type of business license required and its legal requirements.

The Government has systematically categorised risk levels according to business fields, as outlined in the Indonesian Standard Industrial Classification (*Klasifikasi Baku Lapangan Usaha Indonesia* - KBLI). This classification has been implemented and integrated in the Risk- Based Online Single Submission (OSS) system.

The OSS Risk-Based Approach (OSS RBA) facilitates licensing across various business sectors based on the assessed risk level and scale of business activities. This system centralised all business licensing processes under the jurisdiction of relevant authorities, including ministers, agency heads, governors or regents/mayors. The specific requirements and obligations for obtaining a business licence within each KBLI category are detailed in the attachment of GR-5 and further elaborated in technical ministry regulations, such as MoEMR Regulation No. 5/2021). For further understanding, please refer to Section 6.1.2.

3.2 Other relevant laws

3.2.1 The Energy Law No. 30/2007

The Energy Law No. 30/2007 dated 10 August 2007 provides a legal framework for the overall energy sector, with an emphasis on economic sustainability, energy security and environmental conservation (Article 3).

3.2.2 National energy policy

GR No. 79/2014, issued on 17 October 2014, established the National Energy Policy, as originally formulated by the National Energy Council (*Dewan Energi Nasional* - DEN). Established in June 2009, DEN is tasked with formulating and implementing the National Energy Policy, which has been approved by the House of Representatives. In addition, DEN is responsible for determining the National Energy General Plan and devising strategies to address any energy crises or emergencies.

The National Energy Policy covers guidelines for the management of energy resources in Indonesia and addresses key issues such as:

a. Ensuring the availability of energy to meet the national demand;
b. Setting priorities for energy development;
c. Promoting the utilisation of domestic energy resources; and
d. Establishing national energy buffer reserves.

The National Energy Policy aims to achieve an optimal energy-resource mix in 2025 and 2050 target dates as follows:

Table 3.1 - Energy demand and supply modeling projection targets based on PR 22/2017

Energy Source	2025	2050
New and renewable energy	minimum 23%	minimum 31%
Crude oil	less than 25%	less than 20%
Coal	minimum 30%	minimum 25%
Natural gas	minimum 22%	minimum 24%

Source: PR 22/2017

DEN is chaired by the President and Vice-President of the Republic of Indonesia, with the MoEMR serving as the Executive Chairman. DEN comprises 15 members, which include key government officials responsible for overseeing the provision, transportation, distribution and utilisation of energy. Additionally, DEN incorporates diverse stakeholders, including: two representatives from academia; two representatives from industry; one representative from the technology sector; one representative focused on environmental issues; and two representatives from consumer groups.

3.2.3 Investment Law No. 25/2007 and Company Law No. 40/2007

Form of business

Under Law No. 22, foreign investors can enter the upstream oil and gas sector through two avenues: either by establishing a branch of a foreign company (referred to as a PE) or by incorporating a limited- liability company in Indonesia (known as *Perseroan Terbatas* - PT).

The "ring-fencing" principle, outlined in Article 13 of Law No. 22, dictates that only one Production Sharing Contract (PSC) can be granted per PE or PT, necessitating separate entities for each operational area.

For instance, following the enactment of Law No. 22, Pertamina had to create subsidiaries and form PSC agreements with SKK Migas for each operational area.

Positive investment list

On 2 February 2021, a positive investment list was issued through Presidential Decree No. 10/2021 (as amended by Presidential Decree No. 49/2021). The regulation has three appendices that consist of a business activities priority list, cooperatives and small enterprises business activities list and business activities with certain requirements list.

As a rule of thumb, any business activities that are not included in the positive investment list are open for foreign investment. As per Presidential Decree No. 10/2021, restrictions on foreign ownership apply only to national and/or international sea freight for specific goods business activity within Indonesia's oil and gas sector, with a maximum foreign shareholding capped at 49% in the downstream sector, including foreign investment companies (*Penanaman Modal Asing* - PMA).

Law No. 25 allows investors to repatriate profits and pay interest and dividends in foreign currencies as well as for capital facilities. These facilities include the exemption from import duty and the exemption or postponement of Value-Added Tax (VAT) on imports of capital goods needed for production.

Please also note that the authority to issue certain licences is now delegated from the MoEMR to Indonesia's Investment Coordinating Board (*Badan Koordinasi Penanaman Modal* - BKPM), including for trading, refineries, storage, general surveys and various support services.

Legislative responsibilities: Environment and others

Law No. 40/2007 imposes corporate social responsibility and environmental obligations on companies undertaking business activities in the natural resources field, with the costs to be borne by the company (Article 74).

Sanctions for non-compliance are covered in all related legislation. On 4 April 2012, the Government issued GR No. 47/2012 providing explanation of these responsibilities, but it has not been regulated in more detail. Investment Law No. 25 outlines requirements for PT companies, such as giving priority to Indonesian manpower, creating a safe and healthy working environment (Article 16), implementing corporate social responsibility programs (Article 15) and ensuring environmental conservation (Article 16).

Investors exploiting non-renewable resources must also allocate funds to site restoration that fulfil the standards of environmental responsibility (Article 17). Sanctions for non-compliance with Article 15 include restrictions on business activities and the freezing of business activities (Article 34 of the Investment Law).

3.2.4 Environment Law No. 32/2009 and Forestry Law No. 41/1999

Environment Law

In October 2009, Law No. 32 was issued, and entities were required to comply with standard environmental quality requirements and to secure an environmental approval before beginning operations. Sanctions can include the cancellation of operating permits, fines and/or imprisonment.

Forestry Law

Law No. 41 prohibits oil and gas activities from being conducted in protected forest areas except where a Government permit is obtained. GR No. 23/2021 allows projects, including for oil and gas activities, to take place in protected forests where they are deemed strategically important.

Under GR No. 23/2021 the utilisation of forestry areas for non-forestry activities is permitted in both production forests and protected forests subject to obtaining an PPKH (*Persetujuan Penggunaan Kawasan Hutan*) from the Ministry of Forestry. The PPKH


Photo source: PwC

holder will be required to pay various non-tax state revenues pursuant to these activities and will need to undertake reforestation activities upon ceasing its use of the land. The issuance and validity of the PPKH permit depends entirely on the spatial zoning of the relevant forest areas. The use of a forestry area will often also require land compensation transfers or compensation payments to local landowners.

3.2.5 Regulating export proceeds and foreign exchange

Recently, the Indonesian government issued GR No. 36/2023 (GR-36) and GR No. 8/2025 (GR-8), which pertain to export proceeds and foreign exchange for businesses involved in the exploitation of natural resources. Additionally, Bank Indonesia (BI) released regulations on the management of export proceeds and foreign exchange, specifically Bank Indonesia Regulation (*Peraturan Bank Indonesia* - PBI) PBI No. 7/2023 and PBI No. 3/2025.

According to PBI No. 7/2023, GR-36 and GR-8, exporters of natural resources generating Foreign Exchange Proceeds from Exports of Natural Resources (DHE SDA) valued at USD250,000 (or its equivalent) or more, as declared in the Export Customs Declarations (*Pemberitahuan Pabean Ekspor* - PPE) are required to deposit 100% of their DHE SDA in the Indonesian financial system for a minimum period of twelve months from the time of deposit. However, GR-8 provides an exception for the oil and gas industry, permitting it to deposit only 30% of its DHE SDA for a minimum period of three months.

The DHE SDA deposit can be placed in one of the following instruments:

a. A special account opened at the Indonesian Export Financing Agency (*Lembaga Pembiayaan Ekspor Indonesia* - LPEI) or at a foreign exchange bank;
b. Banking instruments, e.g., foreign exchange time deposit;
c. Financial instruments issued by LPEI, like a promissory note in foreign exchange; and/or
d. Financial instruments issued by BI, such as a conventional open market operation term deposit in foreign exchange in BI.

For instruments b, c, and d mentioned above, DHE SDA placement cannot be withdrawn before the maturity of the respective financial instrument.

Pursuant to BI Regulation 7/2023, DHE SDA deposited in the above banking and financial instruments have several benefits for the exporters, among other things, for funds deposited into a special account, it could be used for a foreign exchange (forex) swap transaction between the exporters and the banks and such instruments may also be used by the exporters as a loan security (in rupiah currency). Furthermore, according to GR-8, DHE SDA deposited in the special account may be used by exporters for the payment of export duty and other levies in export sector, loans, imports, profits/dividends, and/or other needs for investment (e.g. transfer of DHE SDA to another party for loan repayment, acquisition compensation and payment of salaries of foreign workers in foreign investment companies).

Administrative sanctions, in the form of suspension of export services/facilities, will be imposed on the exporters of natural resources for non-compliance with the following obligations:

a. Failure to deposit DHE SDA in special accounts;
b. Failure to deposit DHE SDA of at least 100% of the export proceeds (or 30% of the export proceeds for oil and gas businesses) or for less than 12 months (or 3 months for oil and gas businesses); and/or
c. Failure to create an escrow account with the LPEI and/or certain banks conducting activities in foreign exchange if the DHE SDA transfer is conducted through an escrow account.

GR-36 and GR-8 introduce heavier penalties than GR 1/2019 for exporters failing to comply with the regulation. Under GR-36, the requirement for the exporters to deposit at least 30% of their DHE SDA for a minimum of three months caused some concerns for the exporters (including Indonesian mining companies) in managing their cash flows. GR-8 increased the requirement to 100% of their DHE SDA for a minimum of 12 months (except for the oil and gas sector which still follows the provisions in GR-36) but gives some relaxation for certain usages as noted above.

For the oil and gas sector concerns with the requirements include:

a. inconsistency with the "contract sanctity" of the PSC which provides that the contractor may freely lift and export its production share and retain the proceeds of any sale abroad;
b. potentially reducing liquidity for contractors and impacting development activities;
c. the effect on trustee paying agent mechanisms for gas/LNG sales and associated financial covenants; and
d. the cost of minimum periods of deposit and/or mandatory conversions into rupiah.

3.2.6 Mandatory use of Indonesian Rupiah

On 31 March 2015, BI issued Regulation No. 17 (17/3/PBI/2015) as implementing guidance for Law No. 7/2011 (as amended by Law No. 4/2023) regarding the mandatory use of the rupiah for cash and non-cash transactions in Indonesia. Circular Letter (*Surat Edaran* - SE) No. 17/11/ DKSP17) was issued on 1 June 2015.

From 1 July 2015, any cash or non-cash transactions made within Indonesia must use and be settled in rupiah. All price quotations of goods and services must also be in Rupiah, and dual currency quotations are prohibited.

Through Circular Letter SE-17, BI clarified the following infrastructure projects as exempted from the mandatory use of Rupiah rules:

a. Transportation;
b. Road construction and irrigation systems;
c. Infrastructure for water supplies;
d. Power utilities including power plants and transmission systems; and
e. Oil and gas projects.

To obtain the exemption, the project owner should seek confirmation from the relevant ministry and obtain a waiver letter from BI.

On 1 July 2015, the MoEMR and BI issued a press release (No. 40/SJI/2015) outlining a framework to classify transactions into three main categories (for the energy sector), as a transition towards the mandatory use of rupiah. The categories are:

- Category 1 – Transaction proceeds which can be directly converted to rupiah (e.g., leases and salary payments to local employees – six-month transition);
- Category 2 – Transaction proceeds which require time to be converted to rupiah (e.g., long-term service contracts). These can continue to use foreign currency subject to future amendments to the contracts;
- Category 3 – Transaction proceeds where it is fundamentally difficult to use rupiah (e.g., salaries paid to expatriates, drilling services and the leases of ships). These may continue to use foreign currency for a maximum ten-year period.

The MoEMR and BI have formed a task force to set guidelines and procedures for the implementation of PBI No. 17/3/PBI/2015, especially for Category 3 types of transactions.

3.3 Key stakeholders

3.3.1 The MoEMR

The MoEMR is charged with creating and implementing Indonesia's energy policy, ensuring that the related business activities are in accordance with the relevant laws and regulations, and awarding contracts. Presidential Decree No. 169/2024 stipulates the functions of the MoEMR, which include:

a. formulating and determining the development, control, and supervision policies of oil and gas;
b. implementing policies in the field of development, control, and supervising oil and gas;
c. implementing of technical guidance and supervising the implementation of policies in the field of guidance, control and supervision of oil and gas; and
d. implementing development in the field of energy and mineral resources.

3.3.2 Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas)

SKK Migas controls upstream activities and manages oil and gas contractors on behalf of the Government through JCCs. Under Law No. 22 (Articles 44 and 45), all of Pertamina's rights and obligations arising from existing cooperation contracts, for and on behalf of the Government, were transferred to SKK Migas.

Based on MoEMR Regulation No. 2/2022, SKK Migas has the following roles:

a. To provide advice to the MoEMR with regard to the preparation and offering of work areas and JCCs;
b. To act as a party to JCCs;
c. To assess first field development plans in a given work area and to submit evaluations to the MoEMR for approval;
d. To approve development plans (other than those mentioned in point c);
e. To approve work plans and budgets;
f. To report to the MoEMR and monitor the implementation of JCCs; and
g. To appoint sellers of the State's portion of petroleum and/or natural gas to the Government's best advantage.

3.3.3 Downstream Oil and Gas Regulatory Agency (BPH Migas)

BPH Migas was established on 30 December 2002 to assume Pertamina's regulatory role in relation to downstream activities (Articles 46 and 47 of Law No. 22). BPH Migas is charged with ensuring sufficient natural gas and domestic fuel supplies and the safe operation of refining, storage, transportation and distribution of gas and petroleum products via business licences.

BPH Migas' regulatory, development and supervisory roles are set out in the following table:

Table 3.2 - Regulatory, development and supervisory roles

Regulatory and development areas under BPH Migas	Supervisory areas under the MoEMR
• Business licences • Type, standard and quality of fuels • Utilisation of oil fuel transportation and storage facilities • Exploitation of gas for domestic needs • Strategic oil reserves • National fuel oil reserves • Masterplan for a national gas transmission and distribution network • Occupational safety, health, environment and Community Development (CD) • Price setting including the gas selling price for households and small-scale customers • Utilisation of local resources	• Business licences • Type, standard and quality of fuels • Occupational safety, health, environment and CD • Employment • Utilisation of local resources • Oil and gas technology • Technical rules • Utilisation of measurement tools

Source: GR No. 36/2004

BPH Migas is also responsible for the supervision of fuel oil distribution and transportation of gas through pipelines operated by PT companies.

Table 3.3 - Supervision of fuel distribution and transportation of gas

Supervision and distribution of fuel oil	Transportation of gas by pipeline
• Supply and distribution of fuel oil • Supply of fuel oil in remote areas • Allocation of fuel oil reserves • Market share and trading volumes • Settling of disputes	• Development of transmission segment and distribution network area • Determination of natural gas pipeline transmission tariffs and prices • Market share of transportation and distribution • Settling of disputes

Source: GR No. 36/2004

Open access to gas pipelines

Since 2008, BPH Migas has enforced rules supporting open access, requiring gas pipeline owners to allow third-party access. In alignment with this, BPH Migas's strategic plan includes determining gas pipelines based on open access principles. In 2021, BPH Migas, in collaboration with the Aceh Oil and Gas Management Agency (*Badan Pengelola Migas Aceh*), announced plans to construct an open access pipeline from Lhokseumawe to Banda Aceh. Additionally, as the overseer of open access implementation, BPH Migas is guided by the National Core Plan for Gas Transmission and Distribution Networks, as mandated by the MoEMR Decision No. 173.K/MG.01/MEM.M/2024.

3.3.4 House of Representatives (*Dewan Perwakilan Rakyat* - DPR) and regional governments

Commission VII of the DPR covers energy, mineral resources, research and technology and environmental matters. This includes oversight of oil and gas activities, the drafting of oil and gas related legislation, the control of the State Budget (APBN) and oversight of related government policies.

Regional Governments are involved in the approval of Plans of Development (PoD) through the issuance of local permits and land rights. In addition, the Regional Governments have the right to be offered a 10% participating interest in a PSC. For more detail on this, please see Chapter 4.1.8.

3.3.5 PT Pertamina (Persero) and its sub-holding entities

On 18 June 2003, PT Pertamina (Persero) was transformed from a state-owned oil and gas enterprise governed by its own law into a state-owned limited liability company. In recent years, Pertamina has expanded its scope to include gas, renewables and upstream operations both within Indonesia and abroad. It now has upstream operations in Vietnam, Malaysia, Sudan, Qatar and Libya, and provides aviation fuel services at ten international airports. Pertamina has also entered into several Joint Operations (JOs) within Indonesia.

PGN operates a natural gas distribution pipeline network and a natural gas transmission pipeline network. Its subsidiaries and affiliated companies are involved in upstream activities, downstream activities, telecommunications, construction and a floating storage and regasification terminal.

With the issuance of GR No. 6/2018, the Government formalised the establishment of a national State-Owned Enterprise (*Badan Usaha Milik Negara* - BUMN/SOE) holding company in the oil and gas sector, combining the business of PGN with Pertamina and appointing Pertamina as the holding company of SOEs serving the oil and gas industry. In February 2018, Pertamina became the major shareholder of PGN, by acquiring the Government's controlling 56.97% stake while PGN continues to be a publicly listed company.

Following the acquisition, Pertamina and PGN integrated and streamlined the gas distribution business previously held by PGN and PT Pertamina Gas (Pertagas), a wholly owned subsidiary of Pertamina.
In December 2018, PGN acquired Pertamina's 51% controlling interest in Pertagas, and became the sub-holding entity for gas operations.

In 2021, Pertamina conducted a major restructuring within its organisation which resulted in the establishment of several sub-holdings under Pertamina, namely:

1. PT Pertamina Hulu Energy as the upstream sub-holding;
2. PGN as the gas sub-holding;
3. PT Pertamina Power Indonesia as the power and New Renewable Energy (NRE) sub-holding;
4. PT Pertamina Patra Niaga as the commercial and trading sub-holding;
5. PT Kilang Pertamina Internasional as the refining and petrochemical sub-holding; and
6. PT Pertamina International Shipping as the integrated marine logistics sub-holding.

3.3.6. Notable industry associations

The Indonesian Petroleum Association (IPA) was established in 1971 in response to growing foreign interest in the Indonesian oil and gas sector. The IPA's mission is to be the voice of the upstream oil and gas industry in Indonesia and to work collaboratively with all stakeholders to promote the industry for the benefit of the Government, investors, communities, employees, customers and the environment.

Other industry associations include a drilling company association (*Asosiasi Perusahaan Pemboran Minyak, Gas dan Panas Bumi Indonesia* - APMI), a national oil and gas company association (*Asosiasi Perusahaan Minyak dan Gas* - ASPERMIGAS), an oil and gas entrepreneurs association (*Himpunan Wiraswasta Nasional Minyak dan Gas Bumi* - HISWANA MIGAS), and the Indonesian Chamber of Commerce and Industry (*Kamar Dagang dan Industri Indonesia* - KADIN).


Photo source: PwC

4 (Conventional) Upstream sector

As previously mentioned, the Government introduced the Gross Split (GS) Production Sharing Contract (PSC) model for upstream business activities, intended to be implemented for new PSCs from 2017/2018 onwards. However, it is worth noting the flexibility introduced in 2020, as discussed in Section 1.2.

The GS PSC regime has significantly altered the fundamental principles and regulatory framework of the conventional cost recovery model in the upstream sector, which had been established for over 40 years. The GS system is discussed in Chapter 5. This chapter covers the traditional, or conventional, cost recovery PSC system, which is still the main system in force in the Indonesian upstream oil and gas sector.

4.1 Upstream regulations

Activities in the oil and gas upstream sector are regulated by Law No. 22, its implementing regulation Government Regulation No. 35/2004 (GR-35), and the amending GR No. 34/2005 (GR-34), as well as GR No. 55/2009 (GR-55), GR-27 (as an amendment to GR-79), and GR-93. A summary of Law No. 22's key sections is set out below.

4.1.1 Work areas

Upstream business activities, including exploration and exploitation, are conducted within designated regions known as "work areas". These areas are formalised following approval by the MoEMR, in consultation with SKK Migas and relevant local government authorities, and are specified in a Joint Cooperation Contract (JCC).

A work area can be offered either through a tender or a direct offer (see below).


Photo source: PwC

Following the issuance of MoEMR Regulation No. 08/2017 (Regulation-08) regarding GS PSCs in January 2017, direct offers or tenders for new acreage must be awarded under the GS mechanism. However, on 12 August 2024, the MoEMR issued MoEMR Regulation No.13/2024, providing an option for oil and gas investors to choose either a conventional cost recovery PSC or a GS PSC and to convert their PSCs. Hence, this provides legal certainty and flexibility for oil and gas investors.

The key features of a GS PSC can be found in Chapter 5.

Each business entity or permanent establishment (Contractor) is permitted to hold only one work area, adhering to the "ring-fencing" principle. The contractor must return the work area, either in stages or in full, as commitments are fulfilled according to the JCC. Once returned, the work area becomes open for allocation.

4.1.2 Awarding of contracts – Direct offers or tenders for new acreage

Direct offers for new acreage

Under a direct offer, a company that performs a technical assessment through a joint study with the Directorate General of Oil and Gas (DGoG) receives the right to match the highest bidder during the tender round.

Pertamina can apply for a direct offer, with the MoEMR's approval, when: (1) the area is an “open” area; (2) the Contractor is transferring its PSC interest to a non- affiliate; or (3) the area has expired or has been relinquished.

MoEMR Regulation No. 23/2021, as amended by the MoEMR Regulation No. 13/2024, regulates that expiring PSCs can be managed by either:

a. PT Pertamina (Persero);
b. the existing Contractors (via an extension); or
c. a Joint Operation (JO) between the PSC contractor and PT Pertamina (Persero).

Tenders for new acreage

The majority of new acreage is awarded through a tendering process.

The tendering steps are as follows:

a. Register as a tender participant by obtaining the official bid information package from the DGoG as the MoEMR representative. The fee for the bid information package is USD5,000 and is non-refundable;
b. Purchase an official government data package for the particular block being tendered to support the technical evaluation and the proposed exploration programme to be submitted together with the tender. The fee for the data package will vary depending on the nature of the block;
c. Attend a clarification forum a few days prior to the tender date;
d. Submit two identical copies of the complete bid documents by the tender closing date;
e. The evaluation and grading of the tender bid document is carried out by the MoEMR's Oil and Gas Technical Tender Team for New Acreage. Bid evaluations consider technical evaluation (major evaluation), financial evaluation (second

evaluation) and performance evaluation (third evaluation); and

f. The winner of the tender is determined by the DGoG after a recommendation from the Tender Team.

Table 4.1 - Tender document checklist

No.	Subject	Remark
1.	Application form	A completed application form.
2.	Work Programme and Budget (WP&B)	A proposed WP&B for six years of exploration activities (a sample WP&B for a tender is provided below).
3.	Technical report and montage	The geological and technical justification for the proposed exploration programme, including a seismic survey commitment and the completion of one exploration well.
4.	Company profiles	Profile describing the current business activities and human resources of the participant and of its parent company.
5.	Financial statements and financial projections	Annual financial statements of the participant and the parent company of the participant for the last three years, audited by a certified public accountant. Financial projections of the participant for the next three years. A statement letter from a bank confirming the participant's ability to finance all work programme commitments for the first three years.
6.	Statement letter that new entity will be established to sign the PSC	-
7.	Statement letter expressing support from the parent company	-
8.	A statement regarding bonuses	A statement confirming the participant's ability to pay any required bonuses.
9.	Copy of bid bond	A bid bond expressing a bank's undertaking to guarantee and provide funds in respect of the offer from the participant for 100% of the value of the signature bonus valid for six months.
10.	All Consortium agreement	For a consortium bid agreement between and/or among the consortium members together with confirmation as to which member of the consortium is the designated operator.
11.	A statement agreeing to the PSC draft	A statement agreeing with the terms of the draft PSC agreement which will be signed by the winning bidder.
12.	PSC draft	A draft of the PSC agreement.
13.	Original receipt of payment	A copy of the payment receipt for the bid information document.
14.	Copy of data package payment	A copy of the proof of purchase of the official government data package.

No.	Subject	Remark
15.	Copy of notarised deed/ articles of establishment	A copy of the participant's notarised articles of incorporation.
16.	A compliance statement	A letter stating the participant's compliance with the results of the bidding process.

Source: MoEMR Regulation No. 35/2021

4.1.3 General surveys and oil and gas data

In order to delineate work areas effectively, a general survey Geological and Geophysical (G&G) is a prerequisite. However, any survey undertaken by a business entity must be at its own expense and risk, and only after obtaining permission from the MoEMR.

Data obtained from general surveys and exploration and exploitation activities automatically become the property of the state. Therefore, any utilisation, transmission, surrender, or transfer of this data, whether within or outside Indonesia, requires explicit permission from the MoEMR. Furthermore, data resulting from exploration and exploitation activities must be surrendered to the MoEMR (via SKK Migas) within three months of collection, processing and interpretation.

Prior to a work area being returned to the Government, the oil and gas data can be kept confidential for between four years (basic data), six years (processed data) and eight years (interpreted data). Once the work area is returned, the data is no longer confidential.

4.1.4 JCC

Upstream activities are executed via a JCC, defined under Law No. 22 to be a PSC or other form of JCC, such as a service contract, Joint Operation Agreement (JOA) or Technical Assistance Contract (TAC) concerning exploration and exploitation activities, which is signed by the business entity or PE with SKK Migas (the executing agency).

The JCC contains provisions stipulating as follows (Article 6):
a. That ownership of the oil and gas remains with the Government until the point of delivery;
b. That ultimate control over operational management remains with SKK Migas; and
c. That all capital and risks shall be borne by the contractor.

The JCC also contains provisions that stipulate (Article 11):
a. "state revenue" terms;
b. work areas and their reversion;
c. work programmes;
d. expenditure commitments;

e. transfer of ownership of the results of the production of oil and gas;
f. the period and conditions for the extension of the contract;
g. the mechanism for the settlement of any disputes;
h. any domestic supply obligations (a maximum of 25% of production is generally earmarked to meet domestic demand) (Article 22);
i. post-mining operation obligations;
j. workplace safety and security;
k. environmental management;
l. reporting requirements;
m. plans for the development of the field;
n. development of local communities; and
o. priority for the use of Indonesian manpower.

Historically, there were two categories of contracts for Indonesia's petroleum industry. The first category referred to the bundle of rights and obligations granted to investors in return for investing, in cooperation with the Government, in oil and gas exploration and exploitation (i.e. PSCs; TACs; and Enhanced Oil Recovery (EOR) contracts). The second category refers to the agreements entered into by participants in a PSC, TAC or EOR regarding how they will conduct petroleum operations, i.e. Joint Operating Bodies (JOBs). Since the passing of Law No. 22, most new contracts have been in the form of PSCs.

4.1.5 Activity, expenditure and bonus commitments

Contractors are required to begin their activities within six months of the effective start date of the JCC and to carry out the work programme during the first six years of the exploration period.

The contractor is responsible for meeting all financing requirements, and bears full risk if exploration is not successful. This financing is expected to be denominated in USD. Any costs incurred by contractors are subject to recovery from the Government.

Annual exploration expenditure requirements are outlined in the Production Sharing Contract (PSC) for both the initial six years and any extensions. While the annual commitment is stipulated in the PSC, specifics must be endorsed by SKK Migas through annual work programmes and associated budgets (for PSCs with cost recovery mechanisms). Additionally, the Government usually mandates the contractor to obtain a performance bond to cover the initial three contract years of activity. Any excess expenditure can be carried forward, but under-expenditure requires consent from SKK Migas for adjustment.

Failure to carry out the required obligation may lead to the termination of the JCC, and any under-expenditure may need to be paid to the Government along with the forfeiture of any related performance bonds.

The bid usually includes a commitment to pay bonuses to SKK Migas (and increasingly the Government is requesting a bond to cover the signing bonus as part of the bid). These bonuses are of two types:

a. Signature bonuses – payable within one month of the awarding of the contract. These bonuses generally range from USD1 million – USD15 million.
b. Production Bonuses – payable if production exceeds a specified number of barrels per day, e.g. USD10 million when production exceeds 50,000 bbl./ day, or cumulative production.

GR-79, as amended by GR-27, stipulates that bonuses are not cost-recoverable (see comments below). Therefore, in accordance with the uniformity principle, bonuses would also not be tax deductible.

The bonuses to be paid and the amount of committed expenditure stated in a PSC are usually negotiated and agreed by the contractor and SKK Migas before signing the PSC.

4.1.6 Contract period

Joint Cooperation Contracts (JCCs) are valid for a maximum of thirty years from the date of approval. Upon reaching this limit, the contractor has the option to request an extension from the MoEMR for a maximum period of twenty years per extension (as per Article 14). Extension requests can be submitted no earlier than ten years and no later than two years before the JCC expiration date.

The maximum thirty-year period encompasses both the exploration and exploitation phases. Typically, the exploration phase lasts for six years and can be extended for an additional four years at most (as outlined in Article 15). If no commercial discoveries are made during the exploration phase, the JCC is terminated. Upon expiration of the contract period, the contractor is required to return the remaining work area to the MoEMR.

4.1.7 Amendments to a JCC

A contractor may propose amendments to the terms and conditions of a JCC. These may be approved or rejected by the Minister based on the opinions of SKK Migas and their benefit to the state.

4.1.8 Participating interests-transfers

A contractor has the option to transfer part or all of its participating interest, subject to prior approval from the MoEMR and/or SKK Migas, depending on the terms outlined in its PSC. However, the transfer of a majority participating interest to a non-affiliate is prohibited during the first three years of the exploration period. The taxation issues associated with PSC transfers are discussed in Section 4.5, including under GR-79, as amended by GR-27.

Upon making a commercial discovery, the Contractor is obligated to offer a 10% participating interest (at the net book value of the expenditure incurred up to that date) to a Regionally-Owned Business Entity (*Badan Usaha Milik Daerah* - BUMD). This requirement was initially established by the

MoEMR Regulation No. 37 of 2016 and has since been amended by MoEMR Regulation No. 1 of 2025. Despite the amendment, the regulation continues to stipulate that the contractor is responsible for the financial obligations associated with the 10% participating interest of the BUMD and must recoup the investment through oil and gas production without any uplift.

If the offer is not taken up by the BUMD, the contractor is required to offer the interest to a nationally-owned company. The offer is declared closed if the nationally-owned company does not accept the offer within a period of 60 days from the date of receiving the offer. In practice, these timeframes may not be observed strictly.

4.1.9 Occupational health and safety, environmental management and CD

Contractors must adhere to relevant laws and regulations concerning occupational health and safety, environmental management, and Community Development (CD). For PSC contracts signed in or after 2008, the contractor is explicitly tasked with implementing CD programmes throughout the PSC's duration.

Contractors can contribute to CD through various means, including providing physical facilities, empowering local enterprises and the workforce, and conducting community-focused activities. These CD efforts should be done in consultation with the local government, with priority given to communities nearest to the work area.

Additionally, contractors are responsible for funding CD programmes.

For PSCs executed prior to 2008, expenditure on CD is usually cost recoverable. CD expenditure during the exploitation which was non-Cost Recoverable (non-CR) according to GR-79, becomes cost-recoverable under GR-27 (see comments on GR 27 in Section 4.4).

4.1.10 Reservoir extension and unitisation

When a reservoir extends into another contractor's work area, an open area, or the territory/continental shelf of another country, it must be reported to the MoEMR or SKK Migas. Unitisation arrangements may be formalised in these cases. If the reservoir extends into an open area that later becomes a work area, unitisation must be formalised. However, if the open area remains unchanged for five years, a proportionate extension of a contractor's work area can be requested. All unitisation requests require approval from the MoEMR.

4.1.11 Non-profit oriented downstream activities allowed

The activities of field processing, transportation, storage and sale of the contractor's own production are classified as upstream business activities. These should not be profit-oriented. The use of facilities by a third party on a proportional cost sharing basis is generally allowed where there is excess capacity, SKK Migas' approval has been obtained and the activities are not aimed at making a profit. If such facilities are used jointly with the objective of making a profit, these will represent downstream activities, and will require the establishment of a separate business entity under a downstream business permit.

4.1.12 Share of production to meet domestic needs

Contractors are responsible for meeting domestic demand for crude oil and/or natural gas. According to regulations GR-35 and GR-27 (amendment of GR-79), the contractor's share of production earmarked for domestic demand is capped at a maximum of 25%. Additionally, GR-27 introduces a DMO (Domestic Market Obligation) holiday incentive for oil, which can be issued by the MoEMR with approval from the MoF.

4.1.13 Land title (Articles 33-37 of Law No. 22 and Section VII of GR-35)

Rights to working areas are a “right to the sub-surface part” and do not cover land surface rights. Land-rights acquisitions can be obtained after offering a settlement to the owners and occupiers in accordance with the prevailing laws (Article 34). A consideration for land is based upon the prevailing market rate. Where a settlement is offered, land titleholders are obliged to allow the contractor to carry out their upstream activities (Article 35).

Upstream and downstream activities are not permitted in some areas unless consent has been granted by the relevant parties (such as the relevant government and/or community). Restricted areas include cemeteries, public places and infrastructure, nature reserves, state-defence fields and buildings, land owned by traditional communities, historic buildings, residences or factories. Resettlement might be involved as a condition for the granting of any consent. Section VII of GR-35 sets out detailed provisions regarding the procedures for resettlement.

A contractor holding a right of way for a transmission pipeline must permit other contractors to use it after consideration of relevant safety and security matters. A contractor planning to use a right of way can directly negotiate with another contractor or party that holds the relevant rights of way and, if agreement between the parties cannot be reached, the MoEMR/SKK Migas can be approached to resolve the matter.

4.1.14 Use of domestic goods, service, technology, engineering and design capabilities

Under the cost-recovery scheme, all goods and equipment purchased by contractors become the property of the Government. Importation of goods requires approvals from the MoEMR, MoF, and other relevant ministries. Imports are permitted only if the required products are not domestically available at the necessary quality, efficiency, guaranteed delivery time and after-sales service standards.

Management of goods and equipment falls under the jurisdiction of SKK Migas. Surplus goods and equipment may be transferred to other contractors with the Government's approval, ensuring responsible use of cost recovery funds. Surplus inventory resulting from poor planning is not eligible for cost recovery, aligning with GR-79 as amended by GR-27.

SKK Migas is required to surrender excess goods and equipment to the MoF if the equipment cannot be used by another contractor. Any other use of such goods and equipment, including through donation, sale, exchange or use for capital participation by the state, destruction or rental, requires MoF approval, based on a recommendation from SKK Migas/MoEMR.

All goods and equipment used for upstream activities must be surrendered to the Government upon termination of the JCC.

For greater detail on the treatment of inventory; Property, Plant and Equipment (PP&E); and tendering for goods and services, please refer to these respective titles in Section 4.2.4.

4.1.15 Manpower and control of employee costs and benefits

Contractors are encouraged to prioritise hiring local manpower, but they may employ foreign workers for specialised expertise not readily available among Indonesian personnel. The number of expatriate positions is regulated by SKK Migas and undergoes annual review. The current manpower laws and regulations applying to the employees of a contractor are dealt with in Section 3.1.4 above. Contractors are required to provide development, education and training programmes for Indonesian workers.

During the annual work plan and budget review, SKK Migas evaluates training programmes, salary and benefit costs, and plans for localising expatriate positions. Contractors must submit annual manpower or organisational charts for both national and expatriate workers (RPTK and RPTKA) for SKK Migas' approval. SKK Migas controls the salaries and benefits which can be paid and the costs which can be recovered through salary caps. In an effort to offset any inequity in salary caps, PSC operators may offer employee benefits such as housing loan assistance, car loan assistance, long-service allowances, etc., which are cost recoverable if approved by SKK Migas.

PSC operators, under the guidance of SKK Migas, must offer a pension for employee retirement or severance payments for general terminations (referred to as the *Tabel Besar* or the Big Table). The Big Table scheme is a form of defined benefit whereby an employee is given a certain number of months' pay based on their years of service.

Accordingly, some PSC operators have established defined contribution pension plans, managed by a separate trust, under which the PSC operator and the employee contribute a percentage of an employee's salary. Pension contributions are charged as recoverable costs. Some PSC operators also purchase annuity contracts from insurance companies. Pension contribution accruals cannot be cost-recovered until they are fully funded (i.e. paid).

Some PSC operators have opted to manage their pension plans by funding them using bank time deposits, with the interest earned reinvested and used to reduce the future funding. All pension schemes require PSC operators to prepare an actuarial assessment of the fair value of the assets and the future pension liabilities, whether fully funded or unfunded. Historically, any unfunded liability is maintained off balance sheet for PSC-based financial reporting.

4.1.16 Jurisdiction and reporting

JCCs are subject to Indonesian laws. Contractors are obligated to report discoveries and the results of the certification of oil and/or gas reserves to the MoEMR/SKK Migas. Contractors are required to perform their activities in line with good industry and engineering practices, which include complying with the relevant provisions on occupational health and safety and environmental protection and using EOR technology, as appropriate.

4.1.17 Dispute mechanism-arbitration

SKK Migas has established a special dispute resolution mechanism, Work Procedure Guideline (PTK) 051, for PSC cost recovery disputes. This mechanism guides SKK Migas and Contractors in deferring cost recovery based on audit findings, Financial Quarterly Report (FQR) analysis, Authorisation for Expenditure (AFE) audits, and questioned expenditures.

Prior to the deferral of cost recovery, discussions shall be held with successive tiers of management of SKK Migas and the contractor for a period of six months from the issuance of an audit report. Any deferred cost recovery shall be settled within 90 working days through a maximum of three discussions. In the event that discussions fail, the contractor may exercise its rights in accordance with the PSC.

4.2 Production Sharing Contracts (PSCs)

4.2.1 General overview and commercial terms

PSCs are the predominant agreements used in Indonesia's upstream sector. In a conventional PSC, the Government and the contractor agree to split production revenue based on predetermined percentages. Operating costs are recovered from production through contractor cost oil formulas defined in the PSC. Additionally, the contractor has the right to separately dispose of its share of oil and gas, with ownership passing at the point of export or delivery.

Regulation-08 introduces a PSC scheme based upon the sharing of a “gross production split” without a cost recovery mechanism, later revoked by MoEMR Regulation No. 13/2024 (refer to Chapter 5 for more detail).

Generations of conventional PSCs

PSCs have evolved through five "generations", with the main variations between them relating to the production sharing split. The second and third generation PSCs issued after 1976 removed the earlier cost recovery cap of 40% of revenue, and confirmed an after-tax oil equity split of 85/15 for SKK Migas and the contractor, respectively. The third generation of the late 1980s introduced First Tranche Petroleum (FTP) and offered incentives for frontier, marginal and deep-sea areas. In 1994, to stimulate investment in remote and frontier areas (the eastern provinces), the Government introduced a 65/35 after-tax split on oil for contracts in that region (fourth generation). In 2008, a fifth generation of PSCs with a cost recovery mechanism was introduced. While the after-tax equity split is negotiable, the latest model limits the spending available for cost recovery (via a "negative list" regulated under GR-79 as amended by GR-27) and offers incentives in other areas such as via investment credits. More details on cost recoverable items and the negative list are provided in Chapter 4.2.2.

Key differences between the later and earlier generations are as follow:

a. Rather than a fixed after-tax share, recent PSCs have introduced some flexibility regarding the production sharing percentage offered;
b. PSCs now prescribe a DMO for natural gas;
c. SKK Migas and the contractor are both entitled to FTP of 20% of the petroleum production;
d. The profit-sharing percentages in the contracts assume that the contractor is subject to tax on after-tax profits at 20% (i.e. not reduced by any tax treaty);
e. Certain pre-signing costs (e.g. for seismic purchases) may be cost recoverable (although this is less clear for recent PSCs);
f. The MoEMR and/or SKK Migas must approve any changes to the direct or indirect control of the PSC entity; and
g. The transfer of the PSC's participating interest to non-affiliates is only allowable:
    - with the MoEMR and/or SKK Migas' approval; and
    - where the Contractor has retained a majority interest and operatorship for three years after signing.

Relinquishments

The PSC sets out the requirements for areas to be relinquished during the exploration period. Specific details are set out in the contract, but the parties must consult with SKK Migas, and the areas must be large enough to enable others to conduct petroleum operations.

Pre-PSC costs

The recipient of a PSC will typically incur expenditure before the PSC is signed. This pre-PSC expenditure cannot be transferred to the PSC and so will generally become non-recoverable.

Commercial terms

The general concept of a PSC is that the contractor bears all the risks and costs of exploration. If production does not proceed, these costs are not recoverable, but if production does proceed then the contractors can claim a share of production to meet cost recovery, an investment credit (where granted) and an after-tax equity interest in the remaining production.

The terms of a PSC include that:

a. the contractor is entitled to recover all allowable current costs (including production costs), as well as amortised exploration and capital costs;
b. the recovery of exploration costs is limited to production arising from the contracted “field” with an approved Plan of Development (PoD) – effectively quarantining cost recovery to the initial and then subsequent “fields” (earlier generation PSCs did not “ring fence” by PoD and/or by field);
c. the contractor is required to pay a range of bonuses including a signing, education (historically) and production bonus. The production bonus may be determined on a cumulative basis. These bonuses are not cost-recoverable or tax deductible;
d. the contractor agrees to a work programme with a minimum exploration expenditure over a certain number of years;
e. all equipment, machinery, inventory, materials and supplies purchased by the Contractor becomes the property of the State once landed in Indonesia. The Contractor has a right to use and retain custody during operations. The Contractor has access to exploration, exploitation and G&G data, but the data remains the property of the MoEMR;
f. each contractor shares its production, less deductions for the recovery of the contractor’s approved operating costs. Each contractor must file and meet its tax obligations separately;
g. the contractor bears all the risks of exploration;
h. historically, each contractor was subject to FTP of 15% (for fields in eastern Indonesia and some in western Indonesia pursuant to the 1993 incentive package) or 20% (for other fields). This was calculated before any investment credit or cost recovery. Recent contracts provide for the sharing of FTP of 20%;
i. the contractor is required to supply a share of crude oil production to satisfy a DMO. The quantity and price of the DMO oil is stipulated in the agreement. Recent contracts require a gas DMO;
j. after commercial production, the Contractor may be entitled to recover an investment credit historically ranging from 17% to 55% of costs (negotiated as part of the PoD approval) incurred in developing crude oil production facilities; and
k. the contractor is required to relinquish portions of the contract area based on a schedule specified in the PSC.

Cost recovery principles

Basic cost-recovery principles include allowing the following items:

a. Current-year capital (being the current-year depreciation charges) and non-capital costs;
b. Prior years' unrecovered capital and non-capital costs;
c. Inventory costs;
d. Head office overheads charged to operations; and
e. Insurance premiums and receipts from insurance claims.

Over time, several principles and regulations have been developed by entities like SKK Migas/BP Migas/Pertamina and the Indonesian Tax Office (ITO). For instance, PSC contractors typically receive an after-tax equity share of 15% from oil production. However, this share is subject to meeting the DMO, leading to a reduced return for contractors. Additionally, FTPs allow the Government to claim a share of production before full cost recovery by contractors.

Since 1995, PSCs have mandated that contractors are responsible for site restoration, including clearing, cleaning and restoring sites upon completion of work. Funds allocated for abandonment and site restoration are recoverable once spent or funded, with unused funds retained in a joint account, and are not refundable to the contractor.

In 2017, the MoEMR issued MoEMR Regulation No. 26/2017 (as later amended by MoEMR Regulation No. 47/2017, No. 24/2018, and No. 46/2018) stipulating the mechanism for PSC contractors to recover (unrecovered) "Investment Costs" upon the expiration of the PSC. Investment costs are referred to as capital expenditure incurred over the PSC term by PSC contractors with the objective of maintaining an equitable level of production for a maximum of five years before PSC expiration, subject to SKK Migas approval.

In summary, MoEMR Regulation No. 26/2017 stipulates that; for (conventional) PSC, an unrecovered investment costs can be carried forward to the extended (conventional) PSC.

PSC accounting principles

The PSC outlines the accounting principles to be applied by the contractor. Under relevant clauses of the PSC, operating, non-capital and capital costs are defined, together with the related accounting method to be used for such costs. This differs from Generally Accepted Accounting Principles (GAAP) and Indonesian Financial Accounting Standards (IFAS). Most companies, however, do not prepare financial statements compliant with IFAS, and instead prepare PSC statements adjusted at the head office level to comply with GAAP. SKK Migas issued PTK 059 as general guidance on PSC accounting. However, detailed PSC accounting must make reference to the specific PSC agreement.

4.2.2 Equity share - Oil

Investment credits

An investment credit is available on direct development and production capital costs, as negotiated and approved by SKK Migas.

In recognition of the delayed generation of income inherent in the exploration process, a credit ranging from 17% to 55% of the capital costs of development, transport and production facilities has historically been available. Second- generation PSCs allowed a rate of up to 20% for fields that commenced commercial operations after 1976.

The investment credit must be taken in oil or gas in the first year of production but can generally be carried forward.

Under earlier PSCs, investment credits were capped where the share of total production taken by the Government did not exceed 49%. This condition was eliminated in later-generation PSCs.

Under GR-79/27, the Minister has the authority to determine investment incentive credits. The criteria for such credits are not however specified in GR-79/27.

Cost oil

The expenses which are generally allowable for cost recovery include:

a. current year operating costs from a field or fields with PoD approval, intangible drilling costs on exploratory and development wells and the costs of inventory when landed in Indonesia (as distinct from when used – although this has changed in recent PSCs). The contractor can also recover head office overheads (typically capped at a maximum of 2% of current year costs) provided the cost methodology is applied consistently, is disclosed in quarterly reports and is approved by SKK Migas (see further guidance below under Management and head office overheads);
b. depreciation of capital costs calculated at the beginning of the year during which the asset is Placed into Service (PIS) (although for recent PSCs only monthly depreciation is allowed in the initial year). The permitted depreciation methods are either the declining balance or double declining balance method, based on the individual asset amount, multiplied by depreciating factors as stated in the PSC. Generally the factor depends on the useful life of the asset, such as 50% for trucks and construction equipment and 25% for production facilities and drilling and production equipment. Title to capital goods passes

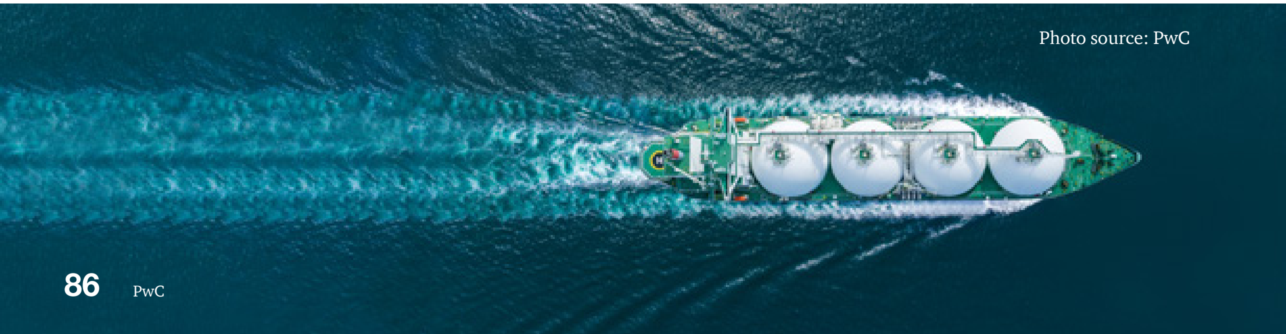


Photo source: PwC

to the Government upon landing in Indonesia, but the contractor can claim depreciation; and

c. unrecouped operating and depreciation costs from previous years. If production is not sufficient to recoup costs, these may be carried forward to subsequent years with no time limit.

In December 2010, GR-79 increased the number of non-CR items to 24. However, the list of non-CR items was then revised under GR-27 to 22 items effective from 19 June 2017. The list of non-CR items under GR-27 is as follows:

a. Costs charged or incurred for personal and/or family members, management, participating interest holders and shareholders;
b. Establishment or accumulation of a reserve fund, except costs for field closure and restoration deposited in the joint account of SKK Migas and the contractor in an Indonesian bank;
c. Granted assets;
d. Administrative sanctions such as interest, fines, surcharges as well as criminal sanctions in the form of penalties related to the tax law and implementing regulations, as well as claims or fines resulting from the contractor's actions;
e. Depreciation of assets which do not belong to the Government;
f. Incentives, payments of pension contributions and insurance premiums for foreign manpower, management and shareholders and/or their family members;
g. Expatriate manpower costs which do not comply with the procedures of the RPTKA or Expatriate Manpower Permits (*Izin Mempekerjakan Tenaga Asing* - IMTA);
h. Legal consultant's costs which have no direct relation to oil operations in the context of PSC;
i. Tax consultant's fees;
j. Marketing costs of oil and/or gas of the contractor's entitlement except for marketing costs for gas as approved by SKK Migas;
k. Representation costs, including entertainment costs in any name and form, except if accompanied by a nominative list and the relevant Tax ID Number (*Nomor Pokok Wajib Pajak* - NPWP);
l. Training costs for expatriate manpower;
m. Merger and acquisition costs or participating interest costs;
n. Interest expenses on loans;
o. Employee Income Tax (EIT) borne by the contractor, except when paid as a tax allowance, or third party EIT which is borne by the contractor or grossed up;
p. Procurement costs which are not in accordance with the arm's length principle and costs exceeding the approved AFE by more than 10%, except for certain costs which are specifically regulated by the MoEMR;
q. Surplus materials purchased due to poor planning;
r. Costs incurred due to the negligent operation of Place Into Service (PIS) facilities;
s. Transactions which are written off, contrary to the terms of the tender process or against the law;
t. Bonuses paid to the Government;
u. Costs incurred prior to the signing of the relevant cooperation contract; and
v. Commercial audit costs.

Sharing of production oil

Crude production in excess of the amounts received for FTP, cost recovery and investment credits is allocated to the Government and the contractor before tax (but adjusted by the DMO supply obligations).

Since a PSC involves the sharing of output, the production to be shared between the Government and contractor is made up of:

a. cost oil;
b. any investment credit; and
c. equity oil.

Management and head office overheads

The contractor has exclusive authority to conduct oil and gas operations in its work area, and is responsible to SKK Migas for the conduct of those operations. In practice, SKK Migas exercises considerable control through its approval of the Contractor's annual work programmes, budgets and manpower plans.

Some general and administrative costs (other than direct charges) related to head office overheads can be allocated to the PSC operation based on a methodology approved by SKK Migas. A Parent Company Overhead (PCO) allocation cap ((*Peraturan Menteri Keuangan* - PMK) 256 dated 28 December 2011) was introduced in 2011, and seeks to govern the cost recoverability and tax deductibility of overhead costs. PMK-256 stipulates a general cap for PCO allocations of 2% per annum (p.a.) of annual spending for cost recovery and tax deductibility purposes. However, the amount that a PSC can actually recover will be dependent upon approval from SKK Migas, and may be lower than 2%.

The overhead allocation methodology must be applied consistently, and is subject to periodic audit by SKK Migas. For producing PSCs, SKK Migas will often travel abroad to audit head office costs. Please refer to Section 4.5 for further discussion.

GS PSCs have a slightly different approach regarding the charging of direct and indirect head office expenditure to PSC operations. See further discussion in Chapter 5.

FTP

Under pre-2002 contracts, contractors and the Government were both entitled to claim FTP and received petroleum equal to 20% of the production before any deduction for operating costs. FTP was then split according to their respective equity shares as stated in the contracts.

Under later PSCs, the Government was entitled to take the entire FTP (although at a lower rate of 10%) without sharing with the contractor.

For recent PSCs, the FTP of 20% is once again shared with the contractor.

Equity share – Oil

Any oil that remains after investment credit and cost recovery is split between SKK Migas and the contractor. Second and third generation PSCs involve an oil split of 85/15 (65/35 for frontier regions) for SKK Migas and the contractor respectively. This is an after-tax allocation, being what the contractor is entitled to lift after paying taxation at the grandfathered rates (i.e. the tax rates in effect when the PSC was signed).

This is summarised as follows:

Table 4.2 - Summary of after-tax oil splits

	Post 2002 PSC (%)	1995 Eastern Province PSC (%)	1995 PSC (%)	1985 - 1994 PSC (%)	Pre-1984 PSC (%)
Tax rate	42.4/40/37.6*	44	44	48	56
Share of production after tax:					
Government	Varies	65	85	85	85
Contractor	Varies	35	15	15	15
Contractor's share of production before tax:	Varies				
35/(100-44)		62.50			
15/(100-44)			26.79		
15/(100-48)				28.85	
15/(100-56)					34.09

* The general combined Corporate and Dividend (C&D) tax rate fell to 42.4% in 2009, 40% in 2010 and 37.6% in 2020.
Sources: GR-79/2010 as amended by GR-27/2017, pre-1984 PSCs, 1985 - 1994 PSCs, 1995 PSCs, 1995 Eastern Province PSCs, 2002 - 2023 PSCs and draft 2025 PSC.

DMO

According to the PSC, after the commencement of commercial production the contractor should fulfil its obligation to supply the domestic market. The DMO (for oil) is calculated at the lesser of:

a. 25% of the contractor's standard pre-tax share or its participating interest share of crude oil; or
b. The contractor's standard share of crude oil (either 62.50%, 26.79%, 28.85% or 34.09% - as described in the table above) multiplied by the total crude oil to be supplied and divided by the entire Indonesian production of crude oil from all petroleum companies for the PSC area.

In general, a contractor is required to supply a maximum of 25% of the total oil production to the domestic market out of its equity share of production. The oil DMO is to be satisfied using equity oil, exclusive of FTP.

It is possible for the oil DMO to absorb the contractor's entire share of equity oil. If there is not enough production to satisfy the oil DMO, there is no carry-forward of any shortfall.

Generally, for the first five years after commencing commercial production, SKK Migas pays the contractor the full Indonesian Crude Price (ICP) value for its oil DMO. This is reduced to 10% or 25% of that price for subsequent years (depending upon the generation of PSC). The price used is the Weighted Average Price (WAP).

Historically there was no DMO obligation associated with gas production. However, under GR-35 and recent PSCs, a DMO on gas production has been introduced.

In July 2021, the MoEMR issued regulation No.18/2021 prioritising the use of crude oil for domestic needs. The issuance of this regulation was in line with the Government's broader policy objective of reducing crude oil imports.

In summary, MoEMR Regulation No. 18/2021 requires Pertamina to prioritise the procurement of crude oil from domestic sources over importing. In this regard, PSC contractors are obliged to offer or include Pertamina in tenders for their portion of crude oil before exporting, pursuant to business-to-business negotiations (presumably meaning that the crude need not be sold at below "market" value). It is also stipulated that the negotiations must be conducted within 20 days.

The tax implications of MoEMR Regulation No. 18/2021 include that crude sales at market price could lead to a gain or loss for PSC contractors based on any variation between the negotiated price (with Pertamina) and the ICP. Any gains generated could be subject to the prevailing income tax rates (including Branch Profits Tax (BPT) - if applicable).

Valuation of oil

For the purpose of calculating a share of production, and for tax purposes, oil is valued using a price reference known as the ICP. Under a PSC, the contractor receives oil or in-kind products in settlement of its costs and its share of equity. This makes it necessary to determine a price to convert oil into USD in order to calculate cost recovery, taxes and other fiscal items such as under/over lifting. The ICP is determined monthly by the MoEMR based on the average daily prices of international indices from the preceding month.

The monthly tax calculations are based on the ICP and on actual contractor lifting. The actual year-end annual PSC Contractor entitlement (cost plus equity barrels) is based on the average ICP for the year. The average ICP during the respective year is known as the WAP.


Photo source: PwC

4.2.3 Equity share – Gas

Sharing of production - Gas

The provisions for the sharing of gas production are similar to those for oil except for the equity splits and DMO. When a PSC produces both oil and gas the relevant production costs will be allocated against each according to the proportion of production in value terms in the year or some other means of allocation as approved by SKK Migas. The costs of each category that are not recouped can either be carried forward to the following year or taken against the production of the other category in the same year only.

The main difference between oil and gas production relates to the equity split. The majority of PSCs are based on an 85/15 after-tax split for oil. For gas, the after-tax split is usually 70/30 for the Government and the contractor respectively although some older PSCs are based on an after-tax split of 65/35. After the 1995 incentive package, Eastern Province gas contractors use an after-tax split of 60/40.

These provisions result in the following entitlements:

Table 4.3 - Summary of after-tax gas splits

	Post 2002 PSC (%)	1995 Eastern Province PSC (%)	1995 PSC (%)	1985 - 1994 PSC (%)	Pre-1984 PSC (%)
Tax rate	42.4/40/37.6*	44	44	48	56
Share of production after tax:					
Government	Varies	60	70	70	70
Contractor	Varies	40	30	30	30
Contractor's share of production before tax:	Varies				
40/(100-44)		71.43			
30/(100-44)			53.57		
30/(100-48)				57.69	
30/(100-56)					68.18

* The general combined C&D tax rate fell to 42.4% in 2009, 40% in 2010 and 37.6% in 2020.
Sources: GR-79/2010 as amended by GR-27/2017, pre-1984 PSCs, 1985 - 1994 PSCs, 1995 PSCs, 1995 Eastern Province PSCs, 2002 - 2023 PSCs and draft 2025 PSC.

If the natural gas production does not permit full recovery of natural gas costs, the excess costs shall be recovered from crude oil production in the contract area. Likewise, if excess crude oil costs (crude oil costs less crude oil revenues) exist, this excess can be recovered from natural gas production.

Illustrative calculation of entitlements

An illustration of how the share between the Government and contractors is calculated is presented in the tables below.

Table 4.4 - Illustrative calculation of entitlement for old PSC

Assumptions:			
Contractor's share before tax =	34.0909%		
Government's share before tax =	65.9091%		
WAP per barrel =	USD60		
C&D tax =	56%		

Description	Formula used	Year to date bbls	USD
Lifting:			
- SKK Migas	USD [a1] = bbls x WAP	2,500	150,000
- Contractors	USD [a2] = bbls x WAP	4,500	270,000
Total lifting	[A]	7,000	420,000
Less : FTP (20%)	[B] = 20% x [A]	1,400	84,000
Total lifting after FTP	[C] = [A] - [B]	5,600	336,000
Less :			
- Cost recovery	Cost in bbls = cost in USD : WAP	4,000	240,000
- Investment credit	Cost in bbls = cost in USD : WAP	100	6,000
Total cost recovery	[D]	4,100	246,000
Equity to be split	[E] = [C] - [D]	1,500	90,000
SKK Migas' share :			
- SKK Migas' share of FTP	65.9091% x [B]	923	55,380
- SKK Migas' share of equity	65.9091% x [E]	989	59,340
- DMO	25% x 34.0909% x [A]	596	35,760
SKK Migas' entitlement	[F]	2,508	150,480
Over/(under) SKK Migas' lifting	[G] = [a1] - [F]	(8)	(480)
Contractor's share :			
- Contractor's share of FTP	34.0909% x [B]	477	28,620
- Contractor's share of equity	34.0909% x [E]	511	30,660
Less :			
- DMO	25% x 34.0909% x [A]	(596)	(35,760)
Add :			
- Cost recovery		4,000	240,000
- Investment credit		100	6,000
Contractor's entitlement	[H]	4,492	269,520
Over/(under) Contractors' lifting	[I] = [a2] - [H]	8	480

Note: SKK Migas on behalf of the Government

Table 4.5 - Illustrative calculation of C&D taxes for Contractor's entitlement in old PSC

Description		USD		
Contractor's share:				
- Contractor's share of FTP		28,620		
- Contractor's share of equity		30,660		
- Cost recovery		240,000		
- Investment credit		6,000		
Less: DMO		(35,760)		
		269,520		
Less: Lifting price variance		(26,949)	**	
Contractor's net entitlement:		242,571		
Less: Cost recovery		(240,000)		
Add: Actual price received from DMO		22,908	*	
Contractor's taxable income		25,479		
Less:			56%	
- Corporate tax (45%)		11,465		Combined effective tax rate :
- Dividend tax (11%)		2,803		= C&D tax/ Contractor's taxable income
C&D tax (56%)		$\boxed{14,268}$		= 14,268/25,479
				= 56%
Contractor's net income		11,211		
* DMO comprised of two items:	Quantity in barrels		USD	Price of DMO
- Old oil (40% of total DMO in barrels)		238	1,428	10% From WAP
- New oil (60% of total DMO in barrels)		358	21,480	WAP
Actual price received from DMO		596	22,908	
** Calculation of lifting price variance:		USD		
Entitlement by using WAP		269,520		
Entitlement by using ICP		242,571		
Lifting price variance		26,949		
@ The entitlement is calculated by using the monthly ICP during the respective year				

Illustrative presentation of old PSC in SKK Migas Financial Quality Report (FQR) format

Description	USD
Gross revenue/lifting	420,000
Less: FTP (20%)	84,000
Gross revenue/lifting after FTP	336,000
Cost recovery:	
- Cost recovery	240,000
- Investment credit	6,000
Total cost recovery	246,000
Equity to be split	90,000
SKK Migas' share:	
- SKK Migas' share on FTP	55,380
- SKK Migas' share on equity	59,340
- Lifting price variance	26,949
- Government tax entitlement	14,268
Add: DMO	35,760
Less: Domestic market adjustment	(22,908)
Total SKK Migas' share	168,789
Contractor's share:	
- Contractor's share on FTP	28,620
- Contractor's share on equity	30,660
- Lifting price variance	(26,949)
Less: DMO	(35,760)
Add: Domestic market adjustment	22,908
Less: Government tax entitlement	(14,268)
Add: Total recoverables	246,000
Total contractor's share	**251,211**

Domestic gas pricing

Gas pricing in domestic supply contracts is determined through negotiations on a field-by-field basis between SKK Migas, buyers and individual producers, based on the economics of a particular gas field development. Historically, all domestic gas had to be supplied to Pertamina under a gas supply agreement. Pertamina in turn then sells the gas to the end-user. Prices were fixed for a designated level of supply for the duration of the contract.

Under Law No. 22, individual producers can sell directly to end users based on contract terms and conditions negotiated directly between the producer and the buyer (with assistance from SKK Migas). However, there continues to be Government involvement in steering contracts towards certain domestic buyers, rather than producers' preference to export due to more favourable pricing and terms.

Take-or-pay arrangements have been negotiated in some circumstances. Although this concept has long been accepted, the policy regarding its treatment from a tax, accounting (revenue recognition) and reporting perspective varies in practice.

PSC contractors and potential investors should also consider the credit risk inherent in any domestic gas sales arrangements when negotiating contract terms and conditions and how they might protect themselves.

The MoEMR issued Regulation No. 8/2020, which was later amended by MoEMR Regulation No. 15/2022, and Regulation No. 10/2020 stipulating a maximum gas price of USD6/MMBTU at the plant gate for gas buyers in certain industries. Industries covered by MoEMR Regulation No. 8/2020 include the fertiliser, petrochemical, oleochemical, steel, ceramic, glass and rubber glove industries, and this was expanded under MoEMR Regulation No. 10/2020 to the power generation sector (including PT PLN (Persero) as gas buyer). The MoEMR will determine the necessary adjustments to the gas purchase price from the gas producer and/or to the related distribution costs, including liquefaction, compression, pipeline transmission and distribution, and transportation based on recommendations from SKK Migas or the Special Oil and Gas Regulatory Body of Aceh (*Badan Pengelola Migas Aceh* - BPMA) and the supervisory body for gas distribution.

Further, MoEMR Regulations No. 15/2022 and No. 10/2020 clarify that the adjustments to the gas price will not affect the gas producer's entitlement to proceeds based on existing gas purchase agreements with gas buyers. Instead, these adjustments will be accounted for as reductions in the Government's entitlement when performing the current year's equity split calculation. Detailed provisions regarding the calculation of the entitlement to gas price adjustments will be further regulated through technical guidance from SKK Migas or BPMA.

Over/(under) lifting

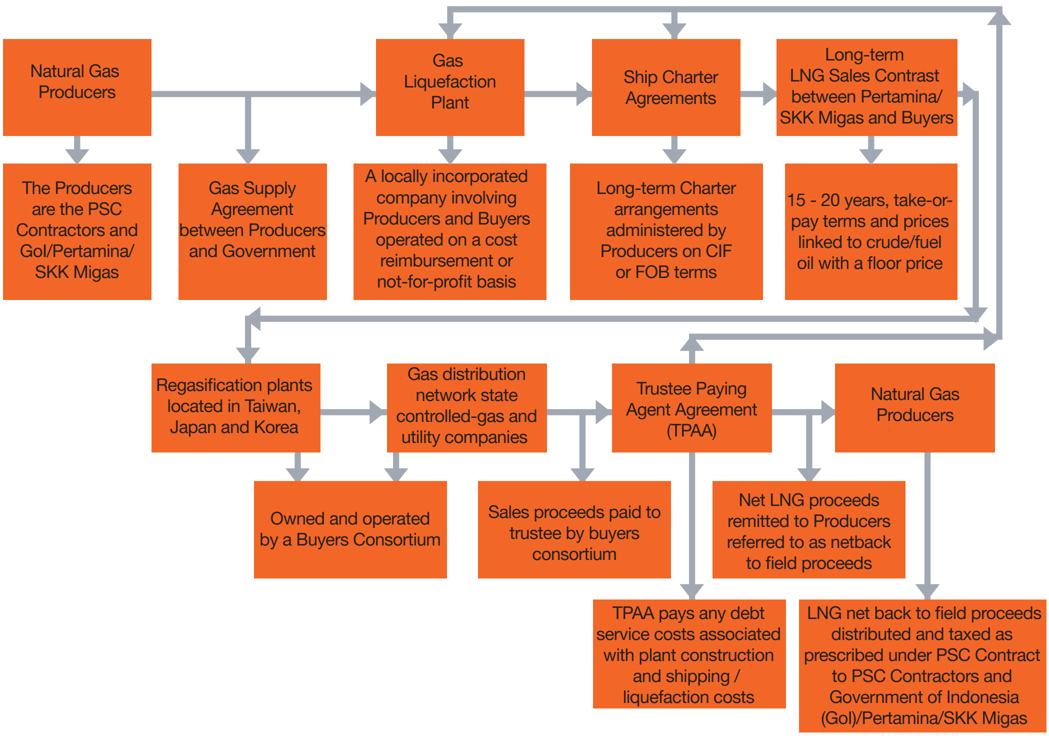
Lifting variances will occur each year between the contractor and the Government. These under/over-lifting amounts are settled with the Government in cash or from production and can be considered as sales/purchases of oil or gas respectively. The individual members of the PSC may in turn have under/over-lifting balances between themselves, which will be settled according to joint venture agreements, but generally in cash or from production in the following year.

Under MoF Regulation No. 118/ PMK/02/2019 as lastly amended with MoF Regulation No. 139/2024 any under-lifting position between the contractor and the Government should be settled in cash within 17 days (subject to the time taken for the examination and processing of the request) after the Directorate General of Budget (DGB) verifies the request from SKK Migas. There is no specified period for the settlement of any over-lifting position. In practice though, the amount is most often settled when the year-end FQR is finalised in March of the subsequent year.

Integrated Liquefied Natural Gas (LNG) supply projects

Indonesia currently has three operating LNG facilities, namely PT Badak LNG, BP Tangguh LNG and PT Donggi Senoro LNG.

Historically, Indonesia has utilised a traditional integrated LNG seller/buyer supply chain structure. The LNG supply chain is generally structured as follows:



For Bontang, PT Badak NGL was established as a continuation of the upstream operations of several PSCs to process gas into LNG on a not-for-profit basis. A number of sales contracts were initially entered into under fixed long-term supply arrangements and at minimum prices in order to reduce the risk for the producers. The initial contracts carried Cost, Insurance, Freight (CIF) terms. From the late 1980s, the shipping arrangements were changed to allow buyers and/or others to participate in long-term shipping charters on a Free on Board (FOB) basis.

The Bontang and Tangguh LNG projects were effectively project-financed with an implied Government guarantee which enabled lower financing costs. A trustee-paying agent arrangement was also established to service this debt and the related Operation and Maintenance (O&M) costs. These processing and financing costs are first netted off against LNG proceeds with the net proceeds then released back to the PSC entitlement calculation (i.e. under the so-called "net back to field" approach). The Tangguh LNG facility uses a similar concept to Bontang, and is operated by BP Tangguh on behalf of the gas producers, but without a separate gas processing entity.

Non-integrated LNG projects

Non-integrated projects involve the legal/investor separation of gas extraction and LNG production assets. Issues under this model focus on the gas offtake price to be struck between the PSC contractors and LNG investors. Under a non-integrated LNG model the investors in the LNG plant separately require a designated rate of return on their investment in order to service project finance, etc. (i.e. unlike the "net back to field" approach outlined above for integrated projects which effectively allows financiers to benefit from the value of the entire LNG project).

The non-integrated LNG structure is relatively rare in Indonesia, and as such it is difficult to assess the Indonesian tax implications. Withholding Tax (WHT), Value-added Tax (VAT), tax rate differentials (and associated transfer pricing) and Public Entity (PE) issues need to be considered. In addition, any offshore project company would need to consider its tax treaty entitlements.

An example of a non-integrated project is the Donggi Senoro LNG Plant in Sulawesi. The Donggi Senoro LNG Plant is owned by Medco, Mitsubishi Corporation, Kogas and Pertamina, but Mitsubishi does not have a participating interest in the two PSCs that supply gas to the LNG plant.

4.2.4 Other PSC conditions and considerations

The procurement of goods and services

Procurement of goods and services by oil and gas contractors is regulated so as to give preference to Indonesian suppliers. For purchases in excess of certain values, specific procedures must be complied with, including the calling of tenders and approval by SKK Migas.

Guidance No.PTK-007/SKKIA0000/2023/S9 (PTK-007) on the Management Framework for the Supply Chain for Cooperation Contracts (*Pedoman Tata Kerja Pengelolaan Rantai Suplai Kontraktor Kontrak Kerja Sama*) is the current SKK Migas-issued guidance on procurement of goods and services.

In general, all purchases are done by either tender or direct appointment (with certain requirements) and only vendors with the Oil and Gas Support Business Capability Certificate (*Surat Kemampuan Usaha Penunjang Migas* - SKUP) and (*Sertifikat Pengganti Dokumen Administrasi* - SPDA) are considered qualified and able to bid. A PSC contractor can procure goods and services by itself but requires SKK Migas approval at the preparation of procurement list and planning stage if the package is worth over IDR50 billion or USD5 million.

Changes in the scope or terms of a contract which can increase the contract value must be approved by SKK Migas, as follows:

a. For contracts where the appointment of the supplier was carried out through approval by SKK Migas and where the overruns exceed 10% of the initial contract or above IDR200 billion or USD20 million; and
b. For contracts where the appointment of the supplier was made by the contractors and where the cumulative amount of the initial contract plus overruns exceeds IDR200 billion or USD20 million.

All equipment purchased by PSC contractors is considered the property of the Government from the time when it enters Indonesia. Oil and gas equipment may enter duty free if used for operational purposes (please see further discussion in Section 4.4.8 below). Imported equipment used by service companies on a permanent basis is assessed for import duty unless this is waived by the Indonesia Investment Coordinating Board (BKPM). Import duties on oil and gas equipment ranges from 0% to 29%. The position for temporary imports of subcontractor equipment is covered in Section 4.4.8.

Inventory

Under the PSC, spare parts inventory is separated into capital and non-capital. Non-capital inventory is charged to cost recovery immediately upon purchase or landing in Indonesia. A counter-entry account is usually maintained to track the physical movements and use of non-capital inventory. For later generation PSCs, however, inventory is charged based on usage.

Under SKK Migas guidelines, any excess or obsolete inventory must be circulated to other PSCs and receive SKK Migas approval before any amounts (capital inventory) can be charged to cost recovery. Under PTK 007, any dead stock and surplus materials above 8% of non-capital inventory is not recoverable.

If inventory is transferred or sold to another PSC the selling price must be at carrying cost. If a PSC contractor cannot dispose of the inventory a Write-off Proposal (WOP) must be submitted to SKK Migas for approval. Once approved, the inventory is usually charged to cost recovery (if not yet charged) and transferred to a SKK Migas warehouse or facility, or held by the contractor on behalf of SKK Migas.

PP&E

Under the PSC framework, PP&E, including land rights, purchased or acquired in Indonesia, become the property of the Government. However, the contractor retains the right to use these assets until approved for abandonment by SKK Migas.

The Net Book Value (NBV) of such property, as reflected in the PSC financial statements, represents expenditure by the contractor which has not yet been cost recovered. Intangible drilling costs of unsuccessful exploratory wells are charged to operating expenses as they are incurred. If commercial reserves are determined in the contract area and the exploratory wells subsequently become productive, the associated costs are capitalised. Additionally, the tangible costs of successful development wells are capitalised.

Depreciation is calculated from the time when the asset is PIS. Earlier generation PSCs allow a full year's depreciation during the initial year, whereas later generation PSCs require a month-by-month approach so that an asset PIS in December is only allowed one month's depreciation during the initial year. Under PTK 033, PIS approval is required prior to the commencement of depreciation. PIS approval should be submitted together with the AFE close-out report in order for the final depreciable project cost to be agreed. Exhibit C to the PSC describes the category method, and useful life for the purposes of PSC depreciation.

Site restoration and abandonment provision

PSC contractors that signed contracts after 1995 must include in their budgets provisions for clearing, cleaning and restoring sites upon the completion of work. For PSCs signed from 2008 onwards any cash funds set aside in a non-refundable joint account for abandonment and site restoration are cost-recoverable. Any unused funds will be transferred to SKK Migas. According to PTK 040, cash funds must be placed into a state-owned bank under a joint account between SKK Migas and the PSC contractor. The PSC contractor shall be liable if the funds are not sufficient to cover the costs of site restoration and abandonment.

It has been suggested that any abandonment and site restoration costs and liabilities related to PSCs signed before 1995 remain SKK Migas's responsibility. However, consistent with PSCs signed since 1995, SKK Migas may at some point require the contractor to contribute to the cost of restoration and abandonment activities.

Based on MoEMR Regulation No. 15/2018 regarding the post-operation of oil and gas upstream activities, contractors are obligated to conduct post-operation activities using post-operation activity funds and to submit a post-operation activity plan to SKK Migas. Contractors are also obligated to reserve post-operation activity funds, which must be deposited in a joint bank account of SKK Migas and the contractors, in accordance with the estimated post-operation activity costs (referred to as the "Abandonment and Site Restoration" or "ASR" fund).

4.3 Upstream accounting

The table below shows some of the key standards relating to upstream oil and gas companies under PSC accounting, GAAP in the United States (US GAAP) and International Financial Reporting Standards (IFRS).

Table 4.6 - Accounting in upstream oil and gas business

Key standards reference and comparison between PSC accounting and US GAAP and IFRS			
Area	**PSC**	**US GAAP**	**IFRS***
Depreciation of capital costs	Accelerated depreciation with a full year's depreciation in the year of acquisition	Units of production	Method not specifically determined: to be allocated on a systematic basis over useful life, reflecting the consumption of assets' benefits
Non-capital/controllable stores	Expensed upon receipt (except for later generation PSCs which are charged to cost recovery as they are consumed)	Expensed as consumed	Expensed as consumed
Obsolete stores or idle facilities	Written off only when approved by SKK Migas	Expensed/ impaired when identified	Expensed/impaired when identified
Deferred taxes	Not provided	Accounting Standard Codification (ASC) 740	International Accounting Standards (IAS) 12 treatment
Contingent liabilities	Recognised when settled or approved by SKK Migas	ASC 450	IAS 37 treatment
Severance and retirement benefits	Recognised when paid or funded	ASC 715	IAS 19 (Revised) treatment
Decommissioning and restoration obligation	Recorded and recovered on a cash basis, if specifically provided for in the PSC	ASC 410 treatment	Provision to be provided under IAS 37 treatment
PSC licence acquisition costs	Expensed (generally not cost recoverable)	Capitalised	Capitalised as long as meeting IFRS asset recognition criteria
Exploration and evaluation - Dry holes	Expensed	Expensed	Expensed
Exploratory wells-Successful: Tangible costs Intangible costs	 Capitalised Expensed	 Capitalised Capitalised	Not specifically addressed; Capitalised as long as meeting IFRS asset recognition criteria
Development - Dry holes	Expensed	Capitalised	Not specifically addressed; capitalised as long as meeting IFRS asset recognition criteria under IAS 38 or IAS 16

Key standards reference and comparison between PSC accounting and US GAAP and IFRS			
Area	**PSC**	**US GAAP**	**IFRS***
Development wells-successful: Tangible costs Intangible costs	 Capitalised Expensed**	 Capitalised Capitalised	Not specifically addressed; capitalised as long as meeting IFRS asset recognition criteria
Support equipment and facilities	Capitalised	Capitalised	Capitalised

* Currently, IFAS do not significantly differ from IFRS, except for the effective date of the application of new standards as they are issued.
** New PSCs signed from 2011 capitalise intangible costs

4.3.1 Statement of Financial Accounting Standards (SFAS) 111/IFRS 11 – Joint arrangements

Oil and gas companies often use joint arrangements to spread risks, share costs or bring specialised skills to projects. These arrangements can take various legal forms, such as formal joint-venture contracts or governance arrangements outlined in company formation documents. What distinguishes joint arrangements is the presence of joint control.

Unanimous consent is generally required for financial and operating decisions in order for joint control to exist. An arrangement without joint control is not a joint arrangement.

Under SFAS 111/IFRS 11, for unincorporated JOs, participants must account for their interest in a JO as a share of assets, liabilities, revenue and costs. A joint venture participant uses the equity method to account for its investment in a joint venture.

In Indonesia's oil and gas industry, upstream joint working arrangements typically take the form of joint arrangements. While some companies establish JOs through separate vehicles, such instances are rare and generally fall under SFAS 111/IFRS 11. Midstream and downstream joint-working arrangements usually involve separate vehicles and incorporated entities.

Photo source: PwC

4.4 Taxation and customs

This section sets out the industry-specific aspects of Indonesian taxation and customs law for (conventional) upstream contractors, and includes an analysis of some common industry issues. Taxation obligations common to ordinary taxpayers are not addressed, however (please see our annual PwC Pocket Tax Guide for discussion of this area). Issues around the taxation of GS PSCs are outlined in Chapter 5.

4.4.1 Historical perspective

"Net of tax" to gross of tax

The modern regulatory era dealing with the framework of oil and gas activities in Indonesia began with the passage of the Oil and Gas Mining Law No. 44/1960 on 26 October 1960. Pursuant to Law No. 44, the right to mine Indonesian oil and gas resources was vested entirely in Indonesian State-owned Enterprises (SOEs). Law No. 44 did, however, allow for SOEs to appoint other parties as Contractors.

Pertamina, established as a state enterprise through GR No. 27 of 1968 and Law No. 8/1971, gained authority over appointing private enterprises, including overseas entities, as contractors under oil and gas mining arrangements. This marked the start of PSC and similar contractual setups.

From the early 1960s until the late 1970s, PSC entities were entitled to take their share of production on a "net of tax" basis (i.e. with the payment of Indonesian income tax made on their behalf by the state/Pertamina).

In the late 1970s, this changed to a "gross of tax" basis to comply with US foreign tax credit rules. Consequently, PSC entities became responsible for calculating taxable income and paying income tax directly. Despite this shift, there was an expectation that PSC entities would maintain a "net of tax" entitlement.

Uniformity principle

As the change from a "net of tax" to a "gross of tax" basis was not meant to disturb the "desired" production sharing entitlements (i.e. the after-tax take), it became necessary to adopt the so-called "uniformity principle" in relation to the calculation of taxable income. This principle, as outlined in MoF Letter No. S-443A of 6 May 1982, provides that the treatment of income and expenditure items for cost recovery and tax deductibility purposes should be identical (with limited exceptions such as for signing/production bonuses). This long-standing principle has now been recognised (at least partially) in GR-27 which requires that there be a general "uniform treatment" between cost recovery and tax deductibility.

Uniformity therefore meant that the calculation of income tax for PSC entities differs to the calculation applying to other Indonesian taxpayers. Significant differences include:

a. that the taxable value of oil "liftings" is to be referenced to a specific formula (currently ICP) as opposed to an actual sales amount (gas "liftings" generally reference the gas sales agreement contract price);

b. that the classifications for intangible and capital costs are not necessarily consistent with the general income tax rules relating to capital spending;
c. that the depreciation/amortisation rates applying to these intangible and capital costs are not necessarily consistent with the depreciation rates available under the general income tax rules;
d. that there is a general denial of deductions for interest costs (except where specially approved) whereas interest is usually deductible under the general Income Tax rules as long as within a 4:1 debt equity ratio under the general income tax rules;
e. that there is an unlimited carry forward of prior year unrecovered costs; and
f. that no tax deductions will arise until there is commercial production as opposed to a deduction arising from the date of the spending being expensed or accrued under the general income tax rules.

4.4.2 GR-79, as amended by GR-27 and GR-93 (GR-79/27/93)

GR-79 was the first dedicated regulation dealing with both the cost recovery and tax arrangements for this important industry. Notwithstanding the issuance of a number of implementing regulations for GR-79, many issues remain unclear. The table below summarises the issues which remain unclear, as well as the status of the respective regulations, etc.

Photo source: PwC

Table 4.7 - Issues that remains unclear on the implementation of GR-79 regulations

Article	Unclear area	Regulation pending	Guidance pending
Article 3, Article 5, Article 12	Definition of the principle of effectiveness, efficiency and fairness, as well as good business and engineering practices		
Article 7	Ring fencing by field or well		
Article 8	Minimum Government share of a work area		Yes, per Article 8(2) - from the Minister
Article 10	FTP amount and share		
	Investment incentives (form/ extent)		
Article 12	Limitations on indirect charges from head office	See our comments on head office costs	
Article 13	Negative lists - Transactions procured without a tender process or cause a loss to the state		
Article 14	Income from by-products (sulphur/electricity)		
Article 17	The use of reserve funds for abandonment and site restoration	Yes, per Article 17 (4)	
Article 18	Severance for permanent employees paid to the undertaker of employee severance funds	Yes, per Article 18(2) - Procedures for the administration of employee severance	Yes, per Article 18(1) - Minister to determine


Photo source: PT Saka Energi Indonesia

Article	Unclear area	Regulation pending	Guidance pending
Article 19 (See also Article 7)	Deferment of cost recovery until a field is produced - Ring fencing by field		
	Policy with regard to the PoD to secure state revenue		Yes, per Article 19(2) – Minister to determine policy
Article 22	Procedures to determine the methodology and formula for Indonesia's crude oil price	Yes, per Article 22(2)	
Article 24	DMO fee for delivery of crude oil and gas	Issued as MoF Reg. No. 137/2013 (now MoF Reg. No. 139/2024)	Yes, per Article 24(9), to be determined by Minister
Article 25	Tax assessment for foreign tax credit purposes	Issued as Director General of Taxes Regulation No.29/ PJ/2011 on Income Tax Payments	
Article 26	Maximum amount of deductions and fee/ compensation paid by the Government	Yes, per Article 26(2) from Minister.	
Article 27	Guidance on the procedures for payment of income taxes on PSC transfer and uplift income	Issued as PMK-257 in 2011 (see below) (now streamlined under PMK-81/2024 – see below)	
Article 31	Form and contents of annual income tax return	Issued as a Director General of Taxes regulation (PER-Peraturan Dirjen Pajak)-05/2014 (see below)	
Article 32	Tax ID registration for PSC (so called "Joint Operation" tax ID number)		Yes, per Article 32(1)
Article 33	Procedures to calculate and deliver Government share in the event of tax payment in kind	Issued as PMK-70/2015 (now streamlined under PMK-81/2024 – see below)	
Article 34	Standard and norms of costs utilised in petroleum operations		Yes, per Article 34(2)
Article 36	Independent third-party appointment to perform financial and technical verification		
Article 38	Transitional rules and adjustment to the GR		

Source: GR-79/2010

Effective date

GR-79 stipulates that:

a. it is effective from its date of signing. This means that GR-79 operates from 20 December 2010 (but see below);
b. it applies fully to JCCs, consisting of PSCs and service contracts, signed after 20 December 2010; and
c. JCCs signed before 20 December 2010 continue to follow the rules relevant to these JCCs until expiration. This is except for areas on which pre-GR-79 JCCs are silent, or which are not clearly regulated. In these cases, contractors should adopt the “transitional” areas covered in GR-79 within three months – a provision which has caused considerable unrest to many holders of pre-GR-79 PSCs. This is primarily because the transitional provisions (in Article 38b) apply in respect of eight significant areas as follows:
   i) Government share;
   ii) Requirements for cost recovery and the norms for claiming operating costs;
   iii) Non-allowable costs;
   iv) The appointment of independent third parties to carry out financial and technical verifications;
   v) The issuance of an income tax assessments;
   vi) The exemption of import duty and import tax on the importation of goods used for exploitation and exploration activities;
   vii) The contractor’s income tax in the form of oil and gas from the contractor’s share; and
   viii) Income from outside of the JCC in the form of uplifts and/or the transfer of JCC/PSC interests.

Whilst the exact scope remains unclear, some holders of pre-GR-79 PSCs have been concerned that the transitional rules could result in the largely retroactive operation of GR-79. This was particularly noting that there is uncertainty as to how to determine what areas were “not yet regulated or not yet clearly regulated”.

Amendment of GR-79 (i.e. GR-27 and GR-93)

GR-27

On 19 June 2017, the President signed GR-27, which amended GR-79. The main changes were as follow:

a) Article 10 in regard to state revenue including Government share and FTP

This article was amended to allow for a range of upstream “incentives” including:

i) a DMO holiday (albeit with no time limit specified);
ii) a range of tax incentives, where these are in accordance with the prevailing tax laws; and
iii) a range of non-tax state revenue incentives, which may include the use of state-owned assets for upstream activities.

The elucidation indicates that this amendment targets the incentives embedded in historical PSCs such as investment credits and DMO holidays. This will not extend to general tax concessions.

These amendments also included a new Article 10(a) to allow for a “sliding scale” equity split to be determined by the MoEMR. It is unclear at this stage how this scale will interface with the splits shown in the PSCs themselves (although see discussion on Article 38 below).

b) Article 11 regarding to recoverable costs

This article has been amended to positively confirm the recoverability of LNG processing costs.

c) Article 13 regarding non-recoverable costs

This article has been amended to remove a number of items from the list of non-CR spending being:

i) tax allowances related to EIT (which appears to be EIT where remitted on a grossed-up basis);
ii) interest formally approved for cost recovery; and
iii) CD during an exploitation phase.

As a result, spending on these items should now be cost recoverable, at least to the extent that this is in accordance with the requirements of the relevant PSC;

d) Article 16 in regard to depreciation

This article has been amended to allow for the residual value of assets that are “no longer able to be used” to be cost recovered outright. Under the previous arrangements, and Exhibit C of most PSCs, this spending would continue to be depreciable based upon the original useful life of the asset.

e) Article 25 dealing with the Income Tax calculation

This article has been amended to include:

i) a new Article 25(7a) which requires that assessments arising from a tax audit are to be issued within 12 months of the receipt of a “complete” tax return (previously there was no formal timeline except in the case of a tax refund).

The intent/impact is not clear, particularly noting the joint-audit framework with the Financial and Development Supervision Agency (BPKP - *Badan Pengawasan Keuangan dan Pembangunan*) and SKK Migas. It is possible, however, that this amendment will mean less of a role for the Directorate General of Taxes (DGT) in its income tax related audits; and

ii) New Articles 25(12) and (13), which provide that income tax on FTP is to be due when the “accumulated” FTP exceeds the relevant cost recovery balance.

This amendment is not entirely clear, but could mean that FTP is to be accumulated as non-taxable income until the exhaustion of all unrecovered costs (and thus an equity oil position) at which point the entire accumulated FTP becomes taxable.

f) Article 26 dealing with Tax Facilities

This article has been amended to include new Articles 26 (A) to (E) to provide specific tax facilities, as follow:

i) "Duty/import tax exemption" in relation to physical imports by PSCs during both the exploration and exploitation phases;

ii) Reductions in Land and Building Tax (PBB - *Pajak Bumi dan Bangunan*) of 100% (during the exploration phase) and up to 100% (during the exploitation phase);
Note that the MoF's approval is required for these import-related and PBB-related incentives during exploitation (the incentives during the exploration phase appear to be automatic);

iii) Income arising from charges from the shared use of assets by PSCs is to be exempt from WHT and VAT. Interestingly, the amendment does not formally provide that the income itself is otherwise exempt; and

iv) "Indirect head office allocations" do not constitute income tax "objects" or VAT-able "supplies". This appears to be a formalisation of the long-established principle set out under the MoF Letter S-604 issued in 1998, which has been challenged by the DGT in recent years.

The consequence of this amendment is presumably to render cost allocations exempt from WHT and VAT. There is however no elaboration on the meaning of a "head office" and so it is unclear how widely this incentive can be extended to affiliate charges from overseas.

g) Article 27 dealing with uplifts and participating interest transfers

This article has been amended to include:

i) a new Article 27 (1a) which provides that taxable income arising from uplifts, after being reduced by final income tax, is non-taxable; and

ii) a new Article 27 (2a) which provides that taxable income arising from PSC transfers, after being reduced by final income tax, is non-taxable.

In these cases, the consequence of the after-tax income becoming non-taxable is presumably that no further tax should apply to the after-tax income. This should therefore now formally exclude the levying of BPT on the after-tax income from PSC transfers, presumably in both direct and indirect transfer scenarios.

It should also be noted that the BPT on PSC transfers was introduced via PMK-257, and so was arguably never part of the original GR-79 architecture. PMK-257 is now revoked and streamlined under PMK-81 regarding the Indonesian Core Tax System. PMK-81 unfortunately maintains the provision of BPT imposition on PSC transfers albeit this may be due to simply mirroring the provisions under PMK-257. Aside the above issue, the recent practice indicates that BPT is no longer imposed on PSC transfers.

h) Article 31(2) dealing with PSC transfer reporting

This article has been amended to require that the value of a PSC transfer be reported to both the DGoG of the MoEMR, and the DGT. Previously GR-79 reporting only took place to the DGT.

i) Articles 37 and 38 dealing with transitional provisions

The transitional provisions provide that:

i) for PSCs signed before GR-79 but post Law No. 22/2001, the relevant PSC holders should elect to either:
   - continue to follow the provisions of the relevant PSC (i.e. exclusive of any GR-27 adjustments); or
   - "adjust" their PSC to comply with GR-27 (although with no guidance on the adjustments mechanism). This election is to be made within six months of the issuance of GR-27 (i.e. by mid-December 2017 – which has obviously already passed, and with no guidance on the selection mechanism);

ii) For PSCs signed post GR-79 but prior to GR-27 issuance, the outcome appears to be similar to i), although presumably with any election to "opt-out" of GR-27 still leaving the PSC holder subject to the rules under the PSC as impacted by GR-79 (although this is not clear).

The most likely interpretation of these transitional provisions is that GR-27 operates to "immediately" amend GR-79 on all matters outlined in GR-27. However, GR-27 will still not apply to the extent that GR-27 is inconsistent with the provisions of the relevant PSC. These inconsistencies can then be overcome only by the PSC contractor agreeing to amend the PSC so as to render the PSC entirely consistent with GR-27.

Whilst the range of PSC–specific matters requiring PSC amendments is debatable, it may not extend to the BPT due on a PSC transfer, as the taxation of PSC transfers is not typically prescribed in PSCs. As a result (and as indicated above), BPT on PSC transfers appears to have been removed effective from June 2017, irrespective of the position taken on any GR-27 related election (although this should be confirmed as part of any transaction advice).

The package of amendments under GR-27 should, on balance, be viewed positively by the industry and particularly for newer PSCs. However, all PSC holders will need to carefully weigh up the economic implications before making an election to opt-in to GR-27.

GR-93

On 31 August 2021, the Government of Indonesia issued GR No. 9 (GR-9), which provides updated guidance on the income tax treatment on transfers of PSC Participating Interests (PIs) in both direct and indirect transfers. GR-93 came into effect on the same date (i.e. 31 August 2021) and revoked several articles in GR-79/27 and GR-53. Other provisions of GR-79/27 and GR-53 remain operational.

Key highlights are as follows:

- GR-93 covers transfers of PSCs falling under either the cost recovery or GS framework;
- GR-93 provides some clarity on a number of long-standing issues, especially on the "tracing rules" in the case of transfers via share sales (i.e., "indirect" transfers); and
- GR-93 also provides clarity on certain transactions that are exempt from PSC transfer tax (particularly in indirect transfers);

Please refer to the PSC transfer section below for more details.

State revenue and payment of tax

The Income Tax payments of a PSC entity were historically counted by the Government as oil revenue rather than as an Income Tax receipt. The Income Tax was also remitted to the DGB as opposed to the ITO. On 31 March 2015, the MoF issued PMK-70 amending the previous PMK-79/2012, as a further implementing regulation of GR-79.

On 18 October 2024, the MoF issued PMK-81 which streamlined several regulations in relation to the implementation of Core Tax administration system, including PMK-70/2015 and PMK-79/2012. PMK-81 however does not make any notable changes from the PMK-70 provisions apart from introducing the BPMA as part of the regulatory body alongside SKK Migas (which was not incorporated yet in PMK-70). The following high-level points remain to be noted:

a. Similar to PMK-70, most of the terms in PMK-81 are consistent with GR-79;
b. State revenue is formally defined as Government share and the corporate and BPT (i.e., the so-called Corporate and Dividend (C&D) tax);
c. Final lifting is to be calculated at year end with procedures on how to settle over/ under liftings to be separately regulated;
d. Income tax for PSC contractors to consist of the monthly and annual C&D tax; and
e. If requested, the C&D tax must be paid "in-kind" based on the ICP (for oil) or the WAP (for gas) of the month when the tax is due. The possibility of tax being paid in-kind is not altogether new although the PMK is the first guidance on a calculation/value mechanism.

Under PMK-81, income tax payments of PSC contracts are therefore generally now on an equal footing with general taxpayers. Under GR-79, a facility also exists for a tax "assessment" letter evidencing the payment of income tax. Prior to this the DGT issued a temporary statement.

C&D tax payment procedures are as follows:

a. For cash payments:
   i) The tax payments are to be remitted into the (general) Directorate General of State Treasury account rather than into the oil and gas accounts (i.e. the MoF account #600.000411980 at the BI). The payment/remittance is still in USD and the transfer shall be made via a "Foreign Exchange" Designated Bank (i.e. *Bank Persepsi Mata Uang Asing*);
   ii) A tax payment slip is to be completed. Director General of Taxes Regulation No.25/PJ/2011 provides different tax payment codes for

petroleum income tax, natural gas income tax and BPT; and

iii) The monthly and annual C&D tax payment deadlines are the 15th of the following month and the end of the fourth month following the year end. Tax will be considered paid when the funds are received into the Directorate General of State Treasury account (i.e., the Tax Payment Slip (SSP - *Surat Setoran Pajak*) will be marked with NTPN (*Nomor Transaksi Penerimaan Negara*) and NTB (*Nomor Transaksi Bank*).

b. For in-kind payments:

i) The payment deadlines are the same as for cash payments;

ii) Contractors and SKK Migas will record the in-kind payments in a "minutes of in-kind handover" (*berita acara serah terima*) to be signed by both parties; and

iii) The SSP shall be completed based on the minutes of in-kind handover including the hand-over date. PMK-81 provides two attachments: Template for the Minutes of Handover and Attachment II – SSP specifically for (in-kind) C&D tax.

c. Where C&D tax is overpaid, the overpayment should be settled in accordance with the prevailing tax laws meaning that tax refunds could be subject to a tax audit (the historical practice has been that PSC entities simply offset overpayments against future C&D tax instalments). The instructions in PER-05 for completing the annual Corporate Income Tax Return (CITR) do not result in the disclosure of under or over payments in the main CITR form;

d. The C&D tax reporting procedures include the following requirements:

i) Contractors must prepare monthly and annual state revenue reports using the template provided in PMK-81 and submit these reports to the DGT (via the Core Tax system starting 1 January 2025), the DGB (specifically the Directorate of Non-Tax State Revenue in this case), and SKK Migas/BPMA. State revenue reports in nil position are not required to be submitted to the DGT although these should still be submitted to the DGB and SKK Migas/BPMA. PMK-81 remains to be silent on the reporting obligations during exploration (i.e. where no state revenue obligation should exist); and

ii) The reports should include the relevant SSP and payment evidence. This will be the transfer evidence (for cash payments) or the minutes of in-kind handover (for in-kind payments).

e. Any late payment or reporting is subject to administrative sanctions under prevailing tax laws. The reports also require the declaration of Government share and (as outlined above) extend the reporting obligations to the DGB, the DGT and SKK Migas.

Cost recovery/tax deductions

GR-79/27 requires that there be a "uniform treatment" between cost recovery and tax deductibility. This is pivotal as it appears to formally enshrine the long-standing "uniformity principle". To satisfy uniformity the amount should still:

a. be spent on income producing activities;

b. satisfy the arm's length principle (for related party transactions);

c. be consistent with good business and engineering practices; and
d. be approved by SKK Migas and be included in the relevant WP&B.

GR-79/27 also outlines two items of spending that are not allowed for cost recovery. For this list please refer Section 4.4.2 above.

Indirect taxes

Indirect taxes, regional taxes and regional levies are stated as cost recoverable. Indirect taxes include VAT, Import Duty, PBB, regional taxes and regional levies. These PBB and regional taxes/levies have generally been exempted (or at least reimbursable) in the past.

Import duty and other import taxes (such as VAT and Article 22 Income Tax) related to exploration and exploitation activities are also generally exempt (see below).

PBB for post GR-79-PSCs

On 12 April 2013, the MoF issued Regulation No.76/PMK.03/2013 (PMK-76) on PBB for the oil and gas sector, replacing Regulation No. 15/PMK.03/2012 (PMK-15). The effective date of PMK-76 was 12 May 2013. PMK-76 has led to a major change in the PBB regulatory framework for PSCs. PMK-76 has gone through several amendments, most recently by MoF Regulation No. 234/PMK.03/2022 (PMK-234).

General PBB regime

Pursuant to Article 5 of PBB Law No. 12/1994 (Law 12) the PBB tax rate is 0.5% of a “deemed” tax base. The “deemed” tax base ranges from 20% up to 100% of the “object value” (being a statutory value called Tax Object Selling Value (*Nilai Jual Objek Pajak* - NJOP)). The taxable event is the tax base of land and buildings “held” as of 1 January each year. PBB should be paid within six months of the receipt of an Official Tax Payable Notification (*Surat Pemberitahuan Pajak Terutang* - SPPT). Whilst an SPPT is not an assessment, it is still a legal notice from the Tax Office against which taxpayers can object.

PBB and PSCs

Article 11(4)(f) of GR-79 indicates that indirect taxes (including PBB) should be cost recoverable. Post GR-79 PSCs accommodate this by requiring indirect taxes to be cost recovered (in earlier PSCs the Government bears all taxes except income tax). On 1 February 2012, the MoF issued PMK-15 updating the PBB procedures (including overbooking) applicable to the PSC sector. The key features were:
a. that PMK-15 was effective on 1 February 2012 and cancelled all previous regulations relating to the PBB compliance for PSCs;
b. that the Tax Office should issue the SPPT by the end of April of each fiscal year;
c. that the PBB due should be settled through an overbooking made by the DGB from the oil and gas revenue account into the Tax Office/DGT account (i.e., PBB is not paid by the PSC contractor); and
d. that the taxable base value will be covered by further regulations.

On 12 April 2013 the MoF replaced PMK-15 with PMK-76. PMK-76 specifically references GR-79 and changes the PBB treatment as follows:

a. For pre-GR-79 PSCs, the overbooking process continues to apply; and
b. For post-GR-79 PSCs, the overbooking does not apply, and the PSCs are required to self-remit the PBB and claim as cost recovery.

With the automatic overbooking entitlement for post-GR-79 PSCs withdrawn, the DGT began directly to "assess" post-GR-79 PSCs.

On 30 September 2013, the DGT issued Circular Letter (*Surat Edaran* - SE) 46 to provide further clarification on the completion of the Notification of PBB Objects (SPOP - *Surat Pemberitahuan Objek Pajak*) for the "offshore" components of these objects. Perhaps the most significant aspect of SE-46 was to clarify that the NJOP should only extend to areas "utilised" by the PSC interest holder.

Whilst the term "utilisation" was not defined, the intent appeared to be to reduce PBB exposure for these PSCs going forward.

This outcome left post-GR-79 PSCs exposed to PBB liabilities.

On 10 December 2019, the MoF issued PMK-186, which became effective on 1 January 2020, and introduced the following changes:

a. An updated classification of "tax objects"; and
b. New procedures to determine the Sales Value of these NJOP.

PMK-186 applies to PBB objects in, among others, the oil and gas sector and other sectors which are:

a. located within Indonesian waters; and
b. not PBB objects of a village or town.

PBB objects

For "other sectors", the definition of "land" has now been clarified to include Indonesian waters used for storage and processing facilities, and thereby extends to the various categories of vessels used on these waters.

The definition of "buildings" has now also been clarified to include technical constructions planted or attached permanently on "land" within Indonesian waters. This includes pipelines, and storage and processing facilities such as Floating Storage Offload (FSO), Floating Production System (FPS), Floating Production Unit (FPU), Floating Storage Unit (FSU), Floating Production Storage and Offload (FPSO) and Floating Storage Regasification Unit (FSRU). Please refer to our comments in Chapter 7 (Service providers to the upstream sector) for more details on the development of PBB issues pertaining to FSRU/FPSO/FSO, etc.

Further, this clarification confirms the recent DGT position during tax audits that PBB should now cover these assets.

NJOP calculation

PMK-186 sets out the procedures to calculate the NJOP for assets falling into the above sectors. For land, the NJOP varies according to the characteristics of use (e.g. productive, not yet productive, non-productive, onshore/offshore, etc.). This is obviously relevant for oil and gas.

For buildings, the NJOP for all sectors is based on the “new acquisition price”. This is defined as all costs incurred to acquire the tax object at the time of assessment, less depreciation based on the physical condition of the tax object.

PBB reduction for post-GR-79 PSCs

On 31 December 2014, and in response to the above, the MoF issued Regulation No.267/2014 (PMK-267) which provided tax incentives for exploration PSCs in the form of a PBB reduction.

The reduction was granted on the sub-surface component, and can amount to up to 100% of the PBB due on that component. This incentive is applicable from 2015 onwards where the contractor fulfils the following requirements:

a. Its PSC was signed after 20 December 2010 (i.e. the effective date of GR-79);
b. An SPOP (notification of PBB objects) has been submitted to the DGT; and
c. A recommendation letter has been provided by the MoEMR which stipulates that the PBB object is still in the exploration stage.

The reduction is granted annually for a maximum of six years from the PSC signing date and can be extended by up to four years (subject to a recommendation letter from the MoEMR).

On 27 August 2019, the MoF issued Regulation No. 122/PMK.03/2019 (PMK-122) which provides incentives including a PBB reduction of up to 100% (effectively a PBB exemption). These incentives apply during both the exploration and exploitation periods, although their application during the exploitation period is subject to an approval from the MoF after reviewing the project’s economics.

From an administrative perspective, the incentive requires a “confirmation letter for the tax facilities” for both the exploration and exploitation phases. Such a confirmation letter should be issued by the Head of the Regional Tax Office (RTO).

Bookkeeping and tax registration

A PSC entity is automatically entitled to maintain its books, and calculate its income tax liability, in English and using USD. However, a PSC entity should still file a notification (three months before the relevant accounting period) with the Tax Office.

Transactions denominated in currencies other than USD are to be converted into USD using the exchange rate as the date of the transactions.

VAT and WHT continue to be calculated in rupiah irrespective of any USD bookkeeping notification.

GR-79/27 does not affect the bookkeeping requirements as set out above. However, GR-79/27 also indicates that:

a. contractors shall carry out their transactions in Indonesia and settle payment through the banking system in Indonesia; and
b. transactions and the settlement of payments (referred to in paragraph a) can only be conducted outside of Indonesia if approval from the MoF is obtained.

A contractor is required to register for their own tax ID number. Registration of the JCC itself should be carried out by the operator of the particular JCC. This development is similar to that applying to existing JOB arrangements.

Operators are responsible for transactional taxes (including WHT and VAT) meaning that the transactional taxes should continue to be reported under the operator's tax ID number.

PSC transfers

GR-79/27 provides that transfers of PSC/ JCC interests will be taxed as follows:

a. During the exploration stage, a final tax of 5% of the gross proceeds will be levied. However, the transfer will be exempted if it was undertaken for "risk sharing purposes" and the following criteria are met:
    i) Less than the entire PSC interest is transferred;
    ii) The PSC interest has been held for more than three years;
    iii) Exploration activities have been conducted; and
    iv) The transfer is not intended to generate gain.
b. During the exploitation stage, a 7% final tax on gross proceeds is due except for any transfer to a "national company" as stipulated in the JCC (i.e. Indonesian participation).

GR-79 via PMK-81 introduced the imposition of BPT on PSC transfers (either direct or indirect). This imposition of BPT appears, however, to have been removed under GR-27 starting in June 2017 (see above).

As briefly mentioned above, GR-93, which was issued on 31 August 2021, provides some further clarity on the long-standing issues pertaining to the PSC transfer tax:

a. GR-93 now looks to define a PSC interest as "immovable property". This "immovable property" concept is more consistent with international tax law suggesting (perhaps) greater recognition of the applicability of tax treaty protections for indirect transfers. However, the definition goes beyond most treaties to include shares in the entities which hold the immovable property;
b. Notwithstanding a), GR-93 more clearly distinguishes between "direct" and "indirect" transfer scenarios. Note in particular the new annual remittance mechanism for indirect transfers, i.e. on the tenth of the following month of the end of fiscal year (e.g. for a fiscal year ending 31 December, the remittance takes place on 10 January);
c. In terms of indirect transfers, GR-93 makes it clear that the transfer tax can apply on an "unlimited" tracing basis (including multi-tier share ownership) and so goes beyond the "in substance" indirect transfer guidelines that currently exist. However, there is no specific relief on "day-to-day" share trading, leaving the scope of taxation via on-market share trading activity unclear;
d. GR-93 now provides that the transfer consideration in indirect-transfer scenarios will be set as a percentage of the transferred ownership (%) multiplied by the Fair Market Value (FMV) of the Indonesian PSC assets. There is, however, no guidance on how to determine the FMV in this case. Perhaps most surprisingly, this FMV default appears to apply even to arm's length transfers;

e. GR-93 provides a number of new transfer tax exemptions, as follows:
   i. For transfers taking place pursuant to approved "book-value" business restructuring transactions (e.g., mergers, spinoffs, takeovers, etc). This suggests that PSC transfers falling within the recently issued MoF Decision No.56/2021 covering SOE business restructuring transactions are now protected;
   ii. For transfers taking place pursuant to any other "restructuring" provided that the restructuring is:
      a) not "profit-oriented"; and
      b) does not lead to a change in the ultimate "parent entity"

      This exemption appears to be available for Multinational Corporations (MNCs). However, requirements that the MNCs must also satisfy, include the filing of various approvals and financial statements;
   iii. For transfers made as part of "local transactions", such as share sales between Indonesian entities subject to 0.1% final tax, where any income tax outcome otherwise falls within the "ordinary" tax rules

f. GR-93 indicates that a new MoF Decision will be issued and provide further guidance in a number of areas. Therefore, until this occurs, PMK- 81 will remain in force to the extent that it is consistent with GR-93.

Overall, the issuance of GR-93 provides some clarity around the areas of contention regarding indirect transfers, but arguably still without the level of precision that this area warrants. GR-93, however, now provides some "welcome" exemptions, especially for local oil and gas investors.

Head office costs

Head office costs are recoverable subject to:

a. the cost-supporting activities taking place in Indonesia;
b. the contractor provides audited financial statements of the head office and an outline of the method of cost allocation this (as approved by SKK Migas); and
c. the head office allocation does not exceed a ceiling determined by MoF Regulation No. 256/PMK.011/2011 being a maximum of 2% of spending (subject to approval from SKK Migas) being cumulative spending during exploration and annual spending thereafter.

Post-lifting costs

Certain post-lifting costs, including for transporting natural gas (such as marketing costs approved by SKK Migas) and other post upstream activities may be recoverable.

Tax calculation, payment and audit

For JCCs signed after GR-79, the income tax rate could be either the rate which prevailed at the time of signing, or the rate that prevails from time to time (i.e., may be subject to changes based on the changes in the tax law). This appears to breathe life into the income tax rate "election" which is included in Law No. 22 (see below).

For JCCs signed before GR-79, the income tax rate is that which prevailed when the JCC was signed. This grandfathering is consistent with the retention of the uniformity principle.

If the income tax payment is reduced, including via a change in the domicile of the head office (for example due to a favourable tax treaty) the after tax "Government share" shall be adjusted to ensure the pre-treaty split. This enshrines the recent trend in PSCs to counter tax treaty use.

Income tax payments are subject to tax audit by the DGT. The DGT will issue any assessments after carrying out an audit. Contractors should be prepared for the tight deadlines that apply in a tax audit context and any associated tax dispute proceedings. This includes a 30-day time limit for producing documents, especially those that might be held at the head office. Apart from providing documents on time, there are also obligations to provide (written) responses to DGT enquiries on time.

Expatriate costs

Expatriate costs are recoverable but should not exceed a ceiling determined by the MoF (in coordination with the MoEMR). MoF Regulation No. 258/PMK.011/2011 (PMK-258) provides details on the applicable cap which is dependent on the role and region that the expatriate comes from as per the table below. Remuneration is not well defined but seems to cover short-term compensation only.

Photo source: PT Saka Energi Indonesia

Table 4.8 - Applicable threshold for recoverable remuneration costs by expatriate according to position and jurisdictions

Position classification	Rates for expatriates who hold a passport from Asia, Africa, and the Middle East (USD)	Europe, Australia, and South America (USD)	North America (USD)	Remarks
Highest executive	562,200	1,054,150	1,546,100	First ranking position in contractor of oil and gas cooperation contract (President, Country Head, General Manager)
Executive	449,700	843,200	1,236,700	Second ranking position in contractor of oil and gas cooperation contract (Senior Vice President, Vice President)
Managerial	359,700	674,450	989,200	Third ranking position in contractor of oil and gas cooperation contract (Senior Manager, Manager)
Professional	287,800	539,450	791,200	Fourth ranking position in contractor of oil and gas cooperation contract (Specialist)

Source: MoF Regulation No. 258/PMK.011/2011 (PMK- 258)

Although the cap applies for cost recovery and tax deductibility purposes, the Article 21/26 EIT withholding obligation is subject to the prevailing income tax law meaning the Article 21/26 WHT is based on the actual payment.

4.4.3 Income tax rates

Various eras

The introduction of the uniformity principle (and its maintenance in GR-79/27) necessitated that the income tax rate should be "grandfathered" to the rate applying at the time that the PSC (or extension) was entered into. This is because the production sharing entitlements set out in the PSC are grossed-up to accommodate the income tax rate applying at the time. These rates then need to apply for the whole life of the PSC.

MoF Decree No. 267 of 1 January 1978, and MoF Decree No. 458 of 21 May 1984, provide "loose" implementing guidelines on the levying of income tax against PSC entities. Decrees No. 267 and No. 458 discuss taxable income in terms of a share of oil and gas production (or lifting). Deductions are discussed in terms of associated exploration, development and production costs.

For entities holding an interest in a PSC signed before 1984, the applicable income tax rate should be 45%. This rate was reduced to 35% in 1984, and then to 30% in 1995 up to 2008. Further reductions occurred to 28% in 2009, and to 25% starting in 2010 based on the new Income Tax Law No. 36/2008, effective from 1 January 2009.

The general assumption in the early years of PSC licensing was that PSC entities would be foreign incorporated. On this basis, the after tax profits of a PSC entity were subject to a further BPT. This tax was due at the rate of 20% giving rise to a total income tax exposure of (say) 56% for pre-1984 PSCs (i.e., 45% plus (55% x 20%)). In the relevant PSC this was shown as a (gross of tax) production share of 0.3409 for oil (i.e., 15%/1-.56%) and 0.6818 for gas (i.e., 30%/1-.56%).

To maintain a consistent after-tax take, adjustments to the gross-of-tax share have been made over the years in response to changes in Indonesia's general income tax rate. Additionally, in certain PSC bidding rounds, the net-of-tax contractor take has increased to (up to) 25% for oil and 40% for gas, resulting in variations in the gross production-sharing rates. These calculations can be summarised as follows:

Table 4.9 - Historical income tax rates and the after-tax split calculation

PSC Era	Income Tax - General	Income Tax – Branch Profits	Combined Tax Rate	Prod. Share (Oil)	After Tax	Production Share (Gas)	After Tax
Pre-1984	45%	20%	56%	0.3409	15%	0.6818	30%
1984-1994	35%	20%	48%	0.2885	15%	0.5769	30%
1995-2007	30%	20%	44%	0.2679	15%	0.5357	30%
2008	30%	20%	44%	0.4464	25%	0.7143	40%

PSC Era	Income Tax - General	Income Tax – Branch Profits	Combined Tax Rate	Prod. Share (Oil)	After Tax	Production Share (Gas)	After Tax
2009	28%	20%	42.4%	0.6250	36%	0.7140	41.142%
2010	25%	20%	40%	0.6000	36%	0.6850	41.143%
2013-2016*	25%	20%	40%	0.5830	35%	0.6670	40%
2020's	22%	20%	37.6%	Varies	Varies	Varies	Varies

*GS PSCs took effect from 1 January 2017
Sources: Pre-1984 PSCs, 1984 - 1994 PSC, 1995 - 2007 PSCs, 2008 PSCs, 2009 PSCs, 2010 PSCs, 2013 - 2016 PSCs, 2020 - 2023 PSCs, draft 2025 PSCs

BPT – Treaty use

The BPT rate can be reduced by a tax treaty. However, with the exception of a small number of treaties (most notably those with the Netherlands, the United Kingdom (UK), Malaysia and Singapore – although there are others) the BPT reduction in a tax treaty does not apply to PSC activities.

A decrease in the BPT rate might translate into a higher after-tax production share for a PSC entity. Consequently, Indonesian government authorities pertinent to the matter have historically contested a PSC entity's right to avail itself of treaty benefits. This contention led to the termination of the Netherlands' treaty in the late 1990s, although subsequent negotiations have taken place. Similarly, there were discussions about canceling other treaties, including the one with the UK. In 1999, the MoF mandated an increase in the Government's production share to offset any advantages derived from treaty concessions by PSC entities.

Over the last 15 years, PSCs have aimed to address these concerns by incorporating contractual provisions to nullify the use of treaties. These provisions typically involve adjusting production shares in accordance with the aforementioned MoF directive. The typical PSC language is now as follows:

*"**SKK MIGAS** and **CONTRACTOR** agree that all of the percentages appearing in Section VI of this **CONTRACT** have been determined on the assumption that **CONTRACTOR** is subject to final tax on profits after tax deduction under Article 26 (4) of the Indonesia Income Tax Law and is not sheltered by any tax treaty to which the Government of the Republic of Indonesia has become a party. In the event that, subsequently, **CONTRACTOR** or any of Participating Interest Holder(s) comprising **CONTRACTOR** under this CONTRACT becomes not subject to final tax deduction under Article 26 (4) of the Indonesia Income Tax Law and/or subject to a tax treaty, all of the percentages appearing in Section VI of this **CONTRACT**, as applicable to the portions of **CONTRACTOR** and **SKK MIGAS** so affected by the non applicability of such final tax deduction or the applicability of a tax treaty, shall be adjusted accordingly in order to maintain the same net income after-tax for all **CONTRACTOR's** portion of Petroleum produced and saved under this **CONTRACT**."*

Some older PSC contractors that are not subject to a "re-balancing" of their production-sharing entitlement from treaty relief have contested their position with the Indonesian tax authorities. In the first quarter of 2019, the Supreme Court issued a series of decisions under which it was found, in a majority of cases (but not all), that treaty relief was available to reduce the BPT in these limited circumstances. That is there was no commercial basis for an implied after-tax production share. It seems that the Supreme Court's focus was on the actual contractual position under the PSCs in question and the individual taxpayer's entitlement to the treaty relief.

Readers should note of course that Indonesia's rules of jurisprudence do not typically result in binding precedents. Consequently, none of the decisions will necessarily bind the assessing behaviour of the tax authorities (other than in respect of the assessments being litigated). It should be noted also that the Tax Court decisions in question, and even (arguably) the Supreme Court decisions, could still be challenged by the DGT (particularly if there are two or more "conflicting" Supreme Court decisions on the same/similar dispute). On this basis these decisions may not represent "settled" law even for the disputes in question.

Indonesian entities – Special issues

The "gross of tax" calculation included in the production share assumes a foreign incorporated PSC holder with a liability to BPT at the rate of 20%.

A PSC however, can be awarded to an Indonesian entity. In such a case, the production sharing formula will typically be unchanged and so assume a dividend (rather than BPT) WHT also at the rate of 20%.

Where a PSC is held by an Indonesian entity with Indonesian shareholders, the taxation of dividends should follow the general taxation rules. Under these rules, for an Indonesian entity, dividend income is generally tax exempt where the dividends are distributed via statutory or legal procedures (e.g. the general shareholders meeting, etc.).

It is not clear however, that any PSC related income tax reduction will be accepted in practice.

Oil and gas law election – Prevailing tax laws or those prevailing when the contract is signed

Article 31(4) of Law No. 22 allows parties to a PSC signed from 2001 onwards to choose which tax laws are to apply:

"The Co-operation Contract shall provide that the obligation to pay taxes referred to in paragraph (2) shall be made in accordance with:

a) The provisions of tax laws and regulations on tax prevailing at the time the Co-operation Contract is signed; or

b) The provisions of prevailing laws and regulations on tax."

However, the exact nature of this election is not clear, including whether the election could lock in the uniformity principle. To avoid uncertainty, PSCs often include the following language:

*"It is agreed further in this **CONTRACT** that in the event that a new prevailing Indonesia Income Tax Law comes into effect, or the Indonesia Income Tax Law is changed, and **CONTRACTOR** becomes subject to the provisions of such new or changed law, all the percentages appearing in Section VI of this **CONTRACT** as applicable to the portions of **CONTRACTOR** and the **GOVERNMENT's** share so affected by such new or changed law shall be revised in order to maintain the same net income after tax for **CONTRACTOR** or all Participating Interest Holders in this **CONTRACT.**"*

Implementation of Pillar Two GloBE Rules in Indonesia

On 31 December 2024, the MoF issued regulation No. 136 Year 2024 (PMK-136) to implement the Top-up Tax (Pillar Two) mechanism under the Global Anti-Base Erosion (GloBE) Rules in Indonesia. The regulation is designed to be aligned with the Organisation for Economic Co-operation and Development (OECD) GloBE Rules.

In a nutshell, GloBE Rules are aimed at implementing global minimum tax rules that enforce a global tax framework ensuring a minimum taxation of 15% for Multinational Enterprises (MNEs) operating in low-tax jurisdictions. The implication of this policy for PSC entities is not straightforward and is expected to require a detailed case-by-case analysis. Further developments in this area should be closely monitored.

4.4.4 Administration

Regulation

A PSC entity (where foreign incorporated) is required to set up a branch office in Indonesia. This branch also gives rise to a PE. This is the case for all foreign incorporated PSC interest holders (i.e. operators and non-operators).

A PSC branch, as a PE, should register for tax by filing an appropriate registration application form including the following attachments:

a. A letter from the branch's "head office" declaring the intention to establish a branch in Indonesia including information on the branch's chief representative;
b. A copy of all pages of the passport of the branch's chief representative;
c. A notification letter on the chief representative's domicile (issued by a local government officer);
d. A notification letter on the domicile/ place of business of the branch (usually issued by a building management company where the branch is located in a commercial office building);
e. A copy of the PSC;
f. A copy of the Directorate of Oil and Gas letter which declares the entity the PSC holder; and
g. A letter of appointment of the chief representative from the head office.

Compliance

The registration obligation applies from the time of commencement of business activities. Therefore, this includes the exploration phase (i.e. there is no entitlement to defer registration until, say, commercial operations is declared).

Ongoing tax obligations include:

a. Filing annual income tax returns for each interest holder (although see comments on GR-79 above);
b. Filing monthly reports on the income tax due on monthly liftings as well as the remittance of income tax payments (for each interest holder-but obviously only after production);
c. Filing monthly returns for withholding obligations (for the operator only);
d. Filing monthly and annual EIT returns (for each interest holder – noting that generally for a non-operator this will be a nil return);
e. Filing of monthly VAT reports (please refer to our detailed explanation in the VAT section); and
f. Maintaining books and records (in Indonesia) supporting the tax calculations (for the operator only).

On 18 February 2014, the DGT issued Regulation No. 5/2014 on the format and content of the annual income tax return for PSC taxpayers. In addition to distinguishing liftings and non-liftings income contractors became required to complete and attach (as appropriate) six special attachments, namely:

a. corporate income tax for PSC contractors;
b. BPT/dividend tax for PSC contractors;
c. details of costs in exploration/ exploitation stage for PSC contractors;
d. depreciation schedule for PSCs;
e. details of the contractor's portion of their FTP share; and
f. details of changes in the participating interests.

Since April 2012, the DGT has attempted to consolidate all PSC contractors into the Oil and Gas Tax Office (KPP Migas) which has specific responsibility for the industry. Notwithstanding this, the current system automatically registers new PSC taxpayers to the local Tax Office, whose jurisdiction covers the taxpayers' registered office address. The PSC contractors can later on be moved to the Oil and Gas Tax Office on an *ex-officio* basis by the DGT.

Please note that starting 1 January 2025, the settlement/remittance and submission of tax returns are to be performed under the DGT's Core Tax system. State Revenue Reports in nil position are not required to be submitted to the DGT as indicated in part "state revenue and payment of tax" of Section 4.4.2.

Joint audits

Pursuant to a Memorandum of Understanding (MoU) entered into between SKK Migas, BPKP and the DGT, joint audits by these bodies have been carried out on all operational PSCs and non-producing PSCs with an approved PoD since April 2012.

This was the first systematic DGT audit of PSCs meaning that many PSCs experienced a DGT tax audit for the first time.

Common issues raised by the DGT to date include:

a. direct/indirect PSC transfers – the DGT policy in this area continues to evolve. The "substance over form" concept is being applied with (final) income tax levied in a wide range of PSC- transfers scenarios. The DGT regularly reconciles taxpayer declarations on individual PSC values with public announcements, etc.;

b. long-standing cost recovery in audit findings – the DGT has unilaterally issued tax assessments despite long-standing cost-recovery audit findings still being subject to discussions/negotiations with SKK Migas and/or BPKP. This creates risk around the coordination of work amongst the DGT, SKK Migas and BPKP;

c. general reconciliations between the financial reports and the monthly tax returns – the DGT often queries discrepancies between the amounts disclosed in financial reporting and the tax objects disclosed in the monthly WHT and VAT returns. Whilst this type of request is common with general taxpayers, this should be less relevant for PSC entities as their financial data may be limited to the FQR;

d. "head office" overhead allocations – since 1998, WHT and VAT on head office overhead allocations has been effectively exempted through Director General of Taxes Letter S-604. While the DGT appears still to be accepting S-604, the challenge has shifted to satisfying the nature of the charges as "head office"; and

e. Benefits in Kind (BiK) – BPKP/SKK Migas can have a different view on BiK costs with SKK Migas often allowing cost recovery but the DGT then arguing for an Article 21 Employee WHT obligation.

The MoF issued Regulation No. 34/PMK.03/2018 (MoF-34) which stipulates procedures and guidance for the implementation of joint audits conducted by SKK Migas, BPKP and DGT. MoF Regulation No. 34 probably was issued to accommodate the industry concern over the lack of coordination amongst the three institutions in performing audits on PSC contractors.
In late 2023, MoF issued MoF Regulation No. 94/2023 as the amendment to MoF Regulation No. 34. Whilst most of the changes stipulated in MoF Regulation No. 94 are mainly related to the administrative procedures of the joint audit process, one of the notable changes introduced in MoF Regulation No. 94 is it seems to provide more room for the DGT to conduct a tax audit separately apart from the joint audit process. Under MoF Regulation No. 34, a separate tax audit may be carried out under three conditions, i.e. i) if the contractor files an overpayment tax return; ii) if the tax return submitted by the contractor shows a different tax calculation compared to the FQR; and/or iii) the contractor does not file the tax return. These three conditions are removed under MoF Regulation No. 94.

Ring-fencing

Pursuant to MoF Regulation SE No. 75/190, an entity may hold an interest in only one PSC (i.e., the "ring-fencing" principle). There are also no grouping or similar consolidation arrangements available in Indonesia. This means that the costs incurred in respect of one PSC cannot be used to relieve the tax obligations of another.

As noted in GR-79/27, PSCs are now ring-fenced by field rather than contract area. This narrows even further the focus of the ring-fencing principle.

4.4.5 EIT

For PSC entities (acting as the operator), the taxation arrangements for employees are largely identical to those for other employers. On this basis, there is an obligation for the operator to withhold and remit income tax, and to file monthly returns, in accordance with either Article 21 or 26 of the Income Tax law. The article (and thus the tax rate) varies according to residency of the employee (please refer to PwC Pocket Tax Guide for further details).

Industry related tax issues include:

a. the treatment of "rotators" or similar semi-permanent personnel. This mainly relates to ensuring that the correct tax rates are applied; and
b. the treatment of non-cash "BiK". The treatment can vary according to the era of the PSC, whether the personnel are working in designated "remote areas" and whether the operator claims cost recovery for the relevant benefit.

Further, resident employees without an NPWP are subject to a surcharge of 20% on Indonesian sourced income in addition to the standard WHT. On this basis, a PSC entity needs to ensure that all employees (including resident expatriates) obtain their individual NPWP especially if a PSC entity provides salaries on a net of tax basis.

4.4.6 WHT

For PSC entities (when acting as operator), the WHT obligations are largely identical to those for other taxpayers. On this basis, there is an obligation for the operator to withhold and remit income tax, and to file monthly WHT returns, in accordance with the various provisions of the Income Tax law (please refer to the PwC Pocket Tax Guide for details).

For PSC entities, the most common WHT obligations arise with regard to:

a. land and building rental (i.e., Article 4 (2) - a final tax at 10%);
b. deemed income tax rates (i.e., Article 15, for shipping at 1.2% and 2.64%);
c. payments for the provision of services, etc. by tax residents (Article 23 - at 2%); and
d. payments for the provision of services, etc. by non-residents (Article 26 - 20% before treaty relief - noting tax on services provided by foreign drillers is often remitted by the driller (see Section 7.3 below).

4.4.7 VAT

General

The sale of hydrocarbons taken directly from source has historically been exempt from VAT. PSC entities had therefore never constituted taxable firms for VAT purposes and were not registered for VAT purposes.

Law No. 7/2021 regarding the Harmonisation of Tax Regulations (*Harmonisasi Peraturan Pajak* (HPP) Law) was signed by the President of the Republic of Indonesia on 29 October 2021 and came into effect on the same date.

The HPP Law has made significant changes to the VAT rules, including the foundational features which have been in place for decades. These changes include the VAT rate and the status of several non-taxable objects. The new VAT provisions were effective from 1 April 2022.

Article 4A paragraph 2 of Law No. 42/2009 regarding VAT ("VAT Law") has now been amended by the HPP Law to exclude the "mining or drilling products taken directly from the source" from non-VAT-able goods. This means that, by default, crude oil and natural gas are regarded as VAT-able goods, and hence any "delivery" of these goods could be subject to VAT.

On 12 December 2022, the Government issued Regulation No. 49/2022 (GR-49) which provides further confirmation of the VAT-exempt status of certain deliveries of goods. GR-49 now confirms that, whilst still regarded as VAT-able goods, deliveries of crude oil and natural gas (among others) are exempt from VAT. The VAT exemption is automatically granted (i.e. there is no requirement to obtain the Tax Exemption Declaration Letter (SKB - *Surat Keterangan Bebas*).

From a VAT administration perspective, the PSC entities making the above VAT-exempt deliveries will still be required to register as a VAT-able firm and issue VAT invoices (with "exempt" status) on each relevant delivery.

In addition to the above "raw" mining products, GR-49 also confirms the VAT-exempt status of the following types of gas derivatives:

1) LNG (no change from the existing treatment); and
2) Compressed Natural Gas (CNG).

Input VAT side

The VAT Law stipulates that any input VAT related to the delivery of exempted VAT-able goods will not be creditable. The impact should arguably be no different compared to the pre-HPP Law conditions.

Irrespective of the above, in our view there should be room to argue that the pre-existing input VAT recoverability mechanism under the PSC (i.e., either reimbursement or cost recovery) could still prevail due to the "*lex specialis*" status of the PSC.

Changes in the VAT rate

The impact of any change in VAT status also needs to take into account the proposed increase in the VAT rate (i.e. to 11% in 2022 and to 12% by 2025).

However, PMK-131/2024 provides that the imposition of the 12% VAT rate applies effectively only to the import and domestic delivery of luxury taxable goods which are currently subject to the Luxury-goods Sales Tax (*Pajak Penjualan Barang Mewah* - PPnBM). These include motor vehicles, luxurious residences with transaction value of at least IDR30 billion, private aircraft, luxurious private cruisers, shotguns, etc. For most other goods and/or services which are not categorised as luxurious, these are subject to an (effective) 11% VAT rate (i.e. 12% VAT rate x 11/12 of the transaction value).

In-country supplies – VAT deferment

Pursuant to Presidential Decree No. 22/1989 (PD 22) and its implementing regulations, VAT payments arising from oil, gas and geothermal exploration and drilling services were deferred until the time of payment of the Government share (when the VAT was then reimbursed - see the VAT reimbursement section). This arrangement effectively eliminated all but a small cash-flow exposure to VAT charged in these scenarios.

However, in 1995, an amendment to the VAT Law aimed to end all VAT deferments by 31 December 1999. The Indonesian tax authorities interpreted this amendment as terminating the deferment available to PSC entities. Consequently, assessments for all deferred VAT up to this date were issued in January 2000. Approximately 30 taxpayers challenged these assessments through the Indonesian court system, resulting in mixed outcomes.

New PSC entities assume no entitlement to defer VAT payments. On this basis, the VAT charged on "in-country" goods and services will need to be paid, and will not be refunded unless the Government share is achieved (and if permitted under the PSC).

Imports – VAT exemption

See import taxes below in Section 4.4.8.

VAT reimbursement (pre-GR-79)

PSCs issued prior to GR-79 (see below) typically provide that Pertamina (now SKK Migas) is to:

> *"assume and discharge all other Indonesian taxes [other than Income Tax including VAT, transfer tax, import and export duties on materials equipment and supplies brought into Indonesia by Contractor, its Contractors and subcontractors.......*
> *The obligations of Pertamina [now SKK Migas] hereunder, shall be deemed to have been complied with by the delivery, to Contractor within one hundred and twenty (120) days after the end of each Calendar Year, of documentary proof in accordance with the Indonesian fiscal laws that liability for the above mentioned taxes has been satisfied, except that with respect to any of such liabilities which Contractor may be obliged to pay directly, Pertamina [now SKK Migas] shall reimburse it only out of its share of production hereunder within sixty (60) days after receipt of invoice therefore. Pertamina [now SKK Migas] should be consulted prior to payment of such taxes by Contractor or by any other party on Contractor's behalf".*

In the past, protection from non-income taxes in PSCs has generally fallen into two categories. Firstly, certain taxes were directly covered by SKK Migas, such as the PBB. Secondly, some taxes were initially paid by the contractor, such as VAT, which were then reimbursed. Further, and depending upon the PSC era, the reimbursement shall only be from SKK Migas' share of production (i.e., there is no entitlement to reimbursement until the PSC goes into production and reaches the Government share).

Reimbursement is, in practice, also subject to the PSC satisfying high standards of documentation (original VAT invoices, etc.). Where VAT is not reimbursed for documentation related to the concern SKK Migas had, on occasion, allowed VAT to be charged to cost recovery.

VAT borne during the exploration phase by PSC contractors who do not subsequently move into production will never be reimbursed, and so the VAT will become an absolute cost.

On 31 December 2024, the MoF issued Regulation No. 139 Year 2024 (PMK-139) which revoked a number of regulations pertaining to payments of charges to the Government under the oil and gas business activities, including PMK-119 which historically provided guidance on the VAT reimbursement procedures.

The key changes under PMK-139 are as follows:

a. The introduction of Unitisation Operator (*Operator Pelaksana Unitisasi*) constituting the PSC contractors covered under the VAT reimbursement arrangement;
b. The "survival" period for PSC contractors to seek VAT (including PPnBM) reimbursement is five years (at the latest) since the end of the PSC period;
c. More details are provided on the procedures of the submission and "examination" (*penelitian*) of the reimbursement claims, such as listing of supporting documents required; and
d. The authorised officials (within SKK Migas/BPMA) aside from the Head of SKK Migas/BPMA who can provide recommendations to the MoF (i.e. DGB) for the payment of VAT reimbursement is the official at the level directly below the head who governs the finance matters.

Aside from the above changes, most key features previously outlined in PMK-119 prevail as follows:

a. Government share is to include the Government's entitlement to FTP (and hence, VAT reimbursement can only be sought once FTP arises);
b. SKK Migas may offset a reimbursement entitlement against any contractor "overliftings" (previously over-liftings were settled in cash);
c. No timeframe for obtaining the full verification on the reimbursement request from SKK Migas;
d. Reimbursement entitlement excludes input VAT arising from LNG processing, unless the PSC stipulates otherwise;
e. A reimbursement is to be subject to confirmation from the DGT via a "tax clearance document". Under the previous MoF Regulations, the availability of an original tax clearance document was compulsory, however such tax clearance document is now to be obtained via the Core Tax system, hence the softcopy generated by the system shall constitute the "original" copy;
f. Whenever reimbursement is specifically regulated under the PSC, the mechanism should follow the provisions under that PSC (rather than PMK-119). This seems to be an acknowledgement of the "*lex specialis*" status of the PSC including perhaps to accommodate unique VAT reimbursement provisions in some early 2000's PSCs; and

g. Following the issuance of GR No. 23/2015 regarding the management of oil and gas resources in Aceh province, any VAT reimbursement related to oil and gas concessions in Aceh province should now be administered by the BPMA rather than by SKK Migas.

VAT reimbursements are denominated in rupiah at the historical exchange rates and so the reimbursement mechanism carries an exchange risk.

VAT cost recovery (post GR-79)

As noted above most recent PSCs, including those issued post GR-79, have seen the standard PSC language regarding VAT reimbursement removed in favour of an entitlement to include all indirect taxes (including VAT) as operating costs of the contractor (i.e. as a cost recoverable item).

4.4.8 Import taxes

On 31 December 2019, the MoF issued two regulations to synchronise a number of existing import facility regulations applicable to PSC contractors. These can be summarised as follows:

Table 4.10 - Summary of import taxes facilities regulations

No	Regulation	Effective date	Replaces/amends
1.	MoF Regulation No. 217/ PMK.04/2019 (PMK-217) – for import taxes facility (Import duty, VAT and income tax). Specific to the oil and gas sector.	1 March 2020	• MoF Regulation No. 20/ PMK.010/2005 (import taxes facility for pre-2001 PSCs) • MoF Regulation No. 177/ PMK.011/2007 ((only) Import duty exemption for post 2001 PSCs)
2.	MoF Regulation No. 198/ PMK.010/2019 (PMK-198) (partially revoked by MoF Regulation No. 96/2023) – specific to import VAT facilities. Applicable to all sectors including the oil and gas sector.	23 December 2019	MoF Decree No. 231/KMK.03/2001 as most recently amended by MoF Regulation No. 137/PMK.010/2018 (import VAT facility)

Sources: MoF Regulation No. 96/2023, MoF Regulation No. 217/2019, MoF Regulation No.198/2019, MoF Regulation No. 20/2005, MoF Regulation No. 177/2007, MoF Decree No. 231/2001 (as amended by MoF Regulation No. 37/2018)

Some of the key features are as follows:

1) PMK-217

Historically the import facilities applicable to PSCs were scattered across various regulations. With the enactment of PMK-217, the MoF attempted to “pool” the arrangements under a single regulation which applies to all generations of PSCs (including GS PSCs).

A summary of the import facilities (which are ultimately unchanged) applied to each generation of PSC can be outlined as follows:

Table 4.11 - Summary of import tax facilities applicable to PSCs

Incentives	Cost recovery PSCs - Generations		GS PSCs
	Fully adjusted to GR-271)	Not adjusted with Fully GR-272)	
Import duty (exempt)	(a)	(b)	(c)
VAT (not collected)	(a)	(b)	(c)
Article 22 Income Tax (not collected)	(a)	(b)	(c)

Source: MoF Regulation No. 217/2019, GR-27/2017

Note:

1) Fully adjusted to GR-27, but can be classified as pre-2001 PSCs, pre-GR-79 PSCs (2001-2010), post-GR-79 but pre-GR-27 PSCs (2010-2017), and post-GR-27 PSCs (post 2017)
2) Predominantly pre-2001 PSCs, for which:
   (a) facilities apply during exploration only (i.e., up to PoD). Incentives during exploitation apply according to project economics;
   (b) facilities apply during the entire contract period; and
   (c) facilities apply during exploration and up to the commencement of commercial Production

Other important features of PMK-217 include:

a. types of goods: Applies to imported goods which:
   (i) are not produced locally; or
   (ii) are produced locally but do not meet the required specifications; or
   (iii) are produced locally but in insufficient quantity.
b. validity period: The validity of the facility is 12 months from approval.
c. "extended" facility for vendors/suppliers: PMK-217 seems to have extended the import facility beyond the "project owner" (as the importer of record) to the relevant suppliers/vendors, provided that the vendor is stated in the application and the relevant procurement contract is attached to the application.
d. no claw back: Goods covered under this facility can be reexported, transferred to other PSC contractors or moved to other PSC work areas without triggering any claw back. This is subject to SKK Migas approval, and a notification should be sent to the Tax Office.

2) PMK-198/96

PMK-198/96 is an updated regulation which confirms the "non-collection" of import VAT for goods which are also exempt from import duty. This is a generic regulation applicable to all industries, including goods imported in the PSC sector.

Furthermore, confusingly, PSC imports during the exploitation phase still do not appear to be granted a VAT facility via PMK-198/96, as no underlying import duty exemption exists.

4.4.9 Tax dispute process

Taxpayers are entitled to object to unfavourable tax assessments. Requirements include that the objection:

a. be prepared for each assessment;
b. be in Indonesian;
c. indicate the correct tax amounts;
d. include all relevant arguments; and
e. be filed within three months of the assessment date.

The ITO is required to make a decision on an objection within twelve months. Failure to decide within this timeframe means that the objection is deemed to be accepted. A taxpayer should pay at least the amount agreed during the tax audit closing conference before filing an objection. If the objection is rejected, any underpayment is subject to a surcharge of 30%. This underpaid tax and surcharge is not due if the taxpayer files an appeal with the Tax Court regarding the decision objected to.

Appeals

Taxpayers are entitled to appeal to the Tax Court against unfavourable objection decisions. Requirements include that the appeal letter:

a. be prepared for each decision;
b. be in Bahasa Indonesia;
c. indicate all relevant arguments;
d. be filed within three months of the date of the objected decision; and
e. attach a copy of the relevant decision that is being objected against.

Based on the Tax Court law, at least the agreed amount of the tax due on the underlying assessment should be settled before filing an Appeal. However, this payment requirement now contradicts with the Tax Law (i.e. there is a mismatch between the Tax Administration law and the Tax Court law). In practice, the tax court will not insist on payment in these circumstances.

The Tax Court will typically decide on an Appeal within 12 months. Any underpaid tax resulting from a Tax Court decision is subject to a surcharge of 60%.

Request for reconsideration

For Tax Court decisions delivered after 12 April 2002, taxpayers are entitled to file “reconsideration requests” to the Supreme Court. The Reconsideration Request must be submitted within three months of receipt of the Tax Court Decision (for the Appeal).

Interest penalties/compensation

Late payments of tax are subject to interest penalties at varying rates based on the MoF Interest Rates (MIR) issued on a monthly basis. Tax refunds attract a similar interest rate using the following formula: MIR/12. The interest penalty and compensation are capped at 24 months.

4.5 Commercial considerations

When reviewing a PSC, potential investors should consider the following issues:

Table 4.12 - Commercial considerations in reviewing PSC

Topics	Issues
Abandonment costs	• SKK Migas has included an abandonment clause in the PSC since 1995 which provides that contractors must include in their budgets provisions for clearing, cleaning and restoring the site upon the completion of work. • To be recoverable (and tax deductible), funds should be physically remitted into a joint bank account between SKK Migas and Contractor. As any funds set aside for abandonment and site restoration are cost recoverable and tax-deductible unused funds at the end of the contract are transferred to SKK Migas. • For PSCs which do not progress to the development stage any costs incurred are considered sunk costs.
DMO Gas	• Historically, there was no DMO obligation associated with gas production. • GR-35 introduced a DMO obligation on a contractor's share of natural gas. • Recent PSCs have also included the DMO obligation requirement for gas, whose impact should be carefully observed.
Carry arrangements (JOBs)	• Some PSCs (as JOBs), require private participants to match Pertamina's sunk costs and to finance Pertamina's participating share of expenditures until commercial production commences. These are known as carry arrangements. • After commercial production commences, Pertamina is to repay the funds provided plus an uplift of 50%, in which the uplift should be taxable (at 20% final tax from gross amount).
Head office costs	• The administrative costs of a "head office" can generally be allocated to a PSC for cost recovery purposes. PMK-256 stipulates a cap of 2% of annual cost recoverable spending. • PMK-256 also indicates that the amount that a PSC is able to recover will be dependent upon approval from SKK Migas, which may be lower than 2%. The type of approval required depends on whether or not the PSC is in the exploration or exploitation phase as follows: - Exploration: The approval is to be ascertained from the WP&B, and monitoring of the allocation cap will be done over the exploration period (i.e., it would not be adjusted until the end of the exploration period); or - Exploitation: Specific written approval must be obtained from SKK Migas and the cap will be monitored each year (i.e., the WP&B will not be sufficient evidence to support the allocation once exploitation has commenced). • Due to uniformity, a tax deduction is also available but allocations above the permitted cost recovery are not tax deductible. These allocations technically create WHT and VAT liabilities (i.e. as cross-border payments). Pursuant to MoF Letter No. S-604 of 24 November 1998, the Government indicated that it would implement arrangements to "bear" these taxes on behalf of PSC entities. • However, MoF Letter No.S-604 was arguably never fully implemented and so has never actually provided a tax exemption. The ITO historically has focused on head office costs in tax audits. • Recent development indicates that, Article 26C of GR-27 has now confirmed the "exemption" of WHT and VAT from indirect head office allocations. This appears to be a formalisation of the long-established principle set out under S-604.
Associated products	• Later-generation PSCs promote contractors developing associated products from their petroleum operations. Questions remain as to whether earnings from the sale of the associated products will be creditable to operating costs (treated as by-products under GR-79 and credited against cost recovery), or treated as profit from oil and gas. The commercial feasibility and profitability of additional product development is subject to a proper review and analysis.

Topics	Issues
Interest recovery	• A PSC entity is generally not allowed cost recovery for interest and associated financial costs. • Subject to specific approval, contractors may be granted interest recovery for specific projects. This facility should be pre-approved and included in the PoD. However, SKK Migas states that interest recovery is only granted for PoDs that have been approved prior to the promulgation of GR-79. • From a taxation point of view, where a contractor is entitled to cost recovery there is also an entitlement to tax deductibility. • The interest-recovery entitlement will generally reference the pool of approved but un-depreciated capital costs, at the end of an agreed “period” of time. The “loan” attracting the respective interest is generally deemed to be equal to the capital spending on the project. Depreciation of the spending is treated as a repayment of the loan. Consequently, the “interest” in question may not be interest in a technical sense. • Interest paid is subject to WHT with potential relief granted under various tax treaties. As a precaution, most contractors gross up the interest charged to reflect any WHT implications. • Pertamina typically allowed a gross up for Indonesian WHT at the rate of 20%. Some PSC entities have been successful in reducing this rate via a tax treaty. This is even though the “interest” may not satisfy the relevant treaty definition.
Investment credits	• An investment credit is provided as an incentive for developing certain capital-intensive facilities including pipelines and terminal facilities. • The credit entitles a PSC entity to take additional production without an associated cost. An investment credit has therefore traditionally been treated as taxable. • More difficult questions have arisen with regard to the timing of investment credit claims. For instance, an investment credit should generally be claimed in the first year of production and any balance should be carried forward (although there are sometimes restrictions on carrying forward).
Take or pay	• A gas supply agreement may include provisions for a minimum quantity of gas to be taken by buyers on a take-or-pay basis. If buyers take less than the committed quantity of gas they must still pay an amount (as per the agreement) in relation to the shortfall. • Take-or-pay liabilities may arise if buyers have taken less than the committed quantity of gas under the agreements. The shortfall in the gas taken by buyers, if any, results in a take-or-pay liability for make-up gas to be delivered to buyers in the future. • It is unclear whether the tax due should be calculated based on the payments (based on the committed quantity to be taken by the buyer) or based on the quantity of gas delivered to the buyer.
Land rights	• Historically, Pertamina (as a regulator which is now assumed by SKK Migas) took a central role in acquiring surface rights for oil and gas development. • Oil and Gas Law No. 22/2001 requires the contractor to obtain the relevant land rights in accordance with the applicable local land laws and regulations. • The process of obtaining appropriate land rights can be time consuming and cumbersome although Law No. 2/2012 on acquisition of land for development in the public interest (and its implementing regulation GR No. 19/2021 on The Implementation of Land Procurement for Public-Interest Developments, as amended by GR No. 39/2023) seeks to overcome some of the issues. • Entitlement to the contract area under a PSC does not include any rights to land surfaces, however, given the change in the treatment of indirect taxes (including VAT and Land and Buildings Tax) under GR-79 this became a material exposure in 2013 and onwards for many PSC holders.

Topics	Issues
"Net back to field" arrangements	• Contractor calculations for transactions involving trustees or similar arrangements (e.g. for piped gas/LNG, etc.) typically commence with a revenue figure which has been netted against certain post-lifting costs (e.g., trustee, shipping, pipeline transportation, etc.). Once again, this follows the uniformity principle which generally disallows cost recovery on spending past the point of the lifting. • Net back to field costs are generally also treated as being outside of a PSC entity's WHT and VAT obligations. With the growing involvement of the DGT in joint audits, this position may be subject to review.
Sole risk operations	• Typically, all costs and liabilities of conducting an exclusive (sole risk) operation for drilling, completing and equipping sole risk wells are borne by "the sole risk party". The sole risk party indemnifies the non-sole risk parties from all costs and liabilities related to the sole risk operation. • Should the sole risk operation result in a commercial discovery the non-sole risk parties have historically been given the option to participate in the operation. If the non-sole risk parties agree to exercise their options, the non-sole risk party pays to the sole risk party a lump sum amount which can typically be paid either through a "cash premium" or "in-kind premium" to cover past costs incurred as well as rewards for risk taken. • It is not clear whether these premiums should be treated as taxable liftings income, other non-lifting income under GR-79/27 or ordinary income, although under GR-79/27 they are more likely to be treated as other non-lifting income.
Unitisations	• Unitisation is a concept whereby the parties to two or more PSCs agree to jointly undertake the Exploration and Production (E&P) operations on a defined acreage (which typically overlaps between the two PSCs) and share risks and rewards from such activity in an agreed proportion. • Typical issues under a unitisation arrangement include: - re-determination of costs and revenues; - maintenance of separate records; - ring-fencing; - audits; and - impact on overall PSC economics
Transfer of PSC interests	• Historically, transfers of PSC interests had not generally been taxed. This was the case irrespective of whether the transfer was: 1. via a direct transfer of a PSC interest (i.e., as an asset sale); 2. as a partial assignment such as a farm-out; or 3. via a sale in the shares of a PSC holding entity (i.e., as a share sale). • GR-79/27 imposes a 5%/7% transfer tax according to whether the PSC is in the exploration or the exploitation stage. GR-79/27 still protects partial assignments such as farm-outs during the exploration stage if that interest has been held for more than three years and the transfer is not intended to generate a gain. However, where the transfer is for "non-risk sharing" purposes, the 5% final tax will be imposed on gross proceeds. GR-79/27 also imposes a 7% final tax on gross proceeds for transfers during the exploitation stage except where they are to a "national company". Please see Section 4.4.2 for more details. • In addition, at least prior to 19 June 2017, PMK-257 stipulates that a BPT applies to a transfer of a direct or indirect interest in the PSC. The BPT is due at a rate of 20% of the "economic profit" less the 5% or 7% tax already paid on the transfer. The imposition of BPT was then removed under the application of GR-27 starting 19 June 2017.

Topics	Issues
	• The overall of GR-79/PMK-257 is however unclear in many areas including: a. the application to share transfers especially where they fall outside Indonesian natural tax coverage (essentially GR-79's rules on tracing powers) b. how BPT should be accounted for (at least for pre-GR-27 transfer) and which treaties can be relied on (bearing in mind BPT is ultimately a tax cost for the vendor entity) c. is a group restructuring (i.e. with no change of control and therefore no requirement for SKK Migas approval) meant to be taxed? d. when does a carry provided as part of the farm-out constitute compensation for the PSC transfer? e. when is a contingent payment subject to tax? f. what is the cost base in calculating the profits for BPT purposes (at least for pre-GR-27 transfers)? • In the first quarter of 2019, the Tax Courts have issued several decisions on some outstanding cases and found: - transfer consideration: That transfer consideration relevant to a PSC transfer, in an entity sale scenario at least, should only extend to amounts paid for the shares in the PSC-holding entity (or higher up the holding structure – this tracing aspect remains unclear). In other words transfer consideration should not extend to amounts received for the transfer of a receivable due from a PSC entity even where carried out as part of the transfer; - BPT: That PMK-257, as the implementing regulation to GR-79, was technically incorrect in applying a 20% BPT on the transfer of a PSC interest (in an entity sale scenario at least). This was because the transfer tax component under GR-79 represented a final tax meaning that no further tax (including BPT) should be due. The Tax Court felt this position was supported by the GR-27 amendments to GR-79 where the BPT exposure for PSC transfers was formally eliminated; and - treaty protection: That, in an entity sale scenario at least, treaty relief should be accepted to the extent that a treaty operates to prevent/mitigate the operation of GR-79 (subject to satisfying Indonesia's treaty use rules). The tax treaty relevant to the operation of GR-79 should also be applicable to the vendor of the shares (in a context of an entity sale scenario). As the above outcomes relate to Tax Court decisions it is possible that the DGT may file appeals to the Supreme Court, so these positions could still change. There are also some arguable contradictions within the decisions themselves. These include that in some decisions treaty relief was recognised according to the legal form of the transaction whilst other decisions appeared to indicate that the GR-79/27 liability arose at the asset level irrespective of the legal form of the transaction. Overall, caution should therefore still be exercised in analysing the impact of these decisions with regard to any individual tax positions. That aside, in regard to PSC transfer, GR-79/27 has now been amended by GR-93 on 31 August 2021. Please refer to the PSC transfer section above for a more detailed explanation.
Domestic gas pricing for certain industries	Following the issuance of Regulation No. 15/2022 and No. 10/2020, the current gas producers shall negotiate with gas buyers (for gas prices and transportation tariffs) and with SKK Migas on potential adjustments to the production split calculation to neutralise the impact of price adjustments on gas producers' entitlement. For potential gas investors, the new gas pricing regulation shall be considered for overall project economics prior to the submission of a PoD if the gas output might be marketed to certain industries as stipulated in the above regulations.

Topics	Issues
DHE SDA special account	Pursuant to GR No. 8/2025, which amends GR No. 36/2023, and in conjunction with PBI No. 3/2025, amending PBI No. 7/2023, exporters of natural resources who generate Foreign Exchange Proceeds from Exports of Natural Resources Exported Goods (DHE SDA) valued at USD250,000 or more, as declared in their Export Customs Declarations (Pemberitahuan Pabean Ekspor - PPE), are mandated to deposit 100% of their DHE SDA within the Indonesian financial system for a minimum duration of twelve months from the time of deposit. Notably, GR No. 8/2025 provides an exception for the oil and gas industry, permitting it to deposit only 30% of its DHE SDA for a minimum duration of three months.

Source: GR-35/2004 as lastly amended with GR-55/2009, PMK-256/2011, MoF Letter No. S-604/1998, GR-79/2010 as lastly amended with GR-27/2017 and GR-93/2021

4.6 Documentation for planning and reporting

4.6.1 PoD (Articles 90-98 of GR-35)

A PoD (also known as a field development plan) represents development planning on one or more oil and gas fields in an integrated and optimal plan for the production of hydrocarbon reserves, considering technical, economic and environmental aspects.

Prior to Law No. 22, an initial PoD only needed Pertamina Director approval. After Law No. 22, an initial PoD in a development area needs approval from both SKK Migas and the MoEMR. Subsequent PoDs in the same development area only need SKK Migas approval. Generally, the time needed for PoD approval is around ten weeks, although the process can take in excess of one year for very large projects.

A PoD is typically a complex document that outlines the proposed development of a particular commercial discovery. The scope and scale of PoDs will vary enormously depending on the size of the project but will typically cover the following information:

a. Executive summary;
b. Geological findings;
c. Development incentives;
d. Reservoir description;
e. EOR incentives;
f. Field development scenarios;
g. Drilling results;
h. Field development facilities;
i. Project schedule;
j. Production results;
k. Health, Security, and Environment (HSE) & CD;
l. Abandonment;
m. Project economics; and
n. Conclusion.

PoDs that are presented to the Minister (and therefore those that are for the development of oil or gas discoveries in the first field, as opposed to subsequent fields) must contain:

a. supporting data and evaluation of exploration;
b. evaluation of the reserves;
c. methods for drilling development wells;
d. number and location of production and/or injection wells;
e. production testing/well testing;
f. pattern of extraction;
g. estimated production;
h. methods for lifting the production;
i. production facilities;
j. plans for use of the oil and gas; and
k. plans for operations, economics and state and regional revenues.

A PoD revision could be performed in the following conditions:

a. Changes in the development scenario;
b. Significant changes to the oil and gas reserves compared to the initial PoD submitted; and
c. Changes in investment costs.

4.6.2 AFE

As part of the SKK Migas supervision and control over the execution of the PSCs, each of the projects in the exploration and development phases should prepare an AFE for SKK Migas approval. For other projects, SKK Migas's approval is required if budgeted expenditure is equal to or greater than USD500,000. An AFE should include the following information:

a. Project information in sufficient detail to allow for SKK Migas's analysis and evaluation;
b. Total budgeted costs; and
c. Total costs that have been incurred.

The time required for AFE approval, AFE revision and AFE close-out is around 10-15 days, although the process is considerably longer for complex and large project AFEs.

An AFE can be revised:

a. twice before the project commences or before the tender has been awarded.
b. where the project has commenced prior to reaching 50% of total expenditure and prior to reaching 70% of physical completion.

Revisions should be made if the total AFE costs are projected to overrun/underrun by 10% or more and/or the individual AFE cost component is projected to overrun/underrun by more than 30%.

4.6.3 WP&B

The WP&B is the proposal of a detailed action plan and annual budget as consideration for the condition, commitment, effectiveness and efficiency of the contractor's operations in a contract area. The WP&B covers the following:

a. Exploration (seismic and geological survey, drilling and G&G study), lead and prospect, and exploration commitment;
b. Production and an effort to maintain the continuity of:
    1. the development plan;
    2. intermittent drilling;
    3. production operations and workovers;
    4. maintaining production; and
    5. EOR projects (secondary recovery and tertiary recovery).
c. The costs allocated for those programmes are as follows:
    1. Exploration;
    2. Development drilling and production facilities;
    3. Production and operations; and general administration, exploration administration and overheads.
d. An estimation of:
    1. entitlement share;
    2. gross revenue, oil and gas price, cost recovery, Indonesia share, contractor share;
    3. unit cost (USD/Bbl.);
    4. direct production cost;
    5. total production cost;
    6. cost recovery; and
    7. status of unrecovered cost.

WP&B generally includes the following schedules:

a. Financial status report;
b. Key operating statistics;
c. Expenses/expenditure summary;
d. Exploration and development summary;
e. Exploratory drilling expenditure;


Photo source: PT Pertamina (Persero)

f. Development drilling expenditure;
g. Miscellaneous capital expenditure;
h. Production expenses summary;
i. Production facilities capital expenditure;
j. Miscellaneous production capital expenditure;
k. Administration expenses summary;
l. Administration capital expenditure;
m. Capital assets PIS old/new;
n. Depreciation old/new;
o. Detailed programme support listing;
p. Production/lifting forecast; and
q. Budget year expenditure.

The WP&B proposal should be submitted to SKK Migas for approval three months before the start of each calendar year. Before SKK Migas grants approval, some changes to the WP&B proposal may be requested. In granting approval for WP&Bs, SKK Migas follows the guidance of Article 98 of GR No. 35/2004, which lists certain mandatory considerations such as: long-term plans; success in achieving activity targets; efforts to increase oil and gas reserves and production; technical activities and the viability of cost units; efficiency; field development plans previously approved; and manpower and environmental management.

Once approved, the contractor may revise the WP&B provided there is reasonable cause, such as:

a. the annual work plan turns out to be unrealistic; or
b. the estimated cost departs significantly from the budget.

The proposed WP&B revision must be accompanied by the reason for the change. For urgent changes to the original annual WP&B, revisions may be submitted to SKK Migas before June.

Generally, the WP&B approval process takes around 22 working days, although the process is considerably longer for complex and large WP&B.

4.6.4 FQR

On a quarterly basis, an operator of a PSC area should submit its FQR to SKK Migas. The FQR primarily consists of a comparison between the budgeted and actual revenue and expenditures. The FQR should be submitted to SKK Migas within a month of the end of the relevant quarter. A typical FQR consists of a summary front page with supporting schedules attached.

4.6.5 Foreign Exchange Report (FCR) and offshore borrowing

Foreign exchange Report including the offshore loan report to BI

Law No. 24 of 1999 on Currency Flow and Exchange Rate System and its implementation regulation, being BI Regulation (PBI) No. 21/2/PBI/2019 on Foreign Exchange Activity Report and PBI No. 21/1/PBI/2019 on Bank Foreign Debts and Other Bank Liabilities in Foreign Exchange require non-financial institution companies (including oil and gas companies) to submit a report of their foreign-exchange activities in Indonesia every month to BI.

The foreign exchange report should include the information about the following:

a. Transaction on the trading of goods, services and other transactions;
b. The principal data of the off-shore borrowing and/or Risk Participation Transaction (RPT);
c. Plan on withdrawal and/or payment of offshore borrowing and RPT;
d. Realisation of withdrawal and/or payment of offshore borrowing and RPT;
e. Foreign financial liabilities position and amendments; and
f. Plan on new offshore loans and their amendments.

In practice, the above report must be submitted online through the borrower's reporting account in BI's system. Failure to submit this report will subject to an administrative sanction in the form of a written warning by the BI.

Reporting obligation in relation to offshore borrowing

- Report to the MoF
  In relation to offshore borrowing and in addition to the BI reporting, a borrower (including an Indonesian oil and gas company) is also required to submit a report to the MoF starting on the effective date of each facility agreement and each subsequent three-month period. In practice, this report is submitted concurrently with the reporting obligation to BI, which is no later than the 15th day of the month following the date of the facility agreement. However, the regulation is silent on the sanctions for noncompliance with this requirement.

In addition to the above, SKK Migas, under PTK 007, mandates that PSC contractors must use a state-owned bank for both the vendor and payer's accounts with respect to payments for goods and services. Please see Section 4.2.4 above for further details.

4.6.5.1 Prudential principle on offshore borrowing for non-bank corporations

PBI No. 16/21/PBI/2014 (as amended by PBI No. 18/4/2016) and SE No. 16/24/DKEM require all non-bank corporations with offshore borrowings to implement prudential principles by fulfilling the following conditions:

a. A minimum hedging ratio being 25% of the negative difference between current foreign-exchange assets and current foreign-exchange liabilities which will be due between three months and six months after the end of a quarter;
b. A minimum liquidity ratio of 70%, calculated by comparing the company's current foreign-exchange assets and current foreign-exchange liabilities which will be due within three months of the end of the reporting quarter; and
c. A minimum credit rating of BB- or its equivalent from credit ratings agencies approved by the Indonesian Financial Services Authority.

Photo source: PwC

5 Gross split production sharing contracts

5.1 MoEMR Regulation No. 13/2024 - Gross Split Production Sharing Contract (GS PSC) features

In 2017, the MoEMR issued the MoEMR Regulation No. 8/2017 introducing a Production Sharing Contract (PSC) scheme based on the "Gross Production Split" methodology. This marked a significant change to Indonesia's PSC arrangement, moving away from the cost-recovery mechanism that had been in place for nearly 50 years.

On 15 July 2020, the MoEMR issued Regulation-12 as the third amendment to MoEMR Regulation No. 8/2017. The amendments reflect a gradual shift away from the emphasis on GS PSCs, arguably in response to the lukewarm reception from industry players in general.

In an effort to create a more efficient and effective profit-sharing scheme for oil and gas through profit-sharing contracts, the MoEMR issued Regulation No. 13 of 2024 on Gross Split Production Sharing Contracts (GS-PSC), effective as of 12 August 2024, and revoked the previous regulation and its amendments.

The new provisions introduced and the adjustments made under this new framework include: GS PSC calculation; additional profit-sharing percentage; by-product profit sharing; and contract amendment mechanism.

Photo source: PwC

The key features of MoEMR Regulation No. 13/2024 are summarised below:

Table 5.1 - GS PSC features

No.	Items	Description
1.	Key features	• A sharing concept based on a gross production and without regard to a cost recovery mechanism. • Retention of the following key principles: a) The ownership of the natural resources remains with the state until the point of delivery of the hydrocarbons (as per existing PSCs); b) Control over the management of operations is ultimately with SKK Migas (as per existing PSCs – although see below); and c) All capital and risks should be borne by contractors (as per existing PSCs). • A GS PSC should stipulate at least 17 items, including (but not limited to) government take, financing obligations, contract term, settlement of disputes, Domestic Market Obligation (DMO), contract termination, etc.
2.	GS mechanism	• This can be illustrated as follows: Contractor take = Base split +/- variable components +/- progressive components Government take = Government share + bonuses + contractor's income tax • The base split serves as the baseline in determining the production split during the determination of the form and main provisions of the PSC, Plan of Development (PoD) approval, and/or PSC extension determination. These base splits are as follows: a) For oil: 53% (Government); 47% (Contractor) b) For gas: 51% (Government); 49% (Contractor) • The variable components are adjustments which take into account the field location, the features of the reservoir, and supporting infrastructure. • The progressive components are adjustments which take into account oil and gas prices. • The "actual" production split shall be agreed on a PoD rather than PSC basis. • Depending upon field economics, the MoEMR has the authority to adjust the production split in favour of either the contractor or the Government. • Experience to date indicates that the production split could be quite flexible in practice as it is generally subject to commercial negotiation with the MoEMR and SKK Migas.
3.	SKK Migas' role	• This is limited to control and monitoring of GS PSCs. • Control means to formulate policies on the Work Programme and Budget (WP&B) (with the budget reportedly considered to be "supporting information" rather than requiring approval). The work programme (i.e. not the budget) should be approved within 30 working days of the complete documentation being received. • Monitoring means to supervise the realisation of exploration and exploitation activities according to the approved work programme. The role of SKK Migas is limited to the monitoring/approving of the work programme rather than the budget. • The first PoD must be approved by the MoEMR. The Head of SKK Migas can approve any second PoD. Any difference between the second PoD and the first PoD should be discussed between the Head of SKK Migas and the MoEMR with final approval by the MoEMR.
4.	Title	• As indicated, ownership of natural resources remains with the State until the point of delivery of the hydrocarbons. • Goods and equipment including land (except leased land) used directly in PSC operations become the property of the state (as per existing PSCs). • Any technical data derived from the PSC shall belong to the state (as per existing PSCs).

No.	Items	Description
5.	Taxation	• The income tax treatment of Contractors follows specific tax rules for upstream activities, as stipulated under Government Regulation (GR) No. 53/2017 (see below). • Because relief for costs occurs via tax deductions rather than cost recovery, the key agency for oversight of this area is the Indonesian Tax Office (ITO).
6.	Procurement	• Only the goods and equipment directly used in the upstream business will become the property of the Government. • GS contractors are obliged to follow the provisions of Work Procedure Guideline (Pedoman Tata Kerja - PTK) 007 to the extent specifically stipulated in PTK-007. If it is not specifically regulated in PTK 007, then the mechanism follows the provisions in the contract.
7.	Transitional Provisions	• The operation of existing PSCs will continue until they expire. • An option to change is also available for cost recovery PSCs (if signed after the enactment of MoEMR Regulation No. 13/2024) to GS PSC. We understand that the conversion of PSC requires approval from the MoEMR. • If the PSC format is changed, any unrecovered costs may be taken as an additional split for the Contractor. • Under MoEMR Regulation No. 13/2024, a PSC that is about to expire but has not been extended is not automatically “re-awarded” under the GS scheme.
8.	Others	• The DMO remains at 25% of the Contractor’s entitlement/split and paid by the Government at the Indonesian Crude Oil Price (ICP). • Contractors should prioritise the use of local manpower, domestic goods, services, etc. (note the potential impact on procurement processes). • Other matters pertaining to Indonesian participation, unitisation, abandonment and reclamation costs, etc follow prevailing rules.
9.	Unrecovered Costs	Unrecovered investment costs shall be considered as an additional split/take for the existing contractor: • a new contractor joins the PSC, such the new contractor should proportionately bear the unrecovered costs, and the existing Contractor shall deduct that same portion from its share. • the reimbursement is included in the new contractor's operating costs, as specifically regulated under GR No. 53/2017. • the settlement of such unrecovered costs should be formalised in a written agreement between the existing contractor and the new contractor. • the new contractor shall reimburse the investment costs to the existing contractor at least seven days prior to the signing date of the extension or the new PSC. • there is any late reimbursement that will be subject to a penalty of 2.5% per day at a maximum.

Source: MoEMR Regulation No. 13/2024, MoEMR Decision No. 230.K/MG.01/MEM.M/2024

5.2 GR-53 – Tax rules for GS PSCs

On 28 December 2017, the Government issued GR-53 providing an initial outline of the tax rules for the GS PSCs. The key tax principles are as follow:

a. Pursuant to the preamble, GR-53 flows from Article 31D of the Income Tax Law and, perhaps surprisingly, from Article 16B of the Value-Added Tax (VAT) Law. As expected, there is no reference to GR-79/27, meaning that GR-79/27 (as discussed in Chapter 4) is not relevant to GS PSCs;
b. Pursuant to Article 18, the “taxable income” arising from “direct” PSC activities is calculated as “gross income” less “operating costs” (see below) but with an entitlement to a ten-year tax-loss carry-forward. This ten-year period is greater than the five years available under the general tax law, but represents a significant reduction on the unlimited carry forward entitlement under conventional PSCs;
c. Pursuant to Articles 18(4) and (5), taxable Income for “direct” activities is income relating to the lifting as well as the sale of by-products and other “economic gains” (see below). The taxable income is taxed at the prevailing rate at the time of signing the PSC, which is currently 22%. Branch Profits Tax (BPT) (currently due at 20%) is applicable to after-tax profits. These rates, however, are not fixed and so may change with any amendments to the general tax law (although the wording of the actual PSC could be important on this point). However, there is no apparent prohibition on the utilisation of tax-treaty relief potentially opening the way to BPT reductions where relevant treaty relief is validly available (but see below for more detailed comments).

   Tax calculations are specific to each contractor, differing from the traditional PSC approach. In other words, individual contractors could validly calculate taxable income outcomes different from those derived for the PSC as a whole. However, a range of issues may arise in such a case, including how individual contractors will ultimately be tax audited, etc., in the absence of a “PSC-driven” audit process such as that which currently takes place under the Financial and Development Supervisory Agency (BPKP) and the Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas);
d. According to Article 14, taxes are applied when the contractor receives the hydrocarbons. This continues the conventional PSC approach whereby economic value is initially recognised upon the contractor taking title to their share of hydrocarbons via a lifting entitlement under the PSC, rather than necessarily via the sale of the hydrocarbons. This should also mean that income from post-lifting activity (e.g. trading) should not fall within GR- 53;
e. The value of oil is determined using the Indonesian ICP (Article 15), while the value of gas is determined via the price agreed under the relevant gas sales contract (Article 16). Again, this is in line with conventional PSCs;

f. Pursuant to Article 19 (1), income separately arising from uplifts is subject to tax at a final rate of 20% of the uplift amount. This is consistent with the taxing outcome under GR-27; and
g. Pursuant to Article 19 (2), income arising specifically from PSC transfers is subject to tax at 5% or 7% of the transfer income (according to whether the PSC is in exploration or exploitation), with no further tax due on after-tax income. This means that no BPT should be due on income from PSC transfers, which is also consistent with the revised arrangements under GR-27 for conventional PSCs. Refer to our explanation of GR-93 in Chapter 4 (Upstream sector) for more details on the PSC transfer tax imposition and exemption conditions.

In summary, GR-53 provides only the initial fiscal framework for GS PSCs, with a number of implementing regulations still to be issued. While the general fiscal framework appears broadly in line with that for conventional PSCs, further regulations are still required before contractors can draw more definitive conclusions.

Nevertheless, the key fiscal differentiators for GS PSCs include:

a. contractor-specific tax calculations are applicable, rather than each contractor following a PSC "cut-back" approach;
b. in GS PSCs, the production split is based on gross production, unlike traditional PSCs where it occurs after cost recovery, except for First Tranche Petroleum (FTP);
c. the contractor's GS revenue is subject to deductions (under GR-53 and the Income Tax Law (ITL)) rather than cost recovery;
d. there is likely to be an exemption from all "non-income tax" taxes during pre-production, with no incentive during the post-production period. This means that, essentially, contractors will bear non-income tax spending (during the post-production period) at its after-tax cost;
e. a ten-year tax-loss carry-forward restriction applies (albeit with an automatic deferral during pre-production) rather than the indefinite period under traditional (cost recovery) PSCs;
f. there is no apparent "lock-down" entitlement to a tax rate applicable to lifting income; although a number of existing GS PSCs have defined the ITL as that in place as at the "effective date" of the PSC in question, and thus "locking-down" the Income tax rate to the PSC signing date is apparently possible; and
g. There are no apparent prohibitions around treaty use, leaving open the possibility of leveraging treaty Reductions, particularly in relation to BPT (but see below).

5.2.1 GS tax calculation

Key features of the GS tax calculation include:

a. similarly to existing PSCs, pursuant to Article 4, a contractor's "gross income" shall consist of both:
   i) gross income "directly" derived from PSC activities; and
   ii) gross income arising from activities "outside" of PSC activities;

b. gross income from "direct" PSC activities is essentially the contractor's share of oil/gas realised from lifting, less a DMO, plus compensation for the DMO, plus/minus lifting price variances;
c. gross income from activities "outside" of direct PSC activities constitutes income arising from:
   i) uplifts;
   ii) transfers of PSCs;
   iii) sales of "secondary" (by-) products arising from upstream activities; and
   iv) other amounts resulting in an "economic benefit" (which the elucidation indicates will extend to contractual penalty entitlements, etc.).

   As indicated above, items (i) and (ii) are subject to specific final tax arrangements, whilst items (iii) and (iv) are simply added to the income arising from "direct" PSC activities;
d. pursuant to Article 5, "operating costs" include:
   i) "exploration costs" that include costs arising from exploration drilling, general and administrative activities and Geological and Geophysical (G&G) activities;
   ii) "exploitation costs" that include costs arising from development drilling, direct production (for oil or gas), processing activities, utilities, general and administrative activities, as well as depreciation and amortisation; and
   iii) "other costs" that include costs arising from the transportation of hydrocarbons, post-operational activities and marketing, as well as for reimbursements paid to prior contractors in the event that a PSC is terminated pursuant to the relevant regulations. LNG processing costs, up to the point of LNG transfer, are specifically mentioned in the elucidation. For both exploration and exploitation, "general and administrative" activities include finance costs as well as "indirect taxes, regional taxes and regional levies". Interest costs nevertheless remain non-deductible (see comments on Article 8 below). Indirect taxes are therefore now also only deductible, rather than reimbursable, meaning that GS PSCs are generally economically inferior to the "assume and discharge" arrangements available under many conventional PSCs.

   Although reimbursements for unrecovered capital costs paid to prior contractors are generally treated as operating costs, some spending may actually constitute reimbursements of capital expenditure, and therefore would be subject to amortisation (as the nature of the costs being reimbursed is capital expenditure incurred by the prior contractor).

Limitations on deductions

Key features include:

a. that, pursuant to Article 7, the deductibility of all operating costs (outlined above) is subject to the satisfaction of a series of general criteria. These include:
   i) pricing must follow arm's-length principles. This opens the door to more mainstream transfer pricing requirements for related party transactions in the upstream space;
   ii) oil and gas operations must follow "good" business practices and be in accordance with the relevant work programmes. However, it is not clear how detailed the residual work programme approval process is required to be. If strictly enforced, this could be seen as effectively creating a *de facto* uniformity principle;
   iii) depreciation is subject to the asset in question being held by the state. This is similar to conventional PSCs;
   iv) direct "head office" charges must relate to activities that cannot be "procured locally". This requirement will hopefully be supported by guidelines on how to measure/determine what can or cannot be "procured locally" as this could otherwise be quite subjective in practice.

   In addition, "indirect" head office allocations must be within MoF guidelines and be supported by financial information (e.g. audited financial statements of the relevant head office entity).

   Neither category of head office costs appears to be limited to "operators" potentially leaving open the possibility for all contractors to achieve deductions for their individual head offices expenses (where validly connected to PSC activities);

   Indirect head office charges are also exempt from income tax and VAT under Article 27;
   v) the deductibility of spending on a range of other items, e.g., Benefits in Kind (BiK), donations, environmental activities and foreign manpower, must comply with existing regulations.

b. pursuant to Article 8, there is no deduction for spending in respect of:
   i) administrative sanctions, fines, etc.;
   ii) payments of income tax;
   iii) incentives, pension contributions, etc. for foreign manpower, etc.;
   iv) the costs of foreign manpower without a work permit;
   v) legal expenses with no direct relationship to upstream activities;
   vi) costs in respect of mergers, acquisitions or PSC transfers;
   vii) spending on consultants, corporate re-branding, management changes, etc.;
   viii) interest costs;
   ix) royalties. The elucidation extends this to payments allowing contractors access to operational technologies;
   x) third party income tax where (effectively) borne by the contractor; and
   xi) government bonuses.

Photo source: PwC

Most of these restrictions mirror those set out in Article 13 of GR-27. This is except for costs for marketing (as indicated above), tax consultants and commercial audits which now seem to be deductible.

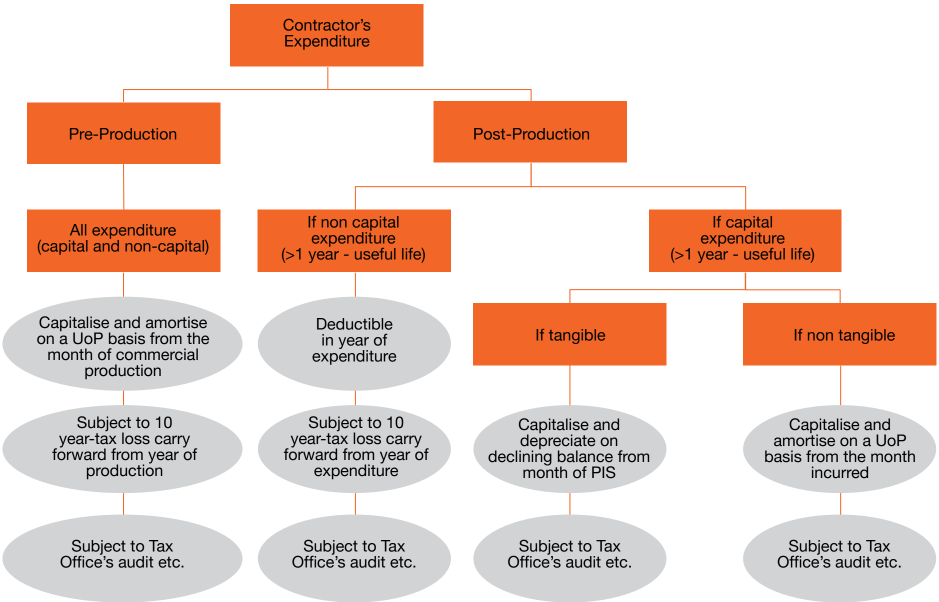
Pre-production/deferred spending

Key features are as follows:

a. Similarly to existing PSCs, pursuant to Article 12, all pre-production spending, including that otherwise constituting an outright deduction or expense is still capitalised. Amortisation of this capitalised spending then commences from the month of commercial production, on a Units of Production (UoP) basis. This deferment measure helps address concerns about losing the ability to carry forward tax losses indefinitely under GS PSCs (see comments above);
b. Pursuant to Article 9(1), post-production spending on amounts creating economic value of less than one year is deductible in the year in which the expenses are incurred;
c. Pursuant to Article 9(2), post-production spending on amounts creating economic value for more than one year is depreciable (if relating to tangible assets) or amortisable (if relating to intangible assets);
d. Pursuant to Article 10, depreciation is on a declining balance basis commencing in the month in which the relevant asset is Placed into Service (PIS), and at rates set out in the Attachment to GR-53. The relevant elucidation defines PIS as the time when the assets are utilised and have fulfilled the conditions/ requirements set out by SKK Migas. Again, the reference to SKK Migas criteria gives rise to questions around a *de facto* uniformity principle;
e. Pursuant to Article 11, amortisation should be on a UoP basis, commencing from the month in which the expense is incurred; and
f. Pursuant to Article 13, spending on approved reserves for remediation, etc. is deductible in the year in which the contribution is made to a specifically approved joint bank account with SKK Migas, etc. Any ultimate differences between the reserves and realisation shall be taxable or deductible, as the case may be.

The tax treatment of a Contractors' expenditure in the context of a GS PSC can be summarised as follows:

Figure 5.1 - Tax treatment of contractor's expenditure under GS PSC scheme



Source: GR-53/2017

Administration

Pursuant to Article 22, all Contractors are required to:

a. register for tax;
b. file annual tax returns;
c. remit tax payments, including monthly tax instalments based on each contractor's lifting for the prior month; and
d. report any PSC transfers to both the MoEMR and the MoF.

Pursuant to Article 23, Operators are required to:

a. deal with the Withholding Tax (WHT) obligations of the PSC itself. These obligations presumably extend only to all jointly incurred costs. A question however arises regarding remittances for any individual contractor-only spending; and
b. manage the bookkeeping of the PSC itself. These obligations extend to the keeping of the general financial records, including traditional financial statements which (presumably) will now also become key fiscal documentation.

Incentives

Pre-production period

Pursuant to Article 25, for the pre- production period (i.e. exploration and development) the incentives include:

a. an exemption from import duty on goods used for oil and gas operations. However, it is still unclear how this can be provided without a general reference, or without placing reliance on the Customs Law;
b. the non-collection of VAT on the import or local procurement of goods and services used in operations. This is obviously a wide-ranging incentive which, at least in relation to in-country procurement at least, is superior to that under conventional PSCs;
c. an exemption from Article 22 on imports of goods on which the contractor is entitled to an import duty exemption as outlined in a) above; and
d. a 100% reduction in Land and Building Tax (PBB - *Pajak Bumi dan Bangunan*).

On 15 June 2020, the MoF issued Regulation No. 67/PMK.03/2020 (PMK-67), which provides guidelines on the granting of VAT and PBB facilities for GS PSCs during the pre-production period. PMK-67 serves as the implementing regulation of GR-53 and is effective from 15 July 2020.

In order to obtain such facilities, the operator needs to submit an application to the Regional Tax Office (RTO) via the Tax Office where the operator is registered, enclosing the following documents:

a. A confirmation letter from the MoEMR stating that the contractor is in the pre-production stage, and providing the following information:
   i. Name of the working area;
   ii. List of contractors;
   iii. Names of the operators; and
   iv. Effective date of the GS PSC or approval of conversion (from a traditional cost recovery PSC);
b. A copy of the GS PSC.

The RTO will then issue the GS Tax Facilities Letter ((*Surat Keterangan Fasilitas Perpajakan* - SKFP) GS) within seven working days of the application being submitted, which will be effective from:

a. the effective date of GS PSC (for PSCs signed post-GR-53);
b. the approval date of PSC conversion into GS format (for converted PSC); or
c. the effective date of GR-53 (for PSCs signed pre-GR-53).

The GS SKFP is considered to be invalid in the event that the contract expires, is terminated or commences commercial production.

VAT not collected facility mechanism

The operator needs to provide local vendors with a copy of the GS SKFP and show them the original prior to the delivery of VAT-able goods/services. Local vendors will then issue their VAT invoices with the statement “VAT NOT COLLECTED IN ACCORDANCE WITH GR-53”.

The operator (as a VAT collector) is therefore:

a. not obliged to collect and pay the VAT on local procurement of goods and/or services; and
b. not required to pay the Self-Assessed VAT (SA-VAT), in regard to SA-VAT, as the VAT facility will be stated on the SKFP.

PBB reduction mechanism

The contractor needs to submit:

a. the Notification of PBB Objects (SPOP - *Surat Pemberitahuan Objek Pajak*); and
b. a copy of the GS SKFP to the Tax Office where the PBB object is administered.

The Directorate General of Taxes (DGT) would then issue an Official Tax Payable Notification (SPPT - *Surat Pemberitahuan Pajak Terutang*) based on the relevant SPOP, which would also enclose the PBB (100%) reduction amount based on the GS SKFP.

In the event that the GS SKFP is submitted after the issuance of an SPPT, the contractor will still be eligible for the PBB reduction facility.

VAT and PBB clawback

VAT and PBB clawback may apply, along with the associated late-payment penalty, in the event that such a facility is used outside the context of oil operations and/or the utilisation of an invalid GS SKFP.

There are no incentives offered for post-production activities, meaning that all such taxes should simply be deductible.

Pursuant to Article 26, where during the post-production period there is excess capacity associated with certain upstream assets made available to other contractors on a cost-sharing basis, then the cost- sharing receipts will be exempt from income tax and VAT provided certain conditions are met.

5.3 Other tax considerations/issues

Whilst not an exhaustive list, below are a number of tax considerations relevant to GS PSCs which are not dealt with in GR-53. Specific advice should be sought where relevant.

Table 5.2 - Summary of other tax considerations/issues not dealt with in GR-53

Topics	Tax consideration/issues
Conversion of conventional PSCs to GS PSCs	A. Unrecovered costs • Whenever a contractor voluntarily converts to a GS PSC, pursuant to Article 32(c) of GR-53, any unrecovered costs on conversion to GS shall be converted to additional split (i.e., additional contractor's take provided as compensation for the unrecovered costs). • Article 31 (2) of Regulation-13, however, stipulates that any unrecovered costs on conversion to GS shall be treated as a deduction from the contractor's share of income in the income tax calculation under the GS scheme. • This is notwithstanding that Article 8 (5) of GR-53 indicates that any costs incurred prior to signing of a GS PSC are not deductible. • However, this appears to be aligned with our experience in practice, whereby some contractors had agreed a carried-forward cost entitlement (via deductibility) with SKK Migas (presumably without any additional split). • Should the costs be forfeited as per GR-53, then a question arises on the accounting treatment. The carrying value may need to be impaired if the costs cannot be fully recovered over the life of the operations of the GS PSC. B. Outstanding VAT reimbursement • For post-GR-79 PSCs, VAT is generally recovered through cost recovery, meaning that VAT is treated similar to other unrecovered costs (refer to above). • However, for a pre-GR-79 PSC, VAT may be recovered via reimbursement which has a greater value than recoverable costs (i.e. effectively a 100% refund to the contractor). • GR-53 and the MoEMR Regulations are silent on any special compensation for outstanding VAT reimbursements if a pre-GR-79 PSC is converted to GS. • We expect that this issue would be subject to separate negotiations with SKK Migas.
PSC holding structure options (PE vs PT)	• A PSC entity holding structure, whether as a Public Entity (PE) or a Limited Liability Company (PT), is essentially tax neutral with respect to revenue and/or deduction recognition. • Under a PT structure profit repatriation is via dividends where there are positive Retained Earnings (R/E). Positive R/E takes into account past losses. • Under a PE structure, profit repatriation is via a deemed BPT arising simultaneously with the corporate tax liability (unless reinvested into an Indonesian PT). The deeming approach ignores past losses.
Reduced BPT rate entitlement	A. Domestic rules • Article 18 (5) of GR-53 indicates that net taxable income (i.e., after income tax) is subject to further "income tax" pursuant to the prevailing tax regulations (i.e., a BPT)). • This potentially acknowledges a contractor's obligation to pay BPT but only in accordance with relevant tax laws including those set out under tax treaties. • This is consistent with the fiscal framework of the GS PSC (under GR-53) moving towards the general tax rules.

Topics	Tax consideration/issues
	B. Indonesia’s tax treaties • Indonesia has concluded approximately 67 tax treaties. Most of the treaties provide a general reduced BPT rate. However, the following should be noted: a. Some treaties provide no restrictions around the application of reduced BPT rates for Indonesian PSCs. This means that a reduced BPT rate should be available; b. Other treaties include restrictions and “non-discrimination” provisions in respect of a reduced BPT rate for Indonesian PSCs. For example the protocol to Indonesia/Japan tax treaty provides: “5(a) …. But such [BPT] shall not exceed 10% of the amount of such earnings, except where such earnings are those derived by such company under its oil or natural gas PSCs with the Government of the Republic of Indonesia or the relevant state oil company of Indonesia” “5(b) The above-mentioned tax in respect of the earnings of a company being a resident of Japan which has a PE in Indonesia derived under its oil or natural gas PSCs with the Government of the Republic of Indonesia or the relevant state oil company of Indonesia shall not be less favourably levied in Indonesia of any third state which has a PE in Indonesia derived under its oil or natural gas PSCs with the Government of the Republic of Indonesia or the relevant state oil company of Indonesia”
Implementation of Pillar Two GloBE Rules in Indonesia	As indicated in Chapter 4, the implications of the Pillar Two policy to PSC Contractors (including the GS PSC) due to the issuance of PMK-136, may not be straightforward and are expected to require a detailed case-by-case analysis. Further developments in this area should be closely monitored.

Sources: GR-53/2017, Regulation-08, GR-79/2010, Indonesia’s tax treaties, PMK-136/2024

5.4 GS PSC accounting - PTK-066/2019

In April 2021, SKK Migas issued guidelines for reporting upstream oil and gas business activities under GS arrangements, known as PTK-066/2021. These guidelines are applicable to the preparation and submission of the WP&B, the FQR and the Financial Monthly Report (FMR) to SKK Migas by contractors. The guidelines cover various topics, including:

a. the procedures for the preparation, submission and revision of the WP&B;
b. the accounting policies and descriptions of line items in the WP&B, FQR and FMR for a GS PSC; and
c. asset management arrangements.

The guidelines also make clear that the GS PSC should follow the prevailing tax laws and regulations, which are currently regulated under GR-53. The guidelines will be adjusted automatically to follow the tax regulations.

6 Downstream sector

6.1 Downstream regulations

Law No. 22 (as last amended by the Job Creation Law) formally liberalised the downstream market by opening the sector (processing, transportation, storage and trading) to direct foreign investment, thereby ending the former monopoly of the state-owned oil and gas company, PT Pertamina (Persero). While the distribution of downstream products and blending of lubricants had previously been conducted by multinationals in Indonesia, since the enactment of Law No. 22, many domestic and multinational companies have established themselves in the more capital-intensive areas of the downstream sector. These areas include:

a. tank farms/storage facilities for bulk liquids and Liquefied Petroleum Gas (LPG);
b. the distribution of gas via pipelines (Citigas and long-distance pipelines);
c. proposed refineries and downstream Liquefied Natural Gas (LNG) facilities;
d. LNG regasification terminals; and
e. the retailing of fuel (both subsidised and non-subsidised).

Below, we present a summary of the key sections of the downstream regulations, as provided in Law No. 22 and its implementing regulations, Government Regulation (GR) No. 36/2004 (as last amended by GR No. 30/2009).

Photo source: PwC

6.1.1 Operation and supervision of downstream business

Downstream businesses are required to operate through an Indonesian incorporated entity (hereafter referred to as a PT company) and must obtain a business licence issued via the Online Single Submission (OSS) platform with approval and assessment from the MoEMR and/or Government agencies through a one-door integrated system. As indicated in Chapter 3, the Investment Coordinating Board (BKPM) and the Downstream Oil and Gas Regulatory Agency (BPH Migas) are responsible for regulating, developing and supervising the operation of the downstream industry.

6.1.2 Business licences

A separate business licence is required for each of the following downstream activities (except where the activity is a continuation of an upstream activity, in which case a licence is not required):

a. Processing (excluding field processing);
b. Transportation;
c. Storage; and
d. Trading (two types of business licences are required – a wholesale trading business licence and a trading business licence).

It is permissible for one PT company to hold multiple business licences.

To obtain a business licence, a PT company must apply for a Risk-Based Licensing (*Perizinan Berbasis Risiko*) approach, conducted via the OSS platform. This platform is integrated with Government agencies (e.g. MoEMR and BPH Migas) and requires the submission of administrative and technical requirements, which include, at a minimum, the following:

a. Name of operator;
b. Proposed line of business;
c. Undertaking to comply with operational procedures; and
d. Detailed plan and technical requirements relating to the business.

The Business licences are issued in two stages:

a. A temporary licence for a maximum period of five years (i.e., three years, plus a two-year extension), during which the PT company prepares the facilities and infrastructure of the business; and
b. A permanent operating licence, once the PT company is ready for operation.

6.1.3 Processing

A PT company holding a processing business licence must submit operational reports, an annual plan, monthly realisations and other reports to the MoEMR and BPH Migas. The processing of oil, gas and/or processing output to produce lubricants and petrochemicals is to be stipulated and operated jointly by the MoEMR and the Ministry of Trade (MoT).

The oil and gas processing business license is valid for a maximum of 30 years and may be extended for a maximum of 20 years at a time.

Non-integrated gas supply chain

The processing of gas into LNG, LPG and Gas to Liquids (GTL) is classified as a downstream business activity, as long as it is intended to realise a profit and is not secondary to an upstream development.

This technically allows for a non- integrated LNG/LPG supply chain concept by virtue of:

a. enabling Production Sharing Contract (PSC) contractors to be the appointed seller of gas (including the Government's share), to be further processed by a separate entity;
b. shorter LNG supply arrangements; and
c. the possible use of an onshore project company, sponsored by a shareholder agreement which receives initial funds for the development and operation of an LNG processing plant.

In practice, downstream LNG and miniature LNG refineries have been impacted by a multitude of regulatory issues, including a change in the Value Added Tax (VAT) treatment of LNG, and concerns over the adequacy of domestic gas supply.

6.1.4 Transportation

Transportation of gas by pipelines via a transmission segment or a distribution network area is permitted only with the approval of BPH Migas, with licences being granted only for specific pipelines/commercial regions.

The oil and gas transportation business licence is valid for a maximum of 20 years and may be extended for a maximum of ten years at a time.

A PT company with a transportation business licence is required to:

a. submit monthly operational reports to the MoEMR and BPH Migas;
b. prioritise the use of transportation facilities owned by cooperatives, small enterprises and national private enterprises when using land transportation;
c. provide an opportunity to other parties to share utilisation of its pipelines and other facilities used for the transportation of gas; and
d. comply with the masterplan for a national gas transmission and distribution network.

BPH Migas has the authority to:

a. regulate, designate and supervise tariffs after considering the economic considerations of the PT company, users and consumers; and
b. grant permits for the transportation of gas by pipelines to a PT company, based on the masterplan for a national gas transmission and distribution network.

A PT company may increase the capacity of its facilities and means of transportation after obtaining special permission.

6.1.5 Storage

A PT company is required to:

a. submit its operational reports to the MoEMR each quarter, or as and when requested by BPH Migas;
b. provide an opportunity for another party to share its storage facilities;
c. share storage facilities in remote areas; and
d. have a licence to store LNG.

A PT company can increase the capacity of its storage and related facilities after obtaining permission from BPH Migas. Transportation or storage activities that are intended to make a profit, or to be used jointly with another party by collecting fees or lease rentals, are construed as downstream business activities and require the appropriate downstream business licence and permits.

6.1.6 Trading

A PT company must guarantee the following when operating a trading business:

a. The constant availability of fuels and processing outputs in its trade distribution network;
b. The constant availability of gas through pipelines in its trade distribution network;
c. The selling prices of fuels and processing outputs at a fair rate;
d. The availability of adequate trade facilities;
e. The standard and quality of fuels and processing outputs, as determined by the MoEMR;
f. The accuracy of the measurement system used; and
g. The use of qualifying technology.

A PT company is required to:

a. submit monthly operational reports to the MoEMR, or at any time required by BPH Migas;
b. maintain facilities and means of storage and security of supply from domestic and foreign sources;
c. distribute fuels through a distributor to small-scale users under the company's authorised trademark;
d. prioritise cooperatives, small enterprises and national private enterprises when appointing a distributor; and
e. submit operational reports to the MoEMR and BPH Migas regarding the appointment of distributors.

A PT company holding a wholesale trading licence can operate a trading business to serve certain consumers (e.g., large consumers). The MoEMR, along with BPH Migas, may determine the minimum capacity limit of a storage facility or facilities of a PT company. The PT company may start its trading business after fulfilling the required minimum capacity.

A direct user who has a seaport or receiving terminal may import fuel oil, gas and other fuels, and process the output directly for its own use, but not for resale, after obtaining specific approval from the MoEMR.

A PT company operating an LPG trading business is required to:

a. control facilities and means for the storage and bottling of LPG;
b. have a registered trademark; and
c. be responsible for maintaining a high standard and quality of LPG, LPG bottling and LPG facilities.

PT companies operating in the business of gas trading may include those with a gas distribution network facility, and those without. The former should only operate after obtaining a licence to trade gas and special permission for a distribution network area. The latter may only be implemented through a distribution network facility of a PT company that has obtained access to a distribution network area, and only after obtaining a licence to trade gas.

The MoEMR has the authority to determine and set technical standards for gas, as well as the minimum technical standards for distribution and facilities.

6.1.7 National fuel oil reserve

The MoEMR is responsible for setting policy regarding the quantity and type of the national fuel oil reserve and may appoint a PT company to contribute to building this reserve. The national fuel oil reserve is determined and supervised by BPH Migas. The reserve can only be used when there is a scarcity of fuel oil, and once the scarcity is resolved, the reserve must be returned to its original level.

6.1.8 Standard and quality

The MoEMR establishes and regulates the type, standard and quality of fuel oil, gas, other fuels and certain processed products for the domestic market. These standards are determined by considering factors such as the technology used, producer capacity, consumer financial capability, and adherence to safety, health, and environmental standards.

A PT company operating as a processing business must have an accredited laboratory to perform tests on the quality of the processing output. Likewise, a PT company operating a storage business which carries out blending to produce fuel oil must provide a testing facility on the quality of the blending output. If the PT company is unable to provide its own laboratory, it is allowed to use an accredited laboratory facility owned by another party.

Fuel oil, gas and processing outputs in the form of finished products that are imported or directly marketed domestically must comply with the quality standards determined by the MoEMR. For fuels and processing outputs that are exported, a producer may determine the standard and quality based on the buyer's request. Fuels and processing outputs specially requested must have their determined standard and quality reported to the MoEMR.

6.1.9 Availability and distribution of certain types of fuel oil

To guarantee the availability and distribution of certain types of fuel oil, trading businesses are not currently able to operate in a fully fair and transparent market.

The MoEMR has the authority to designate areas of trading certain types of fuel oil domestically. This may include trading fuel oil, where:

a. the market mechanism has been effective;
b. the market mechanism has been ineffective; or
c. the market is located in a remote area.

BPH Migas has the authority to:

a. designate a trade distribution area for certain types of fuel oil for corporate bodies holding a trading business licence;
b. determine joint usage of transportation and storage facilities, particularly in areas where the market mechanism is not yet fully effective or in remote areas; and
c. if necessary, the Government, with input from BPH Migas, may determine the retail prices for certain types of fuel oil by calculating their economic value.

A PT company holding a wholesale trading business licence that sells certain types of fuel oil to transportation users, or that trades kerosene for household and small enterprises, must provide opportunities to the appointed local distributor. The distributors include cooperatives, small enterprises and/or national private enterprises contracted with the PT company. The distributor may only distribute the trademark fuel oil of the corporate body. The PT company must report the names of its distributors to BPH Migas and the MoEMR.

6.1.10 Occupational health and safety, environmental management and local community development

PT companies operating with a downstream business licence must comply with provisions relating to occupational health and safety, environmental protection and the development of local communities. This responsibility includes developing and utilising the local community through, among other initiatives, local employment. Such development must be implemented in coordination with the regional government, with priority given to the area surrounding the operation.

6.1.11 Utilisation of local goods, services, engineering and design capacity and workforce

PT companies operating with a downstream business licence must prioritise the utilisation of local goods, tools, services, technology and engineering and design capacity.

In fulfilling labour requirements, a downstream PT company must prioritise the employment of Indonesian workers according to the required competency standards. Where Indonesian workers do not meet the required standards of competence and occupational qualifications, the PT company must arrange training and development programmes to improve those workers' capacities.

6.1.12 Sanctions

BPH Migas has the authority to determine and impose sanctions relating to a PT company's breach of its business licence. Sanctions increase the longer the breach remains unremedied and can include a written reminder, suspension of the business, freezing of the business and finally, annulment of the business licence. All damages arising out of any sanction must be borne by the respective corporate bodies.

Any person who commits:

a. processing without a processing business license shall be punished with a maximum imprisonment of five years and a maximum fine of IDR50,000,000,000.00 (fifty billion rupiah);
b. transportation as without a transportation business license shall be punished with a maximum imprisonment of four years and a maximum fine of IDR40,000,000,000.00 (forty billion rupiah);
c. storage without a storage business license shall be punished with a maximum imprisonment of three years and a maximum fine of IDR30,000,000,000.00 (thirty billion rupiah); and
d. trading without a trading business license shall be punished with imprisonment of up to a maximum of three years and a maximum fine of IDR30,000,000,000.00 (thirty billion rupiah).

6.2 Taxation and customs

6.2.1 General overview

Goods and services supplied by downstream operators, contractors and their businesses are generally subject to taxes under the general tax law. For more information, please see our annual publication, the PwC Pocket Tax Guide, which can be found at http://www.pwc.com/id. Most downstream entities pay taxes in accordance with the prevailing law, although some activities can be subject to different Withholding Tax (WHT) arrangements and a final tax arrangement.

Practical tax issues to be considered before making any significant investment include the following:

a. Whether any tax incentives are available for the proposed investment;
b. Whether a Public Entity (PE) exists in Indonesia either as part of the proposed investment, or prior to the new investment;
c. The import tax obligations, especially within the transportation and storage industry;
d. The income tax treatment of the revenue stream (noting that there could be a different Income Tax treatment according to the nature of the transaction);
e. Ensuring that contracts specifically cater for the imposition of WHT and VAT, i.e., the use of net versus gross contracts;
f. Structuring inter-group transactions and agreements to accommodate the WHT and VAT implications and any transfer-pricing issues that may arise (for example, inventory supplies and/or offtake, management fees, financing, etc.); and
g. Structuring certain contracts to minimise VAT and WHT implications.

From a customs perspective, issues include the following:

a. Royalties – Customs (the Directorate General of Customs and Excise (DGoCE)) pursuing duty on royalty payments during customs audits;
b. Transfer-pricing adjustments – multinationals making year-end adjustments. The DGoCE could charge duty on any additional payments, and

ignore any credits received by the importer;

c. Arrangements with no sale to the importer – examples include leased goods, warranty replacement, imports by branches, ship to A/sell to B. At best, there is a compliance burden in determining the alternative basis of the customs value. At worst, the duty liability may increase significantly;
d. Inventory control in customs facilities – companies using customs facilities may have problems in accounting for the physical inventory as compared to the bookkeeping records; and
e. Transfers of fixed assets under customs facilities - the exempted duties may have to be paid, where the company has not followed the proper procedures.

Implementation of Pillar Two GloBE Rules in Indonesia

Pursuant to MoF Regulation (*Peraturan Menteri Keuangan* - PMK) No -136, the Pillar Two policy would apply to Multinational Enterprises (MNEs). The implications of this policy may not be straightforward and are expected to require a detailed case-by-case analysis. Further developments in this area should be closely monitored.

Thin capitalisation

On 9 September 2015, the MoF issued Regulation No. 169/PMK.010/2015 (PMK-169), establishing a general Debt to Equity ratio (DER) limitation of four to one for income tax purposes. PMK-169 became effective on 1 January 2016. According to this regulation, if debt exceeds equity by a factor of four on a monthly basis, the interest on the "excessive debt" is non-deductible. PMK-169 provides exemptions from the DER rules for certain industries, including infrastructure, although the definition of infrastructure is not provided. Most downstream activities are likely subject to the 4:1 DER limitation.

On 28 November 2017, the Directorate General of Taxes (DGT) issued PER-25/PJ/2017 (PER-25), with additional implementing guidelines on the DER calculation and filing arrangements. PER-25 also introduced a general requirement to file an “offshore” loans report. These rules apply starting from the 2017 annual returns.

On 7 October 2021, the Indonesian Parliament passed the Harmonisation of Tax Regulations (*Harmonisasi Peraturan Pajak* - HPP) Law, expanding the methods to determine the limitation on financing costs deductibility. In addition to the DER method, the HPP Law allows other internationally accepted methods such as using a percentage of Earnings Before Interest, Taxes, Depreciation and Amortisation (EBITDA). However, the implementing regulations for the HPP Law have not been issued to date.

6.2.2 Tax incentives

Tax incentives may be available to certain investors in the following downstream sectors.

Tax holiday for pioneer investors

On 8 October 2024, the MoF issued Regulation No. 69 of 2024 (PMK-69), which revokes the previous MoF Regulation No. 130/PMK.010/2020 (PMK-130), related to the tax holiday facility. PMK-69 was effective from 9 October 2024 and extends the granting period to be applicable for Tax Holiday proposals submitted to the OSS system up to 31 December 2025.

Under PMK-69, the benefits of the tax holiday facility remain largely the same, allowing taxpayers to enjoy a Corporate Income Tax (CIT) reduction of 50-100% for 5-20 years, depending on the investment value. Taxpayers can also enjoy a 50% or 25% CIT reduction for the next two years after the concession period ends (depending on the initial investment value).

The key highlights under PMK-69 are as follows:

A. Pillar Two implementation

PMK-69 provides new provisions related to the implementation of Pillar Two, as follows:

- A taxpayer who has obtained a tax holiday facility but also qualifies as part of a MNE group that is subject to global minimum tax under Pillar Two rules is subject to an additional domestic top-up tax under this rule.
- This domestic top-up tax also applies to those who obtained the tax holiday facility prior to the effective date of PMK-69.

B. General eligibility

Qualifying criteria include:

a. the applicant has never obtained a tax holiday facility under the National Capital to be named “Nusantara” (*Ibu Kota Negara bernama Nusantara*/IKN) facility;

b. the business is in a “pioneer industry”. Within the energy sector, this includes oil refineries or industries and oil refinery infrastructure, including those using the Cooperation of Government and Business Entity (*Kerjasama Pemerintah dan Badan Usaha* - KPBU) scheme, as well as base organic chemicals sourced from oil and gas;

c. the applicant is an Indonesian legal entity;

d. the applicant involves a new capital investment plan;

e. the project involves a capital investment of at least IDR100 billion;

f. the project is carried out through an Indonesian legal entity;

g. the applicant has never had its tax holiday application granted or rejected by the MoF;

h. the applicant has never been granted with other tax facilities, i.e., tax allowance, additional deduction on labour intensive industry and Special Economic Zones (*Kawasan Ekonomi Khusus* - KEK);

i. the taxpayer satisfies the DER requirement; and

j. the taxpayer is committed to start realising the investment plan at the latest one year after the issuance of the tax holiday approval.

C. Avenue for companies not listed as pioneer industries

Companies that are not listed as being in a pioneer industry may also apply for the tax holiday facility. In this regard, PMK-69 now stipulates that the applicant can make a self-assessment to justify why they should be considered as a pioneer industry in accordance with the form attached to PMK-69.

The self-assessment form contains criteria in the following categories:

a. Possessing a broad local connection (e.g., using main raw materials produced domestically, production products used domestically, etc.);
b. Having added value or high externalities (e.g., hiring a large number of workers, investment locations, etc.);
c. Introducing new technology (e.g., using environmentally friendly technology); and
d. Being a priority industry on a national scale (e.g., supporting national strategic projects, building infrastructure facilities independently).

In addition, the self-assessment form also sets out a quantitative scoring system. The taxpayer must obtain a score of at least 80 in the quantitative criteria assessment form. An assessment will be carried out to evaluate the quantitative criteria self-assessment.

D. National Strategic Project (*Proyek Strategis Nasional* - PSN)

There are some beneficial provisions for investors who carry out a PSN business expansion/additional investment through a “spin-off”. Under a spin-off scheme, the capital investment that is counted (and can enjoy benefits) for the tax holiday will include the value of the investment resulting from the spin-off, in addition to the newly invested capital.

The investment value amount used to determine the concession period of the tax holiday will be either:

a. all of the investment value (i.e., the new investment value and investment value resulting from the spin-off) – if the new investment value is higher than the investment value resulting from the spin-off; or
b. the new investment value – if the new investment value is lower than the investment value resulting from the spin-off.

E. Other administrative and procedural matters

Once the application is granted, the taxpayer is required to submit annual investment and production realisation reports. PMK-69 now stipulates that if a taxpayer fails to do so in a timely manner (within 30 days of the year’s end), the DGT will issue a warning letter that may eventually lead to a tax audit.

It should be noted that tax holiday applications from the OSS system to the MoF under PMK-69 now may only be submitted by 31 December 2025 at the latest.

Under PMK-69, the applicant now needs to submit its own Tax Clearance Certificate (SKF) in the tax holiday online application. Previously, under PMK-130, domestic shareholders of the applicant must obtain a tax clearance letter issued by the DGT.

In addition, manual submission of tax holiday facility applications is no longer allowed, meaning that all applications must be submitted through the OSS system. The reporting obligations for capital investment and production realisation are also to be submitted online through the OSS system.

The decision on the start date of utilisation of a tax holiday is determined based on the field audit, which is intended to verify the conformity of the realisation of the investment plan and the initial main business activity plan. Adjustment of the entitlement of the tax holiday facility may occur as a result of this audit.

PMK-69 now provides a time limit for this audit, i.e., at most 45 working days after the audit notification letter has been delivered to the taxpayer.

Tax allowances

Pursuant to Investment Law No. 25/2007 (as lastly amended by the Job Creation Law), the Government can provide incentives for qualifying investments.

On 12 November 2019, the Government issued Regulation No. 78 Year 2019 (GR-78/2019), which constitutes an amendment to the regulations on the tax allowances available for companies that invest in certain business sectors and/or regions.

GR-78/2019 is effective from 13 December 2019 and revokes a series of previous GRs (i.e., GR-18/2015, as amended by GR-9/2016).

The principal tax facilities remain the same, with the following updated features:

a. An "investment credit" equal to 30% of qualifying spending, deductible at 5% per annum (p.a) over six years, provided that the assets invested are not misused or transferred out within a certain period, except to be replaced with new assets.
   The fixed assets should now satisfy the following conditions under GR-78:
   a. They must be new, unless originating from a complete relocation from another country;
   b. They must be listed in the new business licence as the basis for obtaining a tax allowance facility; and
   c. They must be owned directly by the taxpayer (not through a lease) and utilised for the main business activity.
b. Accelerated tax depreciation/ amortisation;
c. Reduced WHT rates on payable dividends to non-residents; and
d. An extended tax loss carry-forward period of up to ten years.

The application is made through the OSS system prior to the start of commercial production.

The following tables outline the energy-related sectors that are eligible for this incentive:

Table 6.1 - Summary of oil and gas sectors eligible for tax allowance facility

Business Field	Scope of Products
Lubricant Manufacturing Industry	All products included within the relevant Lubricants business code Lubricant Business Code KBLI
Oil, Natural Gas and Coal Originated Organic Base Chemical Industry	All products included within the relevant business code (KBLI), except for products which have been covered for the tax holiday facility as regulated under PMK-130
Natural and Artificial Gas Supply	• Regasification of LNG into gas using a FSRU • Coalbed Methane (Non-PSC), shale gas, tight gas sand and methane hydrate • Refining and/or processing of natural gas into LNG and/or LPG • Provision and/or processing of artificial gas resulting from coal gasification

Sources: Investment Law No. 25/2007, GR-78/2019

KEK

On 28 December 2015, the Government issued Regulation No. 96/2015, which was later revoked by Regulation No. 40/2021 (GR-40) that provides facilities for those who invest in a KEK. These facilities cover income tax, VAT, Luxury-goods Sales Tax (LST), import duty and excise.

There have been 24 areas designated as KEKs.

Free Trade Zone (*Kawasan Perdagangan Bebas* - FTZ) in Batam, Bintan and Karimun

Goods entering an FTZ may benefit from tax facilities such as import duty and excise exemptions. In addition, other import taxes (i.e., VAT, LST, and Article 22 Income Tax) are not collected.

Bonded zone

A bonded zone (*kawasan berikat*) allows an exemption of import duty and other taxes on imports of capital equipment and raw materials by companies that produce finished goods mainly for export.

6.2.3 Taxation on the sale of fuel, gas and lubricants by importers and manufacturers

The taxation on the sale of fuel, gas and lubricants by importers and manufacturers is regulated under MoF Regulation No. 34/PMK.010/2017, which has been amended by MoF Regulation No. 110/PMK.010/2018 (PMK-34/110). PMK-34/110 requires importers and manufacturers to collect Article 22 WHT from the sale of fuel, gas and lubricants, as follows:

Table 6.2 - Summary of Article 22 WHT rates on sale of fuel, gas and lubricants by importers and manufacturer

Definition	Rate	Sale to	
		Agent/Distributor	Non-Agent/Non-Distributor
Fuel			
Sale by Pertamina and its subsidiaries to gas stations	0.25%	Final	Non-final
Sale by non-Pertamina to gas stations	0.3%	Final	Non-final
Sale other than the above	0.3%	Final	Non-final
Gas	0.3%	Final	Non-final
Lubricants	0.3%	Final	Non-final

Sources: PMK-34/2017 as amended with PMK-110/2018, PMK 119/2019 as lastly revoked by PMK-96/2023 and PMK-96/116

On 26 December 2019, the MoF issued Regulation No. 199/PMK.010/2019 which was later revoked by MoF Regulations No. 96 Year 2023 and No. 116 Year 2023 (PMK-96/116). These regulations further amend certain clauses in PMK-34/110. However, the amendments do not have a significant impact on the tax-related areas being discussed in this section.

PMK-34/110 were revoked and streamlined under PMK-81. There are no changes pertaining to the objects and rates made in PMK-81.

VAT on commercial sales

Producers or importers are considered taxable entrepreneurs, so general VAT rules apply to their sales, making them subject to VAT. Typically, producers or importers add VAT to their sales, which can be credited by the purchaser. Subsequent sales also incur VAT.

The introduction of the HPP Law increased the VAT rate to 12% starting 1 January 2025.

However, PMK-131/2024 provides that the imposition of the 12% VAT rate applies effectively only to the import and domestic delivery of luxury taxable goods currently subject to Luxury-Goods Sales Tax (PPnBM). These include motor vehicles, luxurious residences with a transaction value of at least IDR30 billion, private aircraft, luxurious private cruisers, shotguns, etc. Furthermore, the HPP Law now also excludes "mining or drilling products taken directly from the source" from the list of non-VAT-able goods (negative list). This means that by default, crude oil and natural gas are regarded as VAT-able goods and hence, any delivery of these goods could be subject to VAT.

For most other goods and/or services which are not categorised as luxurious, these are subject to an effective 11% VAT rate (i.e. 12% VAT rate x 11/12 of the transaction value).

GR No. 49/2022 (GR-49) confirms that although crude oil and natural gas are considered VAT-able goods, they are exempt from VAT upon delivery. This exemption is automatic, eliminating the need for a Tax Exemption Declaration Letter (SKB). However, from an input VAT perspective, any input VAT incurred for these VAT-exempt goods will not be creditable, similar to the previous treatment.

From the VAT administration perspective, the trading companies making the above VAT- exempt deliveries will still be required to register as VAT-able firms, and to issue VAT invoices (with "exempt" status) on each relevant delivery.

6.2.4 Import duties

Import duty on petroleum

Crude oils are classified under Harmonised System (HS) 27.09 (which covers petroleum oils and oils obtained from bituminous minerals, crude). Both the general import duty rate and the ASEAN Trade in Goods Agreement (ATIGA) rate for crude oil is 0%.

Refined oil products are potentially classifiable under HS 27.10, which covers:

"petroleum oils and oils obtained from bituminous minerals, other than crude; preparations not elsewhere specified or included, containing by weight 70% or more of petroleum oils or of oils obtained from bituminous minerals, these oils being the basic constituents of the preparations; waste oils".

The general import duty rate ranges from 0% to 5%, depending on the specific product. The ATIGA duty rate is 0%. Natural gas is classifiable under HS 27.11, which covers "Petroleum gases and other gaseous hydrocarbons". The general import duty rate ranges from 0% to 5%. The ATIGA rate is 0%.

Import duty on fuel

On 25 March 2022, the MoF issued Regulation No. 26/PMK.010/2022, which was amended by the MoF Regulation No. 10 Year 2024 (PMK-26/10). This regulation provides the 2022 Indonesian customs tariff book.

The HS codes for import duty on fuel are:

a. 2710.12, which has a 0% import duty in general and for the ATIGA duty rate; and
b. 2710.19, which has a general import duty rate in the range of 0% to 5% and 0% for ATIGA.

Additionally, the import of fuel is subject to a 2.5% or 7.5% Article 22 Income Tax, and an effective 11% import VAT.

6.2.5 Royalty on fuel oil supply and distribution and transmission of natural gas through pipelines

General

A PT company must pay a royalty to BPH Migas if:

a. it carries out the supply and distribution of fuel oil and/or transmission of natural gas through pipelines; or
b. it owns natural gas distribution network facilities operating in the distribution network area and/or transmission section.

The natural gas distribution area/transmission section is defined as an area/section of the natural gas distribution network/transmission pipeline which is part of the masterplan of the national natural gas transmission and distribution network.

Companies that must pay a royalty on the supply and distribution of fuel oil are:

a. PT companies holding a fuel oil wholesale trading business licence;
b. PT companies holding a fuel oil limited trading business licence; and
c. PT companies holding a processing business licence, where the company produces fuel oil, and supplies and distributes fuel oil and/or trades fuel oil as an extension of its processing business.

Companies that must pay a royalty on transmitting natural gas are:

a. PT companies holding the natural gas transmission through pipeline business licence at the transmission section and/or distribution network area that has owned the special right;
b. PT companies holding a fuel oil limited trading business licence; and
c. PT companies holding a processing business licence, where the company produces fuel oil, and supplies and distributes fuel oil and/or trades fuel oil as an extension of its processing business.

Sanctions

Any late payment of royalties is subject to a 2% penalty.

Tariff

The royalty must be settled on a monthly basis, and is calculated as follows (pursuant to GR No. 48/2019):

Table 6.3 - Royalty tariffs calculated in accordance to GR No. 48/2019

Volume level per annum	Percentage amount
Fuel oil sales	
Up to 25 million kilolitres	0.25% of the selling price
25 million – 50 million kilolitres	0.175% of the selling price
Over 50 million kilolitres	0.075% of the selling price
Gas transmission	
Up to 100 billion standard cubic feet	2.5% transmission tariff per one thousand standard cubic feet
Over 100 billion standard cubic feet	1.5% transmission tariff per one thousand standard cubic feet

Source: GR No. 48/2019
*GR No. 48/2019 has been revoked per 18 March 2025

6.3 Commercial considerations

When reviewing a potential downstream asset, investors should consider a number of commercial considerations, including the following:

Table 6.4 - Commercial considerations for investors when reviewing potential downstream asset

Topics	Issues
Land rights	• The land where a pipeline is located may not be acquired/owned. • The process of land registration is time-consuming and subject to GRs. • Land ownership may be disputed and/or overlap with Government-protected forest areas, or with other businesses' concession rights (e.g., timber, plantation or mining). • Any transfer of land and building rights attracts a duty of 5% of the land value.
Valuation of underlying fixed assets and inventory	• Asset costs may be subject to mark-up. • Equipment may not be in good condition, so the Net Book Value (NBV) may not reflect its market value. • The underlying assets may not have been formally verified. Lack of fixed asset and physical inventory verification increases the risk of non-existence. • Special accounting rules apply for turnaround costs. • There could be contractual or legal obligations for asset retirement. • Asset validity (including any assets pledged as collateral) may need to be verified. • The deductibility of shareholders' expenditure (e.g. feasibility study, etc.) incurred before the establishment of the project company may be scrutinised by the DGT. • Unutilised tax depreciation expenses for fixed assets may exist if the project life is less than the tax useful life.

Topics	Issues
Underlying regulations and permits	• Some of the downstream-related regulations, especially those relating to the rights of access, taxation and tariff structure, are in a transitional stage. • There are no customs regulations supporting storage activities. There could be import taxes and duties leakage, especially for liquid products. • The requirement to share storage facilities needs to be defined in more detail. • A guarantee by a trading business to have a product constantly available to the distribution network needs to be defined, to ensure optimal inventory management. • The requirement to supply to remote areas needs to be clarified.
Stand-by letters of credit	• There is a potential risk of non-payment by a customer if there are no stand-by letters of credit or other credit protection measures in place.
Contractual commitments	• Investors need to assess the impact of the following on their deals: - Gas sales and supply agreements. - Gas transportation agreements. - Take-or-pay obligations. - Ship-or-pay arrangements (including the deferred revenue impact and the correct taxation treatment). - Potential liquidated damages and other exposures (upsides and downsides). - The cash waterfall mechanism. - Avenues for recourse against contractors. - Line-pack gas (treatment, exposures and accounting). - Make-up gas (treatment). - Guaranteed product supply (contract, other arrangements, etc.). - Related-party transactions.
Government relationship	• The Government may intend to control refineries, as has been the case in the past. • Restrictions on the further issue of capital/transfers of shares for a certain period of time. • The Government usually retains the right of first refusal, as well as “tag along” rights, on any future sale. • The requirement to pledge a shareholding to the Government to secure performance may need to be considered. • The form and content of reports to be filed with the MoEMR and regulatory bodies need to be understood. • Further guidance is needed on how private investors will work with the Government in maintaining national strategic oil and fuel oil reserves. • Further guidance is required on how investors may set pricing, and how any subsidy will be paid to investors until the Government fuel subsidy is fully removed. • The designation of trading areas and the requirement to market products in remote areas need further elaboration. • The requirement to distribute to remote areas needs to be further defined. • Expectations of the regulator’s and the Government’s role in the short, medium and long terms need to be understood. • Product pricing restrictions may be applicable in some areas, based on the prevailing GRs.

Topics	Issues
Profitability	• Future operations could be subject to volatility in the supply and prices of key inputs (other than feedstock), e.g. electricity, water, etc. • There may be significant volatility in storage and transportation costs of feedstock and finished product. • Exposures to commodity price movements need to be considered. • Counterparty performance assessments need to be undertaken. • Demand forecasting must be considered. • Operational performance assessment may be needed. • Distortion of trading performance through related-party transactions and other undisclosed arrangements is possible. • Controls and reporting processes need to be undertaken. • A review of the cost structure and impact on overall economics may be required.
Technology	• The licensing arrangements for technology may not have been formalised. • The operators' technical expertise/credit strength may be questionable. • There is a general restriction on the tax deductibility of Research and Development (R&D) expenditure when the R&D activities are not conducted in Indonesia. • Royalty payments to offshore counterparts may attract duty.
Product mix	• The ability to change the product mix and associated costs may be limited. • The contractual commitments associated with the product mix may be significant.
Supply chain	• The continuous availability of feedstock to the refining process is sometimes not secure.
Environmental issues	• Compliance with existing and future environmental regulations (including remediation/abandonment exposures) may be lacking. • Remediation costs for the previous activities of the refinery may be significant. • The environmental impact may need to be considered.
Strategic value enhancement opportunities	• There may be opportunities to improve crude procurement and inbound logistics costs. • There may be opportunities to improve refinery utilisation. • The opportunities to enhance retail outlet throughput may be limited. • Branding and value capture opportunities need to be identified.
Competition	• Prioritising cooperatives, small enterprises and national companies to own/operate transportation and distribution facilities may hinder short-term development due to a lack of operational experience and understanding of the industry, as well as potential capital or financing constraints. • Overall market growth and product-specific demand and supply need to be considered. • Emerging competition in retail market due to liberalisation needs to be assessed.
Other potential taxation issues	• The imposition of WHT on the hire of pipelines. • The imposition of WHT on the hire of oil/gas tanking. • The adoption of a split contract for Engineering, Procurement, and Construction (EPC) contracts can be contested. • The VAT-able status of LNG (now clarified in Chapter 4). • Any related-party transactions (where transactions with a counterparty exceed IDR10 billion in a year) should be supported by transfer pricing documentation which includes an explanation of the nature of transactions, pricing policy, characteristic of the property/services, functional analysis, pricing methodology applied and the rationale for the methodology selected, as well as benchmarking.

Sources: Law No. 22/2001, GR No. 34/2016

6.4 Market developments in Indonesia

6.4.1 Gas pipeline infrastructure

Despite a decline in oil reserves, Indonesia's natural gas reserves are rising. Most research indicates that gas will be Indonesia's fuel for the future. This is also supported by the tremendous growth of the natural gas market in Indonesia over the past decade, which is expected to continue in the coming years. The completion of LNG plants, the arrival of Floating Storage and Regasification Units (FSRUs), and the increasing demand for gas in power generation and transportation have doubled Indonesia's consumption, and it is predicted to keep growing in the future.

Although Indonesia has significant potential in the natural gas sector, substantial investment is needed to develop downstream infrastructure. Building receiving facilities, pipelines and other distribution infrastructure is challenging due to the country's archipelagic shape and land issues. However the opportunities are promising, because the Government aims to encourage households and industries to utilise more natural gas. If natural gas usage increases, infrastructure development will be prioritised. As of now, the construction of a natural gas pipeline for households is included in strategic national projects, and is planned to begin operating this year.

There used to be two major gas pipeline companies: PT Pertamina Gas and PGN. Following the issuance of GR No. 6/2018 and the designation of PT Pertamina (Persero) as the state-owned holding company for oil and gas, the Government's ownership in PGN was transferred to PT Pertamina (Persero) in April 2018. Subsequently, PGN acquired 51% of PT Pertamina Gas shares from PT Pertamina (Persero) in December 2018.

Other gas pipeline companies are privately owned, and their pipelines usually connect to PGN's or Pertagas's main pipelines.

6.4.2 Open access to gas pipelines and gas allocation, utilisation and price

The Government recognises the need to expand its pipeline network to increase gas penetration rates and reduce oil dependency. However, gas marketing development in Indonesia is hampered by slow infrastructure development, limited access to distribution and transmission pipelines, and multiple layers of traders, resulting in high gas prices to end users.

By auctioning new open access gas pipelines, BPH Migas hopes to pave the way for the entire distribution network to adopt open access in due course.

On 25 January 2018, the MoEMR issued Regulation No. 4/2018 (as amended by MoEMR Regulation No. 19/2021) regarding natural gas businesses in downstream oil and gas business activities. This regulation replaced the previous MoEMR Regulation No. 19/2009. This regulation amends the masterplan for the national gas transmission and distribution network, and authorises BPH Migas to put gas transmission sections to tender. The tender winner will have a contract for 30 years, while existing business entities in the distribution network that do not win the tender have the opportunity to continue their business for 15 years, with BPH Migas and the MoEMR monitoring the feasibility and economy of the transmission section results.

Another section of MoEMR Regulation No. 4/2018 abolishes the distribution area system based on the downstream dedicated system in the form of private gas pipes utilised by business entities to transmit their own gas. It sets out provisions on licensing required for engaging in natural gas transmission business activities by pipelines or by using facilities other than pipelines (such as Compressed Natural Gas (CNG) or LNG) in certain transmission segments or distribution network areas, as well as natural gas storage business activities. Holders of special rights in certain distribution network areas are obligated to develop and provide natural gas infrastructure in the form of natural gas pipeline networks. There is also a procedure for natural gas customers to obtain permission to develop and operate natural gas pipelines and supporting facilities for their own interests.

Meanwhile, the provisions and procedures for determining the of allocation, utilisation and price of natural gas are regulated in MoEMR Regulation No. 6/2016:

Table 6.5 - The provisions and procedures on determination of allocation, utilisation and price of natural gas regulated under MoEMR Regulation No. 6/2016

	PerMen No. 6/2016
Order of priorities for gas allocation and utilisation	a. Support the Government's programme to supply natural gas for transportation, households (≤50m^3/month) and small customers (≤100m^3/month); b. Increase national oil and gas production; c. Fertilisers; d. Natural-gas-based industry; e. Electricity; and f. Industries that use gas as fuel.
Buyer	a. State-owned Enterprises (SOEs); b. Regionally Owned Business Entity (Badan Usaha Milik Daerah - BUMD); c. Gas-fired power/electricity companies; d. Companies holding izin usaha niaga gas bumi; e. LPG companies; and f. End-users.
Gas price	Gas price to be approved by the MoEMR through SKK Migas

Source: MoEMR Regulation No. 6/2016

On 29 December 2017, the MoEMR issued Regulation No. 58/2017 which determines gas prices for power plants and households based on three components: gas price, gas infrastructure maintenance costs and commercial costs (7% of gas price) based on proposals from gas producers. Furthermore, on 20 September 2019, the MoEMR issued Regulation No. 14/2019, amending Regulation No. 58/2017, which stipulates that the project economic life assumption for gas infrastructure maintenance cost is 30 years from the first gas price determination. This change may impact the overall economic assessment of the project, as the assumption of a longer useful life may reduce the overall gas price calculation.

The provisions and procedures for determining the allocation and utilisation, as well as the price of flare gas, are regulated under MoEMR Regulation No. 30/2021. According to the regulation, the utilisation of flare gas can be carried out by: (i) business entities which hold a processing business licence and/or natural gas commercial business license; or (ii) Government institutions.

The offering of flare gas to business entities is carried out by SKK Migas, considering the following requirements and criteria:

a. Offering price;
b. Investment commitment;
c. Onstream period;
d. Implementation guarantee (amounting to 1% of the investment value);
e. Annual tax payment receipt; and
f. An application letter.

Furthermore, MoEMR Regulation No. 30/2021 provides that the MoEMR will determine the sales price of flare gas for business entities in accordance with the proposal from SKK Migas. On the other hand, if the flare gas is sold to Government institutions, the maximum sale price is USD0.35/Milion British Thermal Unit (MMBTU).

Documents to be submitted by the oil and gas contractors to obtain allocation:

Referring to Chapter V of MoEMR Regulation 6/2016, there are certain summarised requirements that must be met, as follows:

1. The contractor applies for the allocation and utilisation of natural gas for domestic demand to the MoEMR, through SKK Migas.
2. For domestic sales, documents to be included are:
   - a Plan of Development (PoD) and supporting documents; or
   - if a PoD is not yet obtained, a reserves report and production profile, the results of production tests, any production facility, gas deliverability, estimation of production split; and
   - other documents explaining the potential gas buyers, gas volume and infrastructure for the distribution.
3. For exports, documents to be included should explain potential buyers, volumes, infrastructure or delivery methods, and a timeline for deliveries.
4. For new allocations, SKK Migas must submit the application to the Minister 60 days before delivery time.

5. For extensions, the contractor or gas buyer, through SKK Migas, needs to propose the new gas allocation and utilisation to the MoEMR at least six months before the end of the existing gas sales agreement.
6. For increases in volume, the contractor or gas buyer needs to submit a proposal/ request to the MoEMR, as per regulation.

The contractor needs to propose a new gas price at least three months before the termination date of the existing gas sales agreement. If the contractor wants to propose an additional gas allocation and utilisation agreement, the contractor needs to submit a proposal to the MoEMR, as per regulation. The gas price used in the contract is determined by the MoEMR. In addition, the gas purchase contract must include an additional clause regarding the price review.

Requirements for the contractor to propose a gas price to the MoEMR:

1. Proposed price of gas and the price formula justification;
2. Economic value of gas;
3. Gas resources, distribution and delivery principle, volume in the contract, delivery place per contract, period of distribution, estimated volume of gas distributed daily;
4. Copy of approval from the MoEMR on allocation and utilisation of gas;
5. Copy of approval PoD and supporting documents;
6. Statistics regarding domestic and international gas prices;
7. Copy of the negotiation on price of gas document; and
8. Copy of the contract to purchase and sell gas.

Photo source: PwC

7 Service providers to the upstream sector

7.1 Equipment and services – General

As discussed in Chapters 4, 5 and 6, the Government and SKK Migas set the guidelines and make the final decision on large purchases of most equipment and services provided to the upstream sector.

Purchases by Joint Cooperation Contracts (JCCs) are effectively Government expenditure (except for Gross Split production Sharing Contracts (GS PSCs)) and generally must be provided by a local limited liability company. Foreign companies wishing to sell upstream equipment or render services must therefore comply with the strict procurement rules set out under SKK Migas Guidance Work Procedure Guidelines (PTK 0120) on Goods and Services Procurement Guidelines, as lastly amended in 2018, and the oil and gas services activities guidance under MoEMR Regulation 14/2018. However, the recent SKK Migas Guidance PTK 066 regarding Gross Split (GS) may imply that PTK 0120 only applies to the conventional Production Sharing Contract (PSC), while the procurement activities for GS PSC will be self-managed.

MoEMR Regulation No. 14/2018 requires oil and gas supporting businesses to conduct registration to obtain an oil and gas supporting business capacity certificate (Supporting Business Capability Letter - SKUP) for oil and gas supporting business capacity development and improvement. The SKUP is classified into oil and gas construction services, oil and gas non-construction services, and oil and gas supporting industry. The previous registration certificate has been abolished by the MoEMR, while the issuance of SKUP that previously required ten days is shortened to three days after all documentations and requirements are fulfilled (the issuance process may take more days in practice). The documents required to obtain SKUP can be found in the attachment of MoEMR Regulation 14/2018.


Photo source: PwC

7.2 Tax considerations – general

Goods and services provided to PSC contractors are taxed according to Indonesian tax laws, similar to those applicable in the broader context (refer to the PwC Pocket Tax Guide published annually and accessible at http://www.pwc.com/id). Some exemptions exist for oil field service providers concerning import taxes (Article 22 Income Tax, Value Added Tax (VAT) and import duty).

In the past, service providers benefited from a PSC client's master list facility. Please see our discussion in Section 4.4.8 for an explanation of the master list facility.

Tax audits on service providers have intensified, leading to the establishment of the Oil and Gas Tax Office. This office is now the consolidation point for PSC taxpayers and numerous oilfield service providers.

Transfer pricing is increasingly under scrutiny for oilfield service providers, leading to frequent annual tax audits.

If service providers operate as Indonesian entities, a debt-to-equity limitation of 4:1 (see Section 6.2.1 regarding General Overview of Thin Capitalisation) applies.

Please also note that pursuant to PMK-136, Pillar Two policy would apply to Multinational Enterprises (MNEs). The implications of this policy may not be straightforward and is expected to require a detailed case-by-case analysis. Further developments in this area should be closely monitored.

7.3 Taxation of drilling services

A positive investment list (previously known as a negative investment list) is provided under Presidential Regulation (PR) 10/2021 (as lastly amended by PR 49/2021).
In relation to drilling services, Foreign Investment (*Penanaman Modal Asing* - PMA) entities have no certain restrictions on maximum foreign shareholding.

For further investment restrictions in the oil and gas industry see Section 3.2.3.

7.3.1 Foreign-Owned Drilling Companies (FDCs)

FDCs have historically carried out their drilling activities in Indonesia via a branch or Permanent Establishment (PE) for Indonesian tax purposes. The taxation regime that applies to FDC PEs is outlined below:

a. The PE of an FDC is subject to a general corporate income tax rate based on a deemed profit percentage of 15% of drilling income (resulting in an effective corporate income tax rate of 3.3% assuming a 22% tax rate), plus a 20% Branch Profits Tax (BPT).
b. The 20% BPT rate may be reduced under a relevant tax treaty. A Certificate of Domicile (CoD) is required to claim the benefit of any tax treaty (refer to the new CoD form and the requirements of Director General of Taxes Regulation No. 25 of 21 November 2018).
c. Drilling income is generally accepted as the FDC "day rate" income received. Reimbursements and handling charges (including mobilisation and demobilisation) may not be taxable

income, depending on whether a de minimis threshold test is exceeded. The test is generally applied on an annual rather than a contractual basis.

d. Other non-drilling income, such as interest, is subject to tax at normal rates.

7.3.2 Indonesian drilling companies

Unlike an FDC, Indonesian and PMA drilling companies are taxed on actual revenues and costs, and are subject to an income tax rate of 22%. The drilling services they provide also currently attract Withholding Tax (WHT) at 2%, which represents a prepayment of their tax. Any imports of consumables or equipment by the drilling companies will generally attract Article 22 tax at 2.5%, which represents a further prepayment of their annual income tax bill.

7.3.3 VAT and WHT

The provision of drilling services is subject to VAT, with PSC companies acting as the VAT collectors. This implies that the output VAT of the drilling service entity is directly remitted to the Tax Office by the PSC companies. Consequently, many service providers may find themselves in a perpetual VAT refund position. However, it is important to note that this VAT is technically refundable only after a Tax Office audit.

7.3.4 Labour taxes

Foreign nationals working for an FDC and becoming residents for tax purposes are generally subject to Article 21 – Employer WHT on a deemed salary basis, as published by the Indonesian Tax Office (ITO). However, individual tax returns should still be filed based on the individual's actual earnings.

For rotators or non-resident expatriate staff, it may be possible to file an Article 26 WHT return (i.e., as a non-resident of Indonesia) regarding tax withheld from their salary, resulting in a tax rate of 20%.

Note that lodging a monthly Article 21 Tax Return for staff does not exempt individuals from registering for an Indonesian Taxpayer Identification Number (NPWP) and filing an Indonesian individual tax return.

7.4 Shipping/Floating Production Storage and Offloading (FPSO) and Floating Storage and Offloading (FSO) services

Large crude carriers/tankers are engaged to ship oil from Indonesian territorial waters to overseas markets. Similarly, LNG carriers carry LNG cargo from the Bontang and Tangguh plants. Converted tankers are also used as FPSO or FSO vessels.

The shipping industry is heavily regulated. Both local and international shipping is open to foreign investment through a PMA company with a maximum foreign shareholding of 49%, as confirmed in the positive investment list Indonesian Shipping Law No. 17/2008 (as lastly amended by Law No. 66/2024) generally adopted the cabotage principles first introduced by Minister of Transportation Regulation No.71/2005 (as amended by Minister of Transportation Regulation No. 73/2010).

These regulations oblige the use of Indonesian flagged vessels for local shipping from 1 January 2011. Foreign-flagged vessels for specific types of activities can obtain permission in the form of a Permit to Use Foreign Ships (*Izin Penggunaan Kapal Asing* - IPKA) issued by a holder of a Shipping Company Business Licence (*Surat Izin Usaha Perusahaan Angkutan Laut* - SIUPAL). Exempted activities include oil and gas surveys, drilling, offshore construction and operational support, dredging, and salvage and underwater work. Exempted ships for drilling are jack-up rigs, jack-up barges, self-elevating drilling units, semi- submersible rigs, deepwater drill ships, and tender assist rigs. Ships for oil and gas geophysical, geotechnical and seismic (with electromagnetic or broadband triple source) survey activities are also exempted based on this regulation. The permit for these ships can be obtained by satisfying the requirements set out in the Minister of Transportation regulation.

Although the current positive investment list does not specifically regulate FPSO/FSO operations, the Department of Sea Transportation considers these operations as shipping activities, requiring a shipping licence. Licensing as a shipping company presents investment and ownership challenges. Note that Shipping Law No. 17/2008, lastly amended by the Job Creation Law, mandates that only a company majority-owned by an Indonesian entity can register an Indonesian-flagged vessel. Therefore, a foreign shareholder holding a 95% interest would not be eligible to register as an owner of an Indonesian- flagged vessel and consequently obtain a shipping licence to operate the FPSO/FSO.

7.4.1 Taxation of shipping/FPSO/FSO service providers

Export cargos

Shipping involves the provision of services and is subject to a WHT on the fees generated. The relevant WHT rates are generally:

a. domestic (Indonesian incorporated) shipping companies – taxed at 1.2% of gross revenue; and
b. foreign shipping companies - taxed (final) at 2.64% of gross revenue.

In this regard:

a. the above WHT rates are only applicable to gross revenue from the “transportation of passengers and/or cargo” loaded from one port to another and, in the case of a foreign shipping company, from the Indonesian port to a foreign port (not vice versa);
b. the 2.64% regime presumes that the foreign shipping company has a PE in Indonesia;
c. it may not be possible to take advantage of a tax treaty to reduce Branch Profit rate (BPR) rates;
d. it is unclear whether this (final) WHT rate can be reduced to reflect the recently reduced corporate tax rate (i.e., 28% for 2009, 25% for 2010 - 2019 and 22% for 2020 and onward);
e. tax treaties have specific shipping articles – which may be relevant;
f. Bare-boat Charter (BBC) rentals (i.e., with no service component) might instead be subject to 20% WHT (before tax treaty relief); and
g. BBC payments may alternatively be characterised as royalties.

With regard to VAT:

a. shipping services that include an element of Indonesian “performance” (i.e., being performed within the Indonesian Customs Area) are technically subject to VAT. This is the case irrespective of whether the shipping company has a PE, and irrespective of whether the client is an Indonesia-based entity, or an offshore entity;
b. a VAT exemption may be available if it can be argued that the services involve only a small proportion of Indonesian presence/performance and should thus be viewed as entirely ex-Indonesia (i.e., as entirely international); and
c. shipping services provided entirely outside of Indonesia (say under a separate international contract) may avoid VAT on a “performance” basis. However, VAT could still arise on a self-assessment basis where the services are “utilised” within Indonesia. Whilst “utilised” is not well defined, in practice the ITO deems this to occur in cases where the shipping costs are charged to Indonesia.

FPSO/FSO/FSRU, and other services

Traditionally, many PSC entities have classified their FPSO/ FSO service providers as shipping companies, allowing them to fall under the 1.2%/2.64% tax regime. However, the current perspective suggests that such services do not qualify as transportation or shipping services and should instead be subject to the general tax law provisions.

On 10 December 2019, the MoF issued MoF Regulation No. 186/PMK.03/2019 (PMK-186) regarding the Land and Building Tax (PBB), which includes an updated classification of “tax objects” for the imposition of PBB. PMK-186 became effective on 1 January 2020.

Under PMK-186, the definition of “land” now is clarified to include Indonesian waters used for storage and processing facilities and thereby extending to the various categories of vessels used on the waters.
Furthermore, the definition of “buildings” is also clarified to include technical construction planted or attached permanently on “land” within Indonesian waters. This includes, among other things, the processing facilities such as an FSO, Floating Production System (FPS), Floating Production Unit (FPU), Floating Storage System (FSU), FPSO and FSRU.

PMK-186 has therefore formally confirmed the imposition of PBB on typical vessels such as those used for FSO, FPU, FSRU, etc., which is consistent with the Directorate General of taxes (DGT)’s position during past tax audits.

Despite the issuance of PMK-186, tax disputes persist with the DGT, as taxpayers argue that these vessels should not be subject to PBB, considering their nature as vessels rather than "buildings." PMK-186 remains in effect as of the current writing, with no amendments or revocations to date.

7.5 Tax treatment on joint operation (particularly relevant to construction services)

The MoF issued PMK-79/2024 (PMK-79) providing detailed implementation directives on the tax treatment of a Joint Operation (JO). According to PMK-79, a JO is defined as an entity formed through a joint arrangement between members who have joint control or rights towards assets and obligations towards liabilities, regardless of its name and form.

A JO must be registered as a separate corporate taxpayer (i.e., obtain NPWP and VAT-able entrepreneur (*Pengusaha Kena Pajak*) if the agreement or implementation stipulate that the JO will deliver goods/services, receive income, and/or incur costs or make payments to other parties in the name of the JO. Historically, this was known as administrative JO.

The key provisions outlined under this PMK are as follows:

a. Corporate Income tax (CIT) applies at the level of the JO and its members
    i. General CIT regime: Business-related costs (including those incurred based on each member's contribution) are deductible for tax calculation at the JO level. Correspondingly, such costs are treated as income at JO members' level. Any tax loss balance can only be utilised at the level where the losses are incurred. PMK-79 indicates that the tax losses recognised at the JO members level may also include losses originating from expenses outside the JO agreement;
    ii. Final Income Tax (FIT) regime: For certain business activities under this regime (e.g., construction), business-related costs are not deductible at both the JO and JO members level. Each member's contribution being charged to the JO is subject to FIT. There is no tax loss to be utilised by either JO and JO members;
b. PMK-79 appears to trigger a "double tax" imposition for income under the FIT regime. This is because the JO's income is subject to FIT upon charging customers and the contributions of the JO members charged to the JO are also subject to FIT, with no room to claim any deductible expenses at the JO members' level;
c. The JO is subject to the generally applicable WHT which can be claimed as tax credits in its CIT calculation;
d. For JOs generating income from construction services, the WHT rate shall use the highest WHT rate applicable to its members. This creates complications when the JO comprises members subject to different FIT rates (e.g., due to different classifications). The JO member with the (technically) lower FIT rate would indirectly bear the impact of the higher FIT expense imposed at the JO;
e. JO members' contributions received by the JO are not subject to WHT (unless the member is a foreign taxpayer, in which case Article 26 WHT applies). The JO members shall instead calculate such income under the general CIT calculation or self-remit the FIT; and

f) For VAT purposes, the JO is required to be registered as a VAT-able entrepreneur once one of the JO members has been registered as a VAT-able entrepreneur. The rules for crediting input VAT, payment and reporting obligations still follow the general rules.

It has been observed that there have been different reactions from industry players to the issuance of PMK-79. Therefore, any developments (including further implementing regulations issued by the DGT) should be closely monitored.

Please refer to our TaxFlash Vol. 13/2024 for a more detailed discussion on this.


Photo source: PwC

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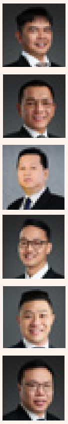

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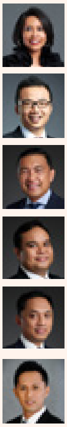

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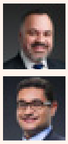

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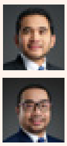

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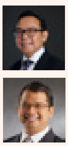

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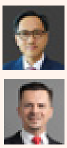

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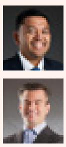

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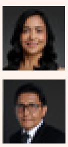

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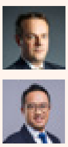

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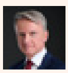

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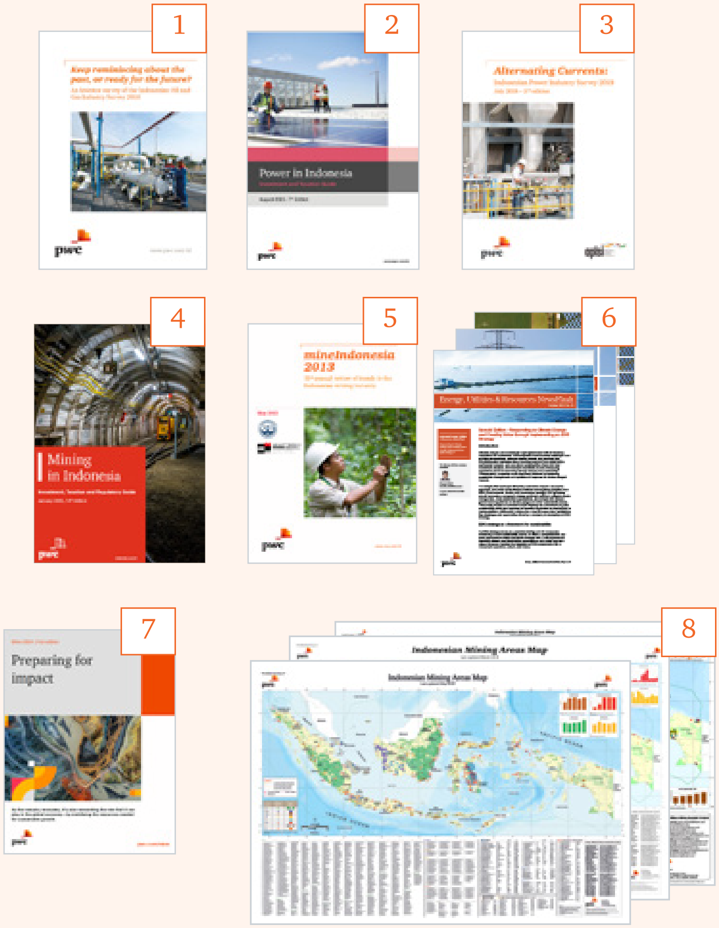

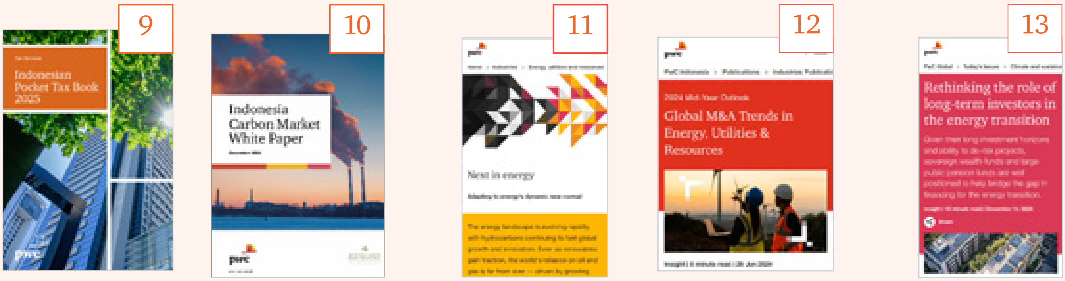

Endnotes

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