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Oil and Gas in Indonesia

Investment, taxation, and regulatory guide

May 2026, 15th Edition

www.pwc.com/id

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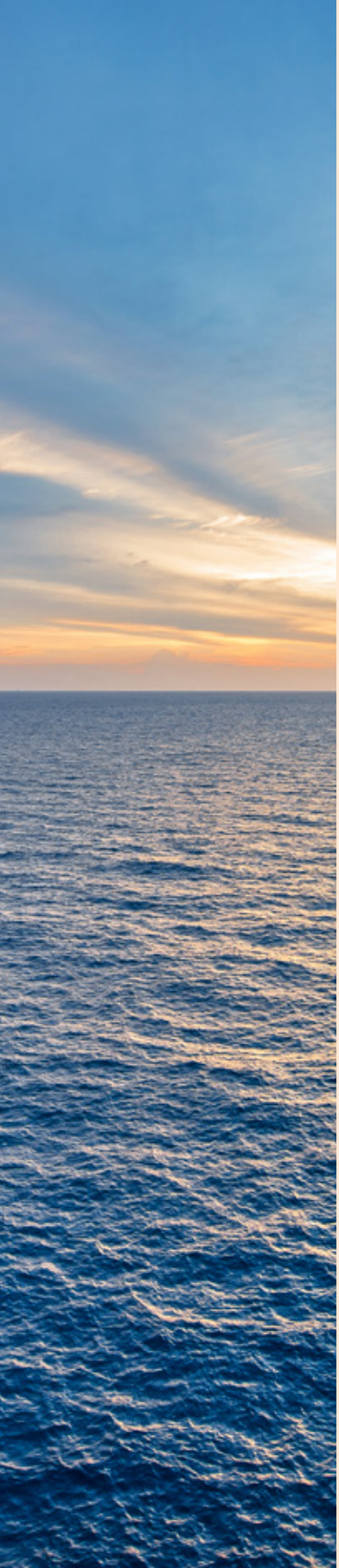
Regulatory information is current to 28 February 2026.



Contents

Glossary

Term	Definition
2W	Two-wheeler
4W	Four-wheeler
ADB	Asian Development Bank
AFE	Authorisation for Expenditure
APBN	State budget (*Anggaran Pendapatan dan Belanja Negara*)
APDN Book	Domestic Product Appreciation Book (*Buku Apresiasi Produk Dalam Negeri*)
ASC	Accounting Standard Codification
ATIGA	ASEAN Trade in Goods Agreement
BBC	Bare-boat charter
BBTUD	Billion british thermal units per day
bcm	Billion cubic metres
BCFD	Billion cubic feet per day
BCPD	Barrels of condensate per day
BI	Bank Indonesia
BiK	Benefits in kind
BKPM	Investment Coordinating Board (*Badan Koordinasi Penanaman Modal*)
BOPD	Barrels of oil per day
BP Migas	Executive Agency for Upstream Oil and Gas Business Activities (*Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi*)
BPDPKS	Palm Oil Plantation Fund Management Agency (*Badan Pengelola Dana Perkebunan Kelapa Sawit*)
BPH Migas	Downstream Oil and Gas Regulatory Agency (*Badan Pengatur Hilir Minyak dan Gas Bumi*)
BPKP	Financial and Development Supervision Agency (*Badan Pengawasan Keuangan dan Pembangunan*)
BPMA	Aceh Oil and Gas Management Agency (*Badan Pengelola Migas Aceh*)
BPT	Branch profit tax
BUIC	Banyu Urip Infill Clastic
BUK Migas	Special Business Entity for Oil and Gas (*Badan Usaha Khusus Minyak dan Gas Bumi*)
BUMD	Regionally-owned enterprise (*Badan Usaha Milik Daerah*)
C&D	Corporate and dividend
CAAS	Civil Aviation Authority of Singapore
CAGR	Compound annual growth rate
CCS	Carbon capture and storage
CCUS	Carbon capture utilisation and storage
CCUS-EOR	Carbon capture utilisation and storage on enhanced oil recovery
CD	Community development
CEOR	Chemical enhanced oil recovery
CGK	Soekarno-Hatta airport, Tangerang, Banten
CIF	Cost, insurance, freight

Term	Definition
CIT	Corporate income tax
CITR	Corporate income tax return
CO_2	Carbon dioxide
CO_2eq	Carbon dioxide equivalent
COD	Commercial operation date
CoD	Certificate of Domicile
COP30	The 30th edition of the Conference of the Parties
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
CPO	Crude palm oil
CRMS	Climate Risk Management and Scenario Analysis
DEN	National Energy Council (*Dewan Energi Nasional*)
DGB	Directorate General of Budget
DGoCE	Directorate General of Customs and Excise
DGoG	Directorate General of Oil and Gas
DGT	Directorate General of Taxes
DHE SDA	Foreign exchange proceeds from exports of natural resources (*Devisa Hasil Ekspor Sumber Daya Alam*)
DJKN	Directorate General of State Assets (*Direktorat Jenderal Kekayaan Negara*)
DMO	Domestic market obligation
DPR	House of Representatives (*Dewan Perwakilan Rakyat*)
DPS	I Gusti Ngurah Rai Airport, Denpasar, Bali
ECA	Export credit agency
EOR	Enhanced oil recovery
EP/E&P	Exploration and production
EPC	Engineering, Procurement, and Construction
ESG	Environmental, social, and governance
ET	Energy transition
EV	Electric vehicle
FDC	Foreign-owned drilling company
FEED	Front-end engineering design
FGE	Fuel-grade ethanol
FIT	Final income tax
FMR	Financial Monthly Report
FMV	Fair market value
FOB	Free on board
FPS	Floating production system
FPSO	Floating production storage and offloading
FPU	Floating production unit
FQR	Financial Quarterly Report
FS	Feasibility study
FSO	Floating storage and offloading
FSRU	Floating storage and regasification unit
FSU	Floating storage system

Term	Definition
FTP	First Tranche Petroleum
G&G	Geological & geophysical
GAAP	Generally Accepted Accounting Principles
GDP	Gross domestic product
GHG	Greenhouse gas
GR	Government Regulation
GS	Gross split
HACPO	High acid crude palm oil
HEFA	Hydroprocessed esters and fatty acids
HPP	Harmonisation of Tax Regulations (*Harmonisasi Peraturan Pajak*)
HS	Harmonised System
ICAO	International Civil Aviation Organisation
ICP	Indonesian crude price
IDD	Indonesia Deepwater Development
IFAS	Indonesian Financial Accounting Standards
IFRS	International Financial Reporting Standards
IPA	Indonesia Petroleum Association
IPKA	Permit to use foreign ships (*Izin Penggunaan Kapal Asing*)
ITL	Income Tax Law
ITO	Indonesian Tax Office
JCC	Joint cooperation contract
JO	Joint operation
JOB	Joint operating body
KBLI	Standard Classification of Business Fields (*Klasifikasi Baku Lapangan Usaha Indonesia*)
KEN	National Energy Policy (*Kebijakan Energi Nasional*)
KPP Migas	Oil and Gas Tax Office (*Kantor Pelayanan Pajak Minyak dan Gas Bumi*)
KUFPEC	Kuwait Foreign Petroleum Exploration Company
LLP	Low Low Pressure
LNG	Liquefied natural gas
LP	Low Pressure
LPEI	Indonesian Export Financing Agency
LPG	Liquefied petroleum gas
MBOPD	Thousand barrels of oil per day
MIR	MoF interest rates
MMBOPD	Million barrels of oil per day
MMBTU	Million British thermal units
MMSCFD	Million standard cubic feet per day
MNC	Multinational corporation
MNE	Multinational enterprise
MoEMR	Ministry of Energy and Mineral Resources
MoF	Ministry of Finance
MoT	Ministry of Trade

Term	Definition
MoU	Memorandum of Understanding
MSME	Micro, small, and medium enterprise
MTOE	Million tonnes of oil equivalent
Mton	Million tonnes
MTPA	Million tonnes per annum
NBV	Net book value
NDC	Nationally Determined Contribution
NEK	National Economic Value of Carbon (*Nilai Ekonomi Karbon*)
NIB	Business identification number (*Nomor Induk Berusaha*)
NJOP	Tax Object Selling Value (*Nilai Jual Objek Pajak*)
NPWP	Tax ID number (*Nomor Pokok Wajib Pajak*)
NRE	New and renewable energy
NZE	Net zero emissions
O&G	Oil and gas
OJK	Financial Services Authority
ONWJ	Offshore Northwest Java
OPEC	Organisation of the Petroleum Exporting Countries
OSS	Online Single Submission
p.a.	Per annum
PBB	Land and building tax (*Pajak Bumi dan Bangunan*)
PBBR	Risk-Based Business Licensing (*Perizinan Berusaha Berbasis Risiko*)
PBI	Bank Indonesia Regulation (*Peraturan Bank Indonesia*)
PCO	Parent company overhead
PE	Permanent establishment
Permenko Eko	Coordinating Minister for Economic Affairs Regulation (*Peraturan Menteri Koordinator Bidang Perekonomian*)
PFAD	Palm fatty acid distillate
PGN	PT Perusahaan Gas Negara
PHE	PT Pertamina Hulu Energi
PHM	PT Pertamina Hulu Mahakam
PHR	PT Pertamina Hulu Rokan
PI	Participating interest
PIS	Placed into service
PLN	Perusahaan Listrik Negara
PMA	Foreign investment (*Penanaman Modal Asing*)
PoD	Plan of development
POME	Palm oil mill effluent
PP&E	Property, plant, and equipment
PPE	Export customs declarations (*Pemberitahuan Pabean Ekspor*)
PPKH	Forest Area Utilisation Approval (*Persetujuan Penggunaan Kawasan Hutan*)
PPnBM	Luxury goods sales tax (*Pajak Penjualan atas Barang Mewah*)
PR	Presidential Regulation (*Peraturan Presiden*)
PSC	Production sharing contract

Term	Definition
PSN	National Strategic Project (*Proyek Strategis Nasional*)
PT	Limited liability company (*Perseroan Terbatas*)
PTK	Work Procedure Guideline (*Pedoman Tata Kerja*)
R&D	Research and development
R/E	Retained earnings
RDMP	Refinery Development Master Plan
RE	Renewable energy
RHAN	National Hydrogen and Ammonia Roadmap (*Roadmap Hidrogen dan Amonia Nasional*)
RPJMN	National Medium-Term Development Plan (*Rencana Pembangunan Jangka Menengah Nasional*)
RPJPN	Long-Term Development Plan (*Rencana Pembangunan Jangka Panjang Nasional*)
RPT	Risk participation transaction
RPTKA	Foreign Workers Utilisation Plan (*Rencana Penggunaan Tenaga Kerja Asing*)
RRR	Reserve replacement ratio
RTO	Regional tax office
RUKN	National Electricity General Plan (*Rencana Umum Ketenagalistrikan Nasional*)
RUPTL	National Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik*)
SAF	Sustainable aviation fuel
SA-VAT	Self-assessed VAT
SE	Circular Letter (*Surat Edaran*)
SKB	Tax Exemption Declaration Letter (*Surat Keterangan Bebas*)
SKFP	GS Tax Facilities Letter (*Surat Keterangan Fasilitas Perpajakan GS*)
SKK Migas	Special Task Force for Upstream Oil and Gas Business Activities (*Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi*)
SKUP	Supporting business capacity certificate (*Surat Kemampuan Usaha Penunjang*)
SNDC	Second Nationally Determined Contribution
SOE	State-owned enterprise
SPOP	Notification of PBB Objects (*Surat Pemberitahuan Objek Pajak*)
SPPT	Official Tax Payable Notification (*Surat Pemberitahuan Pajak Terutang*)
SSP	Tax Payment Slip (*Surat Setoran Pajak*)
SWPG	Sepinggan West Platform Gas
TAC	Technical assistance contract
Tcf	Trillion cubic feet
TKBI	Indonesia Sustainable Finance Taxonomy (*Taksonomi untuk Keuangan Berkelanjutan Indonesia*)
TKDN	Local content (*Tingkat Komponen Dalam Negeri*)
UCC	Ubadari CCUS and Compression
UCO	Used cooking oil
UoP	Units of production
US	United States
USD	US dollar
UU	Law (*Undang-Undang*)

Term	Definition
VAT	Value added tax
WAP	Weighted average price
WHT	Withholding tax
WP&B	Work Programme and Budget

Foreword

Welcome to the 15th edition of our “Oil and Gas in Indonesia: Investment, taxation, and regulatory guide”.

The global energy landscape continues to evolve rapidly. While the transition towards cleaner and more sustainable energy systems is progressing, oil and gas remain essential to meeting global energy demand—particularly across emerging markets in Asia. At the same time, geopolitical developments continue to shape supply dynamics and market stability. Recent United States policy actions influencing oil supply from Venezuela, alongside ongoing tensions in the Middle East involving Iran and associated risks to key transit routes, have reinforced the importance of energy security and supply diversification. This transition is therefore unfolding amid economic uncertainty, geopolitical tensions, and evolving regulatory expectations, adding further complexity for industry participants.

Against this backdrop, Indonesia’s upstream oil and gas sector continues to face structural challenges. Natural decline in mature producing fields, limited new reserve discoveries, and relatively subdued exploration activity have contributed to a more cautious investment outlook. In recent years, a number of international oil companies have rationalised their portfolios, reflecting broader considerations around project economics, contract terms under production sharing contract (PSC) arrangements, regulatory processes, and the overall pace of investment realisation. Notwithstanding these challenges, Indonesia continues to hold significant resource potential, and increasing upstream oil and gas business activities remains a national priority.

Recent policy and regulatory developments reflect an evolving, though still challenging, investment environment. The Government has introduced a range of measures aimed at improving PSC fiscal terms and contract flexibility, including continued refinements to both cost recovery and gross split (GS) PSC mechanisms to better align risk allocation and project economics. In parallel, initiatives supporting emerging areas such as carbon capture and storage (CCS) have been introduced. However, contractors and investors continue to highlight challenges relating to regulatory consistency, as well as the complexity of permitting and licensing processes across multiple government agencies at various

stages of oil and gas operations. In this context, sustained government commitment, policy clarity, and more streamlined cross-agency coordination will be critical to strengthening Indonesia's attractiveness for upstream investment—particularly in securing long-term capital for large-scale and technically complex developments such as the Indonesian deepwater projects, the Andaman Basin, and the Masela block. Progress on these projects will serve as an important indicator of Indonesia's competitiveness in the global upstream investment landscape.

Downstream, Indonesia continues to prioritise energy security and diversification through the expansion of biofuel mandates and increased domestic gas utilisation. These initiatives are intended to reduce reliance on imports and support the development of a more resilient and sustainable national energy system.

This guide provides an overview of these developments and their implications for investors and industry participants across Indonesia's oil and gas value chain. It is intended to support informed decision-making in an increasingly complex and dynamic operating environment.

This publication is intended as a general guide only. As regulatory requirements and interpretations continue to evolve, readers are encouraged to seek up-to-date professional advice tailored to their specific circumstances. All regulatory information in this edition is current as of 28 February 2026.

We hope you find this guide useful as Indonesia's oil and gas sector continues to evolve.

1 Industry overview

1.1 Global oil and gas overview

The global energy landscape continues its shift towards cleaner and more sustainable sources, creating a complex operating environment for oil and gas markets. This transition unfolds against a backdrop of subdued economic activity, tighter trade restrictions, and persistent policy uncertainty, all of which continue to shape commodity markets. Together, these factors have contributed to heightened volatility, particularly impacted by the uncertainty arising from conflict in the Middle East and the resulting impact on global oil and gas supply chains. Compounding these pressures, weather-related and climate-driven events further strain energy supply and demand, intensifying the challenges faced by the oil and gas sector[1].

Oil supply-demand

On the supply side, global oil supply growth in 2024 was relatively modest, with most incremental volumes attributable to producers outside the Organisation of the Petroleum Exporting Countries (OPEC). The United States (US) continued to act as the primary source of additional supply, further consolidating its leading role in global oil output[2].

By the first quarter of 2025, global oil production had risen to 103.2 million barrels of oil per day (MMBOPD)[4,5], despite winter-related disruptions in Canada and the US[3]. Supply, however, rebounded in February and March, as OPEC and several non-OPEC members (OPEC+) such as Kazakhstan, Iran, and Venezuela increased production[5].

This rebound set the stage for a stronger surge throughout the third quarter, when global oil output climbed to 106.8 MMBOPD[6,7,8]. Both OPEC+ and non-OPEC+ producers contributed to this expansion. July output held steady as declines in some OPEC+ countries were offset by gains in others[6]. In August, production hit a new record as OPEC+

producers continued rolling back previous cuts, while non-OPEC+ producers operated near peak capacity[7]. Additional supply growth in September, particularly driven by the Middle East, made the third quarter the high point for annual production gains[8].

Following this peak, the upward trend in global oil output began to reverse in the fourth quarter. Despite remaining at near-record highs of 108.1 MMBOPD[1], October marked the start of declining OPEC+ countries' output[9]. The contraction accelerated in November, largely due to sanctions affecting Russian and Venezuelan production[10], and December recorded a further dip despite a partial recovery in Russian supply[11]. Looking ahead, however, global oil supply is projected to stay robust, potentially reaching 108.5 MMBOPD by 2026. Much of this future growth is expected to be driven by non-OPEC+ producers, highlighting their rising influence in the global oil landscape[1].

On the demand side, oil remained the single largest energy source globally, accounting for 34% of total energy use in 2024. Global oil demand increased by 0.7%, exceeding 101 MMBOPD for the first time[2].

This upward trend continued into the first quarter of 2025, with worldwide oil consumption rising to 102.5 MMBOPD[1], supported by modest recoveries in China and advanced economies. In China, demand grew by 0.2 MMBOPD, although overall gains were tempered by strong electric vehicle adoption. Advanced economies saw slight demand improvements, while other Asian markets outside China and South Asia continued to play a major role in global oil consumption[3].

By the third quarter of 2025, global oil demand had climbed further to 104.8 MMBOPD[1]. Even so, annual consumption in China and advanced economies—together accounting for roughly 60% of global demand—remained broadly unchanged throughout 2025. Demand growth in regions such as Europe and Central Asia, Latin America and the Caribbean, and South Asia is expected to slow, while most other emerging and developing regions are likely to maintain steady demand. Sub-Saharan Africa stands out as an exception, where a rebound in oil consumption is anticipated[1].

India remained a key contributor to global oil demand growth in 2025, driven by increased use of liquefied petroleum gas (LPG) and gasoline. China and India are expected to continue underpinning global demand growth in 2026, although China's expansion will remain constrained by its accelerating shift toward electric and hybrid vehicles. In contrast, demand in advanced economies is projected to remain largely flat. As a result, the global oil market is expected to experience only moderate consumption growth as it moves through 2025 and into 2026, further widening the gap between supply and demand[1]. Looking ahead, the International Energy Agency anticipates that global oil consumption will reach approximately 104.4 MMBOPD by 2026[6].

In January 2026, before the outbreak of the US-Iran conflict, global oil markets were already navigating supply challenges. World oil supply had decreased by 1.2 MMBOPD to 106.6 MMBOPD, as severe winter weather disrupted North American operations while outages and export constraints curtailed Kazakh, Russian, and Venezuelan flows[12].

This fragile balance deteriorated sharply following the eruption of the US-Iran conflict on 28 February, which fundamentally shattered this outlook and triggered what became the largest supply disruption in the history of the global oil market. By early March, the Strait of Hormuz—through which approximately 20 MMBOPD of crude oil and petroleum products previously transited—was effectively shut. As export routes became blocked and onshore storage filled rapidly, Gulf producers were forced to curtail output by at least 10 MMBOPD[13].

As a result, global oil supply plummeted by 10.1 MMBOPD to just 97 MMBOPD in March, with OPEC+ production bearing the brunt of this shock, falling by a drastic 9.4 MMBOPD month-on-month to 42.4 MMBOPD. The disruption cascaded rapidly into downstream markets: more than 3 MMBOPD of refining capacity across the region was shut due to direct attacks and the loss of viable export routes, while Gulf exports of 3.3 MMBOPD of refined products and 1.5 MMBOPD of LPG ground to a near standstill[13]. In response to the scale of the disruption, IEA member countries unanimously agreed on 11 March to release 400 million barrels of emergency oil reserves in an effort to stabilise markets and ease supply shortages[14].

By April, the full extent of demand destruction and refining dislocation had become increasingly apparent. On the supply side, global refining systems continued to struggle with feedback shortages and infrastructure damage, tightening product markets worldwide. Refinery runs in the Middle East and feedstock-constrained Asian markets were cut by around 6 MMBOPD, pushing global crude throughputs down to 77.2 MMBOPD. Looking ahead, global refinery runs are now expected to decline by an average of 1 MMBOPD in 2026 to 82.9 MMBOPD —a stark reversal from pre-conflict expectations. While refining margins surged temporarily, with middle distillate crack spreads reaching record highs, these gains reflected acute product scarcity and the unprecedented stress placed on global supply chains[15].

On the demand side, the shock has been equally severe. Global oil consumption is now expected to contract by 80 thousand barrels of oil per day (MBOPD) in 2026, representing a downward revision of 730 MBOPD from the previous month's forecast. A projected 1.5 MMBOPD decline in demand in Q2 2026 would mark the sharpest contraction since the COVID-19 pandemic slashed fuel consumption in 2020. Initial demand destruction has been concentrated in the Middle East and Asia Pacific, particularly for naphtha, LPG, and jet fuel, driven by widespread flight cancellations and large-scale disruptions to petrochemical feedstock supplies. However, as elevated

prices and material scarcity persist, demand weakness is expected to spread more broadly across the global economy[15].

Gas supply-demand

Global natural gas markets saw a marked recovery in 2024, with production rising to 4,125 billion cubic metres (bcm). More than half of this output came from the United States, the Russian Federation, Iran, and China, underscoring a well-supplied market[2].

During the 2024–25 winter, liquefied natural gas (LNG) supply rose by 2%, with nearly half of the additional volumes sourced from the Plaquemines facility in the United States. At the same time, Russian pipeline deliveries to Europe fell by around 15 bcm, leaving European gas inventories 15 bcm lower year on year at the start of 2025. As the heating season ended, storage levels tightened further, finishing 25 bcm below the previous year and prompting a sharp rise in LNG imports. By the first quarter of 2025, European LNG inflows had already increased by more than 20%, ultimately reaching a 25% rise for the full year. In contrast, Asia faced softer LNG demand, with China's first-quarter LNG imports dropping 25% due to competition for flexible cargoes and a shift from gas to coal[16].

Market fundamentals remained tight in the first half of 2025. Although LNG supply grew by 4%, largely driven by new output from the Plaquemines facility—which alone accounted for about two-thirds of global growth—these gains were offset by a 45% decline in Russian pipeline flows to Europe and a 4.5% drop in Norwegian deliveries due to maintenance. By the end of the 2024–25 heating season, European storage levels were 42% lower than the previous year, leading to a 36% rise in storage injections and pushing LNG imports up by 25% to a record high. Gas prices rose accordingly, with European hub prices increasing by 40% and Asian LNG spot prices by 28%. Throughout 2025, global LNG supply grew by 5.5%, driven in large part by new North American capacity, although these gains were partially offset by a 13 bcm reduction in Russian pipeline exports[17].

Looking ahead, global natural gas production is expected to grow by 2.4% and reach 4,350 bcm in 2026, supported primarily by the start-up of new LNG export capacity in North America. This outlook reflects sustained investment and reinforces North America's growing influence in global gas markets[1].

On the demand side, global natural gas consumption rose to 4,128 bcm in 2024, accounting for 29% of global fossil fuel use and roughly one-quarter of total global energy demand. Demand increased across all regions except Africa[2].

Entering 2025, global demand growth began to ease amid tighter market conditions. During the 2024–25 winter, consumption increased by 1.8%, driven by colder temperatures in Europe and North America. Europe's gas use rose nearly 10%, and North America reached record-high winter usage. In contrast,

Asia recorded weaker demand, with consumption falling in China by 2% and Eurasia by 3% as high LNG prices constrained buying[16].

This trend continued into the first half of 2025, with global natural gas consumption rising by only 1% across monitored markets. Growth was primarily fuelled by Europe and North America, as colder weather and reduced wind and hydro output led to increased gas use for heating and power. Europe's consumption climbed by 6.5%, and North America registered a 2.5% rise. In contrast, demand in Asia softened: China's gas use declined by 1%, India's by 7%, and Eurasia's by 2%, reflecting milder winter conditions and higher LNG prices. Throughout 2025, global demand growth moderated from 2.8% in 2024 to approximately 1.3%, with Asia's expansion remaining below 1%[17].

Looking forward, global natural gas demand is projected to increase by 1.9% in 2026, bringing total consumption to around 4,350 bcm, supported by a recovery in industrial activity and higher gas use in the power sector across the Asia-Pacific region[1].

COP30: Implications for oil and gas markets

The 30th meeting of the Conference of the Parties to the UNFCCC (COP30) marked a recalibration in the global climate agenda, notably for oil and gas markets, while reaffirming natural gas as a credible lower-carbon energy source. The adoption of 59 Belém Adaptation Indicators elevated climate adaptation to the same political footing as mitigation, signalling a more balanced global approach that recognises both energy security and resilience. In this context, natural gas was reaffirmed as a lower-carbon energy source capable of supporting renewable integration and meeting rising energy demand, easing some of the pressure previously placed on hydrocarbons.

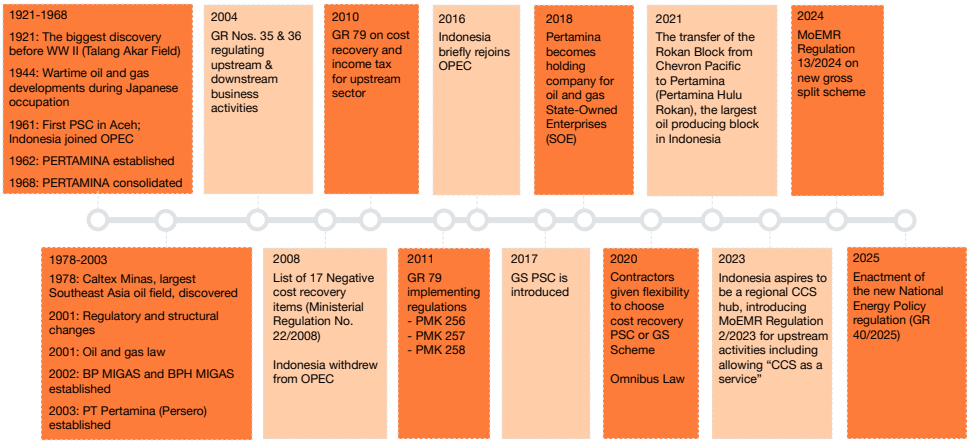
At the same time, COP30 did not advance climate finance nor establish a fossil fuel phase-out roadmap, effectively reinforcing national sovereignty over energy pathways and acknowledging the complexities of managing diverse energy transition trajectories.

Nevertheless, updated Nationally Determined Contributions (NDC) and stricter climate-related trade rules, such as methane regulations and carbon border measures, signal tightening regulatory expectations for oil and gas producers.

These measures place increased emphasis on methane emissions management while also encouraging coal-to-gas switching as a practical and near-term strategy to cut emissions while sustaining supply[18].

1.2 Indonesian context

Figure 1.1 - 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 traces its origins to the country's first oil discovery in North Sumatra in 1885[19], marking the beginning of more than a century of upstream activity. Over time, the sector has evolved alongside shifts in fiscal regimes, regulatory frameworks, and national energy priorities.

Recent developments in investor participation came with the issuance of Ministry of Energy and Mineral Resources (MoEMR) Regulation No. 12/2020, which allows contractors to choose between the traditional cost-recovery PSC and the newer gross split mechanism. This framework was subsequently refined through MoEMR Regulation No. 13/2024.

Broader legislative reform to enhance Indonesia's investment climate followed with the enactment of a series of reforms commonly known as the "Omnibus Law" (Law No. 11/2020 as superseded by Law No. 2/2022 and Law No. 6/2023), aimed at fostering economic growth and innovation across many sectors, including oil and gas. In parallel, MoEMR Regulation No. 2/2023 was introduced to support Indonesia's ambition to become a regional hub for CCS, establishing clearer licensing, collaboration, and revenue-sharing mechanisms.

These policy reforms coincided with renewed upstream momentum. In 2023, Indonesia announced two major discoveries: Layaran-1 in the South Andaman Block (estimated at 6 trillion cubic feet (Tcf) of gas) and Geng North-1 in the North Ganal Block (estimated at 5 Tcf)[20]. Progress also continued on strategic projects, including the Abadi LNG facility—scheduled for completion by 2030[21]—and the expanded production capacity at Tangguh

Train-3[21]. Together, these milestones reinforced Indonesia's commitment to strengthening its long-term gas supply.

Upstream activity intensified further in 2024, supported by improved investment incentives and operational flexibility. A series of exploration successes were recorded, including the Tangkulo-1 deepwater well in the South Andaman Block[22], alongside additional finds by Pertamina subsidiaries such as Astrea[23], Pinang East[24], Julang Emas[25], and Tedong[26].

To enhance commercial attractiveness, the Government of Indonesia and the Special Task Force for Upstream Oil and Gas Business Activities (*Satuan Kerja Khusus Pelaksanaan Kegiatan Usaha Hulu Minyak dan Gas Bumi*/SKK Migas) introduced targeted measures to optimise upstream performance. These included the reactivation of idle fields under MoEMR Decision No. 110/2024 and revisions to the gross split framework through MoEMR Regulation No.13/2024, with technical guidance issued under MoEMR Decision No.230/2024.

In 2024, there were 14 upstream oil and gas projects successfully brought onstream, spanning gas compression, facility optimisation, infill drilling, and new production facilities. These projects, as detailed below, collectively contributed to maintaining output levels amid natural field decline.

Table 1.1 - List of onstream projects in 2024

Project name	Operator	Location	Objective	Onstream
West Belut	Medco E&P Natuna B.V.	West Belut	Develop West Belut gas field and tie-in to South Belut pipeline	September 2024
The Anoa Further Compression Project (AFCP)	Premier Oil Natuna Sea Block B.V.	Natuna Sea	Increase gas export	June 2024
South Sembakung Compressor Facility	Joint Operation Body (JOB) Pertamina–Medco E&P Simenggaris	South Sembakung	Maintain gas production	May 2024
Bekapai Artificial Lift	PT Pertamina Hulu Mahakam (PHM)	Bekapai Field	Increase oil production	May 2024
Sepinggan West Platform Gas (SWPG) Debottlenecking	PHM	SWPG Platform	Improve Low Low Pressure (LLP) production handling	April 2024
Peciko 8B	PHM	Peciko Field	Convert Low Pressure (LP) to LLP mode	June 2024
Dayung Facility Optimisation	Medco E&P Grissik Ltd.	Dayung, South Sumatra	Reduce suction pressure and handle water	June 2024

Project name	Operator	Location	Objective	Onstream
Optimalisasi Pengembangan Lapangan - Optimisation of Field Development (OPL) E-Main	Pertamina Hulu Energi (PHE) Offshore Northwest Java (ONWJ)	ONWJ	Recover reserves via infill wells	May 2024
Puspa Asri Gathering Station	PT Pertamina Exploration and Production (EP)	Puspa Asri	Build a 2,000 barrels of oil per day (BOPD) gathering station	December 2024
Flowline ASDJ-116X	Pertamina Hulu Energi (PHE) Ogan Komering	Air Serdang	Route well fluid to Satellite-G	June 2024
Merbau Compressor	PT Pertamina EP	Merbau Field	Maintain gas production	December 2024
CO_2 and DHU (Dehydration Unit) Karang Baru	PT Pertamina EP	Karang Baru	Meet gas composition (CO_2 and H_2O) specifications	August 2024
Banyu Urip Infill Clastic (BUIC)	ExxonMobil Cepu Ltd.	Bojonegoro	Add seven infill wells	August 2024
Akatara Gas Plant	Jadestone Energy	Lemang, Jambi	Monetise gas to the state-owned electricity utility (*Perusahaan Listrik Negara*/PLN) and LPG supply	July 2024
Carbon Capture, Utilisation, and Storage (CCUS)/ Enhanced Gas Recovery Ubadari	BP Tangguh			

Sources: SKK Migas. (2025). SKK Migas 2024 Annual Report.

Highlights on recent oil and gas developments in Indonesia

During 2025, progress was also recorded across five National Strategic Projects (*Proyek Strategis Nasional*/PSN), including Ubadari, Abadi, Indonesia Deepwater Development (IDD) and Geng North, Asap Kido Merah, and South Andaman. These projects, as outlined below, advanced through key development stages, reinforcing their role as anchors of Indonesia's medium and long-term production outlook.

Table 1.2 - List of PSNs

Project name	Operator	Location	Estimated production	Progress	Estimated onstream date
Ubadari Field Development, CCUS, and Compression (UCC)	BP Berau Ltd.	Tangguh, West Papua	Gas: 476 million standard cubic feet per day (MMSCFD); Condensate: 4,700 barrels of condensate per day (BCPD)	Final Investment Decision (FID) achieved (2024); Early work 92.0%; Engineering Procurement, and Construction (EPC) Onshore (by JGC Holdings Corporation) 73.4%; EPC Offshore (by Saipem SpA – PT Meindo Elang Indah): 30.9%	2029
Abadi Project	Inpex Masela Ltd.	Masela, Arafura Sea	LNG: 9.5 million tonnes per annum (MTPA) (1,600 MMSCFD); 150 MMSCFD; 35,000 BCPD	• Front-end engineering design (FEED): around 50% • Survey: Offshore Geological and Geophysical (G&G) Survey (76.17%), Onshore G&G Survey (28.84%)	2030
IDD and Geng North	Eni Rapak Deepwater Ltd., Eni Ganal Deepwater Ltd., Eni Makassar Ltd.	East Kalimantan	• Southern Hub: 0.5 billion cubic feet per day (BCFD); 5,000 BCPD • Northern Hub: 1 BCFD; 5,000 BCPD	Authorisation for Project Activities (APA) early work 83.35%; Floating Production, Storage, and Offloading (FPSO) hull fabrication 9.15%; G&G & Metocean 11%; Bontang reactivation assessment 100%	2027
Asap Kido Merah (AKM)	Genting Oil Kasuri Ltd.	Bintuni, West Papua	Gas: 330 MMSCFD; Condensate: 1,200 BCPD	EPC Onshore: 31.7%; EPC Offshore: 0.15% (ongoing)	2027
South Andaman	Mubadala Energy	Offshore North Sumatra	Gas: 312 MMSCFD; Condensate: 7,500 BCPD	Early Work Progress 87.06% as of 31 December 2024	2028

Sources: House of Representatives (DPR). (2026). Hearing Meeting of the House of Representatives Commission XII with the Head of SKK Migas.

In accordance with Coordinating Minister for Economic Affairs Regulation (*Peraturan Menteri Koordinator Bidang Perekonomian*/Permenko Eko) No. 16/2025, which amends Permenko Eko No. 7/2021 regarding PSNs, the following carbon capture, utilisation, and storage (CCUS) initiatives also have been officially included in the national project list:

1. Teluk Bintuni Industrial Zone, which encompasses the development of methanol and ammonia industries as well as the utilisation of carbon generated from CCUS/CCS activities in Teluk Bintuni.
2. Ubadari Field Development, including the Ubadari CCUS and Compression (UCC) Project in Teluk Bintuni.

In July 2025, SKK Migas announced that upstream oil and gas investment remained robust, with realised investment in the first half of 2025 reaching USD7.19 billion (around IDR118 trillion). This figure represents a 28.6% increase compared to the USD5.59 billion invested during the same period in 2024[27].

In September 2025, SKK Migas and the South Hub contractors — Eni Indonesia, PHE East Sepinggan, and Tiptop Indonesia — formalised several commercial agreements covering six working areas under the South Hub project: Rapak, Selat Makassar, Sepinggan Timur, Ganal, Muara Bakau, and Ganal Barat[28]. In October 2025, Pertamina secured a 24.5% participating interest in the deep-water Bobara block through a farm-in agreement with Petronas, alongside TotalEnergies, reinforcing Pertamina's commitment to strengthening national energy independence[29].

By the end of 2025, as listed in the tables below, six of the fifteen upstream projects targeted for the year had entered operations.

Table 1.3 - List of gas onstream projects in 2025

		Gas		
No	**Name**	**Production (MMSCFD)**	**Operator**	**Onstream**
1	Letang Tengah Rawa Expansion	70	Medco E&P Grissik Ltd.	March 2025
2	Merakes East Field	100	Eni Indonesia	May 2025
3	Sisi Nubi AOI 1,3,5	120	PHM	December 2025

Source:
SKK Migas. (2025). SKK Migas Press Conference on the Performance for the First Half of 2025
PHE. (2025). Proyek Sisi Nubi AOI Resmi Onstream, Bukti Kontribusi PHM untuk Ketersediaan dan Ketahanan Energi Nasional
Eni. (2025). Eni announces production start-up from Merakes East field, offshore Indonesia.

Table 1.4 - List of oil onstream projects in 2025

No	Name	Oil Production (BOPD)	Operator	Onstream
1	Forel & Terubuk	20,000	Medco E&P Natuna	May 2025
2	Balam GS Upgrade	35,000	Pertamina Hulu Rokan (PHR)	May 2025
3	Akasia Bagus Stage-1	7,250	PT Pertamina EP	September 2025
4	BUIC C14	9,700	ExxonMobil Cepu Ltd.	June 2025

Source:
SKK Migas. (2025). SKK Migas Press Conference on the Performance for the First Half of 2025
PHE. (2025). Pertamina EP Jatibarang Field Capai Liquid Onstream Perdana dari SP ABG Stage 1
MedcoEnergi. (2025). Presiden Prabowo Resmikan Produksi Perdana Lapangan Forel dan Terubuk

In 2026, SKK Migas identified nine upstream oil and gas projects that will begin operations in 2026, as follows:

Table 1.5 – List of planned gas onstream projects in 2026

No	Name	Gas Production (MMSCFD)	Operator	Planned onstream
1	Sisi Nubi AOI 1,3,5 (Stage II)	180	PHM	Q1 2026
2	South Senoro (Stage II)	110	JOB Pertamina-Medco E&P Tomori Sulawesi	Q1 2026
3	OO-OX	21.3	PHE ONWJ	Q1 2026
4	Suban Compressor Cluttering	118	Medco E&P Grissik Ltd.	Q2 2026
5	NSPD Plant	20	Energi Mega Persada (EMP) Bentu Ltd.	Q2 2026
6	Karamba	7.3	PT Indo Sino Oil and Gas (ISOG)	April 2026

Source: House of Representatives (DPR). (2026). Hearing Meeting of the House of Representatives Commission XII with the Head of SKK Migas.

Table 1.6 – List of planned oil onstream projects in 2026

No	Name	Oil Production (BOPD)	Operator	Planned onstream
1	Polymer Minas - D Area	1,212	PHR	Q2 2026
2	Upgrading Puspa Asri	1,034	PT Pertamina EP	Q4 2026
3	Fasprod Sidingin North-1	325	PHR	Q4 2026

Source: House of Representatives (DPR). (2026). Hearing Meeting of the House of Representatives Commission XII with the Head of SKK Migas.

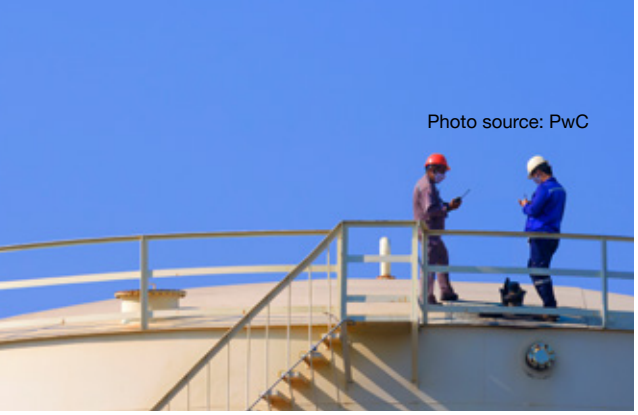


Photo source: PwC

New measures to improve upstream sector

In 2025, the Indonesian Government introduced Government Regulation (GR) 40/2025, marking a key update in the country's energy governance framework. As part of the National Energy Policy, the regulation emphasises energy independence, diversification of the energy mix, and the gradual expansion of low-carbon and renewable sources, while maintaining the role of oil and gas during the transition period through clear targets and roadmaps.

Complementing this, GR No. 8 of 2025 (GR 8/2025) revised the framework governing foreign exchange proceeds from natural resource exports (*Devisa Hasil Ekspor Sumber Daya Alam*/DHE SDA). While most sectors are subject to a 12-month domestic retention requirement, the oil and gas sector benefits from a more flexible regime, requiring only 30% retention of export proceeds for a shorter duration of three months.

A preliminary assessment of these regulatory changes is discussed in Chapter 3.

1.3 Indonesia's oil and gas resources, reserves, and production

Resources

Indonesia's upstream landscape continued to demonstrate considerable geological potential in 2025, supported by a total of 128 identified oil and gas basins. As of June 2025, 20 basins had reached the discovery stage, while 68 remained unexplored, a further 19 basins showed hydrocarbon indications, and 13 had been drilled without commercial discoveries[30].

Recent exploration successes included the announcement by SKK Migas and Eni of a gas discovery at the Konta-1 well within the Muara Bakau PSC, located offshore East Kalimantan in the Kutai Basin. Eni holds an 88.334% interest in the block, while Saka Energi holds the remaining 11.66%[31]. PT Pertamina Hulu Energi also made another oil and gas discovery at the Metulang Deep (MDP)-1x well, located offshore South Mahakam, East Kalimantan[32].

Reserves

In line with the exploration activities, Indonesia registered an uplift in its proven oil and gas reserves in 2025. According to the MoEMR, proven oil reserves rose from 2.29 billion barrels in 2024[33] to 2.33 billion barrels[30], while proven gas reserves increased from 33.8[33] to 34.8 Tcf over the same period[30].

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

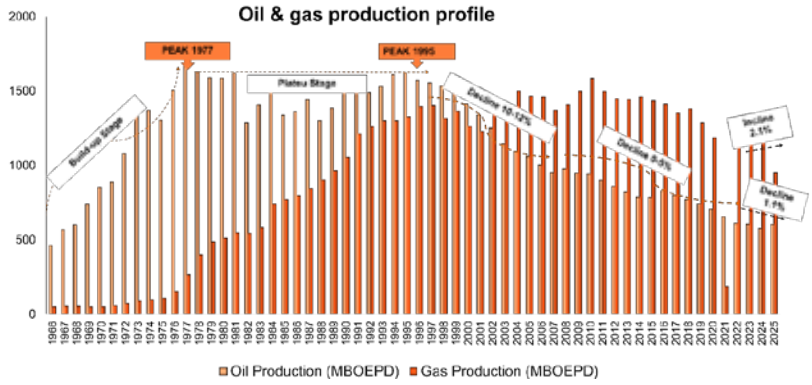
Indicator	2020	2021	2022	2023	2024	2025
Reserves						
Oil (Million Barrels)	4,170	3,950	4,171	4,703	4,312	4,424
Proven	2,440	2,245	2,271	2,413	2,288	2,326
Potential	1,730	1,700	1,900	2,290	2,024	2,098
Gas (Tcf)	62.39	60.61	54.83	54.76	51.98	55.85
Proven	43.57	41.62	36.34	35.30	33.84	34.78
Potential	18.82	18.99	18.49	19.46	18.14	21.07
Production						
Crude oil (MBOPD)	708	658	613	606	580	605
Natural gas (MMSCFD)	6,665	6,668	6,492	6,630	6,802	6,789
New contracts signed	0	2	5	13	4	7

Sources:
Directorate General of Oil and Gas (DGOG). (2026). Performance Report of the Directorate General of Oil and Gas for the year 2025.
2020-2024 Gas & Oil production: SKK Migas. (2025). SKK Migas 2024 Annual Report.
New Contracts Signed 2018 - 2023: DGoG.(2024). Statistik Migas Semester 1 2024, 2024.
New Contract Signed 2024: SKK Migas. (2025). SKK Migas 2024 Annual Report.
MoEMR. (2025). Lima Pemenang Wilayah Kerja Migas Ditetapkan, Bukti Industri Migas Masih Menarik.
MoEMR. (2025). Genjot Cadangan Migas Nasional, Pemerintah Tetapkan Pengelola Wilayah Kerja.
MoEMR. (2025). Pemerintah Umumkan Pemenang Lelang Wilayah Kerja Gagah Dengan Komitmen Investasi USD 4,25 Juta.

Production

Following a series of discoveries between 2024 and 2025, Indonesia's oil output increased in 2025, rising from 580 thousand barrels of oil per day (MBOPD) in 2024[34] to 605 MBOPD in 2025[35]. In contrast, gas production declined in 2025 to 6,789 MMSCFD from 6,802 MMSCFD[33].

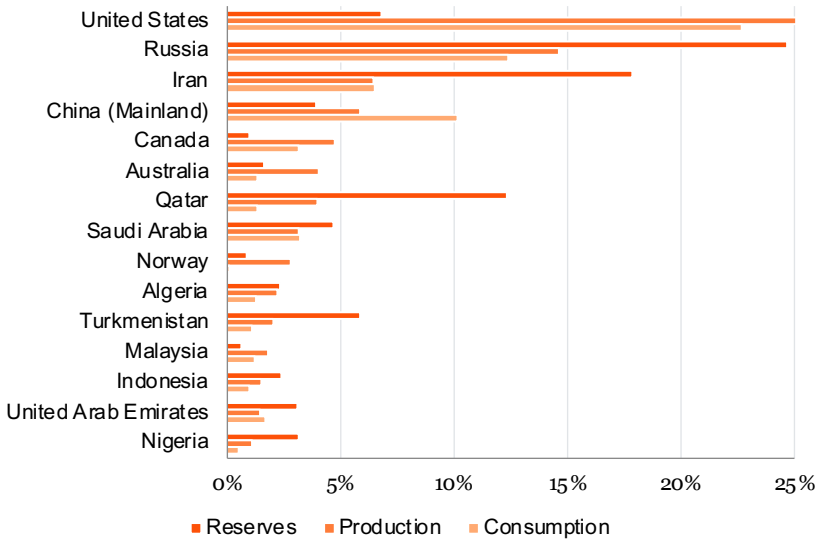
Figure 1.2 - Indonesian oil and gas production profile



Source: 1966 to 2024: SKK Migas, SKK Migas 2023 Annual Report, 2024.
2025: MoEMR. (2025). Capaian Positif Tahun 2025, Negara Hadir Penuhi Kebutuhan Energi Masyarakat.

Unchanged from the previous year, Indonesia maintained its position as the world's 13th-largest natural gas producer in 2025, with total output reaching 65 bcm (equivalent to 2.29 Tcf). On the consumption side, Indonesia ranked 25th globally, with domestic gas use amounting to 41 bcm (equivalent to 1.45 Tcf)[36], as illustrated below:

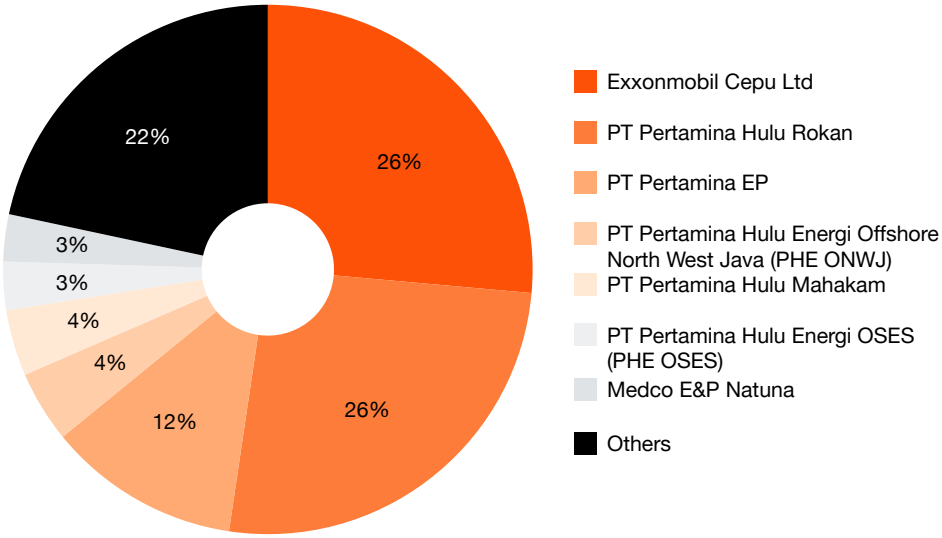
Figure 1.3 - Share world gas 2025 - rank based on 2025 production



Source: Reserve: Energy Institute. "Statistical Review of World Energy 2025." 2025
Production & Consumption: BMI (Fitch Solution), "BMI Data Tools -- Production, Consumption", 2025

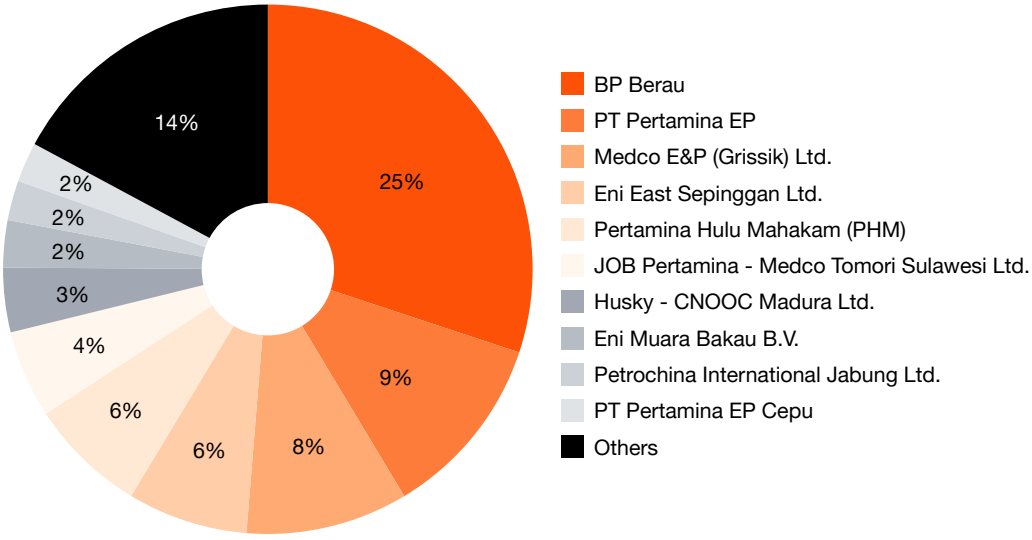
Pertamina-affiliated entities play a dominant role in national production, accounting for approximately 50% of Indonesia's total oil and gas output[37]. Production under PSCs remained concentrated among a small group of major operators, as seen below, reflecting the continued importance of established producers in sustaining national supply.

Figure 1.4 - Oil producers 2025



Source: Commission XII of the House of Representatives (Dewan Perwakilan Rakyat - DPR). (2025). Hearing Meeting of the House of Representatives Commission XII with the Head of SKK Migas and 14 PSC Companies.

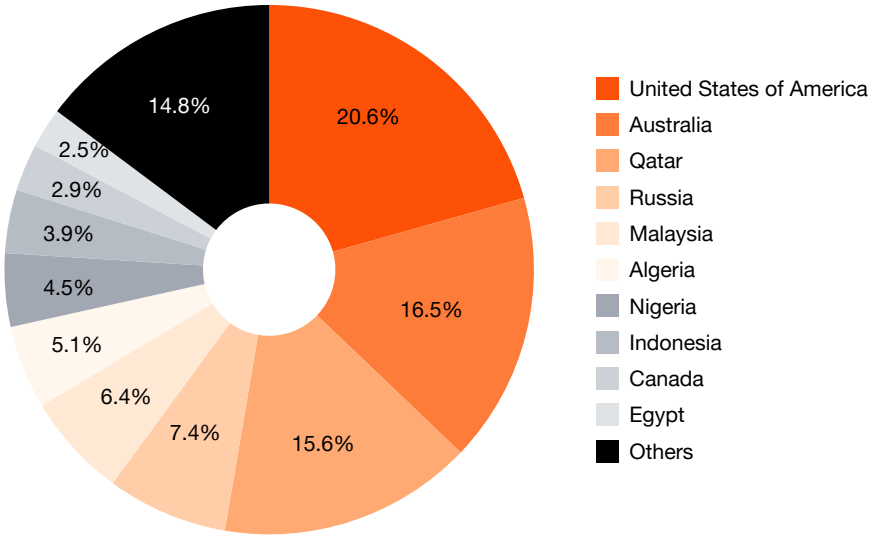
Figure 1.5 - Gas producers 2025



Source: Commission XII of the House of Representatives (Dewan Perwakilan Rakyat - DPR). (2025). Commission XII of the House of Representatives of the Republic of Indonesia Working Meeting with the Minister of Energy and Mineral Resources

LNG remains a central component of Indonesia's energy landscape. In 2025, the country retained its position as the world's eighth-largest LNG exporter, supported by an operational capacity of 19.2 million tonnes per annum (MTPA)[38].

Figure 1.6 - World's top LNG exporters 2025



Source: Global Energy Monitor (GEM), 2025

Further strategy to improve reserve replacement ratio (RRR)

The MoEMR and SKK Migas strategy to strengthen RRR is resting on three pillars: optimising production through advanced technologies, reactivating idle wells, and accelerating exploration efforts in under-explored regions (e.g. eastern Indonesia)[39].

The first pillar of the strategy focuses on maximising recovery from existing and mature fields through targeted technology deployment. Techniques such as fracturing, enhanced oil recovery (EOR), and horizontal drilling are being applied to improve recovery factors and slow natural production decline[39]. This approach is now being implemented through chemical enhanced oil recovery (CEOR) initiatives. A key example is PT Pertamina Hulu Rokan's Minas Stage-1 CEOR project at the mature Minas Field in the Rokan Zone, where facility upgrades are underway. Incremental production is expected to begin following chemical injection from mid-2026[40]. In parallel, SKK Migas and Petrogas (Basin) Ltd. have initiated a CEOR pilot at the Walio Field in the Kepala Burung Block, targeting the mature Kais carbonate reservoir. The pilot aims to increase recoverable reserves, prolong field longevity, and enhance economic value[41].

The second pillar of the strategy centres on reactivating idle and underutilised wells as a short-term mechanism to rapidly recover existing resources. This effort is supported by MoEMR Regulation No. 14 of 2025, which provides a formal framework for the collaborative management of mature and idle wells.

Finally, the third pillar of the strategy emphasises accelerating exploration activity in Indonesia's under-developed oil and gas basins to sustain RRR over the long term. The MoEMR has highlighted the importance of targeting the 68 out of 128 basins that remain largely untapped, most of which lie outside the mature western regions[39].

In the area of unconventional oil and gas development, Indonesia has continued to advance its efforts following the discovery of the Gulamo and Kelok non-conventional oil and gas wells. Building on these initial successes, PHR is preparing the next appraisal phase to further evaluate the reservoir potential of the Brown Shale formation in the Rokan Block[42].

1.4 Downstream sector

Demand

Indonesia's downstream oil sector remains highly susceptible to fluctuations in global crude and refined product prices, a vulnerability that has intensified alongside rising dependence on fuel imports. Domestic gasoline demand continued to grow, increasing from 36.64 million kilolitres in 2024 to 37.3 million kilolitres in 2025. Over the same period, gasoline imports rose from 22.8 million kilolitres to 22.9 million[43], further increasing dependence on external supply and heightening exposure to international market volatility.

Despite domestic refining capacity continuing to lag fuel demand growth, the weak refining margins limit Pertamina's ability to execute its Refinery Development Master Plan (RDMP) and green refinery plans[44].

The Government of Indonesia has accelerated its biofuel strategy to strengthen energy security and reduce import dependence. Under MoEMR Regulation No. 4/2025, which replaced the previous MoEMR Regulation No. 12/2025, the Government mandates the blending of biodiesel, bioethanol, and bio-jet fuel into the national fuel mix. Among these, biodiesel is the most established while bioethanol and sustainable aviation fuel (SAF) remain at earlier stages of deployment.

In 2025, Indonesia implemented the B40 biodiesel mandate, with domestic consumption reaching 14.2 million kilolitres—surpassing targets and reducing diesel imports by approximately 3.3 million kilolitres. Expanded refinery capacity, including the Balikpapan RDMP, is expected to enable the Government to eliminate diesel imports by 2026 and reduce aviation fuel imports by converting excess diesel into avtur. As a result of the mandatory B40 biodiesel policy in Indonesia, diesel imports declined to 3.3 million kilolitres in 2025[45].

Photo source: PwC

Looking ahead, the Government of Indonesia plans to increase the biodiesel blending rate to B50 by 2026. Technical assessments for B50 have already been completed. However, nationwide implementation of B50 will require careful planning. Current projections suggest that achieving the new B50 target will necessitate annual biodiesel output of approximately 20 million kilolitres[46].

Bioethanol is also expected to play a growing role in Indonesia's energy mix. MoEMR Regulation No. 4/2025 sets blending targets of 5% by 2025 and 10% by 2029. To support these objectives, Pertamina New & Renewable Energy and PT Medco Energi Internasional Tbk have formed a strategic partnership focused on renewable energy (RE) development, including high acid crude palm oil (HACPO)-based biodiesel and bioethanol. The collaboration encompasses feasibility studies, technology transfer, and the planned revitalisation of Medco's Lampung bioethanol facility. Collectively, these efforts are set to strengthen Indonesia's bioenergy sector and accelerate the nation's energy transition[47].

Indonesia's biofuel policy has further expanded to include SAF alongside biodiesel and bioethanol, leveraging existing infrastructure to support aviation decarbonisation and energy security. While early SAF development relied primarily on palm-based feedstocks, attention is increasingly shifting toward lower-emission alternatives such as used cooking oil (UCO) and palm fatty acid distillate (PFAD). In this context, Indonesia's annual UCO supply—estimated at 3.9 million tonnes (Mton)—offers a meaningful domestic feedstock base to underpin SAF scale-up. Current regulations now require a minimum SAF blending rate of 1% by 2027, rising to 5% by 2035, positioning SAF as a key pillar of Indonesia's advanced biofuels strategy[48]. Pertamina already produces SAF from UCO and is set to expand capacity from 27 to 887 kilolitres per day (KLPD) by 2029—an initiative expected to reduce fossil fuel reliance, lower carbon emissions, create jobs, and stimulate nationwide UCO collection[49].

1.5 Contribution to the economy

Dynamics in fuel and gas demand

Indonesia's demand for crude oil and oil products continued to rise, resulting in the increase in oil and gas imports from 53,746 thousand tonnes in 2024[50] to 55,329 thousand tonnes in 2025[51]. This growing dependence on imports placed additional strain on the balance of trade, with the oil and gas trade deficit widening to USD2.09 billion by December 2025[52], underscoring the macroeconomic sensitivity of the sector.

Refined fuel consumption remains heavily concentrated in the transportation sector, where gasoline, diesel, and jet fuel account for the majority of demand. According to Fitch, diesel consumption was projected to increase by around 3.7% in 2026, supported in part by relatively low crude oil import prices, although price increases and supply disruption due to the Middle East conflict in 2026 are likely to have an impact. Downside risks to demand growth are also emerging as the Government advances comprehensive fuel subsidy reforms, including reductions in diesel subsidies and more targeted support for lower-income households. While these planned measures are expected to improve fiscal efficiency, they may moderate fuel demand growth over the medium term[53].

In 2025, approximately 3,908 billion British thermal units per day (BBTUD)—equivalent to 3,769 MMSCFD, or around 69% of total gas supply—was allocated for domestic use. This supported a broad range of downstream and local applications, including gas fuel (*bahan bakar gas*/BBG), city gas networks, EOR, power generation, as well as LNG and LPG supply chains. Prioritising domestic gas use aligns with policy objectives to strengthen energy security, manage import exposure, and position natural gas as a key transitional fuel within the national energy mix[54].

Over the longer term, Indonesia's oil and gas demand outlook will be increasingly shaped by the Government's decarbonisation agenda. The Industrial Decarbonisation Roadmap, which targets net-zero emissions in industry by 2050, introduces structural headwinds to fossil fuel demand growth. Policies promoting energy efficiency, electrification, fuel substitution, low-carbon power generation, and carbon pricing under the National Economic Value of Carbon (*Nilai Ekonomi Karbon*/NEK) framework are expected to reduce fossil fuel intensity across the economy. Several industrial subsectors are projected to reach peak emissions between the mid-2020s and 2035, implying a gradual decoupling of oil and gas demand from economic growth. As a result, oil and gas are likely to transition from primary growth fuels toward a more complementary and transitional role within Indonesia's evolving energy system[55].

Photo source: PwC

Economic impact of oil and gas

In 2025, the Ministry of Finance (MoF) reported a further increase in actual energy subsidy expenditure, rising to IDR185.2 trillion from IDR177 trillion in the previous year[56]. At the same time, non-tax state revenue (*Penerimaan Negara Bukan Pajak*/PNBP) generated from the oil and gas sub-sector declined to IDR105 trillion in 2025[35], down from IDR111 trillion in 2024[57], which represented 3.81% of total state revenue in 2025, the lowest contribution in recent years.

Table 1.8 - State budget (*Anggaran Pendapatan dan Belanja Negara*/APBN)

Year	Total state revenue (IDR trillion)	Oil and gas revenue (IDR trillion)	% of contribution from oil and gas
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%
2025	2,756	105	3.81%

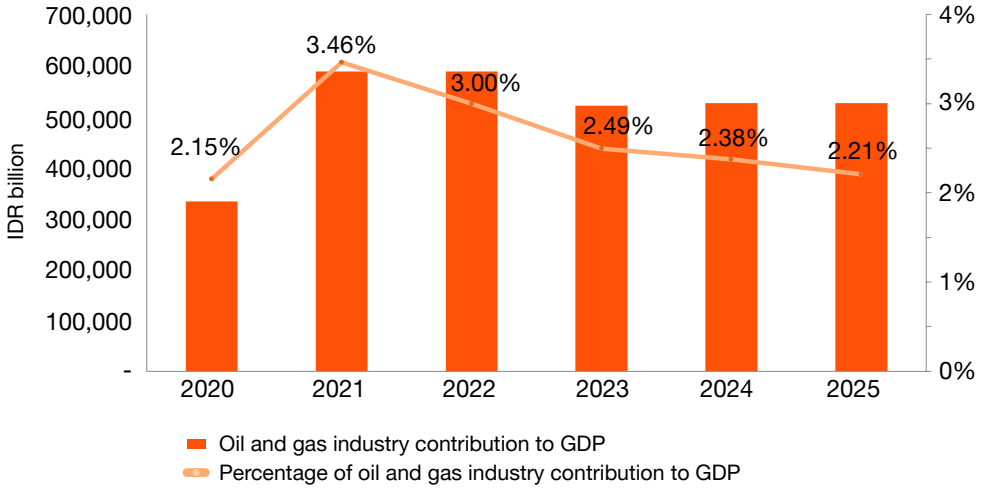
Sources:
State Revenue 2025: MoF. (2026). Realisasi Sementara APBN 2025, Menkeu Purbaya: APBN Tunjukkan Kinerja yang Solid
Oil and Gas Revenue: MoEMR. (2026). Press Conference of the Ministry of Energy and Mineral Resources - Achievements of the Energy and Mineral Resources Sector 2025.

Oil and gas exports also continued to weaken. The sector accounted for 2.99% of Indonesia's total exports in 2025, down from 3.86% in 2024[58] (see Figure 1.7 - Oil and gas products as a % of total Indonesia exports). Consistent with this trend, the oil and gas sector's contribution to Indonesia's gross domestic product (GDP) continued its gradual downward trajectory, declining from 2.38% in 2024 to 2.21% in 2025[58] (see Figure 1.8 - Oil and gas products as a % of total Indonesia GDP). As a result, while oil and gas remains strategically important for energy security and fiscal revenues, its relative contribution to economic growth is gradually diminishing.

Figure 1.7 - Oil and gas products as a % of total Indonesia exports

Source: Bank Indonesia (BI). (2026). Indonesian Economic and Financial Statistics (SEKI).

Figure 1.8 - Oil and gas products as a % of total Indonesia GDP



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

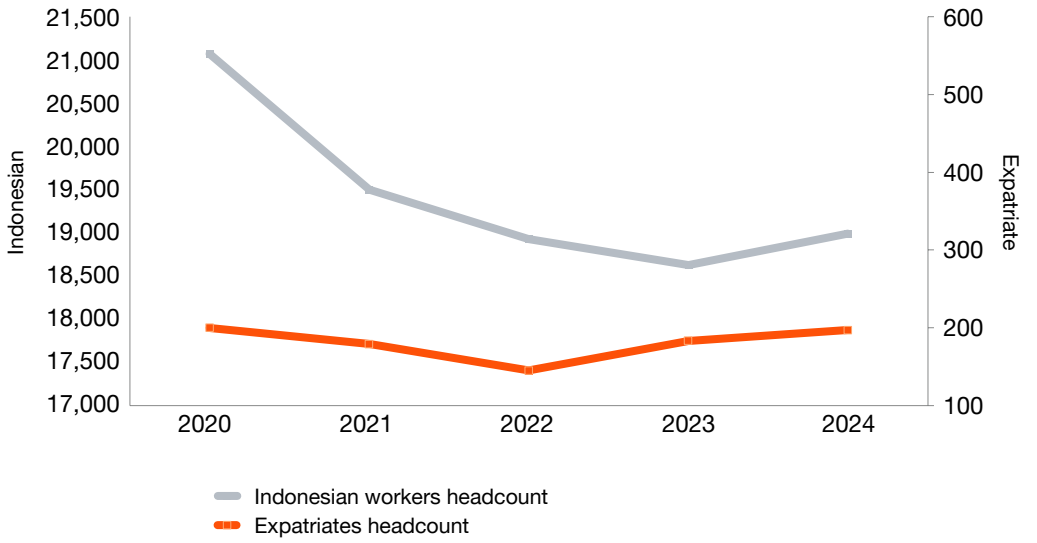
Investment in oil and gas

In 2025, Indonesia's oil and gas investment reached USD18 billion, up from USD17.5 billion in 2024. Of the total in 2025, USD15.4 billion was invested in upstream oil and gas activities and USD2.6 billion for downstream oil and gas operations. These figures reflect ongoing developments in the sector's investment trends[33].

Workforce in oil and gas

According to the latest SKK Migas report, the total workforce employed by PSC contractors is projected to reach 19,186 personnel, comprising 18,989 Indonesian employees and 197 expatriates. Workforce levels declined steadily between 2015 and 2023 as operators pursued efficiency and cost optimisation[59].

Figure 1.9 - Indonesian workers and expatriates headcount in oil and gas



Source: SKK Migas. (2025). SKK Migas 2024 Annual Report.

2 The role of oil and gas in energy transition

2.1 Introduction

In Indonesia, and globally, oil and gas have historically served as the primary sources of energy, particularly within the transportation sector, alongside a heavy dependence on coal for power generation. In the power sector, diesel, a key oil and gas derivative, plays a critical role in rural power generation and captive mining operations, where grid access is limited. Despite having a crucial role in energy production, oil and gas contribute significantly to greenhouse gas (GHG) emissions.

As the world intends to move towards net zero emissions (NZE), the sector is now facing increasing pressure to transition towards a lower-carbon economy. This pressure intensified following the submission of Indonesia's Second Nationally Determined Contribution (SNDC) in October 2025, which further strengthened the Government's commitment to the Paris Agreement. The pressure does not stem solely from domestic climate policies, but is also driven by international regulatory frameworks that are reshaping global trade, such as the European Union's Carbon Border Adjustment Mechanism (CBAM), the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA), and the International Maritime Organisation (IMO)'s Net Zero Framework. These global commitments are expected to accelerate emissions management across the value chain.

To support the transition in oil and gas, the Government has set out a gradual transition strategy through several measures as stipulated in the National Energy Policy (*Kebijakan Energi Nasional*/KEN) or GR No. 40 of 2025. The strategy outlined in the KEN aligns with the Government's 2025–2045 Long-Term Development Plan (*Rencana Pembangunan Jangka Panjang Nasional*/RPJPN) and 2025–2029 National Medium-Term Development Plan (*Rencana Pembangunan Jangka Menengah Nasional*/RPJMN). Furthermore, the current

administration's *Asta Cita* vision seeks to operationalise this by elevating energy self-sufficiency to a fundamental pillar of national security, reinforcing that the transition is a managed rebalancing. The MoEMR, through its energy transition roadmap outlined in MoEMR Regulation No 10/2025, indirectly articulates a transition role for the oil and gas sector in supporting the energy transition in the power sector.

According to the national plan, the oil and gas sector will support the transition taking place across the power, transport, and industrial sectors. Natural gas is expected to play a major role as a lower-carbon transitional fuel, especially in replacing coal for power generation and industrial processes. This shift is intended to help reduce emissions during the transition period up to 2045. In the transportation sector, reducing fossil-based fuel consumption is the key agenda, with the focus on introducing biodiesel (a renewable fuel derived from plant oils and fats to be blended with conventional diesel), bioethanol (an alcohol-based fuel produced from fermented agricultural crops to be blended with gasoline), biomethane, and SAF (a low-carbon replacement for traditional jet fuel) into the energy mix. Furthermore, hydrogen and electricity emerge as alternative fuels and will be the future energy sources planned for development by the Government to replace fossil fuels.

The transitions above are to support the Government's climate target to reduce emissions from a projected peak of 1,016 Mton of carbon dioxide equivalent (CO_2eq) by 2030 to 129 Mton CO_2eq by 2060. It also highlights the need for continued decarbonisation efforts and supporting programmes across the energy sector. As a result, the oil and gas industry's role extends beyond production to include investments in low-carbon technologies and infrastructure. Carbon offset technology, such as carbon capture, is integrated into the roadmap, utilising Indonesia's 4.85 billion tonnes of carbon dioxide (CO_2) storage potential in depleted reservoirs to abate emissions from high-CO_2 gas fields and intensive refining processes. Oil and gas (O&G) companies may adopt carbon capture, utilisation, and storage on enhanced oil recovery (CCUS-EOR) to lower the carbon intensity of their portfolios while maintaining production. Alongside CCUS adoption, upgrading the refineries for lower-sulphur fuel production can also be considered as the option to lower carbon intensity.

Regarding infrastructure, repurposing existing infrastructure both in midstream and downstream emerges as a potential solution. In midstream, leveraging gas pipeline infrastructure for hydrogen transport can be considered as the entry point, coupled with the development for hydrogen refuelling infrastructure. Other opportunities in the downstream are related to the electric vehicle (EV) ecosystem due to the rise in EV adoption. The growth of the EV ecosystem is expected to reduce demand for traditional retail fuels, driving the need to shift towards developing charging infrastructure as legacy fuel volumes decline[1].

In contrast to these opportunities, the scale of this transition introduces several structural challenges that directly impact capital allocation and investment strategies. For biofuel products, achieving the aggressive blending mandates like B50 and E10 faces significant feedstock constraints, specifically the supply competition between the energy and food sectors for crude palm oil (CPO). Furthermore, the commercial viability of these refined products currently relies heavily on the price gap funding managed by the Palm Oil Plantation Fund Management Agency (*Badan Pengelola Dana Perkebunan Kelapa Sawit*/BPDPKS)[2]. In the transport sector, while the electrification pipeline advances, strong growth in electric four-wheeler (4W) contrasts with the recent stagnation in the two-wheeler (2W) segment, coupled with the dynamic changes in the regulatory framework, elevating investment risk.

In terms of financing, the energy sector faces a shift in capital allocation. Institutional investors, green banks, and major financing institutions are increasingly restricting capital for unabated fossil fuel projects. Domestic frameworks, such as the Indonesia Sustainable Finance Taxonomy (*Taksonomi untuk Keuangan Berkelanjutan Indonesia*/TKBI), further support the availability of financing instruments for lower carbon technologies at the expense of legacy oil and gas businesses. As global and domestic capital pivots toward sustainable and transition-aligned portfolios, oil and gas operators face tightening liquidity and higher costs of capital for legacy hydrocarbon assets. This financial reprioritisation indicates that maintaining access to institutional funding is now contingent upon the demonstration of credible decarbonisation strategies. As energy transition advances, the maturation of low-carbon technologies, such as CCS and advanced resource efficiency tools to reduce flaring, venting, and methane leakage, create new operational baselines. Companies lagging in the adoption of these technologies could face competitive and operational disadvantages in the near future. Furthermore, as long-term global demand trajectories for conventional oil and gas adjust, the market value of traditional hydrocarbon assets may be increasingly challenged due to potential limitation on new oil and gas concessions. Operators face the risk of stranded assets if the economic life of their portfolio is not continuously evaluated against evolving market and policy projections, potentially resulting in asset impairments and adverse impacts on corporate balance sheets.

In conclusion, while energy security concerns will sustain legacy business for decades to come, the transition provides an unprecedented opportunity to capture new business value. By participating in the development of low-to-zero carbon fuels, companies can navigate this shift and maintain commercial viability through the transition.

2.2 Oil and gas for energy transition and challenges

2.2.1 The climate ambitions of Indonesia towards decarbonisation

Indonesia's pathway to decarbonisation is shaped by the dual mandate of achieving NZE by 2060 while simultaneously ensuring national energy security. This transition does not signify an immediate phase-out, but rather a rebalancing[3]. The sector's future investment landscape is anchored by two overarching national frameworks: the *Asta Cita* vision of the current administration provides the immediate strategic direction to operationalise the vision through the 2025-2029 RPJMN, while the 2025-2045 RPJPN serves as the overarching long-term vision[4]. These two documents show consistent narrative: the country is pursuing decarbonisation, but oil and gas remain part of the energy mix until 2060, with gradual switching from fossil fuels to low-carbon fuels, such as biofuel.

At the strategic level, the RPJPN embeds the decarbonisation ambition in oil and gas through the energy transition (ET) roadmap. Natural gas is designed as the essential bridge fuel for power generation, transportation, and industry, substituting coal and oil in the forms of natural gas, LNG, and compressed natural gas (CNG). The biofuel mandate will be further enforced alongside the EV ecosystem in the short-medium term (up to 2034), reducing the use of crude oil as fuel, especially for the transportation sector. Hydrogen and ammonia emerge as potential low-carbon sources for transportation and industry as the alternative for fossil-based fuels. Lastly, to reconcile continued hydrocarbon use with the NZE 2060 target, the RPJPN emphasises CCS and CCUS, especially for hard-to-abate sectors.

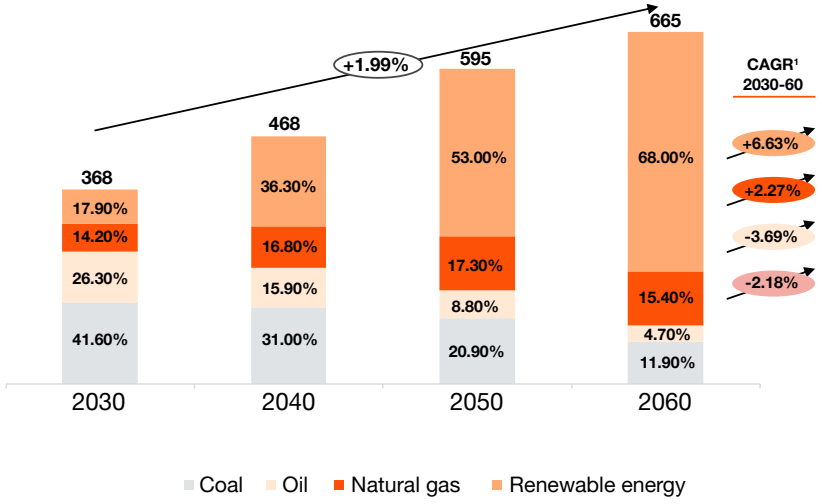
The current administration's *Asta Cita* vision elevates energy self-sufficiency to a fundamental pillar of national security, reinforcing that the transition is designed as a managed rebalancing rather than an abrupt hydrocarbon exit. To contextualise energy self-sufficiency in the oil and gas sector, the MoEMR has articulated near-term strategies to emphasise energy security: (1) increasing oil and gas lifting by reactivating idle wells, optimising existing wells through technology such as EOR and accelerating the development of discovered resources that have not yet been commercialised; and (2) accelerating downstream refining to ensure a stable energy baseline. This strategy aims to reduce Indonesia's reliance on imported energy products while maintaining supply resilience[5].

2.2.2 The path ahead for oil and gas in Indonesia's energy transition

Indonesia's energy transition in the oil and gas sector is expected to follow a gradual pathway to transition from fossil fuels toward low-to-zero carbon fuels. This gradual, phased approach allows the oil and gas sector to continue to play an important role in supporting national development while creating room for new technologies, infrastructure, and regulatory frameworks to mature in line with the decarbonisation objectives.

Aligning with the RPJPN, the KEN converts the strategies into quantified trajectories to achieve decarbonisation in the energy sectors, including oil and gas, as seen in Figure 2.1.

Figure 2.1 Indonesian energy supply projection by fuel source (in million tonnes of oil equivalent (MTOE), 2030-60)



Source: GR No. 40/2025
Notes: CAGR: Compound annual growth rate

In this transition journey, natural gas plays a role as a transitional lower carbon fuel up to 2050, with its contribution increasing from ~14.2% in 2030 to ~17.3% of the energy supply in 2050. Natural gas is suitable for various applications, including power generation, industrial commodities, and household needs, and it offers lower CO_2 emissions compared to coal and oil. The growth of natural gas coincides with an expanding market for gas infrastructure, LNG receiving terminals, and domestic pipeline networks, with a focus on replacing coal in power generation and providing high-heat energy for the industrial sector. Furthermore, aligned with the MoEMR's energy transition roadmap, natural gas is included in the Government's 'de-dieselisation' programme, replacing highly pollutive diesel generators in isolated grids across Indonesia's archipelago, provided that midstream gas infrastructure has been established to reach these remote areas. Conversely, oil is projected to decline from ~26.3% in 2030 to ~8.8% by 2050, reflecting the Government's plan to reduce reliance on conventional fossil fuels. As a part of this shift, Indonesia plans to replace a portion of fossil-based fuels with various forms of biofuels. This includes biodiesel (B-series), bioethanol (E-series), and the development of SAF for the aviation sector. For instance, the implementation of B50 (50% of biofuel blending) in the second quarter of 2026[6], the mandate towards E10 (10% of biofuel blending) in 2028[7], and the introduction of SAF 1% in 2027[8]. Biofuels provide a decarbonisation option by leveraging existing fuel

infrastructure while supporting domestic feedstock development, rural economic growth, mining transport, and long-haul transport, making them an important component of the transition in the transportation sector.

Beyond biofuels, the adoption of EVs and the development of the EV ecosystem, represent another critical pillar of Indonesia's transport decarbonisation strategy. The Government aims to shift road transport from internal combustion engines (ICE) to EVs, including 2Ws, urban fleets, and public transport fleets, while simultaneously building domestic capability in battery manufacturing, charging infrastructure, and supporting industries. This approach is expected to reduce fossil fuel consumption and emissions from the transport sector, while positioning Indonesia as the key player in the region for EV and battery supply chain.

The transition into next-generation energy carriers is a staged process dependent on broader power systems and grid evolution. Currently, ammonia and biomass are primarily targeted for co-firing with conventional fuels in power and industrial plants to incrementally reduce carbon intensity, rather than fully replace fossil fuels. Hydrogen, by contrast, is being developed to function as a standalone fuel for high-heat industries, and potentially for power and transport.

However, the climate benefit of these next-generation carriers depends heavily on their production pathways. Crucially, as outlined in the MoEMR's energy transition roadmap, achieving net zero requires balancing continued hydrocarbon use with the large-scale deployment of CCUS. Because early production will rely on fossil feedstocks, both hydrogen and ammonia require adequate CCUS infrastructure and a renewable energy (RE) surplus to be genuinely classified as "low carbon".

Indonesia's energy transition pathway indicates oil and gas will remain a relevant component of the national energy landscape through 2060, albeit with an evolving role. The sector is not facing a phase-out, but rather an evolution towards energy applications. Natural gas will continue to support transitional fuels, transport, and industrial uses, and the deployment of low-carbon technologies. However, to reconcile this continued hydrocarbon use with the 2060 NZE target, it is imperative that the remaining oil and gas operations are integrated with CCS/CCUS technologies; otherwise, achieving the national climate objectives will be highly challenging. As such, the long-term role of the sector is not one of decline, but of transformation, aligned with Indonesia's broader objectives of sustaining economic growth while progressing toward a lower-carbon energy future.

2.2.3 Opportunities in integrating sustainability within the oil and gas industry

Within Indonesia's evolving energy landscape, the transition toward lower-carbon operations is fostering the development of new commercial avenues for oil and gas companies, particularly within the biofuel and "new energy" ecosystems. CCS technologies emerge as a mechanism to abate emissions from legacy extraction, while simultaneously establishing carbon management as a viable, standalone commercial service. Concurrently, the formalisation of the hydrogen and ammonia roadmap, alongside the downstreaming of the nickel value chain for EV batteries, establishes the foundational frameworks for hydrogen and ammonia to decarbonise the industrial, power, and transport sectors. Natural gas is a transition fuel, supporting power generation and serving high-heat and feedstock-intensive industries, such as fertiliser, cement, and steel.

On the demand side, structural shifts in transport are reshaping downstream opportunities rather than eliminating them. The nation's push towards higher biofuel blending mandates, such as B50 (50% biodiesel blending) and SAF, presents an expanding market, supported by abundant domestic agricultural feedstocks. Meanwhile, rising EV penetration affects gasoline demand growth in urban centres. However, this transition does not erase the overall demand. Instead, future market projections indicate a gradual decline in demand for oil and gas up to 2060. It results in the use of natural gas as a transition fuel and enabler, crude oil as petrochemical feedstock, and the commercialisation of low-carbon infrastructure across energy and industrial systems.

2.2.3.1 CCS/CCUS in Indonesia's energy transition

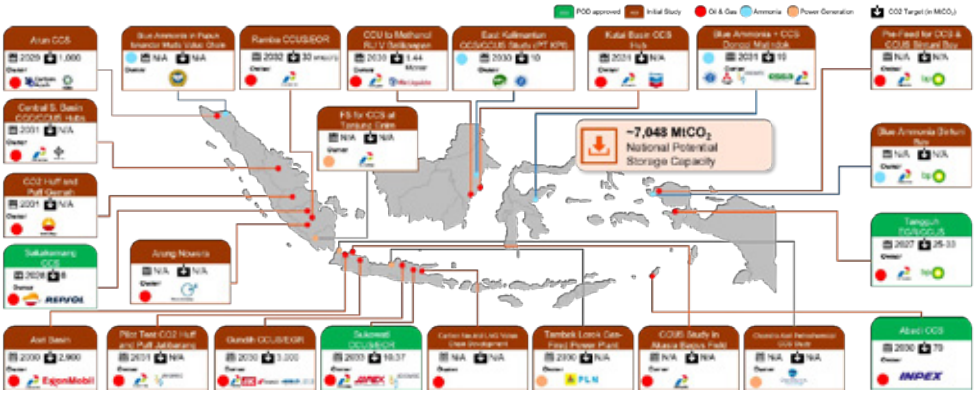
CCS and CCUS are technology options that Indonesia will rely on for decarbonising energy sector emissions, especially in hard-to-abate sectors, such as oil and gas. The core objective of these technologies is to allow for continued oil and gas production while ensuring it is less carbon intensive, as the primary environmental concern is the carbon and methane emissions generated during operations. According to the National Energy Policy, some energy solutions, mainly oil and gas or power generation operations, will utilise CCS/CCUS technologies based on the Government's plan to reduce GHG emissions[9].

Beyond the energy sector, CCS and CCUS technologies are essential for decarbonising hard-to-abate industrial processes that involve high-temperature heat or specific chemical reactions. In the fertiliser and petrochemical industries, these technologies are used to capture carbon dioxide generated during steam methane reforming for hydrogen production. This enables a transition from carbon-intensive grey ammonia to low-carbon blue ammonia, which is increasingly necessary for maintaining competitiveness in global markets. A leading example is *Pupuk Kalimantan Timur* (Pupuk Kaltim), which is exploring

the implementation of CCS in Bontang, East Kalimantan. The project aims to capture emissions from ammonia production and store them in nearby geological formations or saline aquifers within the Kutai Basin. By locating these initiatives in industrial clusters near geological storage, such as Bontang, companies can effectively utilise local infrastructure to lower long-term operational and logistics costs[10].

The storage of captured carbon in Indonesia utilises the capacity of inactive or unproductive oil and gas basins. These sites are located across the country. CCUS also involves using carbon capture for operational activities, such as EOR within active fields to boost oil and gas production in declining fields. In addition to domestic emitters, the Indonesian CCS/CCUS infrastructure is planned to accommodate cross-border markets. The required infrastructure includes injection facilities as well as transportation networks comprising the whole supply chain from shipping and pipelines to terminals. To manage the capital investment required for these projects, several partners and companies have formed cooperatives to develop CCS/CCUS facilities across the region[11].

Figure 2.2 Existing CCS/CCUS projects and studies[12]



Source: Law 7/2021, Ministry of Energy and Mineral Resources, Public Information, PwC analysis
Notes: COD: Commercial operations date (COD); N/A (not available) indicates that information regarding COD or capacity is not publicly available or has not yet been determined; $MtCO_2$: Million tons of CO_2

Currently, there are 20+ CCS/CCUS projects and studies ongoing in Indonesia. Among these, Tangguh UCC (operated by BP Berau) is the most advanced, and is currently in the construction phase with a targeted commercial operation date (COD) of 2026/2027. The Sukowati CCUS/EOR (Pertamina) project is a high-priority development that has successfully completed pilot injection tests, with full-scale implementation currently projected for 2033. Other priority projects nearing the end of this decade include Sakakemang CCS (2028) and Arun CCS (2029).

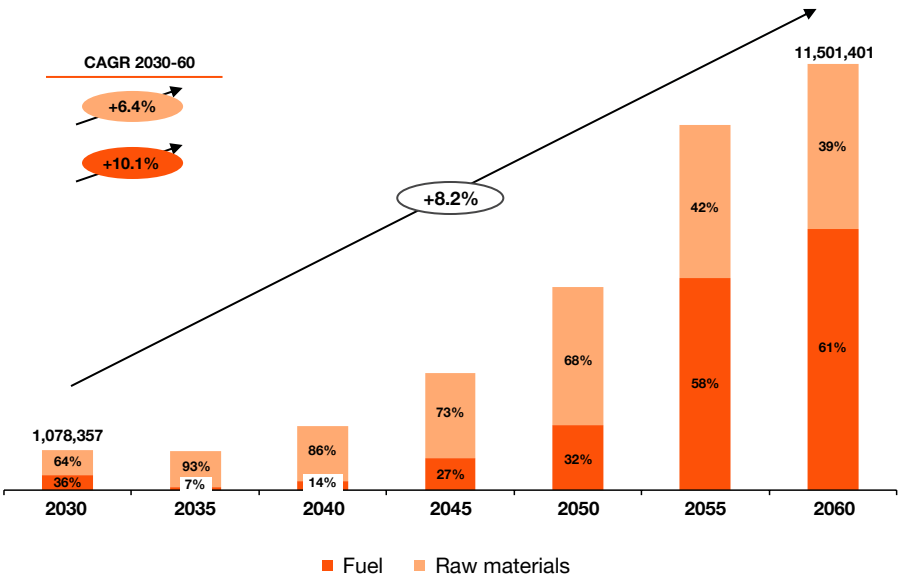
The remaining projects are primarily in the feasibility study (FS) or FEED stages.

The Government has released regulations to support CCS/CCUS implementation, such as regulations on CCS/CCUS operation (MoEMR Decree No. 2 of 2023 and Presidential Decree No. 14 of 2024), carbon trading through carbon exchange (Financial Services Authority Regulation/POJK No. 14 of 2023) that relates to the utilisation of CCS/CCUS capacity for traded carbon, and potential CCS/CCUS-based carbon credits for trading in the form of *Sertifikat Pengurangan Gas Rumah Kaca* (SPE GRK) based on Presidential Regulation (PR) No. 90/2021 and PR 110/2025[13]. Further technical guidelines and policy are required to strengthen national CCS/CCUS implementation, from incentives, licensing/permits, cross-border collaboration, to financing[14].

2.2.3.2 Hydrogen in the oil and gas sector for transition

In Indonesia, hydrogen is currently utilised as an industrial feedstock for oil refining and fertiliser production. Building on this foundation, the National Hydrogen and Ammonia Roadmap (*Roadmap Hidrogen dan Amonia Nasional*/RHAN), sets out a planned expansion where hydrogen is to be used as a clean fuel across multiple sectors. In the transportation sector, hydrogen serves as an alternative for conventional diesel in heavy-duty vehicles, such as trucks and buses, because fuel cell technology can handle heavier payloads and offers faster refuelling times compared to battery alternatives. In addition to transport, hydrogen provides a cleaner substitute for fossil fuels in industrial processes like steelmaking and chemical manufacturing. The roadmap also includes integration into national gas networks and power generation.

Figure 2.3 Hydrogen demand forecast based on usage (in tonnes, 2030-60)

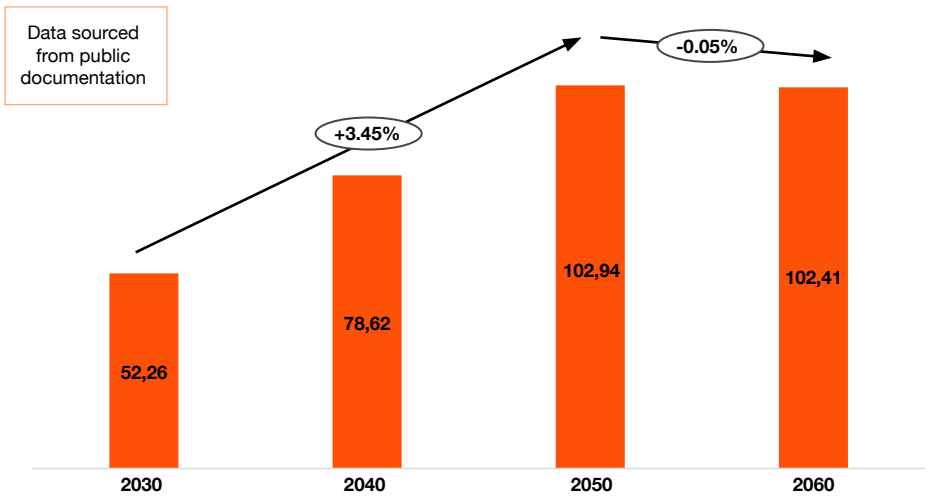


Source: National Hydrogen and Ammonia Roadmap (*Roadmap Hidrogen dan Amonia Nasional*RHAN)

For the oil and gas sector, the RHAN pathway signals opportunities to shift to hydrogen-led asset transformation. Existing gas infrastructure may be repurposed towards hydrogen integration, with hydrogen blending projected to increase to 40% by 2045 and to reach 100% by 2060, alongside a longer-term trajectory that includes 100% hydrogen use in gas turbines. This reframes midstream priorities towards asset conversion, integrity management, and enhanced safety, requiring phased upgrades to pipelines, compressors, valves, metering, and storage to address leakage risk, material performance, and end-use compatibility. Near-term momentum is anchored in industrial demand, as refineries already use hydrogen for fuel processing, creating an early commercial entry point for oil and gas incumbents through hydrogen production, logistics, and long-term supply alongside hydrogen infrastructure and fuel transport networks by leveraging their existing midstream capabilities. Over time, hydrogen adoption in heavy-duty applications provides a plausible decarbonisation route for the diesel-reliant segment, gradually moderating diesel demand and shifting downstream business towards hydrogen distribution and refuelling infrastructure.

2.2.3.3 LNG and flexible gas power for grid stability and industry applications

Figure 2.4 Natural gas as primary energy supply of Indonesia (in MTOE, 2030-60)



Source: KEN or GR No. 40/2025

According to the National Energy Policy, natural gas is positioned as a transitional fuel in the power, transport, and industrial sectors, as RE develops towards 2060. From Figure 2.4, natural gas will grow at a CAGR of 3.45% between 2030 and 2050, reaching a peak of 102.94 MTOE, reflecting its position as a transitional fuel.

From 2050 to 2060, the supply is projected to decline by approximately 0.05% annually, settling at 102.41 MTOE. This projected decrease after 2050 is driven by structural shifts in end-user demand; as RE expands, which is projected to grow at a 6.63% CAGR to reach a 68% share of the mix by 2060, the power and transport sectors will increasingly rely on mature technologies, such as advanced grid storage and widespread electrification, thereby reducing overall dependency on natural gas[15].

In the power sector, the 2025-2034 National Electricity Supply Business Plan (*Rencana Usaha Penyediaan Tenaga Listrik*/RUPTL) integrates natural gas to supply gas-fired power plants that enhance grid reliability, acting as a flexible backup supply for variable RE sources. While the share of natural gas in the total energy mix is projected to shift from 17.30% in 2050 to 15.40% by 2060, it remains the second-largest energy source after renewables. A key component of this strategy is the administrative mandate for power plant gasification. This programme targets the conversion of approximately 4 gigawatts (GW) of existing diesel-based (oil) power plants into gas-fired units. This conversion is supported by the development of midstream LNG infrastructure, including small-scale LNG receiving terminals and floating storage and regasification units (FSRUs), designed to reach isolated grids across the archipelago.

Beyond power generation, natural gas demand is sustained by its application in high heat and feedstock-intensive industries. The 2025-2045 RPJPN identifies natural gas as a required input for sectors where electrification remains technically constrained, including:

- Fertiliser and food security: serving as the primary feedstock for ammonia production, which is a critical component of the national food security agenda
- Heavy industry: providing high-temperature process heat for the cement, steel, and ceramics industries
- Downstream processing: supporting the energy requirements of the domestic mineral smelting industry, particularly in the nickel value chain.

The projected demand profile suggests that investment in the natural gas sector is shifting toward midstream connectivity and infrastructure flexible enough to handle future low-carbon molecules. Although oil and coal shares are projected to fall to 4.70% and 11.90% respectively by 2060, the absolute volume of natural gas demand will continue to expand. Natural gas maintains a 2.27% CAGR from 2030 to 2060, second only to renewables. This indicates that natural gas assets remain a foundational component of Indonesia's energy infrastructure for the next three decades, with the long-term investment landscape favouring LNG infrastructure that can eventually be integrated with CCS to align with 2060 decarbonisation objectives.


Photo source: PwC

2.2.4 Energy transition as a strategic enabler for sustainable finance and capital access

Inaction on energy transition exposes the oil and gas sector to heightened transition risks that can disrupt financial performance and balance sheets, with potential spillover effects on the wider financial system. Investments and lending linked to fossil fuel projects are increasingly perceived as higher risk, which may constrain capital inflows and limit access to long term financing. Since 2024, The Financial Services Authority of Indonesia (*Otoritas Jasa Keuangan*/OJK) has introduced the TKBI[16] to provide a standardised classification system for economic activities categorised as green, transition, or non-eligible. This framework was enhanced with the release of TKBI Version 2 in February 2025, which broadens the scope from a focus on energy to include critical sectors, such as construction and real estate, transportation, and agriculture (specifically addressing sustainable palm oil). The 2025 update introduces a more robust assessment methodology centred on four environmental objectives (EOs) and three "essential criteria": do no significant harm (DNSH), remedial measures to transition (RMT), and mandatory social aspects (SA)[17].

Against this strengthened assessment framework, the implication for high-emission sectors, particularly oil and gas, has become substantial. Under the 2025 TKBI, oil and gas activities are classified based on emission intensity, environmental safeguard, and alignment with Indonesia's decarbonisation pathway. While conventional oil activities are non-eligible, certain gas-related infrastructure may qualify as transition or even green if they demonstrably meet emission threshold criteria, implement energy management, and obtain a Company Performance Rating Programme in Environmental Management (*Program Penilaian Peringkat Kinerja Perusahaan Dalam Pengelolaan Lingkungan*/PROPER) rating of green for three consecutive years. CCS and related research and development (R&D) activities are typically categorised as green, given their role in reducing emissions from hard-to-abate sectors. This categorisation enhances financing optionality for oil and gas companies, as green or transition-aligned activities may access a broader range of sustainable financing instruments.

By introducing a dual-track evaluation, utilising the technical screening criteria (TSC) for large corporations and a simplified sector-agnostic decision tree (SDT) for micro, small, and medium enterprises (MSMEs) in the TKBI 2025

ensures that sustainable financing remains inclusive across the entire economy. In parallel, the OJK has issued the Climate Risk Management and Scenario Analysis (CRMS) framework, which encourages banks to assess and integrate climate-related risks into their financial risk management, including credit, market, and liquidity risks. Through the integration of these two initiatives, banks are increasingly expected to evaluate their exposure to high-emissions sectors using the updated 2025 criteria, proactively managing transition risks to safeguard financial stability while aligning with Indonesia's NZE targets[18]. In practice, this increasingly limits financing options for legacy oil and gas activities while expanding access to capital for transition-aligned investment.

Under these circumstances, energy transition has become a strategic enabler of capital access for oil and gas companies. Companies that diversify into transition-aligned investments, such as biofuel, EV infrastructure or other low-carbon solutions can access a broader range of financing instruments, including:

- Grants, particularly for technical assistance for projects or initiatives related to energy transition, climate action, and sustainable development, provided by several agencies, such as multilateral development banks (e.g. Asian Development Bank (ADB) and World Bank), climate funds (e.g. Green Climate Fund), bilateral aid (e.g. Japan International Cooperation Agency (JICA) and Just Energy Transition Partnership (JETP)), United Nations (UN) bodies (e.g. United Nations Development Programme), and philanthropies (e.g. Global Energy Alliance for People and Planet)
- Bank loans, including project loans, corporate loans, and export credit agency (ECA) facilities. Companies may also access concessional loans either in the form of: (1) concessional project loans with a rate below market terms for projects with strong environmental or development impact but limited commercial viability, typically offered by multilateral development banks, bilateral agencies, or climate funds, such as the ASEAN Catalytic Green Finance Facility (ACGF) under the ASEAN Infrastructure Fund (AIF) and managed by ADB; or (2) sustainability-linked loans, which link financial incentives in pricing/terms to agreed environmental, social, and governance (ESG) key performance indicators (KPIs), supported by annual reporting and mandatory independent external verification, with pricing penalties if targets are not achieved.
- Green bonds through aligned frameworks, such as PT SMI's Green Bond Framework, which identifies eligible green projects with clear environmental benefits and promotes low-carbon and climate-resilient growth.

Access to these financing options depends on the company's ability to demonstrate a credible transition strategy, supported by clear targets, eligible project pipelines, good governance, and transparent reporting aligned with TKBI and CRMS expectations. Early engagement with financiers is critical to clarify requirements, eligibility, align expectations, and streamline the process.

The key financing takeaways for oil and gas companies are clear. First, business transformation is no longer optional: while oil and gas demand may continue to grow in the near term, growth is expected to be moderate over time, gradually eroding legacy business. Second, delaying the transition increases both cost and competitive risk, as late movers face higher capital costs and reduced financing options. Third, the current window of transition-focused financial support, through policy incentives, concessional funding, and sustainable finance instruments represents a time-bound opportunity that must be actively leveraged. Whether through self-cannibalisation of existing business lines or partnerships with new technology providers, early diversification into transition-aligned activities provides a strategic hedge against more disruptive transition scenarios and strengthens long-term access to capital.

2.3 Tax considerations on carbon

2.3.1 Carbon tax

In November 2021, Indonesia enacted Law (*Undang-undang*/UU) No. 7/2021 on The Harmonisation of Tax Regulations (*Harmonisasi Peraturan Perpajakan*/HPP), which introduced carbon tax as part of the national tax system. The underlying objective is to integrate carbon pricing within the fiscal framework to support climate mitigation action, the transition to a low-carbon economy, as well as to support achieving Indonesia's NDCs.

Article 13 of this law states that the Government is authorised to impose a carbon tax on entities whose activities produce GHG emissions and/or involve the purchase of goods containing carbon. Furthermore, Article 13 also sets the rate of carbon tax to be higher than or equivalent to the carbon price in the carbon market per kilogram (kg) of CO_2e. In the circumstance that the carbon price in the carbon market is lower than IDR30,000/kg of CO_2e, the rate of carbon tax shall be set at not less than IDR30,000/kg of CO_2e.

The provisions as referred to in Article 13 shall come into effect on 1 April 2022, which is first imposed on movable bodies in the coal-powered steam power plant sector at a rate of IDR30.00 (thirty rupiah) per kilogram of CO_2e or equivalent unit. Initial plans from UU No. 7/2021 targeted the coal-fired power sector, with an agenda to expand this to broader sectors subject to readiness.

Further, the Indonesian Government issued PR No. 98/2021 on the Implementation of NEK to operationalise carbon pricing mechanisms in support of Indonesia's NDC under the Paris Agreement.

PR No. 98/2021 provided the first regulatory infrastructure for carbon economic value and the development of the Indonesian carbon market in national climate policy, covering:

1. **Carbon trading**: Establishing mechanisms for trading carbon emission allowances and certificates based on greenhouse gas registries.

2. **Carbon tax**: Linking carbon tax instruments with the broader carbon market, where liabilities for emissions exceeding caps could be addressed through trading or taxation.
3. **Institutional arrangements**: Guidance on governance, monitoring, and evaluation of carbon pricing instruments to support mitigation action.

As the carbon market further develops, the Government most recently issued PR No. 110/2025 regarding the Implementation of Carbon Economic Value Instruments and National Greenhouse Gas Emission Control, establishing a more integrated and regulatory framework for carbon pricing and GHG control.

PR No. 110/2025 acts as an umbrella policy for carbon economic value instruments, which includes carbon tax implementation in Indonesia. Carbon tax applies to the energy sector, of which oil and gas is a sub-sector. With the establishment of the steering committee responsible for these carbon economic value instruments' implementation, the ministries for energy, industry, and other economic sectors will engage in the carbon economic value implementation to achieve NDC targets, also implying that oil and gas operations will be subject to these instruments as regulatory readiness and implementing rules mature.

2.3.2 Carbon trading for voluntary market

Indonesia's development in the carbon trading framework is in support of the country's broader climate policy. Introduced in 2021, Indonesia has progressively refined its carbon pricing and market mechanisms to align both with national emissions reduction targets and with emerging international market practices.

The enactment of UU No. 7/2021, known as the HPP law, provided the initial statutory foundation for carbon pricing instruments in Indonesia. Under this law, carbon emissions that negatively impact the environment can be subject to fiscal measures, including carbon tax and mechanisms that integrate carbon trading into fiscal policy. It formalised the principle that emissions reduction activities could be supported through economic incentives and market-based mechanisms linked to national policy objectives. UU 7/2021 explicitly sets out the polluter pays principle and anticipates the phased implementation of carbon taxation and trading mechanisms, including the combination of cap-and-tax/carbon tax and cap-and-trade/carbon trade systems to effectively internalise carbon externalities in economic activities.

Photo source: PwC

In October 2021, the Government issued PR No. 98/2021 to implement the NEK and support the achievement of Indonesia's NDC. This regulation established the first formal structure on carbon trading, focusing on mechanisms for measurement, reporting, and verification (MRV) frameworks to oversee the carbon market. PR No. 98/2021 placed carbon market activities in the context of meeting national emissions targets, including the use of tradable credits within Indonesia's emissions reduction strategies.

Under this framework, Indonesia launched a domestic carbon exchange (IDXCarbon) in 2023, marking the operational entry point for carbon units trading. However, this was initially limited to domestic emissions. The framework PR No. 98/2021 set out did not sufficiently accommodate voluntary carbon markets (VCM) or provide clear mechanisms for international trading of carbon credits.

In October 2025, PR No. 110/2025 was established on the Implementation of Carbon Economic Value Instruments and National GHG Emission Control, following up PR No. 98/2021 with a better framework. PR No. 110/2025 restructures carbon market governance to support both compliance and voluntary markets, whilst enhancing the legal regime for international carbon trading, and introducing a Carbon Unit Registry System (*Sistem Registri Unit Karbon*/ SRUK).

Additionally, PR No. 110/2025 simplifies the procedural requirements for carbon transactions, enables broader private-sector engagement as well as supports integration of internationally recognised standards such as the Verra and Gold Standard into Indonesia's carbon trading framework. An additional important aspect is also the resumption of international carbon trade, allowing foreign buyers to purchase Indonesian carbon credits under recognised standards.

PR No. 98/2021 and PR No. 110/2025 acknowledge the potential for carbon credits arising from CCS/CCUS activities to be traded in the carbon market. These credits would be required to undergo verification and validation under recognised third-party methodologies (e.g. Verra, Gold Standard, etc.), which would then be traded in the form of Greenhouse Gas Emission Reduction Certificate (*Sertifikat Pengurangan Emisi Gas Rumah Kaca*/SPE-GRK). However, the current regulations do not yet mention or approve a specific carbon credit methodology for CCS/CCUS, leaving the applicable methodological framework to be defined in further implementing guidance.

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 (*Peraturan Pemerintah Pengganti Undang-Undang*/Perppu) No. 2 of 2022 on Job Creation. Perppu No. 2 revoked and completely replaced Law No. 11 of 2020 concerning Job Creation (Law No. 11/2020), which had previously been declared legally defective and conditionally unconstitutional by Indonesia's 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. 22/2001). The laws amended by the Job Creation Law relating to the oil and gas sector and mentioned in this guide are:

1. Oil and Gas Law No. 22/2001 (Law No. 22/2001)
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 Law No. 22/2001. The objectives of Law No. 22/2001, 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
f. Enhance public welfare and prosperity equitably, while maintaining the conservation of the environment

Following the 2012 Constitutional Court decision to disband the upstream regulator (*Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi*/BP Migas), there has been an expectation that Law No. 22/2001 would be further amended. A draft amendment to Law No. 22/2001 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 SOE. *Badan Usaha Khusus Minyak dan Gas Bumi* (BUK Migas) will be authorised by the state to conduct business activities in the upstream (independently and/or through cooperation with contractors) and downstream sectors.

Whilst Law No. 22/2001 specifies 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 (JCC), predominantly PSCs, between the PEs and the executing agency (SKK Migas). Meanwhile, Article 7 of Law No. 22 specifies that downstream activities are governed through the business licences 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
i. The development and application of oil and gas technology

Both upstream and downstream business activities may be carried out by 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

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 oil and gas industry concerning the implementation of GR 79, the Government enacted GR No. 27 (GR-27) on 19 June 2017 and subsequently GR No. 93 on 31 August 2021 (GR-93). These amendments introduced important refinements, particularly with respect to the income tax treatment applicable to the transfer of participating interests—an issue of critical relevance for both investors and operators engaged in such transactions. The principal provisions of GR 79, together with the modifications introduced 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 GS PSC model for conducting upstream business activities through MoEMR Regulation No. 8/2017. However, this regulation was 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 MoEMR Regulation No. 14/2025

The Indonesian Government has enacted MoEMR Regulation No. 14/2025 regarding Cooperation in the Management of Parts of Working Areas for Enhancing Oil and Gas Production (MoEMR Regulation 14/2025). This regulation establishes a comprehensive framework outlining various forms of collaboration between oil and gas contractors and local entities, including regionally-owned enterprises (*Badan Usaha Milik Daerah*/BUMD), cooperatives, MSMEs, and other eligible business entities. The objective is to optimise national oil and gas production, particularly from idle wells and marginal fields, and to provide clearer guidelines on broader operational and technological cooperation that were not addressed under the previous MoEMR Regulation 37/2016.

Pursuant to this policy, the contractor may receive an incentive of up to 10% under the PSC, contingent upon recommendations from SKK Migas or Aceh Oil and Gas Management Agency (*Badan Pengelola Migas Aceh*/BPMA) and approval by MoEMR. However, the mechanism for determining the incentive is under development. No PSC agreements have been executed or amended to reflect this policy to date. The implementation remains in a transitional and socialisation phase, as the Government is currently identifying potential working areas for application. Further developments in this area should be closely monitored.

3.1.5 Restrictions on foreign workers

Currently, by the revocation of MoEMR 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.).

3.1.6 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.

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.

3.1.7 Licences

Business licensing, including for business activities in the oil and gas sector, is governed by Government Regulation No. 28 of 2025 on the Organisation of Risk-Based Business Licensing (GR No. 28/2025), which replaced GR No. 5/2021.

GR 28/2025 establishes Risk-Based Business Licensing (*Perizinan Berusaha Berbasis Risiko*/PBBR) as a risk-based approach derived from the risk analysis of each business activity. Under GR No. 28/2025, a business licence (*Perizinan Berusaha*/PB) is mandatory to conduct business activities and, in principle, is obtained after fulfilling the basic requirements (*Persyaratan Dasar*/ PB) and the processing of basic requirements. PB and supporting business licences (*Perizinan Berusaha untuk Menunjang Kegiatan Usaha*/PB UMKU) is conducted electronically through the 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 Standard Classification of Business Fields (*Klasifikasi Baku Lapangan Usaha Indonesia*/KBLI) category are detailed in the attachment of GR 28/2025 and further elaborated in technical ministry regulations, such as MoEMR Regulation No. 5/2021.

PEs engaging in upstream oil and gas activities in Indonesia are required to obtain a business identification number (*Nomor Induk Berusaha*/NIB), as the production sharing contract is treated as a licence and contracting entities must hold an NIB under the risk based licensing framework (Article 144).

3.2 Other relevant laws

3.2.1 The Energy Law No. 30/2007

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).


Photo source: PwC

3.2.2 National energy policy

GR No. 40/2025, enacted on 15 September 2025, sets out Indonesia's KEN and updates the previous National Energy Policy framework under GR No. 79/2014.

GR No. 40/2025 confirms that the National Energy Policy has been approved by the House of Representatives and serves as a guiding framework for national planning in the electricity, oil, gas, coal, and other energy subsectors, and as a reference for medium-term development planning and relevant ministries/agencies' strategic plans. GR No. 40/2025 defines the National Energy Council (*Dewan Energi Nasional*/DEN) as a national, independent, and permanent body responsible for the National Energy Policy, and assigns DEN specific roles, including:

i. Providing guidance on the preparation of the Regional Energy General Plans
ii. Supervising cross-sectoral energy policy implementation and determining the type/volume/timeframe/location of national energy buffer reserves (*Cadangan Penyangga Energi*)
iii. Stipulating response measures in the event of an energy crisis and/or emergency

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 modelling projection targets based on GR No. 40/2025

Energy Source	2025	2050
New and renewable energy (NRE)	minimum 19%-23%	minimum 53%-55%
Crude oil	75.3 mil – 82.1 mil TOE	45.8 mil – 54.7 mil TOE
Coal	67.2 mil – 68.7 mil TOE	80.3 mil – 81.8 mil TOE
Natural gas	18.8 mil – 20.1 mil TOE	40.4 mil – 47.4 mil TOE

Source: GR No. 40/2025.

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 permanent establishment (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 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 PR No. 10/2021 (as amended by PR 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 PR 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.

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, implementing corporate social responsibility programmes and ensuring environmental conservation.

Investors exploiting non-renewable resources must also allocate funds to site restoration that fulfil the standards of environmental responsibility. Sanctions for non-compliance with the implementation of corporate social responsibilities programmes are include restrictions on business activities and the freezing of business activities.

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 the Forest Area Utilization Approval (*Persetujuan Pengunaan Kawasan Hutan*/PPKH) from the Ministry of Forestry. The PPKH 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) 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 12 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
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 No. 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 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 three months for oil and gas businesses)
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 No. 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 flow. 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
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 for 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
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. PR 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
d. Implementing development in the field of energy and mineral resources

3.3.2 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
g. To appoint sellers of the State's portion of petroleum and/or natural gas to the Government's best advantage.

3.3.3 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 BPMA, 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 XII of the DPR covers energy, mineral resources, environmental, and investment matters. This includes oversight of oil and gas activities, the drafting of oil and gas related legislation, control of the state budget (APBN), and oversight of related government policies specifically on oil and gas matters.

Regional governments participate in approving plans of development (PoD) by issuing local permits and land rights.. In addition, regional governments have the right to be offered a 10% participating interest in a PSC. For further details, 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.

The state gas company (*PT Perusahaan Gas Negara*/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 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 NRE sub-holding
4. PT Pertamina Patra Niaga as the commercial and trading sub-holding

Photo source: PwC

5. PT Kilang Pertamina Internasional as the refining and petrochemical subholding
6. PT Pertamina International Shipping as the integrated marine logistics subholding

In February 2026, PT Pertamina Patra Niaga, PT Kilang Pertamina International, and certain components of PT Pertamina International Shipping operations have officially merged to become the downstream subholding with PT Pertamina Patra Niaga as the surviving entity.

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).

4 (Conventional) Upstream sector

As previously mentioned, the Government introduced the GS 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 GR 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 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, which not only provides oil and gas investors option to choose between a conventional cost recovery PSC or a GS PSC and to convert their PSCs, but also expressly revokes Regulation-08 along with its subsequent amendments. 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 PE (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)
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).
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.

No.	Subject	Remark
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.
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 G&G survey 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.
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
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 EOR contracts). The second category refers to the agreements entered into by participants in a PSC, TAC, or EOR contract 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 carry out the work programme during the first six years of the exploration period, however, under recent PSCs, the work programme must be completed within the first five 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 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 submit a performance bond to cover the initial three contract years of activity amounting to 10% of the firm's working commitment. 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 within one month after cumulative petroleum production within the contract area has reached certain barrels of oil equivalent in certain stage.

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

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 BUMD. This requirement was initially established by

MoEMR Regulation No. 37/2016 and has since been amended by MoEMR Regulation No. 1/2025. 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 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 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 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 approval 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 (*Rencana Penggunaan Tenaga Kerja*/RPTK and *Rencana Penggunaan Tenaga Kerja Asing*/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 *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 obliged 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, environmental protection, and using EOR technology, as appropriate.

4.1.17 Dispute mechanism-arbitration

SKK Migas has established a special dispute resolution mechanism, 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 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 contractors 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.
g. The transfer of the PSC's participating interest to non-affiliates is only allowable:
    - With the MoEMR and/or SKK Migas' approval
    - 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 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.
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
e. Insurance premiums and receipts from insurance claims

Over time, several principles and regulations have been developed by entities like SKK 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 contractors to be 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 a (conventional) PSC, 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 refer to the specific PSC agreement.

4.2.2 Equity share - Oil

Investment credits

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 have 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 on 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 to the Government upon landing in Indonesia, but the contractor can claim depreciation.
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
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 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
v. Commercial audit costs

Sharing of production oil

Crude production in excess of the amounts received for FTP, cost recovery, and investment credits are 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
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, 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
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 profit 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 terms of value 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 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%)	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

Photo source: PwC

Illustrative presentation of old PSC in SKK Migas 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 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 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

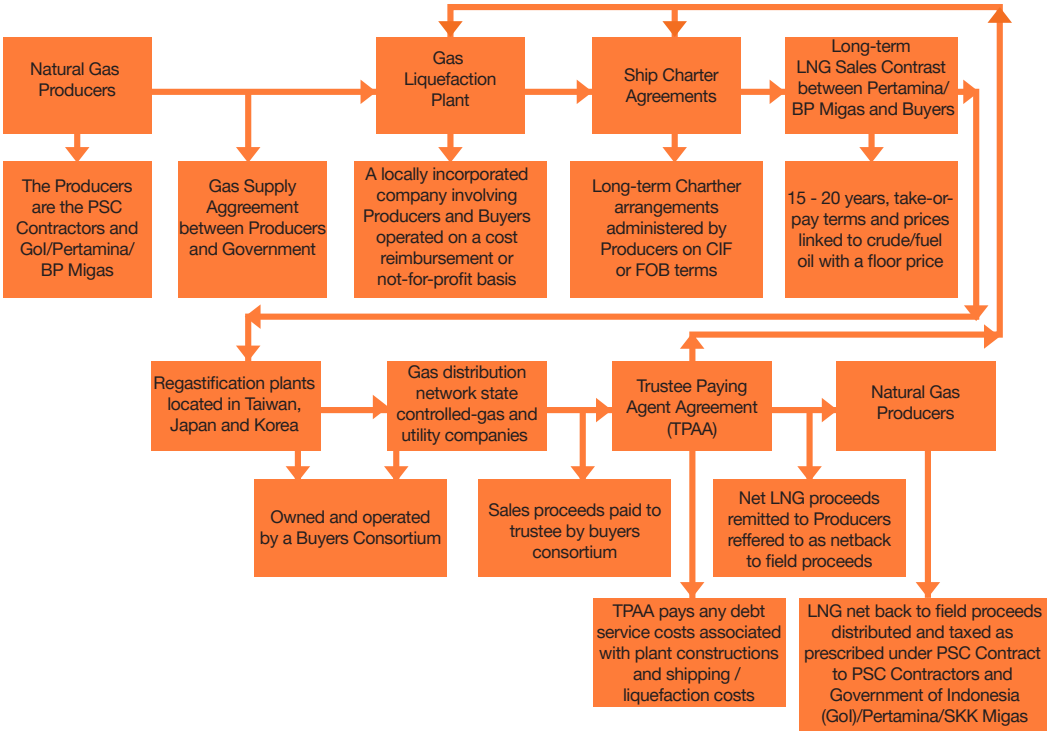
Lifting variances will occur each year between the contractor and the Government. These under/ over-lifting amounts are settled with the Government in cash or from production and can be considered as sales/purchases of oil or gas respectively. The individual members of the PSC may in turn have under/over-lifting 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 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, 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), VAT, tax rate differentials (and associated transfer pricing), and 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 made by either tender or direct appointment (with certain requirements) and only vendors with Supporting Business Capacity Certificate (*Surat Kemampuan Usaha Penunjang*/ SKUP) and an Administrative Document Replacement Certificate (*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
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 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. SKK Migas and the MoEMR will conduct a physical inspection of inventory items slated for write-off. The

results of this verification will be submitted to the Directorate General of State Assets (*Direktorat Jenderal Kekayaan Negara*/ DJKN) under the MoF. DJKN will issue a recommendation letter specifying whether the inventory should proceed through the auction process, be transferred to another PSC, or be fully disposed of. Upon approval, the inventory is typically charged to cost recovery (if not yet charged), removed from database records, and either transferred to an 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 exploration wells are charged to operating expenses as they are incurred. If commercial reserves are determined in the contract area and the exploration 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, 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

Key standards reference and comparison between PSC accounting, US GAAP, and IFRS			
Area	**PSC**	**US GAAP**	**IFRS***
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
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.

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 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
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: PwC

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 No. 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.
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
    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
    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
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 (*Badan Pengawasan Keuangan dan Pembangunan*/BPKP) 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.
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 (*Pajak Bumi dan Bangunan*/PBB) 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.

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

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).
   - "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. 93 (GR-93), 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).
- 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 the Coretax 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 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.
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 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.

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 (*Surat Setoran Pajak*/SSP)) will be marked with State Revenue Transaction Number (*Nomor Transaksi Penerimaan Negara*/NTPN) and Bank Transaction Number (*Nomor Transaksi Bank*/NTB).

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.

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-11 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 Coretax 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).

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
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 to 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 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)
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.
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 SE -46 to provide further clarification on the completion of the Notification of PBB Objects (*Surat Pemberitahuan Objek Pajak*/ SPOP) 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"
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
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, storage, and processing facilities such as floating storage and offloading (FSO), floating production system (FPS), floating production unit (FPU), floating storage unit (FSU), floating

production storage and offloading (FPSO), and floating storage and 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 when 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.
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.
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
   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, 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

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".
      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.

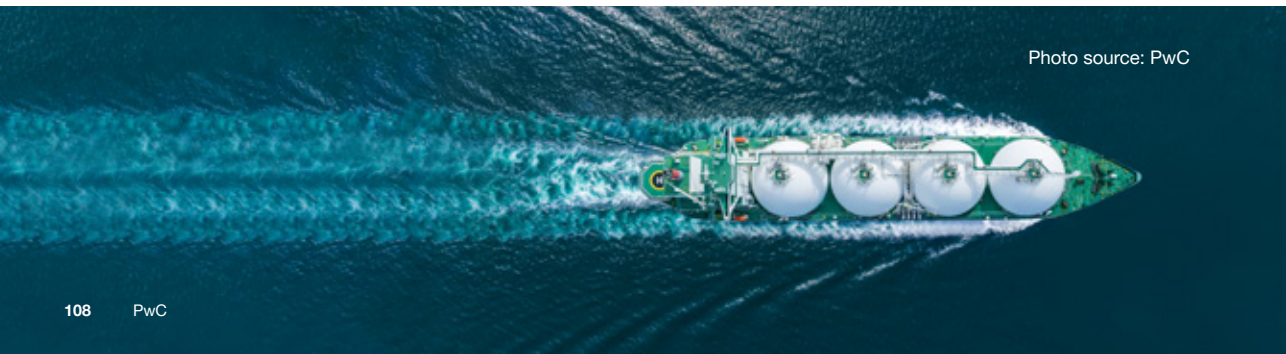


Photo source: PwC

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)
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 some 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 the 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 that 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.

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			Remarks
	Asia, Africa, and the Middle East (USD)	Europe, Australia, and South America (USD)	North America (USD)	
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	Production 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%

PSC Era	Income Tax - General	Income Tax – Branch Profits	Combined Tax Rate	Production Share (Oil)	After Tax	Production Share (Gas)	After Tax
2008	30%	20%	44%	0.4464	25%	0.7143	40%
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, and 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 cancelling 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 (MNE) 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

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 are 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)
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
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 (*Kantor Pelayanan Pajak Minyak dan Gas Bumi*/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 KPP Migas 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 Coretax 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".
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.
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%)
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 the 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 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 (*Surat Keterangan Bebas*/ SKB).

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)
2) 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 No. 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 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 cashflow 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. 139/2024 (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.
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.

Photo source: PwC

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 Coretax 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 2000s PSCs.
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) and incentives during exploitation apply according to project economics
   (b) Facilities apply during the entire contract period
   (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
   (ii) Are produced locally but do not meet the required specifications
   (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 that 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
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
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 a 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 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 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 and CD
l. Abandonment
m. Project economics
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
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
c. Changes in investment costs

4.6.2 AFEs

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
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

Photo source: PwC

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
    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, 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
    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
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
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, and 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.
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 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

FCR including the offshore loan report to BI

Law No. 24 of 1999 on Currency Flow and Exchange Rate System and its implementation regulation, being 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 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
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 be subject to an administrative sanction in the form of a written warning by BI.

Reporting obligation in relation to offshore borrowing

- Report to the MoF
  In relation to offshore borrowing and in addition to 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.
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 - GS PSC features

In 2017, MoEMR Regulation No. 8/2017 introduced a PSC scheme based on the “gross production split” methodology. This marked a significant change to Indonesia’s PSC arrangements, 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 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 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 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%. 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 BPKP and 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 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.
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 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.
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
   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
   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 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.
   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. 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 effectively borne by the contractor
xi) Government bonuses

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.

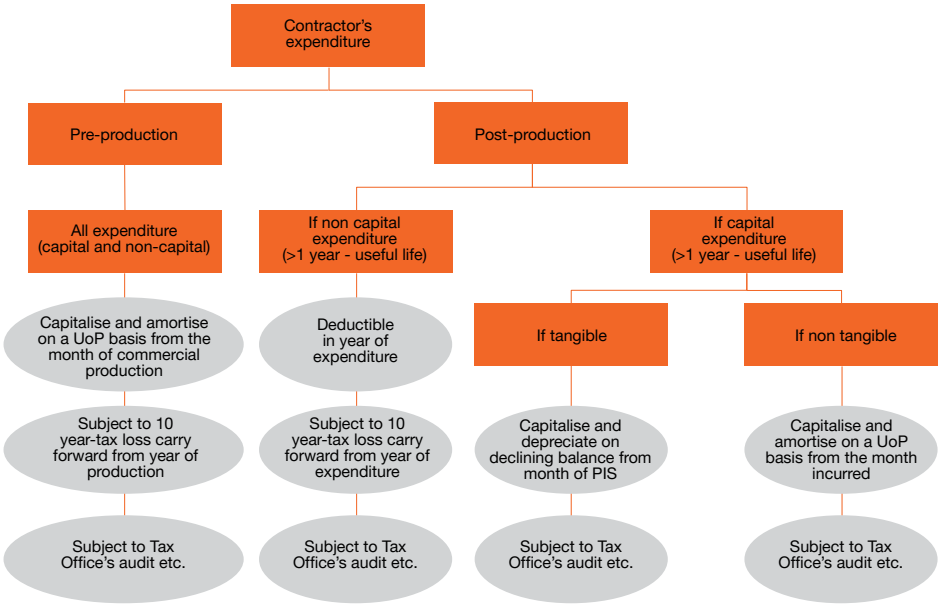
Pre-production/deferred spending

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 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.
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 No. 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
d. Report any PSC transfers to both the MoEMR and the MoF

Pursuant to Article 23, Operators are required to:

a. Deal with the 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.
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.
d. A 100% reduction in PBB.

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 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
    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 GS*/SKFP) 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)
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
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 SPOP
b. A copy of the GS SKFP to the Tax Office where the PBB object is administered

The DGT would then issue an SPPT) 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.

Photo source: PT Pertamina (Persero)

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 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-066/2021

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
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 LPG
b. The distribution of gas via pipelines (Citigas and long-distance pipelines)
c. Proposed refineries and downstream LNG facilities
d. LNG regasification terminals
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, 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 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 BKPM and 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
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 PBBR 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
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
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 licence 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 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
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 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
d. Comply with the masterplan for a national gas transmission 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
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
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
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
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
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
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
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.

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 pwc.com/id. Most downstream entities pay taxes in accordance with the prevailing law, although some activities can be subject to different 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 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.).
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.
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 PMK No. 136, the Pillar Two policy would apply to 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 DGT issued PER No. 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 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. 69/2024 (PMK-69), which amends 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 (already lapsed).

Up to the time of writing, the MoF has not, however, issued any amendment or revocation to PMK-69 to extend this incentive. Development in this area must closely be monitored.

That aside, it may still be worth mentioning the incentives that PMK-69 can provide, as outlined below.

Under PMK-69, the benefits of the tax holiday facility remain largely the same (with PMK-130), 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 an 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 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. Te 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.
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).
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. 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
b. The new investment value – if the new investment value is lower than the investment value resulting from the spin-off

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% 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.
   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.
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, PPnBM, import duty, and excise.

There have been 25 areas designated as KEKs.

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 are 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, now streamlined under PMK-81), PMK-96/2023 (as amended with PMK-111/2023 and PMK-4/2025).

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 No. 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 the 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 an 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 lastly amended by the MoF Regulation No. 62/2025 (PMK-26/62). 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 BPH Migas' business entity levies on fuel oil supply, distribution, and natural gas transmission

General

A PT company must pay business entity levies to BPH Migas if:

a. It carries out the distribution and trading of fuel oil.
b. It carries out natural gas transportation through pipelines or natural gas trading business through pipes that have distribution network facilities.

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 business entity levies 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.
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 business entity levies on transporting natural gas are:

a. PT companies holding a licence for oil and natural gas transportation through pipelines in the transmission section and/or distribution network areas that already have special rights.
b. PT companies holding an oil and natural gas trading business licence for natural gas trading business activities that use natural gas distribution facilities and networks in distribution network areas that have special rights.

Sanctions

Any late payment of business entity levies is subject to a 2% penalty per month for a maximum of 24 months.

Tariff

Based on the latest regulation, i.e. GR No. 9/2025, the business entity levies must be settled on a monthly basis and are calculated as follows:

- Fuel oil supply and distribution: 0.25% of the selling price x actual monthly volume sold.
- Natural gas transportation via pipelines: 2.5% of transportation tariff x actual volume transported.
- Natural gas trading via pipelines: 0.25% of the selling price x actual volume or energy sold.

6.3 Commercial considerations

When reviewing a potential downstream asset, investors should consider a number of commercial considerations, including the following:

Table 6.3 - Commercial considerations for investors when reviewing a 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.
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.

Topics	Issues
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.
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.

Topics	Issues
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 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 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.

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.

MoEMR Regulation No. 4/2018 introduces greater flexibility in Indonesia's downstream natural gas sector, including through the recognition of alternative transportation and distribution modalities such as CNG and LNG, as well as dedicated gas pipeline systems for own use, subject to regulatory approval. The regulation establishes the licensing framework for natural gas transmission and distribution business activities, in addition to licensing requirements for natural gas storage activities. Business entities assigned to specific distribution network areas are required to develop and provide gas infrastructure, particularly pipeline networks, in accordance with their designated areas.

The provisions and procedures for determining the of allocation, utilisation, and price of natural gas are regulated in MoEMR Regulation No. 6/2016:

Table 6.4 - The provisions and procedures on determination of allocation, utilisation, and price of natural gas regulated under MoEMR Regulation No. 6/2016

	MoEMR Regulation 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 f. Industries that use gas as fuel
Buyer	a. SOEs b. BUMD c. Gas-fired power/electricity companies d. Companies holding *izin usaha niaga gas bumi* e. LPG companies 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 a project's 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.

The MoEMR determines the sales price of flare gas for business entities based on the proposal from SKK Migas. If the flare gas is sold to government institutions, the maximum sale price is USD0.35/million British thermal unit (MMBTU).

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 up the guidelines and under those guidelines, they have to approve on large purchases of most equipment and services provided to the upstream sector.

Purchases by JCCs 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 No. 14/2018. However, the recent SKK Migas Guidance PTK 066 regarding gross split (GS) may imply that PTK 0120 only applies to the conventional PSC, while the procurement activities for GS PSCs will be self-managed.

MoEMR Regulation No. 14/2018 requires oil and gas supporting businesses to conduct registration to obtain an oil and gas 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 an 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 No. 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 pwc.com/id). Some exemptions exist for oil field service providers concerning import taxes (Article 22 Income 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 KPP Migas. This office is 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 MoF Regulation No. 136 (PMK-136), Pillar Two policy would apply to 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 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.

7.3.1 Foreign-owned drilling companies (FDCs)

FDCs have historically carried out their drilling activities in Indonesia via a branch or 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 profit 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 MoF Regulation No. 112/2025 (PMK-112).
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 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 NPWP and filing an Indonesian individual tax return.

7.4 Shipping/FPSO and 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
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 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)
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).
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 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, FPS, FPU, 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 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 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 stipulates 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.

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.

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Acknowledgements

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

Photographic contributions

We gratefully acknowledge and thank the following company that has provided photographs for inclusion in this publication:
PT Pertamina (Persero)

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