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MEDCOENERGI

PT MEDCO ENERGI INTERNASIONAL Tbk

(incorporated with limited liability under the laws of the Republic of Indonesia)

Investor Document

July 2017

TABLE OF CONTENTS

	Page
BUSINESS	**1**
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	**47**
RISK FACTORS	**78**
GLOSSARY	**104**

BUSINESS

Overview

We are an integrated energy and natural resources company operating through our core oil and gas exploration and production business and through significant investments in power generation and mining. We are the largest independent publicly listed oil and gas exploration and production company in Indonesia based on market capitalization. In addition, based on a peer analysis conducted by Wood Mackenzie, we are the largest upstream oil and gas exploration and production company among our Peer Group as of and for the year ended December 31, 2016 based on proved and probable reserves and production in Asia (our Peer Group refers to the group of peers identified by Wood Mackenzie, consisting of independent exploration and production companies with a noteworthy proved and probable reserves and production footprint in South and South East Asia. These consist of PT Saka Energi Indonesia, PT Energi Mega Persada Tbk., Ophir Energy plc, Premier Oil plc and KrisEnergy Ltd.). We primarily focus on our activities in Indonesia, and also have operations in the Middle East, North Africa and the United States.

We believe that 2016 was a transformational year for our business. We achieved key milestones in our oil and gas business through, among other things, our acquisition of an interest in, and becoming the operator of, the South Natuna Sea Block B and the associated West Natuna Transportation System, increasing our interest in Block A Aceh to 85%, obtaining a 10-year extension of, and increasing our interest to 100% in, the Lematang PSC in South Sumatra and receiving estimation or assessment of an additional 880 BCF of gross 100% field 1C contingent resources of gas at the Senoro-Toili PSC. We also entered the copper and gold mining sector through our acquisition of a 41.1% indirect interest in AMNT, which operates the Batu Hijau mine, a very large, established open pit mining and processing operation on the Island of Sumbawa in Indonesia, processing about 42 Mtpa of ore per annum to produce copper and gold concentrates.

In 2015 and 2016, we significantly improved our organizational cost structure. Our full year unit cash production cost was reduced to US$8.8/BOE in 2016 compared to US$12.3/BOE in 2015 and US$15.4/BOE in 2014. Our unit cash production cost per BOE for the three month period ended March 31, 2017 was US$8.1/BOE. Our cost reduction programs have targeted both larger scale cost reduction opportunities, such as drilling rig rate reductions and smaller scale granular opportunities, such as travel and training budgets. We currently are committed to maintaining a unit cash production cost per BOE below US$10 through 2021.

We have interests in ten oil and gas properties in Indonesia, six of which are currently producing and in oil and gas properties in five countries outside of Indonesia, namely the United States, Tunisia, Yemen, Libya and Oman. In Indonesia, our blocks are held under production sharing arrangements with SKK Migas, Indonesia's national upstream oil and gas regulator. Under these production sharing arrangements, we are entitled to recover our costs and earn an agreed after-tax share of the production once the block is declared commercially exploitable by SKK Migas.

We plan to continue to strengthen our producing assets portfolio by the phased development and monetization of our existing portfolio of discovered gas assets. We aim to bring our projects on-stream on time and within budget, particularly our Block A Aceh block, which is our most advanced development in Indonesia. First gas production and gas deliveries under the Block A take-or-pay backed, fixed-price domestic contract are expected to begin in 2018. We then plan to focus on Senoro-Toili phase II where the investment decision with respect to the preferred development scenario is expected to be made in the third quarter of 2018. Our operations at Senoro-Toili phase I are fully contracted under off-take agreements both for the upstream and downstream sectors. After this Senoro-Toili phase II investment, we plan to focus on our next large development, which is phase II of our Block A Aceh block and the monetization of our other discovered gas resources at this block. As a result, going forward, we expect that a larger percentage of our production will consist of production from Senoro-Toili, South Natuna Sea Block B and Block A Aceh, as certain of our existing blocks, including Rimau PSC and South Sumatera PSC, are in mature stages of production.

In 2016, our oil and gas production split was 46.7% oil and 53.3% gas (including production under our Oman service contract) and 39.0% oil and 61.0% gas (excluding production under our Oman service contract). Of the gas production, 50.9% was sold under fixed price contracts to PLN, the Indonesian state electricity generator, Pertamina (the national oil company of Indonesia) and Pusri (an Indonesian fertilizer producer wholly owned by the Government). The remaining gas production is sold to Sembgas, Petronas or indirectly pursuant to LNG contracts to KOGAS, Chubu Electric Power Co. Inc and Kyushu Electric Power Co. Inc. Our gas off-takers include blue chip customers with strong credit profiles.

In addition to our core oil and gas business, we have significant investments in power generation and mining. Through MPI, we have a significant investment in the power generation sector in Indonesia. MPI is an IPP and O&M provider, in which we currently own a 49% interest, the remaining interest in which is owned by PT Saratoga Power, an unrelated third party, which is owned indirectly by PT Saratoga Investama Sedaya Tbk (77.7%) and Finance Corporation (22.3%). MPI promotes a green energy platform and has interests in gas-fired power plants, geothermal energy and hydro-electricity. Established in 2004, MPI owns and operates seven gas-fired power generation assets with a total gross capacity of over 296.7 MW and is also currently developing its 275 MW gas-fired IPP project and six other renewable assets, including geothermal and mini hydro power plants. MPI also owns a minority share in the Sengkang gas-fired power plant in South Sulawesi and acquired a long-term O&M contract for the Tanjung Jati B power plant in Jepara, Central Java through one of its subsidiaries. MPI is also developing 3x110 MW geothermal power plant in Sarulla, North Sumatra, where the commercial operation of the first 110 MW unit was achieved in March 2017 (the remaining two units, each of 110MW capacity, will be finished by the end of 2017 and mid-2018, respectively). For the Sarulla geothermal power plant, MPI is also appointed as operator under the O&M contract.

Our copper and gold mining operations are conducted through our joint venture, AMNT, in which we made our investment in November 2016. We and our joint venture partner, PT AP Investment ("API") each own a 50% interest in AMIV, which in turn indirectly owns 82.2% of AMNT (AMIV also acquired certain pledged rights from PT Pukuafu Indah, an unrelated non-controlling shareholder in AMNT, which gives AMIV a 100% economic interest in AMNT). AMNT owns and operates the Batu Hijau mine, located on the island of Sumbawa, approximately 950 miles east of Jakarta. The mining concession covers an area of 66,000 hectares, which includes the Elang copper and gold resource and several exploration prospects including, Lampui, Rinti, Batu Balong, Nangka and Teluk Puna.

As of March 31, 2017, our estimated gross working interest proved plus probable reserves was 328 MMBOE. We produced approximately 31.6 MBOPD, 31.6 MBOPD and 30.8 MBOPD of oil and condensate and approximately 142.9 MMSCFD, 140.5 MMSCFD and 205.9 MMSCFD of natural gas in 2014, 2015 and 2016, respectively, and approximately 30.7 MBOPD and 36.7 MBOPD of oil and condensate and approximately 197.6 MMSCFD and 292.0 MMSCFD of natural gas in first three months of 2016 and 2017, respectively. As of December 31, 2016, AMNT had 4,616 thousand ounces of proven and probable gold reserves and 1,234 thousand ounces of gold stockpiles and 4,810 million pounds of proven and probable copper reserves and 2,505 million pounds of copper stockpiles. In 2016 and the three months ended March 31, 2017, AMNT had gold sales of 777 thousand ounces and 129 thousand ounces and had copper sales of 461 million pounds and 94 million pounds, respectively. In 2016 and the three months ended March 31, 2017, MPI as an IPP produced 1,733 GW and 435 GW of power and in its O&M business produced 8,656 GW and 1,912 GW of power, respectively. As of March 31, 2017, MPI had installed capacity as an IPP of 1,930 MW and its operations and maintenance business services installed capacity of 407 MW, and its IPP pipeline was 220 MW and its O&M business pipeline was 685 MW.

For the years ended December 31, 2014, 2015 and 2016, our net oil and gas sales were US$701.9 million, US$575.3 million and US$583.0 million, respectively, and EBITDA was US$265.4 million, US$220.0 million and US$263.5 million, respectively. For the three month periods ended March 31, 2016 and 2017, our net oil and gas sales were US$130.8 million and US$210.3 million, respectively, and EBITDA was US$66.1 million and US$108.3 million, respectively.

We were established in 1980 as an Indonesian drilling contractor and have grown substantially since becoming an oil and gas exploration and production company in 1992. In particular, we expanded our exploration and production activities with our acquisition of an interest in the Rimau block in 1995, followed by the subsequent discovery of the Kaji and Semoga oil fields in the same block in 1996. In 1995, we acquired all of Stanvac Indonesia's shares from Exxon/Mobil. Since January 2000, we have acquired interests in additional blocks both within and outside of Indonesia. We entered the power producing business in 2004 by forming PT Medco Power Indonesia and its associated brand.

Our registered and principal executive office is located on the 53rd floor of The Energy Building (which we own) SCBD Lot 11A, Jl. Jend. Sudirman, Jakarta 12190, Indonesia.

Competitive Strengths

A leading regional exploration and production company

We are the largest independent publicly listed oil and gas exploration and production company in Indonesia based on market capitalization. In addition, based on a peer analysis conducted by Wood Mackenzie we are the largest upstream oil and gas exploration and production among our Peer Group as of and for the year ended December 31, 2016 based on proved and probable reserves and production in Asia. Our Peer Group refers to the group of peers identified by Wood Mackenzie, consisting of independent exploration and production companies with a noteworthy proved and probable reserves and production footprint in South and Southeast Asia. These consist of PT Saka Energi Indonesia, PT Energi Mega Persada Tbk., Ophir Energy plc, Premier Oil plc and KrisEnergy Ltd.. As of March 31, 2017, our estimated gross working interest proved plus probable reserves were 328 MMBOE. We are either the operator or joint operator of each of our blocks in Indonesia, where our in-country geographic diversity, experience and size allow us to control or significantly influence and optimize the pace of exploration, development and the associated capital expenditure at each block.

We believe our large portfolio of blocks offers a diversification of the risks associated with the management of reserves, production and exploration opportunities. We have interests in ten oil and gas properties in Indonesia, six of which are currently producing, and in oil and gas properties in five countries outside of Indonesia, namely the United States, Tunisia, Yemen, Libya and Oman. The majority of our reserves are located in Indonesia 69.8% of our gross working interest proved plus probable reserves as of March 31, 2017. We produced approximately 31.6 MBOPD, 31.6 MBOPD and 30.8 MBOPD of oil and condensate and approximately 142.9 MMSCFD, 140.5 MMSCFD and 205.9 MMSCFD of natural gas in 2014, 2015 and 2016, respectively, and approximately 30.7 MBOPD and 36.7 MBOPD of oil and condensate and approximately 205.9 MMSCFD and 292.0 MMSCFD of natural gas in first three months of 2016 and 2017, respectively.

We believe that we can leverage our position as a leading Indonesian oil and gas company to access, review and, if desirable, competitively bid for and acquire both domestic and international blocks. Moreover, we believe our reputation, together with our financial and operational strength, allows us to competitively access domestic and international funds through our banking relationships and/or capital markets to fund both project development and, if needed, acquisitions.

Stable cash flows from long-term gas sales agreements with blue-chip customer base

We benefit from relatively stable cash flows, particularly from sales of our domestic gas production where we benefit from long-term GSAs that provide consistent revenue streams and, to a certain extent, hedge us from the effects of oil price volatility. Gas prices under our domestic gas GSAs are fixed in US$/MMBTU with an application of a relatively small escalation factor (typically 2.5% to 3.0% per annum). Therefore our revenue from natural gas sales is not subject to as much price volatility as our oil revenues. Some of our export contracts contain pricing linked ultimately to oil prices, such as the Senoro GSA and approximately half of our production under the South Natuna Sea Block B GSA. In particular, as of March 31, 2017, gross volumes from all of our

1,065 BCF of gross proved plus probable gas reserves were commercially committed for sale through long-term contracts, with sales through such contracts representing 51% and 53% of our total revenues in 2016 and three months ended March 31, 2017. Of this, for three months ended March 31, 2017, 60% of gas revenue and 46.5% of gas production was sold through fixed price gas contracts with the remaining gas revenue sold under oil-linked prices. In addition, all of our GSAs, including both fixed-domestic and oil-linked-export GSAs, have take-or-pay protections, pursuant to which, if a buyer is unable to absorb the agreed supply during a period (typically over twelve months) then the buyer will have to pay a portion (usually in the range of 80% to 90%) of the total contracted supply for the period. The revenue contribution from GSAs has increased in recent years and we expect will continue to increase as a percentage of our revenue in 2017 and 2018, especially with the first gas being sold under our fixed-price GSA for the Block A, Aceh gas development expected in March 2018.

In addition, our gas off-takers include blue chip customers with strong credit profiles, including domestic companies such as Pertamina, PGN and PLN, and large international customers such as SembCorp and Petronas each of whom have demonstrated solid payment histories.

Competitive cost structure and low cost exploration and production producer

In 2015 and 2016, we significantly improved our organizational cost structure. Our 2016 full year unit cash production cost declined to US$8.8/BOE compared to US$12.3/BOE in 2015 and US$15.4 in 2014. We continue to expand our cost reduction and efficiency efforts and where necessary consult and contract with industry specialists to advise on our practices. Our unit cash production cost per BOE for the three month period ended March 31, 2017 was US$8.1/BOE. This cost reduction has been achieved through a number of efficiency initiatives including (i) changing operating modes, such as revising crew rotation schedules and outsourcing certain non-core activities such as security services, housekeeping and others; (ii) optimizing existing operations and relationships, such as vendor renegotiations to capture deflation and sharing infrastructure with neighboring operators; and (iii) reassessing all operations to apply "fit-for-purpose" methodologies, such as rescheduling planned maintenance and engine exchanges. The cost reduction programs have targeted, and continue to target, both large opportunities, such as drilling rig rate reductions, to smaller scale granular opportunities, such as travel and training budgets. While cost and efficiency are important to us, we maintain checks and controls to avoid and, if needed, mitigate and manage, exposure to risks to employee and contractor safety, production uptime and environmental performance.

We aim to maintain a unit cash production cost per BOE below US$10 through 2021. We believe that our cost structure assists in extending the economic life of producing blocks and provides stronger operating margins in a given oil price environment, and is particularly beneficial in maturing fields as volumes inevitably decline. A lower cost structure also allows for economic reserve growth and PSC life extension at lower capital cost levels.

Long-standing track record of executing, integrating and operating complex projects

We have a successful track record of project development in Indonesia, which makes us an attractive and reliable partner for both state-owned and foreign operators. We believe we are a reliable local partner for foreign companies due to our ability to navigate Indonesian regulatory and institutional risk. We are also a reliable partner for state-owned entities because of our access to foreign capabilities and expertise.

Our development of both the Senoro gas field (with Pertamina as the joint operator) and the DSLNG joint venture are examples of both such partnerships. DSLNG is the first project in Indonesia to use an upstream-downstream LNG structure whereby the downstream LNG business is set up as a separate business entity from the upstream business activity, our Senoro gas field. This innovative structure enabled significant savings in procurement and scheduling. Our involvement in the downstream gas sector is through DSLNG, a joint venture company established in 2007 by a consortium consisting of PT Medco LNG Indonesia (a wholly-owned subsidiary of our Group), Mitsubishi Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi. In 2016, a further 880 BCF of gross 100% field 1C contingent resources were estimated or assessed by a third party.

We have also proven our ability to successfully close and integrate new acquisitions. In 2016, we acquired our interest in, and become the operator of, the South Natuna Sea Block B and the associated West Natuna Transportation System. After becoming the operator of the South Natuna Sea Block B, we retained the majority of the existing Indonesian management team and work force of the PSC, which assisted in the integration process and maintaining production at the block. In 2016, with our joint venture partner, we also financed and obtained the complex regulatory and government approvals necessary for the successful acquisition of the gold and copper concession containing the Batu Hijau mine.

In addition, we have historically been successful in obtaining extensions for all of our PSCs prior to expiry. For example, most recently in 2016, we obtained extensions for the Lematang PSC until 2027 and the extension of exploration period for the South Sokang PSC until 2020, and prior to that in 2010, we obtained 20-year extensions for the Block A Aceh and South Sumatera PSCs.

We believe that our successful involvement in such projects with both state-owned and foreign operators, as well as our track record in securing extensions of, and acquiring interests in, PSCs and concessions, provides us with a competitive advantage to continue to be the partner of choice for both state-owned and foreign operators.

Diversified portfolio of energy and natural resources related investments

In addition to our core oil and gas operations, we have diversified our business through our investments in power and mining.

We operate in the power business through our 49% interest in MPI. MPI is an IPP and O&M services provider, and is a sizeable clean and renewable power platform in Indonesia. In the geothermal energy sector, MPI is (jointly with its partners) developing a 3x110 MW geothermal power plant in Sarulla, North Sumatra, where the commercial operation of the first 110 MW unit was achieved in March 2017, and the remaining two units, each of 110 MW capacity, are currently expected to be finished by the end of 2017 and mid-2018. MPI was also appointed as operator under the O&M contract for the Sarulla project. The Sarulla project is one of the largest single-contract geothermal projects in the world.

MPI has a track record in power plant development and O&M servicing. MPI owns and operates seven gas-fired power generation assets with a total gross capacity of over 296.7 MW and is also currently developing its 275 MW gas-fired IPP project and six other renewable assets, including geothermal and mini hydro power plants, and has a long-term O&M contract for the Tanjung Jati B power plant in Jepara, Central Java. MPI has stable cash flows from its growing O&M business and long-term minimum off-take backed PPAs with PLN from its IPP portfolio.

We conduct copper and gold mining operations through our joint venture, AMNT, in which we acquired our interest in November 2016. AMNT owns and operates the Batu Hijau mine, located on the island of Sumbawa, approximately 950 miles east of Jakarta. The mining concession covers an area 66,000 hectares include the Elang copper and gold resource and several exploration prospects. AMNT was established under a contract of work expiring in 2030, which is extendable up to 20 years. As of December 31, 2016, AMNT had 4,616 thousand ounces of proven and probable gold reserves and 1,234 thousand ounces of gold stockpiles and 4,810 million pounds of proven and probable copper reserves and 2,505 million pounds of copper stockpiles. Due to regulations related to in-country smelting and refining as well as export of copper concentrate, AMNT has begun feasibility studies for the capacity, design and construction as well as operation of an on-site smelting facility with two groups of competing foreign partners. AMNT will contribute land, its deep water port and its power plant to the joint venture, with the joint venture partner or partners making capital contributions for the construction of the smelter. AMNT's mining concession includes the Elang copper-gold resource which is larger than the Batu Hijau deposit and is situated approximately 60 kilometers east of the Batu Hijau mine. AMNT believes that development of the Elang resource has significant long term cash generation potential with resources of about 13 billion pounds of copper and about 20 thousand troy ounces of gold.

Well-positioned to leverage the favorable growth outlook for gas and power markets in Indonesia.

Gas

Indonesia's gas market is expected to continue to expand to support the growing economy. Wood Mackenzie expects Indonesia's gas demand to increase by approximately 0.4 BCF/D from 2017, reaching approximately 4.1 BCF/D in 2027, corresponding to a CAGR of 1.1%; as piped gas production declines, share of liquid natural gas will grow strongly. This robust growth is supported by consistent GDP increases and corresponding growing demand from the industrial and power sectors.

In addition, the Indonesian government has introduced policies designed to promote the use of alternative fuels, including domestic natural gas, given the strong economic, environmental and budgetary incentive to do so.

We believe we are well-positioned to capitalize on recent new regulations, such as the Indonesian Energy Ministry regulation No. 11/2017 on the use of natural gas for the power sector to reduce the regulatory hurdles and time taken to develop IPPs to allow synergies between gas and LNG portfolios.

Power

Indonesia has one the lowest levels of power demand per capita in South East Asia. Programme Indonesia Terang (PIT) was launched in March 2016 and aims to develop more renewable energy power plants in rural areas, mostly located in East Indonesia. The program aims to increase the overall national electrification rate from 85% in 2015 to 97% by 2019 according to Wood Mackenzie. In January 2015, the Indonesian government announced the next wave of new power plant developments, comprising 35 GW capacity across Indonesia. The 35 GW program comprises 291 power plants, targeting around 65% of the new capacity to be coal-fired, with the remaining to comprise of gas (30%) and renewables (5%). PLN will develop 15 GW of the capacity, and the remaining 20 GW is expected to be developed by IPPs. These additional power plants are needed to meet growing electricity demand.

Medco Power is one of the players in the Indonesia power market. According to Wood Mackenzie, in North Sumatra and West Java and in terms of new build plants with a capacity below 200 MW, Medco Power is associated with the greatest number of power plants and total available capacity. We believe this makes MPI well-positioned to benefit from expected growth in the power sector and allows us to vertically integrate and effectively and quickly monetize some of our existing gas discoveries.

Experienced management team with a successful exploration and development record

We benefit from an experienced board of directors and senior management team with significant experience in oil and gas exploration and production both in and outside of Indonesia. Our management team includes oil and gas professionals with experience at large multi-national corporations such as Premier Oil, Hess, BP, ENI and ConocoPhillips.

In addition, our board of commissioners has significant experience working with regulators and government institutions, which is evidenced by our success with our PSC renewals and our ability to partner with state-owned operators on significant projects or in jointly operating PSCs. Furthermore, we value good corporate governance and our board of commissioners includes two independent commissioners.

Business Strategies

Our strategy is to continue to build our operations through our core oil and gas exploration and production business and our investments in power and mining. To that end, the following are our key strategies:

Continued focus on core business of oil and gas exploration and production by monetizing existing discoveries

We plan to continue to strengthen our producing assets portfolio by the phased development and monetization of our existing portfolio of discovered gas assets. We aim to bring our projects on-stream on time and within budget, particularly our Block A, Aceh block, which is our most advanced development in Indonesia. First gas production and gas deliveries under the Block A take-or-pay backed, fixed-price domestic contract are expected to begin in 2018. We then plan to focus on Senoro-Toili phase II, where in 2016, a further 880 BCF of gross 100% field 1C contingent resources were estimated or assessed by GCA and where we are now evaluating potential development scenarios and preliminary engineering for Senoro-Toili phase II. The investment decision with respect to the preferred development scenario is expected to be made in the third quarter of 2018. After this Senoro-Toili phase II investment, we plan to focus on our next large development, which is phase II of our Block A Aceh block and the monetization of our other discovered gas resources on this block. As a result, going forward, we expect that a larger percentage of our production will consist of production from Senoro-Toili, South Natuna Sea Block B and Block A Aceh, as certain of our existing blocks, including Rimau PSC and South Sumatera PSC, are in mature stages of production. As of December 31, 2016, our reserve life index was 14 years**.**

Replace and add reserves through selective low-risk exploration and development

We plan to continue to replace depleting reserves and add reserves through selective low-risk exploration and development on our existing Indonesian PSCs. We intend to implement this strategy primarily by conducting infrastructure-led exploration, development and tie-ins to existing infrastructure on our existing PSCs. Our existing PSCs have cost recovery funded, economic advantages when compared to the contracts offered on new PSCs. While we will continue to assess new block offerings, we intend to continue our disciplined approach to exploration over the next five years. We believe this will help us to economically offset decline in our core PSCs in a continued low oil price environment.

Continue to maintain competitive cost structure

In 2015 and 2016, we significantly improved our organizational cost structure. Our 2016 full year unit cash production cost was reduced to US$8.8/BOE compared to US$12.3/BOE in 2015 and US$ 15.4 /BOE in 2014. Our unit cash production cost for the three month period ended March 31, 2017 was US$8.1 /BOE. Our cost reduction programs have targeted both larger scale cost reduction opportunities, such as drilling rig rate reductions, to smaller scale granular opportunities, such as travel and training budgets. We are committed to maintaining a unit cash production cost per BOE below US$10 through 2021 by continuing to implement our cost efficiency measures. While cost and efficiency are important, we continue to focus on minimizing risks to employee and contractor safety and promoting production uptime and environmental performance.

Maintain financial flexibility with a prudent capital structure and rigorous financial discipline

We intend to maintain a prudent capital structure by keeping the use of debt within reasonable limits and to delever utilizing a mix of internally generated funds, equity financing and the sale of non-core assets.

Our total annual non-debt funded capital expenditures necessary to maintain our production levels are expected to remain below US$200 million per year over the next five years, which should allow for a reduction in gearing. We intend to cap expenditures for discretionary exploration and managing declines in production to US$60 million per year. We plan to do this by phasing expenditures on our large developments and making carefully selected investments to offset declines in production. We expect that our capital expenditure for drilling and oil and gas infrastructure will be funded by the cost recovery mechanism under our PSCs.

We do not expect capital injections into our AMNT mining joint venture. We expect to make equity contributions of approximately US$88 million in MPI over the next five years to complete the Sarulla geothermal project and Medco Ratch Power Riau project prior to an initial public offering of MPI.

In addition, we plan to refinance our debt maturing in the next 12 to 18 months through long-term financing. We also have shareholder approval for a non-preemptive rights offering for up to 39.2% of our share capital, and if such rights offering proceeds, we expect to use the net proceeds primarily for reducing our leverage.

We intend to continue our disciplined approach to acquisitions and only invest in projects that meet or exceed our hurdle rate. We expect that our ongoing focus to delever and cost control may allow us to take advantage of very selective future potential acquisition and development opportunities. We also expect that we will be able to make use of operational efficiencies from completed acquisitions, such as integration and synergies of newly acquired assets through shared services. We also plan to divest from certain non-core assets, including our holding in The Energy building, and our coal mining business unit, each of which are currently classified as held for sale. In addition, we plan to rationalize our oil and gas portfolio by disposing of non-material exploration and production assets and our smaller non-oil and gas businesses. We recently obtained government approval for the disposal of our Bawean oil producing block, for example.

Continue to develop our power and renewable energy and mining businesses

Power

Medco Power is one of the players in the Indonesia power market. According to Wood Mackenzie, in North Sumatra and West Java and in terms of new build plants with a capacity below 200 MW, Medco Power is associated with the greatest number of power plants and total available capacity. We believe this makes MPI well-positioned to benefit from expected growth in the power sector.

In the geothermal energy sector, MPI is jointly developing a 3x110MW geothermal power plant in Sarulla, North Sumatra, where the commercial operation of the first 110MW unit was achieved in March 2017, and the remaining two units, each of 110MW capacity, are currently expected to be finished by the end of 2017 and mid-2018, respectively. The Sarulla project is one of the largest single-contract geothermal projects in the world. In addition, in February 2013, MPI through its subsidiary, PT Medco Cahaya Geothermal, signed a PPA with PLN, in which MPI as an IPP agreed to develop, operate and maintain a 2x55 MW geothermal power plant in the working area of Mount Ijen in the East Java province. MPI is also currently developing mini hydro power generating plants located in West Java.

In 2016, MPI through its wholly owned subsidiary PT Medco Geothermal Sarulla ("MGS") signed an O&M agreement with Sarulla Operations Ltd with respect to a 330 MW geothermal plant and, through its subsidiary PT Mitra Energi Batam ("MEB"), signed an O&M contract with PT PLN Batam for an aggregate of 500 MW gas-fired generation plants across eight locations in Indonesia. We expect to make equity contributions of approximately US$88 million in MPI over the next five years to complete the Sarulla geothermal project and Medco Ratch Power Riau project prior to an initial public offering of MPI.

MPI's other major shareholder, PT Saratoga Power, has expressed its interest in divesting from MPI, and we are assessing the opportunity to increase our stake in MPI by purchasing PT Saratoga Power's interest in MPI.

Copper and Gold Mining

Our copper and gold mining operations are conducted through our joint venture, AMNT, in which we acquired our interest in November 2016. We and our partner intend to complete the refinancing of the acquisition debt, begin the development of Phase 7 and the smelter project and realize significant procurement savings. Current mining at Batu Hijau is focused on ore production from Phase 6, which is expected to be completed

during 2017. Waste development for Phase 7 is expected to commence in 2017. This waste stripping is required to access the ore in Phase 7 and is expected to take three years. During this hiatus in ex-pit ore production, Batu Hijau will raise capital and feed its processing plant from existing long-term stockpile in order to generate cash for operating activities. We believe that AMNT's business and external sources of funding will be sufficient to fund its capital expenditure going forward and we do not expect to make cash contributions to AMNT. AMNT's contract of work also includes at least six prospective reserves. The Elang copper-gold resource is the largest of the resources and is situated approximately 60 kilometers east of the Batu Hijau mine. AMNT intends to develop plans to evaluate the Elang resources during its ongoing discussions with the government of Indonesia.

In the short to medium term, we expect that AMNT will undertake a domestic-focused initial public offering, with the proceeds potentially being used for, among other things, repayment of our shareholder loan of US$246.0 million to AMIV.

Continue to develop strategic partnerships

We intend to continue to build strategic alliances through our core oil and gas business and through our investments in power and mining. We have, in the past, successfully collaborated on projects with both foreign and government operators. For example, we were the private Indonesian partner in DSLNG, a joint venture company established in 2007 by a consortium consisting of PT Medco LNG Indonesia (a wholly-owned subsidiary of our Group), Mitsubishi Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi. AMNT also plans to form a joint venture with another party or parties to develop its smelter. AMNT expects to contribute access to land, the port and its power plant to the joint venture, with the joint venture partner making capital contributions towards project finance needed to construct of the smelter.

We have employed a similar strategy in AMNT's recent agreement to acquire a 44% stake in Macmahon Holdings Limited in exchange for a life-of-mine contract to provide earthmoving and mining services at the Batu Hijau mine and existing mobile mining equipment. We expect that Macmahon will reduce AMNT's costs and timeline for the development of phase 7 of the Batu Hijau mine as well as other resources on the concession.

Maintain high corporate governance standards

We are focused on maintaining high corporate governance standards, which are driven by principles of transparency, accountability, responsibility and fairness. We believe that we enjoy a positive reputation within Indonesia, and we believe that implementation of good corporate governance principles is important in sustaining our future growth and aim to execute our business in line with these principles. In addition, we implement and enforce our non-discrimination policies with regard to gender, race and religion and have two externally managed whistleblowing systems in place to enhance oversight of conduct that is not in line with our code of ethics. We intend to continue implementing these and other prudent policies to maintain our corporate governance standards.

Maintain support from local communities

We believe that relationships with local communities around our operations while being a corporate objective are also important for our business and the security of our operations. We practice CSR policies which foster empowerment and entrepreneurship, and include assisting in the improvement of public welfare and sanitation facilities in local communities, creating economically self-sustaining communities, encouraging local government re-greening and re-forestation programs and supporting social, religious and education activities. We are the only Indonesian listed member of the NGO, Business for Social Responsibility and we intend to continue to engage in community development programs encompassing a variety of social and economic areas, including infrastructure, education and sports, medical and health, and religion and culture. For example, we built a hospital near the Block A Aceh PSC for the use and access of the local community.

Oil and Gas Exploration and Production Business

Our oil and gas activities are focused on Indonesia, where we are involved in upstream activity, exploration, development and production of crude oil and natural gas. We have interests in ten oil and gas properties in Indonesia, six of which are currently producing; and in oil and gas properties in five countries outside of Indonesia, four of which are currently producing. Our oil and gas properties that are not currently producing are at various stages of exploration and development.

Summary of Production Sharing Arrangements

The following table summarizes our production sharing arrangements:

Contract Area (Type)	Date of Acquisition	Effective Interest[3]	Gross Area (Km^2)	Contract Expiry Date	Share to Contractor[1] Profit Crude Oil (%)	Share to Contractor[1] Profit Natural Gas (%)	Operator
Indonesia:							
Producing Properties							
Rimau (PSC)	1995	95.00%	1,103	2023	15.00%	35.00%	Medco
South Sumatera Block (PSC)	1995	100.00%	4,470	2033	12.50%	27.50%	Medco
Lematang (PSC)	2002	100.00%	409	2027	15.00%	30.00%	Medco
Tarakan (PSC)	1992	100.00%	180	2022	15.00%	35.00%	Medco
Senoro-Toili (PSC-JOB)	2000	30.00%	451	2027	35.00%	40.00%	Pertamina-Medco JOB
South Natuna Sea Block B	2016	40.00%	11,162	2028	15.00%	35.00%	Medco
Development Properties							
Block A (PSC)	2006	85.00%	1,681	2031	15.00%	35.00%	Medco
Simenggaris (PSC-JOB)	1998	62.50%	547	2028	15.00%	35.00%	Pertamina-Medco JOB
Exploration Properties							
Bengara (PSC)	2001	100.00%	922	2029	15.00%	35.00%	Medco
South Sokang (PSC)	2016	100.00%	998	2040	35.00%	40.00%	Medco
United States:							
Producing Properties							
East Cameron (Blocks 317 and 318) (Lease Agreement)	2004	75.00%	41	2031	N/A	N/A	Medco
East Cameron (Block 316) (Lease Agreement)	2009	100.00%	20	2031	N/A	N/A	Medco
Main Pass (Blocks 64 and 65) (Lease Agreement)	2004	75.00%	28.4	EOP	N/A	N/A	Medco
Libya:							
Development Properties							
Area 47 (EPSA)	2005	50.00%	6,182	Five years exploration, 25 years production	6.85	6.85	Nafusah Oil Operation BV[4]
Tunisia:							
Producing Properties							
Bir Ben Tartar Block (PSC)	2014	100.00%	352	2041	35	35	Medco
Adam Block (Royalty and Tax)	2014	5.00%	860	2033	50	50	ENI
Development Properties							
Cosmos Block (Royalty and Tax)	2014	80.00%	440	2035	50	50	Medco
Yasmin Block (Royalty and Tax)	2014	100.00%	96	2020	50	50	Medco

Contract Area (Type)	Date of Acquisition	Effective Interest[3]	Gross Area (Km^2)	Contract Expiry Date	Share to Contractor[1] Profit Crude Oil (%)	Share to Contractor[1] Profit Natural Gas (%)	Operator
Exploration Properties							
Sud Remada (PSC)	2014	100.00%	3,516	2018	35	35	Medco
Borj El Khadra Block (Royalty and Tax)	2014	10.00%	2,864	2020	50	50	ENI
Jenein Block (PSC)	2014	65.00%	312	2018	30	30	Medco
Hammamet Block (PSC)	2014	54.00%	3,740	2018	40	40	Medco
Oman:							
Producing Properties							
Karim Small Fields (Service Agreement)	2006	51.00%	781	2040	12	N/A	Medco
Exploration Properties							
Block 56 (PSC)	2014	75.00%	5,808	3 years production, 3 years exploration	25	30	Medco
Yemen:							
Producing Properties							
Block 9 Malik (PSC)	2008	21.25%	4,728	2030[5]	30	N/A	Calvalley Petroleum (Cyprus) Ltd
Exploration Properties							
Block 82 (PSC)	2008	38.25%	1,853	2040[5]	20	N/A	Medco

Notes:

(1) Effective post-Government tax and post-cost recovery. Prior to any potential DMO and any local government taxes.

(2) Effective interest is presented net of the participating interests of our partners (if any) but gross of all Government participating interests.

(3) Comprised of the Libya Investment Authority, Medco International Ventures Ltd. and National Oil Corporation.

(4) For production over 25,000 BOPD.

Reserves and Resources

From time to time, we engage independent petroleum engineering consultants to estimate or assess the reserves at each of our major production blocks.

Estimations or assessments have been prepared by the following independent petroleum engineering consultants for the blocks listed below within the last twelve months:

Asset	Estimating/Assessing Consultant	Reserves Date
Senoro-Toili (Senoro Gas Field)	Gaffney, Cline, & Associates	November 30, 2016
Block A Aceh	Netherland, Sewell & Associates, Inc.	December 31, 2016
South Natuna Sea Block B	RISC Operations Pty Ltd	December 31, 2016

Estimates on reserves for assets that are not listed above and which amount to approximately 46.3% of our gross working interest proved oil and gas reserves and 50.73% of our gross working interest proved plus probable oil and gas reserves as of March 31, 2017 are estimated by us based on our own investigations and prior reserve estimates or assessments by reputable international consultants. Investors should note that the above-

mentioned estimations or assessments made by us, may differ from the bases of estimation for reserves and resources used by other companies in the industry.

These gross working interest values are calculated based upon our portion of the estimated gross proved reserves and gross proved plus probable reserves attributable to our effective working interest, which have been derived from reserves estimations or assessments as of their dates and then deducting production, without accounting for reserves appreciation or depreciation, at each production block over the period from the respective estimations or assessments effective date (if a block has been so earlier estimated or assessed) to March 31, 2017. If a recent reserves estimations or assessments for a block is unavailable, the estimates have been derived by our internal technical team based on guidelines promulgated by SPE, and as reported to SKK Migas on an annual basis. To the extent that we have presented our gross working interest reserves on the basis of our effective working interest under the applicable contractual arrangement and not in accordance with SPE guidelines, we and not our independent petroleum engineering consultants are responsible for such data. However, our independent petroleum engineering consultants are responsible for the reserves data prior to adjustment for the effective working interest.

The following table sets forth the reserves for each of our blocks, excluding our exploration blocks and certain development blocks for which reserves have not yet been estimated, as of March 31, 2017.

	As of March 31, 2017								
	Gross Working Interest Proved Reserves[1]			Gross Working Interest Proved Plus Probable Reserves[1]			Gross Working Interest Proved Plus Probable Plus Possible Reserves[1]		
	Gas	Oil	Total	Gas	Oil	Total	Gas	Oil	Total
	(BCF)	(MMBBLS)	(MMBOE)	(BCF)	(MMBBLS)	(MMBOE)	(BCF)	(MMBBLS)	(MMBOE)
Indonesia:									
Producing Properties									
Rimau	—	16	16	—	22	22	—	30	30
South Sumatera	118	10	30	153	11	37	168	11	39
Lematang (PSC)	16	—	3	26	—	4	33	—	6
Tarakan (PSC)	2	3	3	2	3	3	4	4	5
Senoro-ToC-JOB)	377	7	71	380	7	72	386	9	75
Bawean (PSC)[2]	—	—	—	—	—	—	—	—	—
South Natuna Sea Block B	55	10	19	104	15	33	170	23	52
Development Properties									
Block A (PSC)	215	3	40	315	4	58	317	5	60
United States:									
Producing Properties									
Main Pass (Blocks 64 and 65) (Lease Agreement)	17	3	6	25	4	9	25	4	9
Libya:									
Development Properties									
Area 47 (EPSA)	36	39	45	57	61	71	57	61	71

	As of March 31, 2017								
	Gross Working Interest Proved Reserves[1]			Gross Working Interest Proved Plus Probable Reserves[1]			Gross Working Interest Proved Plus Probable Plus Possible Reserves[1]		
	Gas	Oil	Total	Gas	Oil	Total	Gas	Oil	Total
	(BCF)	(MMBBLS)	(MMBOE)	(BCF)	(MMBBLS)	(MMBOE)	(BCF)	(MMBBLS)	(MMBOE)
Tunisia:									
Producing Properties									
Bir Ben Tartar Block (PSC)	—	4	4	—	9	9	—	18	18
Adam Block (Royalty and Tax)	2	—	1	3	1	1	3	1	1
Yemen:									
Producing Properties									
Block 9 Malik (PSC)	—	4	4	—	9	9	—	12	12
Total Reserves	**838**	**99**	**242**	**1,065**	**146**	**328**	**1,163**	**178**	**378**

Note:

(1) In September 2016 we entered into a sale and purchase agreement for the divestment of our interest in Bawean PSC. The sale was completed in June 2017.

Certain reserve information contained in this document, which amounts to approximately 46.3% of our gross working interest proved oil and gas reserves and 50.3% of our gross working interest proved plus probable oil and gas reserves as of March 31, 2017, has not been recently estimated or assessed by any third party, but constitutes our estimates, based on our own investigations and prior reserve estimations or assessments.

There are numerous uncertainties inherent in estimating natural gas and oil reserves, including many factors beyond the control of the Company. For a description of certain of the risks and uncertainties with respect to the Company's reserve data, see "Risk Factors—The oil and gas reserves data in this document are only estimates and the actual production, revenue and expenditures achievable with respect to our reserves may differ from such estimates; there are no recent reserve estimations or assessments available for a significant portion of our reserves, and the oil and gas reserves data for these blocks are based on our internal estimates. In addition, probable reserves are generally believed to be less likely to be recovered than proved reserves."

Contingent Resources

Contingent resources are quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

The contingent resources set forth below are presented based on the "best estimate" scenario of contingent resources, or "2C," meaning that the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts has been assessed to be at least 50%. The following table sets forth the contingent resources regarding our oil and gas assets based on the independent third party estimations or assessments and our or the relevant operator's estimates as of March 31, 2017 on a gross 100% field basis multiplied by our working interest in each block:

	As of March 31, 2017		
	Oil (MBBLS)	Gas (MMSCF)	Total (MBOE)
Indonesia:			
Producing Properties:			
Senoro-Toili (PSC-JOB)	11,400	670,200	125,964
South Natuna Sea Block B	16,553	244,245	58,304
Simenggaris	—	92,770	15,858
Libya			
Development Properties:			
Area 47 (EPSA)	30,503	95,109	46,355
Yemen			
Producing Properties:			
Block 9 Malik (PSC)	2,828	16,419	5,564
Total	**61,284**	**1,118,747**	**252,046**

Production

Our oil and gas activities are focused on Indonesia, where we focus on upstream activity, exploration, development and production of crude oil and natural gas. We have interests in ten oil and gas properties in Indonesia, six of which are currently producing; and in oil and gas properties in five countries outside of Indonesia, four of which are currently producing. Our oil and gas properties that are not currently producing are at various stages of exploration and development.

Oil Production

	For the Year Ended December 31,			For the Three Months Ended March 31,	
	2014	2015	2016	2016	2017
	BOPD				
Indonesia:					
Rimau	11,552	10,523	9,826	9,568	9,311
South Sumatera[1]	6,799	6,523	5,198	5,392	5,471
Tarakan	1,734	1,822	1,941	1,877	1,850
Senoro-Toili	291	244	2,516	2,782	2,430
South Natuna Sea Block B[2]	—	—	617	—	7,343
Bawean	734	466	635	670	
International:					
Main Pass (Blocks 64 and 65) (Lease Agreement)	360	381	413	412	401
Bir Ben Tartar Block (PSC)	728	1,589	1,135	1,227	1,040
Adam (Concession)	99	233	207	243	192
Karim Small Fields (Service Agreement)	8,652	8,633	8,295	8,525	8,789
Block 9 Malik (PSC)	608	205	—	—	—
Total Production	**31,556**	**30,620**	**30,784**	**30,697**	**36,828**

Notes:

(1) Includes production from Kampar block in 2014, which was transferred to the Government of Indonesia in December 2014.

(2) From December 1, 2016.

Gas Production

	For the Year Ended December 31,			For the Three Months Ended March 31,	
	2014	2015	2016	2016	2017
	MSCFD				
Indonesia Assets					
Rimau	—	—	—	—	3,339
South Sumatera Extension	108,242	65,567	62,197	60,103	65,846
Tarakan	982	745	842	844	1,096
Senoro-Toili	170	35,499	95,648	102,531	94,139
Lematang	32,264	36,800	37,831	31,857	38,102
South Natuna Sea Block B[1]	—	—	7,596	—	88,430
Simenggaris			107	266	42
International:					
Main Pass (Blocks 64 and 65) (Lease Agreement)	707	378	270	499	—
Bir Ben Tartar Block (PSC)	—	—	—	—	—
Karim Small Fields (Service Agreement)	—	—	—	—	—
Adam (Concession)	530	1,498	1,465	1,501	1,683
Block 9 Malik (PSC)	—	—	—	—	—
Total Production	**142,895**	**140,487**	**205,954**	**197,601**	**292,677**

Note:

(1) From December 1, 2016.

Hydrocarbon Production

	For the Year Ended December 31,			For the Three Months Ended March 31,	
	2014	2015	2016	2016	2017
	MSCFD				
Indonesia Assets					
Rimau	11,552	10,523	9,826	9,568	10,116
South Sumatera Extension	25,302	17,731	15,830	15,666	18,158
Tarakan	1,901	1,949	2,085	2,021	2,058
Senoro-Toili	320	7,540	18,866	20,309	20,674
Lematang	5,515	6,068	6,487	5,446	5,826
South Natuna Sea Block B[1]	—	—	1,916	—	23,841
Bawean	734	466	635	670	—
Simenggaris	—	—	18	45	7
International:					
Main Pass (Blocks 64 and 65) (Lease Agreement)	478	444	458	495	401
Bir Ben Tartar Block (PSC)	728	1,589	1,135	—	—
Karim Small Fields (Service Agreement)	8,652	8,633	8,295	8,525	8,789
Adam (Concession)	188	483	451	1,719	1,514
Block 9 Malik (PSC)	608	205	—	—	—
Total Production	**55,978**	**55,631**	**65,982**	**64,466**	**91,384**

Note:

(1) From December 1, 2016.

Oil Lifting

	For the Year Ended December 31,			For the Three Months Ended March 31,	
	2014	2015	2016	2016	2017
	MBOPD				
Indonesia Assets					
Rimau	11.40	10.43	9.21	9.05	9.46
South Sumatera[1]	6.69	6.48	5.22	5.41	5.45
Tarakan	1.52	1.95	2.01	1.69	1.72
Senoro-Toili		0.93	2.51	2.34	2.16
Senoro Tiaka	0.30	0.32	0.05	—	—
Lematang	—	—	—	—	—
Bawean	0.55	0.47	0.62		
South Natuna Sea Block B[2]			0.74		7.28
International:					
East Cameron (Blocks 317 and 318) (Lease Agreement)	—	—	—		—
East Cameron (Block 316) (Lease Agreement)	—	—	—		—
Main Pass (Blocks 64 and 65) (Lease Agreement)	0.36	0.38	0.39	0.41	0.40
Tunisia	1.09	1.04	0.75	—	0.84
Karim Small Fields (Service Agreement)	—	—	—	—	—
Block 9 Malik (PSC)	0.29	0.1	—	—	—
Total	**22.21**	**22.12**	**21.50**	**18.90**	**27.31**

Notes:

(1) Includes production from Kampar block in 2014, which was transferred to the Government of Indonesia in December 2014.

(2) From December 1, 2016.

Gas Sales

	For the Year Ended December 31,			For the Three Months Ended March 31,	
	2014	2015	2016	2016	2017
	BBTUPD				
Indonesian Assets					
Rimau	—	—	—		—
South Sumatera	115.08	61.33	63.99	61.28	68.08
Tarakan	0.96	0.73	0.92	0.91	0.89
Lematang	24.18	28.09	36.77	29.21	31.51
Senoro-Toili	0.19	38.86	101.65	108.70	101.22
South Natuna Sea Block B[1]			7.00		85.45
Simenggaris			0.03	0.03	0.04
International:					
Main Pass (Blocks 64 and 65) (Lease Agreement)	0.62	0.31	0.26	0.50	—
Tunisia	0.42	1.42	1.53	1.50	1.43
Karim Small Fields (Service Agreement)	—	—	—	—	—
Block 9 Malik (PSC)	—	—	—	—	—
Total	**141.43**	**130.76**	**212.15**	**202.14**	**288.62**

Note:
(1) From December 1, 2016.

Hydrocarbon Sales

	For the Year Ended December 31,			For the Three Months Ended March 31,	
	2014	2015	2016	2016	2017
	MBOPD				
Indonesia Assets					
Rimau	11.40	10.43	9.21	9.05	9.46
South Sumatera[1]	26.65	17.12	16.32	16.04	17.26
Tarakan	1.68	2.08	2.17	1.85	1.87
Senoro-Toili	—	—	—	—	—
Senoro Tiaka	0.03	7.67	20.14	21.19	19.72
Lematang	4.19	4.87	6.38	5.07	5.47
Bawean	—	—	—	—	—
South Natuna Sea Block B[2]	—	—	1.95	—	22.10
Simenggaris	—	—	0.01	0.01	0.01
International:					
Main Pass (Blocks 64 and 65) (Lease Agreement)	0.98	0.70	0.65	0.91	0.40
Tunisia	1.51	2.47	2.28	1.50	2.27
Karim Small Fields (Service Agreement)	—	—	—	—	—
Block 9 Malik (PSC)	0.29	0.10	—	—	—
Total	**46.75**	**45.44**	**59.09**	**55.62**	**78.55**

Notes:
(1) Includes production from Kampar block in 2014, which was transferred to Pertamina in December 2014.
(2) From December 1, 2016

Exploration and Development

We are involved in both exploration (the search for oil and gas) and development (the drilling and development of facilities) to bring oil and gas into production and to market. Our exploration operations include aerial surveys, geological and geophysical studies (such as seismic surveys), drilling of wildcat wells, core testing and well logging.

Seismic surveys involve recording and measuring the rate of transmission of shock waves through the earth with a seismograph. Upon striking rock formations, the waves are reflected back to the seismograph. The time lapse is a measure of the depth of the formation. The rate at which waves are transmitted varies with the medium through which they pass. Seismic surveys may either be 3D or 2D surveys, the former type generally giving a better detailed picture and the latter a better overall picture.

Analysis of the data produced allows us to formulate a picture of the underground strata to enable us to form a view as to whether there are any "leads" or "prospects". "Leads" are preliminary interpretation of geological and geophysical information that may or may not lead to prospects and "prospects" are geological structures conducive to the production of oil and gas. The actual existence of such oil and gas must be confirmed, usually by the drilling of a wildcat well. If the wildcat well confirms the prospect (that is, is considered "successful"), we may then drill a delineation (or appraisal) well to acquire more detailed data on the reservoir formation. Once the presence of hydrocarbons is proved to be in commercially recoverable quantities, or the delineation well is "successful", development wells may be drilled to prepare for production. An area is considered to be developed when it has a well on it capable of producing oil or gas in paying quantities. We may also "work over" producing wells (wells that produce oil or gas) to restore or increase production and rework producing wells and abandoned wells (wells which are no longer in use) in an effort to begin, restore or increase production from those wells.

We plan to continue to replace depleting reserves and add reserves through selective low-risk exploration and development on our existing Indonesian PSCs. We have identified over 60 leads and 45 prospects in our Indonesian producing, development and exploration blocks. We currently plan to spend between US$20 million to US$40 million per year on exploration activities close to existing infrastructure at our South Sumatra asset and South Natuna Sea Block B PSC.

Description of Key Oil and Gas Properties

Key Producing Blocks in Indonesia

Our production blocks are managed in three main business units. These are our (i) South Sumatra asset (the Rimau PSC, South Sumatera PSC and Lematang PSC), (ii) the offshore South Natuna Sea Block B PSC, and (iii) the Senoro-Toili JOB. We also manage the smaller Tarakan PSC. Going forward, we expect that a larger percentage of our production will consist of production from Senoro-Toili, South Natuna Sea Block B and Block A Aceh, as certain of our existing blocks, including Rimau PSC and South Sumatera PSC are in the mature stage of production. In 2016 and the three month period ended March 31, 2017, our key producing blocks in the aggregate accounted for 95% and 94% of revenue respectively.

Rimau

Location:	South Sumatra
Area (sq. km):	1,103
Status:	Production
Type of Contract:	PSC
Expiry:	2023
Participating Interests:	95.0% PT Medco E&P Rimau (wholly owned by us) 5.0% South Sumatra Regency (Perusahaan Daerah Pertambangan & Energi Sumsei/PDPDE)
Operator:	PT Medco E&P Indonesia

Background. Oil production from the Rimau block began in 1986, and we acquired an operating interest in the block in 1995. The block became a significant oil producing operation when we discovered the Kaji-Semoga fields in September 1996. We also discovered gas reserves at the Kaji-Semoga fields.

Key Fiscal Terms. After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 26.8% and the Government's share is 73.2%. For natural gas, the PSC participants' share is 62.5% and the government's share is 37.5%. A portion of the PSC participants' profit oil share is subject to DMO, but the participant's profit gas share is not subject to DMO.

Sales. We have a Crude Oil Sale and Purchase Agreement ("COSPA") with Lukoil Asia Pacific Pte Ltd. for the sale of our oil entitlement from this block. Under this agreement, Lukoil is required to make certain prepayments with respect to their off-take obligations.

Development Strategy. We aim to minimize production decline on our existing wells and improve recovery rates by drilling further producing wells and potentially implementing an enhanced oil recovery program.

In addition, the Rimau PSC includes the Iliran heavy oil discovery with approximately 440 MMBOE of contingent resources. In 2016, we drilled 25 workover wells, including the installation of 14 electrical submersible pumps. This pilot program is continuing in 2017 as we assess the optimum development scenarios. The pilot program has used adapted mining rigs with small bore sizes which reduce drilling costs by approximately 90% compared to conventional drilling rigs.

Rimau PSC also contains the Telisa oil discovery with approximately 194 MMBOE of contingent resources. In 2017, we began to apply hydraulic fracking technology on a number of wells in another pilot program. The program will continue during 2017 and 2018 as we refine our capabilities. The results, which have generally been successful, have been presented to the government in support of our forthcoming PSC extension request. We currently plan to undertake a larger fracking campaign in 2018 or 2019. This program uses rigs owned and operated by us.

South Sumatra

Location:	South Sumatra
Area (sq. km):	4,470
Status:	Production
Type of Contract:	PSC
Expiry:	2033
Participating Interests:	100.0% PT Medco E&P Indonesia (wholly owned by us)
Operator:	PT Medco E&P Indonesia

Background. Gas production from the South Sumatera Block began in 1989 and was acquired by us in 1995. This block was awarded a PSC contract extension until 2033.

Key fiscal terms. After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 19.6% and the Government's share is 80.4%. For natural gas, the PSC participants' share is 43.1% and the government's share is 56.9%. A portion of the PSC participants' profit oil share and profit gas share is subject to DMO.

Sales—Oil. We have a Crude Oil Sale and Purchase Agreement with Lukoil Asia Pacific Pte Ltd. for the sale of our oil entitlement from this block.

Sales—Gas. We have several fixed price GSAs with, among others, PT Pupuk Sriwidjaja (a subsidiary of one of the largest state-owned fertilizer companies in Indonesia) and PT Meta Epsi Pejebe Power Generation ("Meppogen") an independent power producer.

Development Strategy. In 2016, we drilled 13 workover wells, and installed four electrical submersible pumps. This program to offset decline is continuing in 2017. The field also contains the Temelat gas discovery with an ongoing gas development plan with the potential to recover an estimated 30 BCF. First gas is expected in the third quarter of 2018. We are also assessing the North Temelat oil discovery to recover an estimated 2.5 MMBOE of oil beginning in the first quarter of 2019.

Senoro-Toili

Location:	Sulawesi
Area (sq. km):	451
Status:	Production
Type of Contract:	PSC-JOB
Expiry:	2027
Participating Interests:	30.0% PT Medco E&P Tomori Sulawesi
	50.0% PT Pertamina Hulu Energi Tomori Sulawesi
	20.0% Tomori E&P Limited
Operator:	JOB Pertamina-Medco E&P Tomori Sulawesi ("JOB-PMEPTS")

Background. We acquired our interest in this block in 2000. The block consists of two areas: Senoro (onshore), which covers 188 sq. km and contains our largest gas reserves, and Toili (offshore), which covers 263 sq. km and contains the Tiaka field in Toili, which has produced a high quality condensate since 2005 (approximately 1.5 MBOPD).

Key Fiscal Terms. The key fiscal terms of the PSC are as follows: After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 62.5% and the Government's share is 37.5%. For natural gas, the PSC participants' share is 71.4% and the government's share is 28.6%. A portion of the PSC participants' profit oil share is subject to DMO, but the participant's profit gas share is not subject to DMO.

Oil

Sales—Condensate. We have an agreement with Petro Diamond Singapore (Pte.) Ltd. to sell our entire liquid entitlement from production at this block.

Gas

Upstream Sector

The Senoro field started production on time and on budget in August 2015. The production facilities now have a capacity of up to 340 MMSCFD.

JOB-PMEPTS signed a GSA with DSLNG to supply 250 MMSCFD of gas in 2009. In addition, JOB-PMEPTS also entered into an agreement with PT Panca Amra Utama in March 2014 to supply 55 MMSCFD of gas to an ammonia plant for which the price is linked to ammonia prices in the South East Asia market.

In 2016, a further 880 BCF of gross 100% field 1C contingent resources were estimated or assessed by an independent third party. The potential development scenarios to monetize these resources are currently being

evaluated. Front end engineering and design is ongoing and the final investment decision with respect to the preferred development scenario is expected to be made in the second half of 2018. This phase II development is planned to begin following the commencement of gas production and sales from our Aceh gas development project. The phase II development is expected to increase production from the Senoro field from 2021.

Downstream Sector

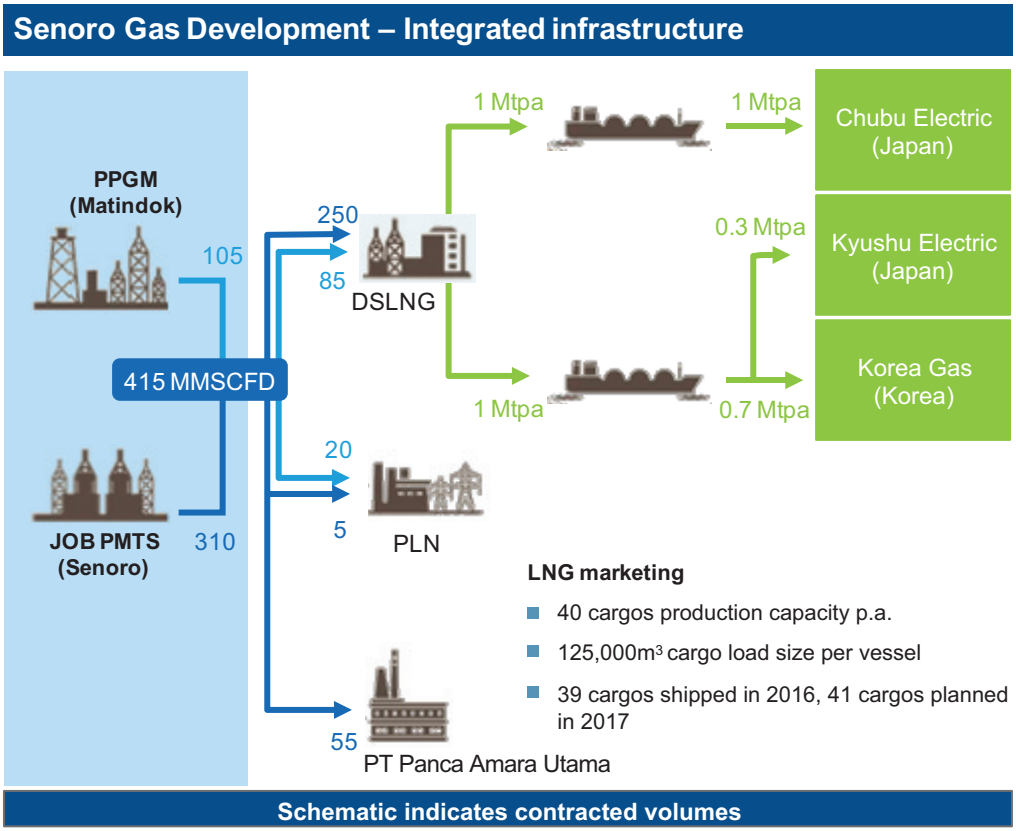
Our involvement in the downstream sector is through DSLNG, a joint venture company established in 2007 by a consortium consisting of PT Medco LNG Indonesia (a wholly-owned subsidiary of our Group), Mitsubishi Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi. The downstream LNG plant has a capacity of approximately 2.1 million tons per annum located at Banggai Regency, Central Sulawesi. The plant is contracted to take the phase I 1.44 TCF from the Senoro gas reserves and 0.70 TCF from the Matindok gas field owned by Pertamina.

DSLNG is the first project in Indonesia to use an upstream-downstream LNG structure whereby the downstream LNG business is set up as a separate business entity from the upstream business activity. Within this scheme, DSLNG purchases gas from the upstream sector, operates the LNG plant, and sells LNG to international customers.

In January 2009, DSLNG entered into a GSA pursuant to which the Senoro Gas Field agreed to supply 277 BBTUD per day (250 MMSCFD) of gas for a term of 15 years at a price based on the Japan Crude Cocktail. Due to the late completion of Pertamina's Matindok gas field, the Senoro field has supplied an average of above 300 MMSCFD, which is above the contracted volume of 250 MMSCFD, since first production.

More than 1.4 TCF of Senoro's gas is expected to be supplied to the downstream LNG plant, which will then sell to three LNG buyers being, KOGAS, Chubu Electric Power Co. Inc ("CE"), and Kyushu Electric Power Co. Inc. ("QE"). The LNG Sale & Purchase Agreement ("LNG SPA") with KOGAS dated January 2011 has total commitment of 0.7 million ton per annum, the CE LNG SPA dated June 2012 is for the supply of 1.0 million ton of LNG per annum, and QE LNG SPA also dated May 2012 has commitment for the shipment of 0.3 million ton of LNG per annum.

The DSLNG plant was inaugurated by President Joko Widodo in August 2015 and the first LNG shipment was delivered in September 2015. In 2016, 40 cargos were sold to three long-term buyers or otherwise on the spot market. A total of 41 cargos are planned for sale in 2017.



Lematang

Location:	South Sumatra
Area (sq. km):	409
Status:	Production
Type of Contract:	PSC
Expiry:	2027
Participating Interests:	51.1% PT Medco E&P Lematang (wholly owned by us)
	23.0% Lematang E&P Limited (wholly owned by us)
	25.9% Lundin Lematang BV (wholly owned by us)
Operator:	PT Medco E&P Lematang

Background. The Lematang PSC contains the Harimau gas field, which was discovered in 1989, and the Singa gas field, which was discovered in 1997. BP Migas approved the development plan for this block in 2008. We successfully completed the construction of production facilities and produced first gas in 2010, using advanced technology. The Singa-3 was the first well in Indonesia to be drilled horizontally using managed pressure drilling technology, applicable for wells of extreme conditions (high temperature, high pressure). Currently, Lematang has two active gas wells. In the first quarter of 2016, we obtained an extension of the Lematang PSC until 2027.

Key Fiscal Terms. After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 28.8% and the Government's share is 71.2%. For natural gas, the PSC participants' share is 57.7% and the government's share is 42.3%. A portion of the PSC participants' profit oil share and profit gas share is subject to DMO.

Sales. Gas is sold under a fixed-price long-term GSA to PLN.

Development Strategy. We are currently studying options for further development of this block.

South Natuna Sea Block B

Location:	Riau Island
Area (sq. km):	11,162
Status:	Production
Type of Contract:	PSC
Expiry:	2028
Participating Interests:	Medco E&P Natuna Ltd. 40% (wholly owned by us)
	Chevron South Natuna B Inc. 25%
	Medco South Natuna Sea 35%
Operator:	Medco E&P Natuna Ltd.

Background. In November 2016, we acquired the companies owning a 40% participating interest in the South Natuna Sea Block B PSC and the related Singapore based gas receiving facilities. We now operate the PSC and the facilities located in the Natuna Sea in approximately 300 feet of water with one FPSO, one FSO, four central processing platforms, seven wellhead platforms, four producing subsea fields, and offshore support vessels. Production at this block began in 1979. The facilities support three producing oil fields together with 16 natural gas fields in various stages of development, eight of which are currently producing. We operate an onshore supply base on Matak Island in the Anambas Regency providing logistical support with facilities for helicopters, fuel and accommodations and a 1,190 meter airstrip. The offshore facility houses nearly 370 people with a further 420 providing onshore support in Jakarta. The Singapore gas is shipped from the PSC through the 656 kilometer West Natuna Transportation System pipeline to an onshore receiving facility in Singapore. Both the pipeline and the facility are operated by us.

Key Fiscal Terms. After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 28.8% and the Government's share is 71.2%. For natural gas, the PSC participants' share is 67.3% and the government's share is 32.7%. A portion of the PSC participants' profit oil share is subject to DMO, but the participant's profit gas share is not subject to DMO.

Sales. South Natuna Sea Block B, has been selling its gas to two customers in Singapore (Sembgas Corp) and Malaysia (Petronas) under two long-term GSAs since 2001 and 2002, respectively. Pricing under the Sembgas contract and a portion of the Petronas contracts are linked to HSFO.

Development Strategy. Fields within the South Natuna Sea Block B PSC are not ring fenced for cost recovery within the PSC. This allows the immediate cost recovery of exploration and development expenditures on non-producing fields from other producing fields within the same PSC. This provides favorable economics for exploration and development expenditures.

In 2017, we plan to conduct a six well continuous development drilling program, with four wells in North Belut and two wells in Belanak and, Kerisi. These wells will be drilled from existing platforms and include both new drill wells and side tracks. Drilling began in early March 2017 in the North Belut field to target an undrained oil rim in the Gabus formation. This well was completed in May 2017, following which we plan to further extend the well into deeper new zones. We are assessing a 2018 drilling program of an initial six further wells targeting gas sales under our Singapore contract. If the results are successful, then a further 21 well targets will be assessed. In addition, we are undertaking engineering for a subsea development of the Buntal field which, if successful, would also supply gas under our Singapore contract by the first quarter of 2019. The Buntal development will employ intelligent well design in order to reduce drilling costs and optimize recovery rates.

Key Development Blocks in Indonesia

Block A

Location:	Aceh, North Sumatra
Area (sq. km):	1,867
Status:	Development
Type of Contract:	PSC
Expiry:	2031
Participating Interests:	85.0% PT Medco E&P Malaka (wholly owned by us) 15.0% Kris Energy (Aceh) B.V.
Operator:	PT Medco E&P Malaka

Background. Exploration for deeper gas in Block A took place in the 1970s through the 1980s, resulting in five discoveries: Alur Siwah, Alur Rambong, Julu Rayeu, Bata/Peulalu and Kuala Langsa. Plans of Development have been prepared for Alur Siwah, Alur Rambong and Julu Rayeu. We acquired our participating interests in 2006 (16.67%) and 2007 (25.0%) and became the operator in 2007. A 20-year extension for the Block A PSC was obtained in 2011. In 2016, we acquired a 16.67% participating interest from Japex Block A Ltd., and in 2017 a further 26.67% from Kris Energy (Aceh) B.V. In 2016, we also signed an Engineering Procurement and Construction ("EPC") contract with PT JGC Indonesia and PT Encona Inti lndustri for US$240.0 million as well as an EPC for flowline, trunkline, and pipeline construction with PT Kelsri. Total investment costs for the first phase of this block are estimated to be approximately US$540 million. In July 2017 we obtained project financing for the development of this block of US$360.0 million, and do not expect to make further equity contributions for its development.

Key Fiscal Terms. After deduction for the FTP and allowing for cost-recovery, the Government and the PSC participants share the remaining petroleum in accordance with the parties' profit oil shares and profit gas shares. For crude oil, the PSC participants' share is 25.0% and the Government's share is 75.0%. For natural gas, the PSC participants' share is 58.3% and the government's share is 41.7%. A portion of the PSC participants' profit oil share and profit gas share is subject to DMO.

Sales. In January 2015, we signed a GSA with Pertamina to sell 1,000 MMBTU of gas per day. Gas supply for Phase I of Block A Aceh, is targeted to start in the first half of 2018 for a period of 13 years.

Development Strategy. In addition to the five discoveries mentioned above, we drilled a successful exploratory well on the Matang field in 2013. The Matang-1 well has gas flow at a rate of up to 25 MMSCFD with low hydrogen sulfide content. Further appraisal of this field together with the other gas discovery on the block, Kuala Langsa, will commence after the current Block A development is completed. The Matang field contains gross recoverable and in-place gas resources of 82 BCF and 116 BCF, respectively, while the high CO2 Kuala Langsa field is expected to allow the recovery of up to 0.9 TCF with 6.4 TCF in place, on a gross basis. The current development scenario for the Matang field is for us to develop an IPP gas-fired power plant to sell electricity into Sumatra.

Key International Blocks

Block 56, The Sultanate of Oman

Location:	The Sultanate of Oman
Area (sq. km):	5,808
Status:	Exploration
Type of contract:	PSC
Expiry:	2017 for the first exploration phase with an option to extend the exploration phase for another three years to 2020. Thereafter, there will be a 20 year production phase, which can be extended for another five years.
Participating interests:	50.0% Medco Arabia Ltd 25.0% Biyaq LLC 25.0% Intaj LLC
Operator:	Medco Arabia Ltd

Background. In November 2014, our subsidiary, Medco Arabia Ltd, entered into the contract for the exploration and production of Block 56 in Oman with the Government of Oman, and its local partner, Intaj LLC. Block 56 is located in a productive hydrocarbon basin, the Oman Salt Basin. We have complied with our minimum work obligations for the first exploration phase in the amount of US$10.6 million and expect to conduct a seismic study later this year. We expect to be able to extend the exploration phase until 2020 depending on the outcome of our activities.

Strategy. The location of Block 56 is adjacent to Karim Small Fields ("KSF"), with similar geological characteristics. We expect to have operational synergy with KSF going forward, as it is also operated by us. In 2016, we completed geological and geophysical studies including 2D seismic studies. We are currently drilling three exploration wells.

Oman, Karim Small Fields, Service Contract

Location:	Oman
Area (sq. km):	718
Status:	Producing
Type of Contract:	Service contract with Petroleum Development Oman LLC
Expiry:	2040
Participating Interests:	Medco LLC (Oman) 51% (68% owned by us) Oman Oil Company 25% Kuwait Energy 15% Vision Oil & Gas 5% PetroVest 4%
Operator:	Medco LLC (Oman)

Background. In January 2006, we, through Medco LLC (Oman), were awarded the right to enter into a service contract with Petroleum Development Oman LLC ("PDO") to operate and manage the Karim Small Fields in Oman. We entered into a 10-year service contract with PDO ("Service Contract") effective in 2006, pursuant to which we are entitled to recover all of our costs (up to a level not to exceed 30.0% of production) and to receive a 3.98% share in the profits from oil sales.

In March 2006, we entered into a Participating and Economic Sharing Agreement ("PESA") with Oman Oil Company S.A.O.C. ("Oman Oil"). Under the terms of the PESA, we and Oman Oil agreed jointly to develop the Karim Small Fields and to share in the costs and expenses relating to the Service Contract, with us taking a 75% participating interest and Oman Oil taking a 25.0% participating interest. As we are the responsible party under

the Service Contract, under the PESA, we have the exclusive right to provide the services as required by the Service Contract. In April 2015, Medco LLC (Oman) signed a new Amendment and Restated Service Contract extending the term of the contract to 2040.

Strategy. In 2016, we completed geological and geophysical studies including certain 2D seismic studies. We are currently preparing to drill three exploration wells in 2017.

Libya, Area 47

Location:	Libya
Area (sq. km):	6,182
Status:	Exploration and Development
Type of Contract:	EPSA
Expiry:	2030
Participating Interests:	50.0% Medco International Ventures Ltd. (wholly owned by us) 50.0% Libyan Investment Authority ("LIA")
Operator:	Medco International Ventures Ltd. (with respect to development, the operator is Nafusah Oil Operation B.V.)

Background. Since obtaining our participating interest in Area 47, from 2005 until 2009 a total of 20 exploration wells and six appraisal wells have been drilled, with 18 of the exploration wells showing indication of considerable oil reserves. The LIA acquired its interest in 2009 from a third party. In April 2010, we were entrusted to replace LIA as the operator for the block throughout the exploration period. Since our appointment as operator, we have drilled three exploration wells, with all showing indications of large oil discoveries.

Strategy. Due to adverse security conditions there has been no activity at this block since 2014. We have made a force majeure claim to freeze the license period for our exploration areas within this block. In 2016, we finalized the invitation-to-tender package for an engineering procurement construction contract on the development areas within this block. However, due to our assessment of the ongoing security situation, and although front end engineering design had been completed, we believe that obtaining financing on acceptable terms for the expected scale of our operations would have been impracticable and as a result wrote off our prior expenditure on this block in 2016. We are currently pursuing a strategy of several early production facilities in order to begin and prove up small scale oil production. However, the resumption of in-country activity will be dependent on our assessment of developments in the ongoing security situation in Libya.

Other Oil and Gas Properties

Indonesia

Tarakan. We began operations at the Tarakan PSC in 1992 and were awarded a PSC extension through 2022. Tarakan has 21 active oil wells and one active gas well. We have an agreement with Pertamina for the sale of all of our entire net entitlement of oil produced at this block. We have a fixed price GSA with PT PLN Tarakan to supply gas for the purpose of electricity generation in the Tarakan area. In 2016, we drilled two workover wells which resulted in increased oil production. We are assessing potential exploration of this PSC but have no immediate plans for further expenditure.

Simenggaris. The Simenggaris block consists of the Sesayap and South Sembakung gas fields. In 2013, the Government of Indonesia approved the reallocation of gas supply from the Bunyu Methanol Plant to fill the need of PLN to generate power in the Eastern parts of Indonesia. We target to supply gas to meet energy needs in the vicinity, especially for the power generation sector of North, East and South Kalimantan. The plant has the capacity to supply 25 MMSCFD.

Bengara. In December 2001, we purchased 95.0% of PT Petroner Bengara Energi, which holds a 100.00% participating interest in the Bengara Block. The first drilling was conducted in June 2006, with the first discovery of gas at South Sebuku-1 in July 2009. Delineation drilling at South Sebuku-2 was subsequently conducted in July 2011. In the first quarter of 2013, we undertook an asset swap with Salamander Energy pursuant to which our participating interest in the block became 100.0%.

South Sokang. In early 2016, we acquired Medco South Sokang B.V. (formerly known as Lundin South Sokang B.V.) and operatorship of the South Sokang PSC, in the Natuna Sea. In 2016, we obtained an extension of the exploration period until December 2020.

United States

We have the right to explore for and produce oil and gas in five producing assets in the United States, located offshore in the Gulf of Mexico off of Louisiana and held through leases with the United States Department of the Interior, Bureau of Ocean Energy Management. Our East Cameron block 316 has been decommissioned, and we expect that blocks 317 and 318 will be decommissioned in 2018. At our Main Pass blocks, which consist of blocks 64 and 65, in 2016, we temporarily abandoned four wells at block 64. All of our United States oil and gas properties are held by our wholly-owned subsidiary, Medco Energi US LLC. All of our oil production in the United States is sold on the spot market and we have no plans to enter into long-term sales arrangements. Gas produced is used for our own operations.

Tunisia

In August 2014, we, through our subsidiary, Medco Tunisia Petroleum Limited, acquired a 100.0% shareholding interest in Storm Ventures International (Barbados) Limited, an oil and gas exploration and production company that operates in Tunisia. The acquisition provided us with a participating right to eight blocks in Tunisia, consisting of Adam Block, Bir Ben Tartar Block, Cosmos Block, Yasmin Block, Borj El Khadra Block, Jenein Block, Sud Remada Block and Gulf of Hammamet Block. Five onshore blocks (Adam, Sud Remada, Bir Ben Tartar, Jenein and Borj El Khadra) are located in the Ghadames Basin and the remaining three offshore blocks (Cosmos, Hammamet and Yasmin) are located in the Pellagian Basin off the northeast coast of Tunisia. Our operations in Tunisia were suspended due to labor protests which occurred from April 2017 to June 2017. Operations resumed from June 2017. In addition, exploration activities at our onshore exploration blocks in Tunisia are currently suspended under force majeure.

Yemen, Block 82 and Block 9

Our fields in Yemen consist of Block 82 and Block 9. We were awarded Block 82 through a bid process held by the Ministry of Oil and Minerals of the Republic of Yemen through the Petroleum Exploration and Production Authority ("PEPA") in December 2006. We and our partners, Kuwait Energy, Oil Corporation, Oil India Ltd. and Yemen Oil & Gas Corporation, signed a profit sharing arrangement in 2008. Due to adverse security conditions there has been no activity at this block since 2014. This block is in the process of being relinquished to the Government of Yemen.

Our subsidiary Medco Yemen Malik Ltd., acquired a 25.0% participating interest in Block 9 from Reliance Exploration & Production DMCC in 2012. Drilling in 2013 was carried out at five exploration wells. Due to adverse security conditions, there has been no activity since 2014. We have made a force majeure claim with respect to this block as a result of the security situation in Yemen and continue to monitor the security situation in Yemen. As of December 31, 2016, the participating interest of our subsidiary in Block 9 is 21.25%.

Blocks Relinquished or Divested

The table below sets forth interests in blocks that we divested from or relinquished from January 1, 2014 through March 31, 2017.

Entity	Divest/ Relinquish	Working interest prior to transaction	Working interest after transaction	Transferee	Date of divestment/ relinquishment
PSC Bawean (Camar Bawean Petroleum Ltd & Camar Resources Canada Inc.)	Divest	65%	0%	Hyoil	June 2016
PT Medco E&P Nunukan (PSC Nunukan)	Divest	40%	0%	PT Pertamina Hulu Energi	September 2015
Medco Cendrawasih VII	Relinquish	100%	0%	Government of Republic Indonesia	—
Medco Yemen Arat Ltd (Block 83—Wadi Arat)	Relinquish	45%	0%	Government of Yemen	April 2014
Moonbi Energy Ltd (PPL 470)	Divest	90%	0%	Moonbi Enterprise Limited	February 2016
PT CBM Lematang (GMB Lematang)	Divest	55%	34%	PT Methanindo Energi Resources	February 2016
PT CBM Sekayu (GMB Sekayu)	Relinquish	50%	0%	Government of Republic Indonesia	December 2016
PT Medco E&P Indonesia (PSC Central Sumatera Kampar)	Relinquish	100%	0%	Government of Republic Indonesia	December 2014

In addition, in September 2016, we entered into a sale and purchase agreement for the divestment of our entire interest in the Bawean PSC. The sale was completed in June, 2017. We recognized an impairment loss on assets recognized at fair value less costs to sell of US$11.9 million in 2016 in connection with this sale.

While we do incur some costs in relinquishing assets, these costs are typically not material and in certain cases we do not bear costs.

Sales and Distribution

Average Realized Sales Prices

	For the Years Ended December 31,			For the Three Month Period Ended March 31,	
	2014	2015	2016	2016	2017
Average realized sales prices:					
Oil and condensate (US$ per Bbl)	97.83	49.29	42.29	30.62	51.64
Natural gas (US$ per MMBTU)	5.60	5.23	4.40	4.14	5.47

Crude Oil

We sell our net oil entitlement from our Indonesian operations to the domestic Indonesian market as well as to the overseas market. In line with the Indonesian government regulations, we sell our oil at prices based on ICP. The ICP price is determined by the Indonesian government, and is the monthly average of the mean of two publications of independent oil traders and marketers in the Asia Pacific region published by Platts and RIM in the following proportions: 50% Platts and 50% RIM until June 2016. Starting in July 2016, the basis of ICP changed to Dated Brent price plus Alpha.

All of our oil production in the United States is sold on the spot market, and we have no plans to enter into long-term sales arrangements.

The following table summarizes the key terms and arrangements of our current material crude oil sales agreements.

Block	Counterparty	Term	Pricing	Total Gross Volume for Life of Contract
Indonesia:				
Rimau	Lukoil	2 years	ICP Kaji + premium	whole entitlement
South Sumatera	Pertamina[1]	—	ICP Kaji Flat	—
Tarakan	Pertamina UP V Balikpapan[2]	—	ICP Tarakan Flat	—
Senoro-Toili (condensate)	Petro Diamond Singapore (2016-2020)	4 years	ICP Senoro Condensate minus premium	whole entitlement
Senoro-Toili	Petro Diamond Singapore (2014-now)	Volume based	ICP Tiaka + premium	1,025,000 bbls

Notes:
(1) Swap with Rimau's crude oil.
(2) Domestic market.

Natural Gas

We sell our gas production from our Indonesian onshore operations to buyers including state-owned companies (in the power and fertilizer industries), independent power producers, gas transport companies, and local state and city gas providers.

We typically enter into GSAs which set the TCQ, DCQ and gas price. While TCQ and DCQ vary between buyers, gas prices are largely fixed using the same structure, in US$/MMBTU with an application of an escalation factor (typically 2.5% to 3.0% per annum). However starting in late 2015 we started commercial gas sales from Senoro-Toili with prices linked to Japanese Crude Cocktail (JCC) prices. The GSAs also typically include a "Take-or-pay" mechanism, pursuant to which, if a buyer is unable to absorb the agreed DCQ, the buyer will have to pay a portion (usually in the range of 80.0% to 90.0%) of the DCQ.

All of our gas production in the United States is sold on the spot market, and we have no plans to enter into long-term sales arrangements.

The following table summarizes the key terms and arrangements of our current material GSAs for our Indonesian blocks.

Block	Counterparty	Term	Daily Contract Quantity	Take-or-Pay as a percentage of DCQ
Indonesia:				
South Sumatera	PT Pupuk Sriwidjaja (Persero)	2008-2018	45 BBTUD	90%
	PT Mitra Energi Buana	2006-2017	2.5 BBTUD increasing to 3.7 BBTUD	90%
	PT MEPPO-GEN	2014-2018	10 BBTUD	85%
	Perusada Mura Energi	2009-2028 (on stream on 2015)	1.80 BBTUD increasing to 2.50 BBTUD	90%
	Perusda Pertambangan dan Energi (BBG)	2009-2018 (on stream on 2013)	0.3 BBTUD	N.A.
	Perusda Pertambangan dan Energi (Kelistrikan)	2011-2020	3 BBTUD	90%
	PT Medco E&P Rimau	2016-2023	0.66 BBTUD increasing to 2.65 BBTUD	90%
	PD. Petrogas Ogan Ilir	2016-2019	1.4 BBTUD increasing to 1.6 BBTUD in year 2 and declining to 1.3 BBTUD in year 4	90%
	Perusda Sarana Pembangunan Palembang Jaya	2010-2018	0.1 BBTUD increasing to 0.3 BBTUD	N.A
	PLN (South Sumatera Power Plant)	2019-2027	20 BBTUD (Joint supply with Lematang Block)	90%
Lematang	PLN (South Sumatera Power Plant)	2017-2020	20 BBTUD (Joint supply with South Sumatera Block)	90%
Tarakan	PLN-Gunung Belah	2010-2021	0.5 BBTUD	90%
	PT PGN (Persero) Tbk	2016-2021	0.2 BBTUD	N.A
Block A	PT Pertamina (Persero)	13 years from initial commencement of gas sales	58 BBTUD	90%
Senoro-Toili	Donggi Senoro LNG	2009-2027	250 MMSCFD / 277.75 BBTUD	90%
	PT Panca Amara Utama	2018-2027	55 MMSCFD	80%-90%
Simenggaris	PLN	2015-2020	0.3 - 0.5 MMSCFD	0.3 MMSCFD
	Perusda Nura Serambi Persada	2012-2023	5 MMSCFD	85%

Block	Counterparty	Term	Daily Contract Quantity	Take-or-Pay as a percentage of DCQ
South Natuna Sea Block B	Pertamina	2001-2032	247.0 BBtu in year 1, 337.2 BBtu in year 2, 341.25 BBtu after year 2 and gradually declining to 51.81 BBtu in 2023	85%-90%
	Pertamina	1999-2026	105.0 BBtu to 263.0 BBtu	80%-85%

Gas Distribution Unit

Our subsidiaries MGI and MEGS operate a gas compression station with a pipeline facility at Gunung Megang, South Sumatra, with three main gas compressors of 22.5 MMSCFD capacity each and ten 17.5 kilometer pipeline facilities. From August 2009 to December 2014, this compression station served to increase gas pressure for delivery from our South Sumatra block to a PGN facility at Pagardewa and the PLTG Gn Megang (Meppogen) power plant, with a target of 37 BBTUD of compressed gas and 20 BBTUD of transported gas each day.

On December 10, 2014, MEGS entered into a new contract with PT Medco E&P Lematang and PLN South Sumatera for the transport of gas from Singa Field, Lematang block to PLN through existing pipeline facilities, with a target of 42 MMSCFD.

In April, 2017, MEGS continued transporting Singa Gas from Central Production Plant Singa to Gunung Megang with a daily rate averaging 25 MMSCFD.

In addition, from 2013 to 2015, we also operated a gas compression station with three high pressure primary gas compressors at the Soka station with a capacity of 15 MMSCFD each.

Investments

In addition to our core oil and gas business, we have significant investments in power generation and mining.

Power Business

Our power business is conducted through MPI, an IPP and O&M service provider, in which we own a 49% interest and PT Saratoga Power, an unrelated third party, owns a 51% interest.

As an IPP, MPI owns majority interests in and operates three gas-fired power plants in Batam with aggregate gross capacity of 266 MW. In 2020, the asset in Batam operated by PT Energi Listrik Batam (“ELB”) is expected to increase gross capacity by 40 MW through a combined cycle addition. In 2021, MPI expects to commence operations from an additional gas-fired power plant in the Riau with a capacity of 275 MW. MPI is also developing a 330 MW geothermal power plant in Sarulla, North Sumatra, at which the first unit commenced operations in March 2017 and the other two units are expected to commence operations in the fourth quarter of 2017 and in the second quarter of 2018.

As an O&M service provider, MPI operates a large 1,320 MW coal-fired power plant in Central Java under a 24-year O&M contract with PLN. In September 2016, MPI through its subsidiary MGS signed an O&M

agreement with Sarulla Operations Ltd with respect to a 330 MW geothermal plant, and, in December 2016, through its subsidiary in MEB, signed a two year O&M contract with PT PLN Batam for an aggregate of 500 MW gas-fired generation plants (TM2500 truck-mounted gas turbine generator unit) across eight locations in Indonesia.

MPI's business is focused on small to medium sized natural gas and geothermal independent power projects and captive power plants in western Indonesia and seeks to maximize its power services operations and synergies with its other businesses.

In 2016, MPI was selected as one of the top five IPPs and O&M companies at the Indonesia Best Electricity Awards held by "Majalah Listrik Indonesia", which is an Indonesian energy magazine and Tanjung Jati (the Central Java coal plant which MPI services as an O&M services provider) received green PROPER award from the Indonesia Ministry of Environment and Forestry ("MEF").

IPP Business

Mitra Energi Batam

Location:	Batam Island
Status:	Operational
Ownership:	10% MPI 54% MEM 30% PT PLN Batam 6% YPK PLN
Operator:	MEB
Capacity:	Gross capacity of 84.1 MW produced from two 27.75 MW simple cycle units, 20.6 MW combined cycle, and 8 MW chillers.

Background. In March 2004, MPI acquired a 54% interest in MEB, and commenced commercial operations in October 2004. MPI transferred its interest in MEB to MEM and MPI subsequently acquired an additional 10.0% stake in MEB from YPK PLN. MPI currently owns an effective 64.0% stake in MEB, with the remaining shareholders being MEM with a 54% stake, PT PLN Batam with a 30.0% stake and YPK PLN with a 6.0% stake respectively.

MEB owns a gas-fired power plant located in Panaran I on Batam Island, Indonesia, which was MPI's first power plant on Batam island. The facility is comprised of a 55.5 MW simple cycle power plant ("SCPP") with an additional 8.0 MW chiller and a 20.6 MW combined cycle power plant ("CCPP"). The facility has a total installed capacity of 84.1 MW.

The SCPP unit was commissioned in October 2004 with Kelsri-Dalle Engineering as the EPC contractor. The SCPP is capable of supplying 55.5 MW of capacity. In 2013, a chiller was added to the facility to increase the net output of the facility. An additional CCPP was commissioned in 2014 with Mitsui and Hyundai as the EPC contractors to further expand the capacity of the facility. The CCPP can generate 89.4 tons per hour of steam by recovering heat from the exhaust gas of the SCPP.

Power Purchase Arrangements. In April 2004, MEB entered into a Transfer of PPA with PT Menamas and PT PLN Batam, pursuant to which all the rights and obligations of PT Menamas were transferred to MEB. The PPA was amended three times, which were in July 2004, in October 2012 and recently in February 2017. The current PPA is valid for 20 years from 2014 and includes the addition of the chiller and steam turbine generator to convert the SCPP to a CCPP. The chiller and CCPP achieved commercial operations in October 2013 and September 2014 respectively.

The PPA tariff also includes investment recovery of IDR 7 per kWh for 12 years until October 2016 based on production of 408.4 GWh per annum (which is the minimum off-take by PLN for the SCPP) installation of the switchyard for the facility. For the first 12 years until October 2016, PLN agreed to pay a total of IDR 190 per kWh. Beginning November 2016, PLN agreed to pay a total of IDR 89 per kWh subject to exchange rate adjustments based on an exchange rate of IDR 9,000 to US$1.00.

For CCPP, the PPA tariff includes a fixed component of IDR 350 per kWh and variable components of IDR 100 per kWh and IDR 12 per kWh, portions of which are subject to exchange rate adjustments at a base rate of IDR 9,000 to US$1.00.

The PPA also stipulates a minimum take-or-pay level of 84.0% for the SCPP. The PPA has a contracted capacity of 82.1 MW and enjoys a full gas pass through (subject to certain conditions stipulated in the PPA) with PLN paying gas costs directly to the gas supplier. In addition, the PPA also stipulates contract penalties in the event that MEB is not able to meet certain performance benchmarks in terms of output, force outage, availability factor and heat rate.

Gas Sales Agreement. Under the PPA, PLN is responsible for securing natural gas from PGN for the operation of the plant.

PT Dalle Energy Batam

Location:	Batam Island	
Status:	Operational	
Ownership:	79.99% MPI	
	20.00%	PT PLN Batam
	0.01%	PT Dalle Energy
Operator:	PT Dalle Energy Batam	
Capacity:	84.1 MW produced from two 27.75 MW simple cycle units, a 20.6 MW combined cycle unit, and chillers producing 8 MW.	

Background. In June 2005, MPI acquired a 40% interest in PT Dalle Energy Batam ("DEB"), which is the owner and operator of the Panaran II power plant, and MPI further increased its stake in the project to 79.99% by contributing most of the project's required equity commitment. PT PLN Batam acquired a 20.0% interest in the plant from PT Dalle Energy in 2006.

DEB owns a gas-fired power plant located in Panaran II on Batam Island, Indonesia. The facility is comprised of a 55.5 MW SCPP with an additional 8.0 MW chiller and a 20.6 MW CCPP. The facility has a total installed capacity of 84.1 MW.

The SCPP and chiller unit were commissioned in 2006 with Kelsri-Dalle Engineering (a joint operation established between PT Kelsri and PT Dalle Engineering Construction), as the EPC contractor. The SCPP is capable of supplying 55.5 MW of capacity. The chiller was able to increase the electricity output of the facility and also contributes to 1 to 3% fuel savings for the SCPP. An additional CCPP was commissioned in 2010 with Mitsui and Hyundai as the EPC contractors to further expand the capacity of the facility. The CCPP can generate 89.4 tons per hour of steam by recovering heat from the exhaust gas of the SCPP through a heat recovery steam generator. In 2007, DEB entered into a rental agreement with MPI for a truck-mounted mobile gas turbine. The initial variable rental fee of IDR 217.8 per KWh has since been revised to 204.9 per KWh.

Power Purchase Arrangements. DEB and PT PLN Batam entered into a PPA expiring in 2025 pursuant to which DEB is required to procure, operate and maintain a combined cycle power plant consisting of two gas turbine generator units, a chiller unit and a steam generator turbine. PT PLN Batam is to purchase the power supply generated by the units on a minimum take-or-pay basis of 90% of power produced at a price of Rp. 285 per KWh subject to exchange rate adjustment.

Feedstock. DEB entered into a gas supply contract with PGN for the supply of gas, the cost of which is passed through to PT PLN Batam. The GSA for DEB has been extended until 2019.

Truck-Mounted 19 MW Gas-Fired Power Plant

Location:	Batam Island (adjacent to the Panaran II gas-fired power plant)
Status:	Operational
Ownership:	100% MPI
Operator:	PT Dalle Energi Batam
Capacity:	19 MW produced from a truck-mounted unit

Background. In 2007, MPI added a 19 MW truck-mounted gas turbine generator unit to its power generating operations on Batam Island.

Power Purchase Arrangements. To ensure the reliability, stability, and continuity of power supply from PT Dalle Energy Batam to PT PLN Batam, a joint arrangement between PT Dalle Energy Batam and PT PLN Batam was concluded in 2007. This truck-mounted unit was considered to be a back-up unit to supplement an existing combined cycle power plant, and therefore there was no applicable take-or-pay arrangement, but based on an amendment to the PPA on the CCPP in 2008, the truck-mounted unit was turned into an existing unit for a period of 16 years from the availability of trafo kV and bay. The tariff is set at Rp. 798 per kWh.

Feedstock. Gas costs are passed through to PT PLN Batam.

PT Energi Listrik Batam

Location:	Batam Island
Status:	Operational
Ownership:	99.99% PT Universal Batam Energy
	0.01% PT Universal Gas Energy
Operator:	PT Energi Listrik Batam
Capacity:	70 MW produced from 2 units of simple cycle.

Background. ELB was established in March 2012 through a joint venture company, PT Universal Batam Energy (“UBE”), which is 70.0% owned by MPI and 30.0% owned by PT Universal Gas Energy (“UGE”). UGE currently owes receivables to MPI representing advances made by MPI to ELB on behalf of UGE for the construction of this project. The receivables accrue interest at a rate of 20.0% interest and are secured by UGE’s 30.0% stake in ELB. Given that the interest on the receivables owed by UGE to MPI are higher than the project equity return, under the agreement between MPI and UGE, MPI has the economic benefit of 100.0% of ELB.

ELB owns a gas-fired power plant located in Tanjung Uncang on Batam Island which began commercial operations in January 2016.

In September 2012, ELB entered into an EPC agreement with a consortium of MPI and PT Dalle Engineering Construction (the “Consortium”) whereby the Consortium agreed to provide EPC services. Under the contract, MPI agreed to supply the gas turbine generator while PT Dalle Engineering Construction agreed to carry out the construction of the project.

Power Purchase Arrangements. ELB entered into a PPA with PT PLN Batam in 2012 which was amended in October of 2015 for a period of 20 years starting from the COD which began on January 6, 2017 for the second unit and on May 14, 2017 for the first unit.

The PPA tariff consists of different components, portions of which are subject to varying adjustments based on, among other things, Rupiah to U.S. dollar foreign exchange rate movements, Indonesia and U.S. CPI, and operational metrics. The PPA also provides for minimum take-or-pay levels.

PT Energi Prima Elektrika

Location:	Patih Galung, Prabumulih, South Sumatra
Status:	Operational
Ownership:	92.5% PT Medco Power Indonesia (49% owned by us) 7.5% PLN-E
Expiration:	June 12, 2017; PPA expired 2026
Operator:	PT Energi Prima Elektrika
Capacity:	12.5MW produced from gas engines

Background. PT Energi Prima Elektrika ("EPE"), which began operating in 2006, was acquired by MPI in 2010. EPE owns a gas-fired power plant located in Prabumulih, South Sumatra. The facility is comprised of two gas engines with a total installed capacity of 12.5 MW. In December 2010, MPI acquired an additional 7.5% stake and renamed the company EPE.

The power plant was commissioned in June 2006 with PT Samapta Energi Nusantara as the EPC contractor.

Power Purchase Arrangements.

In November 2004, EPE entered into a transfer of PPA with PLN-E and PLN WS2JB, whereby all rights and obligations of PLN-E under the PPA entered into between PLN-E and PLN WS2JB were transferred to EPE. Based on this agreement, EPE is required to fund, establish and operate the 12 MW power plant. The parties agreed that PLN WS2JB will purchase all of the electricity from EPE for 20 years subject to annual extension upon approval by both parties.

The PPA tariff consists of different components, portions of which are subject to varying adjustments based on, among other things, Rupiah to U.S. dollar foreign exchange rate movements, gas prices, Indonesia and U.S. CPI, and operational metrics. The PPA expires in 2036.

PT Multidaya Prima Elektrindo

Location:	Kali Doni, Palembang, South Sumatra
Status:	Operational
Ownership:	85% PT Medco Power Indonesia (49% owned by us) 15% PLN-E
Expiration:	May 5, 2018; PPA expired 2028
Operator:	PT Multidaya Prima Elektrindo (85% owned by MPI)
Capacity:	12.5 MW produced from gas engine

Background. PT Multidaya Prima Elektrindo ("MPE") owns a gas-fired power plant located in Sako, South Sumatra. The facility is comprised of two gas engines with a total installed capacity of 12 MW.

The power plant was commissioned in May 2008 with PT Wijaya Karya and PT Samapta Energi Nusantara as the EPC contractors. The power plant supplies electricity to PT PLN Batam through a 6.3 / 20.0 kV step up transformer.

Power Purchase Arrangements.

Under the PPA between MPE and PLN WS2JB with effect from 2004, MPE is required to fund, establish and operate the 12 MW power plant. The parties agreed that PLN WS2JB will purchase all of the electricity from MPE for 20 years subject to annual extension upon approval by both parties. In June 2016, MPE and PLN WS2JB amended the PPA to increase the tariff to a total sum of its components of IDR 736.75 per KWh based on a capacity factor of 80.0%. The PPA tariff consists of different components, portions of which are subject to varying adjustments based on, among other things, Rupiah to U.S. dollar foreign exchange rate movements, gas prices, Indonesia and U.S. CPI, and operational metrics. The current purchase power period under the PPA expires in May 5, 2018.

Singa

Location:	Singa Field, Lematang, South Sumatra
Status:	Operational
Ownership:	100% PT Medco Power Indonesia
Expiration:	Mar 2018 (in the process of extension)
Operator:	PT Medco Power Indonesia
Capacity:	6 MW produced from gas turbine

Background. PT Medco E&P Lematang (*"MEPL"*) owns and operates an onshore gas field in the Lematang area in South Sumatra. The field requires approximately 6.0 MW of electricity supplied by the 7.5 MW gas-fired captive power plant Singa. Singa began commercial operations in 2010 with Indo Turbine and Grand Cartex as the EPC contractors. MPI currently owns a 100% stake in the project.

Power Purchase Arrangements. In January 2010, Singa entered into a PPA with MEPL for a period of five years, ending in January 2015. The PPA tenor has been extended until March 2018. MPI is currently in process of obtaining an extension of the tenor of the PPA with MEPL, since MEPL obtained its PSC extension of the Lematang PSC in 2016. The PPA has a minimum take-or-pay of 80% of the capacity factor, at a fixed tariff of US$3.97 cents per KWh and gas is provided by MEPL. For gas, MEPL guarantees and provides gas supply to the power plant from the Singa gas field.

Geothermal Projects

MPI currently has two geothermal power plant projects in Indonesia, namely Sarulla in North Sumatra with a planned capacity of 330 MW and Ijen in East Java with a planned capacity of 110 MW.

Sarulla Geothermal Power Project

Location:	Sarulla, North Sumatra
Status:	Operational/Under Construction
Working Interests:	18.9975% PT Medco Power Indonesia (49% owned by us)
	18.2525% Inpex
	25% Itochu
	25% Kyushu Electric Power Co
	12.75% Ormat
Operator:	MPI, Kyuden International Corporation
Capacity:	330 MW (110 MW in operation and 220 MW under construction)

Background. This is a geothermal project with two reservoirs (Silangkitang and Namora Langit) located in the Pahae Julu and Pahae Jae districts, North Tapanuli Regency of North Sumatra Province, approximately 300

kilometers from Medan. Commercial operations for the first unit of 110 MW commenced in March 2017, while the remaining two units, each with a capacity of 110 MW, are expected to commence operations in late 2017 and in the second quarter of 2018. Sarulla has a 30 year energy sales contract with PLN with take or pay protections at 90% of capacity. This project is financed by Japan Bank of International Cooperation, Asian Development Bank and several commercial lenders.

Medco Cahaya Geothermal (Ijen project)

In February 2013, MPI through its wholly owned subsidiary, PT Medco Cahaya Geothermal, signed a PPA with PLN (amended in December 2014), in which MPI as an IPP agreed to develop, operate and maintain a 2x55 MW geothermal power plant in the working area of Mount Ijen in the East Java province. A slim hole drilling campaign began in January 2016. The first well (IJN 01) has been completed with a depth of 2,000 meters and a flow test is expected to be performed in June 2017, while the drilling for the second well (IJN 02) is on hold while waiting for a new partner and expected to be completed by the end of 2017. IJN is currently in discussions with several potential partners.

Pursuant to the PPA with PLN, the target for the commencement of commercial operations at Ijen is 2020. This power plant will supply electricity to the Java-Bali grid. The PPA is for a term of 30 years.

Mini Hydro Project

MPI is currently developing mini hydro power generating plants ("PLTMH") located in West Java. The following is a brief description of the PLTMH projects currently being developed by MPI.

Cibalapulang 1 PLTMH. The Cibalapulang 1 PLTMH is MPI's first mini hydro project, located in Cianjur, with a capacity of 9 MW. The PPA between PT Bio Jathpora Indonesia and PLN was signed in 2012. Commercial operations are expected to start in the third quarter of 2017. MPI has a 70% interest in Cibalapulang 1.

Cibalapulang 2 and 3 PLTMH. The Cibalapulang 2 and 3 PLTMH is located in Cianjur, with a capacity of 13 MW. The PPA with PLN was signed in 2013. Progress is currently on hold pending commencement of Cibalapulang 1. Commercial operations are expected to commence in 2019. MPI has a 100% effective interest in this project.

Pusaka Parahiangan PLTMH. MPI acquired the assets of PT Pembangkitan Pusaka Parahiangan, which is involved in the development of a PLTMH project in Cianjur with a total generating capacity of 9 MW. The PPA with PT PLN West Java was signed in 2013. Commercial operations are expected to commence by the end of 2017. MPI wholly owns this project.

Sumpur PLTMH. The Sumpur PLTMH is located in Pasaman with a capacity of 8 MW. The PPA with PLN was signed in 2013. Commercial operations are expected to commence in 2019. MPI has an 80% effective interest in this project.

Medco Ratch Power Riau (Riau Project)

Location:	Riau, Sumatra
Status:	Development
Ownership:	51% MPI
	49% Ratchaburi Electricity Generating Holding Public Company Limited
Expiration:	2041
Operator:	PT Medco Ratch Power Riau
Capacity:	275 MW
Off-taker:	PLN

Background. In November 2016, MPI and Ratchaburi Electricity Generating Holding Public Company Limited established PT Medco Ratch Power Riau ("MRPR"), which was awarded the rights to develop a 275MW combined cycle power plant located at Pekanbaru City, Riau province.

Construction is planned to commence in 2018 and commercial operations are expected starting in 2021. The power plant will be connected to a PLN 150 kV transmission line.

The project cost is expected to be approximately US$300 million, expected to be funded primarily through project finance.

Power Purchase Arrangements. On April 7, 2017, MRPR entered into a 20-year PPA with PLN. Gas will be supplied by PLN based on its gas sales contract with its supplier.

Tanjung Jati B Steam Power Plant (Operations and Maintenance Agreement)

Location:	Jepara, Central Java
Status:	Operational
Ownership:	99.9% PT Medco Power Indonesia and 0.1% PT KIM through 80.1% owned by Medco Gajendra Power Services 19.9% PT. Fortum Service Oy
Expiration:	2029
Operator:	PT Tanjung Jati B Services (80%-owned by MPI and 20%-owned by Fortum Service Oy)
Capacity:	1,320 MW produced from two 660 MW coal-fired units
Off-taker:	PLN

Background. In June 2005, a consortium consisting of the Company and Fortum Service Oy ("Fortum"), a leading Nordic energy company headquartered in Finland, and PLN signed an O&M agreement for the PLTU Tanjung Jati B coal fired steam power plant, which was approved by the shareholders of PLN and became effective in September 2005. For this purpose, in April 2006, PT TJB Power Services, an 80%-owned subsidiary of MPI, was established to undertake the role as operator.

Under the O&M agreement, the O&M fees consist of five different components including labor for operations, labor for maintenance, labor administration, consumables and general expenses. Certain components are subject to adjustment based on movements in the Indonesian CPI and exchange rate fluctuations between the U.S. dollar and Rupiah.

Medco Geothermal Sarulla (Sarulla Operations and Maintenance Services)

In September 2016, Medco Geothermal Sarulla entered into an O&M agreement with Sarulla Operations Ltd for Sarulla geothermal power facilities in North Sumatra. This agreement is for a six-year period starting from the earlier of September 2018 or the commercial operation date of the second unit of Namora I Langit.

Mitra Energi Batam (Scattered PLN power plant—Operation and Maintenance Services)

In December 2016, MEB signed a contract with PT PLN Batam to provide O&M services to mobile power plants ("MPPs") owned by PLN. The total capacity of these MPPs is 500 MW across eight locations including Nias, Lombok, Pontianak and Belitung. The O&M contracts are valid for two years starting from the commencement date of each MPP area, extendable by mutual agreement of the parties.

Copper and Gold Mining

Our copper and gold mining operations are conducted through AMNT, a joint venture in which we and our joint venture partner, API, acquired our interests in November 2016. We and API each own a 50% interest in

AMIV, which in turn indirectly owns 82.2% of AMNT. In addition, pursuant to a loan agreement entered into with the prior shareholders of AMNT, PT Pukuafu Indah, an unrelated non-controlling shareholder in AMNT which owns the remaining 17.8% of AMNT, had pledged certain rights in its shares in AMNT to the prior shareholders of AMNT. AMIV acquired the pledges of such rights in connection with its acquisition of AMNT and has succeeded to certain of those pledged rights and therefore AMIV currently has the economic benefit of PT Pukuafu Indah's shares in AMNT. As a result, AMIV has a 100% economic interest in AMNT, and we have a 50% economic interest in AMNT.

We acquired our 50% interest in AMIV for a consideration of US$404 million, financed through cash on hand. AMIV's purchase of AMNT was financed through the following sources: (i) Medco Energi provided AMIV with a shareholder loan pursuant to a loan agreement entered into on August 23, 2016 of US$246.0 million. Borrowings under this facility bear interest at rates of LIBOR plus 10% per annum during the first year from drawdown, LIBOR plus 12% per annum during the second year from drawdown and LIBOR plus 16% per annum from the end of the second year until maturity. The facility matures on August 23, 2021; (ii) a 99% owned subsidiary of AMIV, PT Amman Mineral Ventura ("AMV"), entered into a mezzanine facility agreement with PT Multi Daerah Bersaing on June 30, 2016, for US$275.0 million. Borrowings under this facility bear interest at rates of LIBOR plus 8% per annum during the first year from drawdown, LIBOR plus 10% per annum during the second year from drawdown and LIBOR plus 14% per annum from the end of the second year until maturity. The maturity date of this facility is the earlier of June 30, 2019 and six months from the date of release of the facility and (iii) on June 20, 2016, PT Amman Mineral Internasional ("AMI"), a 99% owned subsidiary of AMV, entered into a senior facility agreement with PT Bank Mandiri (Persero) Tbk, PT Bank Negara Indonesia (Persero) Tbk and PT Bank Rakyat Indonesia (Persero) Tbk for US$750.0 million. Borrowings under this facility bear interest at a rate of LIBOR plus 6% per annum. The facility will mature in June 2018. Pursuant to a corporate guarantee and indemnity agreement dated October 14, 2016, Medco Energi provided a guarantee of this loan in proportion to its direct or indirect shareholding in AMI, or 50%.

In addition, in connection with the acquisition of AMNT, AMI has agreed to certain continent consideration payable to the sellers. This contingent consideration consists of: (i) US$225.0 million from Phase 7 of Batu Hijau mine production, 50% of which would be payable after any year end where the London Mercantile Exchange average copper price per pound for such year is US$2.75 or more starting in 2023, (ii) US$229.7 million would be payable if during any quarter commencing after the second quarter after closing of the acquisition, the London Mercantile Exchange average copper price from the Batu Hijau mine exceeds US$3.75 per pound; and (iii) US$203.7 million will be payable by the first anniversary of the first shipment of concentrate (or any other form of saleable copper, gold or silver) from the Elang resource.

AMNT owns and operates the Batu Hijau mine, located on the island of Sumbawa, approximately 950 miles east of Jakarta. The mining concession covers an area 66,000 hectares include the Elang copper and gold resource and several exploration prospects including, Lampui, Rinti, Batu Balong, Nangka and Teluk Puna. Exploration activities from 2017 onward are expected to focus on Nangka, Batu Balong and Teluk Puna which are the most easily accessible areas from Batu Hijau. The Elang copper-gold resource is situated approximately 60 kilometers east of the Batu Hijau mine. AMNT expects to perform feasibility studies on Elang and engage in discussions with the government of Indonesia with a view to developing the mine before the cessation of pit operations at Batu Hijau.

As of December 31, 2016, AMNT had 4.62 million ounces of proven and probable gold reserves and 1.23 million ounces of gold stockpiles and 4.81 million pounds of proven and probable copper reserves and 2.505 million pounds of copper stockpiles.

On January 11, 2017, the Indonesian government issued new regulations on the export of copper concentrate, namely MEMR Regulation No. 5 of 2017 on Increase of Added Value of Minerals through Domestic Mineral Processing and Refinery ("MEMR Regulation No. 5 of 2017"). MEMR Regulation No. 5 of 2017 requires AMNT as COW holder to convert its COW into Special Mining Business License—Operation

Production (*Izin Usaha Pertambangan Khusus—Operasi Produksi*, an "IUPK OP") in order to export its copper concentrate. On February 10, 2017, AMNT obtained the IUPK OP from MEMR. The 2017 regulations also mandates that IUPK OP holders refine their minerals domestically. AMNT continues to work with the government to guarantee investment certainty and operational continuity, including AMNT's commitment to build an in-country smelting and refining as well as export of copper concentrate. AMNT has begun a feasibility study for the capacity, design and construction as well as operation of an on-site smelting facility. For the smelter, AMNT plans to form a joint venture with another party to develop the smelter and also plans maintain majority ownership of the smelter. AMNT expects to contribute access to land, the port and its power plant to the joint venture, with the joint venture partner making capital contributions for the construction of the smelter. AMNT currently is required to complete the smelter by 2022.

Corporate Governance Rights at AMIV and AMNT

On October 20 2016, we, API and AMIV entered into a shareholders' agreement relating to AMIV. Under the shareholder's agreement, management of each of AMIV and its subsidiaries, including AMNT, rests with their respective boards of directors as supervised by their respective boards of commissioners. Under the shareholders' agreement, we and API alternate the ability to appoint the president commissioner and president director every three years at each of AMIV and AMNT. Currently, we are in the first year of the three year cycle where we are entitled to appoint the president director. However, in practice, we and our partner have discussed and agreed upon appointments. The current president director of AMNT is the existing president director at the time of acquisition, and our appointee is currently serving as vice president director and as president director of AMIV. In addition, the current president commissioner of AMNT is our current president commissioner, Mr. Muhammad Lutfi, while the president commissioner of AMIV was appointed by our partner. Under the shareholders' agreement, we and API are entitled to pre-emptive rights to new issuances of securities or proposed transfers by the other to third parties. In addition, there are certain reserved matters that require a 51% approval at a shareholders meeting, including, among others, adoption of business plan, material acquisitions or disposals, creation of certain encumbrances, instituting or settling legal proceedings in excess of certain thresholds, material changes to the scope of business, modifying terms of material contracts outside of the ordinary course, amending constitutional documents, entering into certain related party transactions, change in auditors, incurring certain indebtedness or borrowings, declaring dividends and making any guarantees.

Batu Hijau Mine

The Batu Hijau mine site is located on the island of Sumbawa. The mine employs approximately 4,500 workers. Access to the site is possible by ferry from Lombok or by seaplane from either Lombok or Denpasar, Bali. Batu Hijau is a large porphyry copper and gold deposit which is mined using a standard open pit truck and shovel method. The site has supporting facilities owned by AMNT which include an ore processing plant capable of processing up to 120,000 tons per day and comprising two semi-autonomous grinding mills, four ball mills and flotation circuits, coal and diesel fired power stations totaling 157 MW, a deep water port, a ferry terminal and townsite.

At the mine, copper and gold ore is crushed and then transported from the mine by a six kilometer conveyor to the process plant, where it is finely milled and then treated by two stages of flotation resulting in a copper/gold concentrate containing 23% to 30% copper. The concentrate is transported from the process plant through an 18 kilometer long pipeline to the port at Benete where it is filtered-dried and prior to ship-loading. AMNT's customers include traders and smelters outside of Indonesia under short to medium term agreements.

Current mining at Batu Hijau is focused on ore production from Phase 6, which is expected to be completed during 2017. Waste development for Phase 7 is expected to commence in 2017. This waste stripping is required to access the ore in Phase 7 and is expected to take three years. During this hiatus in ex-pit ore production, Batu Hijau will raise capital and feed its processing plant from existing long-term stockpiles of lower grade ore resulting in lower metal production during the Phase 7 waste development period in order to generate cash for operating activities.

Gold

In 2016, AMNT had gold production of 801 thousand ounces and an average realized price of $1,224. Gold generally is used for fabrication or investment. Fabricated gold has a variety of end uses, including jewelry, electronics, dentistry, industrial and decorative uses, medals, medallions and official coins. Gold investors buy gold bullion, official coins and jewelry. AMNT generally sells gold in U.S. dollars at the prevailing market price during the month in which the gold is delivered to the buyers.

Copper

In 2016, AMNT had copper sales of 478 million pounds and an average realized price of $2.05. AMNT generally sells copper in U.S. dollars at the prevailing market price during the month in which the copper is delivered to the buyers. Copper sales are in the form of concentrate that is sold to smelters for further treatment and refining, and copper cathode (raw material for the production of copper rods for the wire and cable industry).

In the three month period ended March 31, 2017, the joint venture entity, AMIV, had net revenue of US$376.7 million.

The Energy Building

We, through our subsidiary PT Api Metra Graha, or AMG, own The Energy building, the building in which we and most of our subsidiaries are headquartered. The Energy building is a modern and intelligent building located in a strategic area of Jakarta, the Sudirman Central Business District ("SCBD"). The building occupies an area of 8,263 square meters, comprising 40 floors for office space and five basement floors for parking. The building was designed by Kohn Pedersen Fox, a prominent architecture firm from New York, USA, The Energy building was built in 2006 with high-quality specifications and was fully operational by the end of 2008.

We acquired a 49% interest in AMG, the company that owns The Energy building, in 2013 and the remaining 51% in December 2015 since we and our subsidiaries are headquartered in the building. AMG leases the building to businesses which operate in a number of industries, mostly petroleum, mining, financial institutions and professional services. The building has continuously maintained a high occupancy rate, with approximately 92% occupied as of March 31, 2017.

Categorized as a Premium Grade A office building, The Energy building has extensive facilities including a multi-function Hall, a banking hall, international restaurants, a salon and wellness center, money changers, a post office, child care facilities, pharmacy and a mini-market. Moreover, given the location in the SCBD, the building is in close proximity to premium office buildings, shopping centers, hotels and apartments and is also easily accessible from other areas of Jakarta.

Our ownership in AMG is currently held for sale, as part of our strategy of portfolio rationalization. The value of investment properties, which is primarily The Energy building, as of March 31, 2017 was US$349.7 million.

Coal Mining Unit

Through our wholly owned subsidiary, PT Medco Energi Mining Internasional, which in turn owns, PT Duta Tambang Rekayasa ("DTR") and PT Duta Tambang Sumber Alam ("DTSA"), we own and operate coal mines in Nunukan, North Kalimantan. DTR currently produces approximately 575,000 tons per annum and exports its coal under a term contract. From the site, DTR coal is trucked to the loading port, then barged through the Sebakis river to Nunukan anchorage as the offshore transshipment point. Located adjacent to DTR, DTSA is under development and expected to start producing in the fourth quarter of 2017, at annual rate of approximately 300,000 tons. DTR's coal is primarily sold under short-term off-take agreements with foreign buyers. We currently classify this business as a discontinued operation and hold our coal mining assets as assets held for sale.

Competition

We face competition from other oil and gas companies including Pertamina, the state-owned national oil and gas company, in all areas of our oil and gas operations, including the acquisition of production sharing arrangements. Our competitors in Indonesia and South East Asia include international oil and gas companies, many of which are large, well-established companies with substantially greater capital resources and larger operating staff than we have and many of which have been engaged in the oil and gas business for a longer period than us. Such companies may be able to offer more attractive terms when bidding for concessions for exploratory prospects and secondary operations, to pay more for productive natural gas and oil properties and exploratory prospects, and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical or personnel resources permit. Our ability to acquire production sharing arrangements and to discover, develop and produce reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. However, given the importance of the oil and gas industry to the Indonesian economy, local participation has been actively encouraged by the Government. Being one of the few Indonesian companies involved in the oil and gas exploration and production industry, we believe we have certain advantages when seeking to expand our business in this sector.

Indonesia's independent power sector is fragmented, with multiple IPPs operating in the small to medium sized (< 400 MW capacity) and large sized segments (≥ 400 MW). Local Indonesian power players generally operate across multiple segments but are largely focusing on the small to medium sized segments. Indonesia Power and PJB (both state-owned) are the strongest local players as they are well-positioned in the market due to their legacy and relationship with PLN and the government. International power players largely operate in the large sized segment with their main focus being coal and geothermal resources. MPI mainly competes for new projects based on tariff pricing and technical quality location.

AMNT competes with other copper and gold mines, primarily in Asia. AMNT competes based on track record in fulfilling orders, fulfilling customer commitments and ore quality.

Operating Hazards, Insurance and Uninsured Risks

Our main operations are subject to hazards and risks inherent in the exploration, production and transportation of natural gas and oil, and through AMNT and MPI, mining and power generation. Such risks and hazards include fires, natural disasters, explosions, encountering formations with abnormal pressures, blowouts, cratering, pipeline ruptures and spills; most of which can result in the loss of hydrocarbons, mineral and power production, environmental pollution, personal injury claims and other damage to our properties. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. Our coverage includes, but is not limited to, physical damage on certain assets, control of wells, blowouts and certain costs of pollution control, comprehensive general liability including automobile and worker's compensation. In line with what we believe to be industry practice, we do not carry business interruption insurance.

Safety

We have extensive safety procedures designed to ensure the safety of our workers, assets, the public and the environment. General safety procedures are available at the corporate level. More specific procedures are developed by each operating subsidiary to manage high risk jobs or tasks. Working procedures must be available, approved and reviewed by authorized person before a high risk job can be undertaken.

It is our policy that in the event of any conflict between the progress of work and safety or environmental concerns, the safety of employees including third parties and preservation of the environment are paramount. We also continue to build employee and contractor health, safety and environment (**"HSE"**) basic competence. Basic standardized training ensures that all employees and contractors have similar HSE insight and knowledge.

We have implemented an HSE management system known as Performance Integrity of Medco E&P (**"PRIME"**). PRIME uses a structured approach applied in order to ensure that our business activities fulfill and comply with relevant legal and other requirements relating to HSE. Our management system is aligned with management system models and structures in OHSAS 18001, ISO 9001, ISO 14001, and include the relevant requirements of ISRS 7th. We have also developed our operating systems, guidelines and standard operating procedures to comply with PRIME procedures.

As a result of our robust HSE programs, we recorded a total recordable incident rate of 1.01 in our oil and gas exploration and production domestic operations, which we believe is in line with top level performance in the exploration and production industry. In 2016, we received several safety awards from MEMR: which are the Patra Nirbhaya Karya Madya for Tarakan PSC, Patra Nirbhaya Karya Pratama for Lematang PSC, Patra Nirbhaya Karya Utama in Senoro-Toili. Patra Nirbhaya awards are awarded in recognition of the success rate of an oil and gas company in ensuring the continuity of safety in oil and gas business activities.

Employees

We had 3,778 employees as of March 31, 2017, of which 2,414 were permanent employees and 1,364 were contract employees.

The following table sets forth the number of our regular employees, temporary employees and total employees for the periods indicated below.

As of December 31,	Regular Employees	Temporary Employees	Total
2014	1,327	328	1,655
2015	1,398	133	1,531
2016	2,398	1,287	3,685
As of March 31,			
2017	2,414	1,364	3,778

Our employees have ten labor unions, and we have signed collective bargaining agreements with a term of two years with one year optional extension. As of March 31, 2017, these unions have approximately 949 members, or 92.77% of our regular workforce. Our oil and gas business has not been subject to any material strikes or other labor disturbances that have interrupted our operations. AMNT and MPI have been subject to certain labor disturbances. See "Risk Factors — Risks Relating to Our Business and Operations — Our operations could be disrupted by community or labor issues." We believe we have a good and cooperative relationship with our employees.

Environmental

Our operations are subject to Indonesian laws and regulations governing the environment or otherwise relating to environmental protection. These laws and regulations require the acquisition of a permit before drilling commences development construction, which restrict the types, quantities and concentration of various substances that can be released into the environment related to drilling and production operation activities, and limit or prohibit drilling activities on certain lands lying within wilderness, natural reserves, wetlands and other protected areas. The regulations also require parameter measurement to prevent pollution resulting from former or recent operations, such as plug abandoned wells, and impose substantial liabilities for pollution resulting from our operations. To some extent, the regulatory system regulates the oil and gas industry such that the cost of doing business increases and consequently affects its profitability. Changes in environmental laws and regulations may result in a more stringent and costly waste handling, disposal and clean-up requirements and this could have a significant impact on our operating costs, as well as the oil and gas industry in general. Management believes that we are in compliance with current applicable environmental laws and regulations in

all material respects and that continued compliance with existing requirements will not have a material adverse impact on us.

The Government has imposed environmental regulations on oil and gas companies operating in Indonesia and in Indonesian waters. Operators are prohibited from allowing oil into the environment and must ensure that the area surrounding any onshore well is restored to its original state after the operator has ceased to operate on the site. Environmental impact study and a Government permit are required before any exploration work can commence. Under the Oil and Gas Law, SKK Migas has direct control over operators to ensure that they meet the Government regulations. We are required to provide a report containing an environmental impact analysis to the Indonesian environmental agency on a bi-annual basis.

We believe we have demonstrated our compliance with regulations, particularly in environmental aspect. We have consistently received Blue, Green and Gold PROPER awards from the Environmental & Forestry Ministry for certain of our Indonesian assets. While we have generally received Blue, Green and Gold PROPER awards from the Environmental & Forestry Ministry for certain of our Indonesian assets, in 2016, we received a Red rating from Environmental and Forestry Ministry for our Bawean PSC, which we sold in 2017, due among other things to the Governments request for a wastewater treatment facility to be constructed. A Red rating means that we have made efforts to be in compliance, but are not completely in compliance with regulations. AMNT's mining business is also subject to Indonesian environmental regulations.

We have a strong commitment to participate in reducing the effects of climate change. Energy-related activities contribute around 70% of global greenhouse gas ("GHG") emissions, with oil and gas jointly representing approximately 60% of those energy-related emissions through their extraction, processing and subsequent combustion. While the direct emissions of the oil and gas sector are significant contributors to total global GHG emissions, the bulk of GHG emissions generated through the oil and gas lifecycle are in the consumption and combustion of final products and remain beyond the boundaries of oil and gas companies' operations. Indonesia has ambitious goals to reduce greenhouse gas emissions by 26% away from "business-as-usual" levels by 2020, or by as much as 41% with international support, while at the same time maintaining strong economic growth. As an energy company that mainly does exploration and development in the oil and gas industry, we are highly-committed to overcoming effects of climate change. We conduct efforts to minimize our GHG emissions and to instill good practices in terms of energy and resource efficiency. We minimize our GHG emissions by monthly monitoring of GHG emissions and a reporting process to our board of directors, and we also continuously seek to innovate processes to perform energy efficiency activities. We also report our GHG emission levels to the Ministry of Environment and Forestry on an annual basis. We have also taken measures including converting our operational vehicles from fossil fuel-based engines to gas-based engines, pioneering the reduction and utilization of flaring gasses across multiple assets, and applying low-pressure gas emission reductions and utilization with low pressure compressors (gas jack) in asymptotic conditions.

Corporate Social Responsibility

Our Corporate Social Responsibility ("CSR") program is designed and managed to benefit the stakeholders around our main operating areas and is customized according to each community's primary needs and competencies. In each community our CSR investments are focused on three policy pillars:

- to foster empowerment and entrepreneurship;
- to manage and mitigate security risks to our operations; and
- to encourage and invest in the development of environmentally friendly renewable energy.

In 2016, we spent a total of US$0.7 million on CSR programs in operations ranging from East Aceh (DI Aceh), Anambas and Natuna (Riau Islands), Lahat, Musi Rawas, Banyuasin, Banyuasin, Muara Enim,

Penukal Abab and Lematang Ilir (South Sumatra), Tarakan (North Kalimantan), North Morowali, Toili to South Batui (Central Sulawesi). Such programs included, among others, promoting sustainable agriculture in more than 20 villages, providing electricity to 558 houses in five villages, providing early childhood education, books and housing, supporting the cultivation of medicinal herbs and organic vegetables in 1,950 family gardens in 37 villages, providing tools and training for 1,944 fishermen on post-harvest processing techniques for captured fish and developing organic rubber farms for 375 farmers in South Sumatra. We also established institutions to ensure a consistent effort in developing these programs.

We have consistently received Blue, Green and Gold PROPER awards from the Environmental & Forestry Ministry for certain of our Indonesian assets. The Company also received Adiwiyata School Award in Anambas for our contribution to child education. With the help of our program, in 2016 the organic rubber farmers from South Sumatra were invited to the Indonesian presidential palace and received Farmers' Achievement Awards for the third time.

Legal Proceedings

From time to time, we have been and may be a party to various legal proceedings.

We are not currently a party to any other pending legal proceedings that we believe will have a material adverse effect on our business, financial condition or results of operations.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The discussion below should be read together with our consolidated financial statements as of and for the years ended December 31, 2014, 2015 and 2016 and for the three months ended March 31, 2016 and 2017 together with the accompanying notes. Our consolidated financial statements have been prepared in accordance with Indonesian FAS, which differs in certain material respects from U.S. GAAP.

Overview

We are an integrated energy and natural resources company operating through our core oil and gas exploration and production business and through significant investments in power generation and mining. We are the largest independent publicly listed oil and gas exploration and production company in Indonesia based on market capitalization. In addition, based on a peer analysis conducted by Wood Mackenzie, we are the largest upstream oil and gas exploration and production among our Peer Group as of and for the year ended December 31, 2016 based on proved and probable reserves and production in Asia (our Peer Group refers to the group of peers identified by Wood Mackenzie, consisting of independent exploration and production companies with a noteworthy proved and probable reserves and production footprint in South and Southeast Asia. These consist of PT Saka Energi Indonesia, PT Energi Mega Persada Tbk., Ophir Energy plc, Premier Oil plc and KrisEnergy Ltd.). We primarily focus on our activities in Indonesia, and also have operations in the Middle East, North Africa and the United States.

We have interests in ten oil and gas properties in Indonesia, six of which are currently producing; and in oil and gas properties in five countries outside of Indonesia, namely the United States, Tunisia, Yemen, Libya and Oman. In Indonesia, our blocks are held under production sharing arrangements with SKK Migas, Indonesia's national upstream oil and gas regulator. Under these production sharing arrangements, we are entitled to recover our costs and earn an agreed after-tax share of the production once the block is declared commercially exploitable by SKK Migas.

We plan to continue to strengthen our producing assets portfolio by the phased development and monetization of our existing portfolio of discovered gas assets. We aim to bring our projects on-stream on time and within budget, particularly our Block A, Aceh block, which is our most advanced development in Indonesia. First gas production and gas deliveries under the Block A take-or-pay backed, fixed-price domestic contract are expected to begin in 2018. We then plan to focus on Senoro-Toili phase II where the investment decision with respect to the preferred development scenario is expected to be made in the third quarter of 2018. Our operations at Senoro-Toili phase I are fully contracted under off-take agreements both for the upstream and downstream sectors. After this Senoro-Toili phase II investment, we plan to focus on our next large development, which is phase II of our Block A Aceh block and the monetization of our other discovered gas resources at this block. As a result, going forward, we expect that a larger percentage of our production will consist of production from Senoro-Toili, South Natuna Sea Block B and Block A Aceh, as certain of our existing blocks, including Rimau PSC and South Sumatera PSC, are in mature stages of production.

In 2016, our oil and gas production split was 46.7% oil and 53.3% gas (including production under our Oman service contract) and 39.0% oil and 61.0% gas (excluding production under our Oman service contract). Of the gas production, 50.9% was sold under fixed price contracts to PLN, the Indonesian state electricity generator, Pertamina (the national oil company of Indonesia) and Pusri, an Indonesian fertilizer producer wholly owned by the Government. The remaining gas production is sold to Sembgas, Petronas or indirectly pursuant to LNG contracts to KOGAS, Chubu Electric Power Co. Inc and Kyushu Electric Power Co. Inc. Our gas off-takers include blue chip customers with strong credit profiles.

In addition to our core oil and gas business, we have significant investments in power generation and mining. Through MPI, we have a significant investment in the power generation sector in Indonesia. We

currently own a 49% interest in MPI, an IPP and O&M provider. The remaining interest in MPI is owned by PT Saratoga Power, an unrelated third party, which is owned indirectly by PT Saratoga Investama Sedaya Tbk (77.7%) and Finance Corporation (22.3%). MPI promotes a green energy platform and has interests in gas-fired power plants, geothermal energy and hydro-electricity. Established in 2004, MPI owns and operates seven gas-fired power generation assets with a total gross capacity of over 296.7 MW and is also currently developing its 275 MW gas-fired IPP project and six other renewable assets, including geothermal and mini hydro power plants. MPI also owns a minority share in the Sengkang gas-fired power plant in South Sulawesi and acquired a long-term O&M contract for the Tanjung Jati B power plant in Jepara, Central Java through one of its subsidiaries. MPI is also developing a 3x110 MW geothermal power plant in Sarulla, North Sumatra, where the commercial operation of the first 110 MW unit was achieved in March 2017 (the remaining two units, each of 110MW capacity, will be finished by the end of 2017 and mid-2018, respectively). For the Sarulla geothermal power plant, MPI was also appointed as operator under the O&M contract.

Our copper and gold mining operations are conducted through our joint venture, AMNT, in which we made our investment in November 2016. We and our joint venture partner, PT AP Investment ("API") each own a 50% interest in AMIV, which in turn indirectly owns 82.2% of AMNT (AMIV also acquired certain pledged rights from PT Pukuafu Indah, an unrelated non-controlling shareholder in AMNT, which gives AMIV a 100% economic interest in AMNT). AMNT owns and operates the Batu Hijau mine, located on the island of Sumbawa, approximately 950 miles east of Jakarta, as well as various discovered resources, several exploration prospects and the supporting infrastructure in the same area. These resources consist of at least six prospective reserves, namely: Elang, Lampui, Rinti, Batu Balong, Nangka and Teluk Puna.

For the years ended December 31, 2014, 2015 and 2016, our net oil and gas sales were US$701.9 million, US$575.3 million and US$583.0 million, respectively, and EBITDA was US$265.4 million, US$220.0 million and US$263.5 million, respectively. For the three month periods ended March 31, 2016 and 2017, our net oil and gas sales were US$130.8 million and US$210.3 million, respectively, and EBITDA was US$66.1 million and US$108.3 million, respectively.

Significant Factors Affecting Results of Operations

Oil and Gas Prices

Our net sales, profitability and asset values and financial condition have been and will continue to be significantly affected by movements in oil and gas prices.

Oil Prices

The international market for crude oil is volatile, and has recently been characterized by significant price fluctuations including significant decreases in the second half of 2014 and in 2015. The monthly average price of Brent crude oil price decreased from a high of US$111.9 as of June 2014 to US$62.8 as of December 2014, and then to US$38.8 as of December 2015 and to US$54.9 as of December 2016. From January 2017 to July 2017, the monthly average Brent crude price was US$52.2.

Oil prices fluctuate due to a number of factors, which include, among others, demand for crude oil, global events and circumstances, political developments and instability in petroleum producing regions, such as the Middle East; the ability of OPEC and other petroleum-producing nations to set and maintain production levels and therefore influence market prices; market prices and supply levels of substitute energy sources, such as natural gas and coal; domestic and foreign government regulations with respect to oil and energy industries in general; the level and scope of activity of oil speculators; weather conditions and seasonality; and overall domestic and regional economic conditions. Our average realized sales prices for oil for the years ended December 31, 2014, 2015 and 2016 were US$97.8 per BBLS, US$49.3 per BBLS and US$42.3 per BBLS, respectively, reflecting the decline in crude oil prices globally. Our average realized retail sales prices for oil in

the three month periods ended March 31, 2016 and 2017 were US$30.6 per BBLS and US$51.6 per BBLS, respectively. The changes in oil prices have significantly impacted our net oil and gas sales, which decreased from US$701.9 million in 2014 to US$575.3 million in 2015 to US$583.0 million in 2016. The increase in 2016 was primarily due to increased sales volumes which offset the decrease in oil prices. In addition, fluctuations in oil prices have impacted and may continue to impact our results of operations and asset values. In 2015, we recorded a loss on impairment of assets of US$217.2 million, primarily due to changes in value of our oil and gas properties resulting from the sharp decrease in oil prices during the year. To the extent oil prices fluctuate in the future, we could record impairment losses or gains on fair value of our assets.

We sell most of our net crude oil production through short to medium term off-take contracts which we grant under a competitive tender process. In line with the Indonesian government regulations, we sell our oil at prices based on ICP. The ICP price is determined by the Indonesian government, and was the monthly average of the mean of two publications of independent oil traders and marketers in the Asia Pacific region published by Platts and RIM in the following proportions: 50% Platts and 50% RIM until June 2016. Starting in July 2016, the basis of ICP changed to Dated Brent price plus Alpha. The ICP is published every month. The sales contracts that we enter into are based on the ICP, with certain pre-agreed premiums depending on the quality of the crude oil and provide for the sale of substantially all of our net crude oil production from a given producing block. Increases in ICP therefore increase our net oil sales and have a favorable impact on our results of operations. The cost-recovery portion of net crude entitlement is also calculated based upon ICP prices. Our profitability is significantly affected by the prices of, and demand for, crude oil, and the difference between the prices received for the oil we produce and the costs of exploring for, developing, producing, transporting and selling oil.

The terms of our production sharing contracts at oil-producing blocks require us to effect DMO sales at 10% to 25% of the market price. As a result, we are unable to sell our entire net oil production at the full international market price and consequently our average realized sales price may be lower than the applicable ICP. These prices are also subject to fluctuations which may have a material adverse effect on our revenues and net income and on our business, financial condition and results of operations.

Gas Prices

We typically enter into GSAs which set the total contracted quantity ("TCQ"), daily contracted quantity ("DCQ") and gas price. While TCQ and DCQ vary between buyers, gas prices under our domestic gas GSAs are fixed in US$/MMBTU with an application of a relatively small escalation factor (typically 2.5% to 3.0% per annum). Therefore our revenue from natural gas sales is not subject to as much price volatility as our oil revenues. Some of our export contracts contain pricing linked ultimately to oil prices, such as the Senoro GSA and approximately half of our production under the South Natuna Sea Block B GSA. In particular, as of March 31, 2017, gross working interest volumes from all of our 1,065 BCF of proved plus probable gas reserves were commercially committed for sale through long-term contracts, with sales through such contracts representing 51% and 53% of our revenues in 2016 and three month period ended March 31, 2017, respectively. Of this, for three month period ended March 31, 2017 gas revenue of approximately 70.0% was sold through fixed price gas contracts with the remaining gas revenue sold under oil-linked prices. In addition, all of our GSAs, including both fixed-domestic and oil-linked-export GSAs, have take-or-pay protections, pursuant to which, if a buyer is unable to absorb the agreed supply during a period (typically over twelve months) then the buyer will have to pay a portion (usually in the range of 80% to 90%) of the total contracted supply for the period. The revenue contribution from GSAs has increased in recent years, and we expect will continue to increase as a percentage of our revenue in 2017 and 2018, especially with the first gas being sold under our fixed-price GSA for the Block A, Aceh gas development expected in March 2018. Our average realized sales prices for gas per MMBTU for the years ended December 31, 2014, 2015 and 2016 were US$5.6, US$5.2 and US$4.4, respectively, reflecting production from Senoro starting in 2015, which has a GSA with prices linked to movements in oil prices. Our average realized sales prices for gas per MMBTU for the three month periods ended March 31, 2016 and 2017 were US$4.1 and US$5.5, respectively, reflecting increased sales under our oil price-linked GSAs. For a summary description of our gas sales arrangements, see "Business—Sales and Distribution—Natural Gas."

Acquisitions and Divestments

Our results of operations and business are significantly affected by acquisitions and divestments.

AMNT

In November 2016, we entered into the copper and gold mining sector through our acquisition of our joint venture interest in AMIV, which in turn indirectly owns 82.2% of AMNT (AMIV also acquired certain pledged rights from an unrelated non-controlling shareholder in AMNT, which gives AMIV a 100% economic interest in AMNT), the operator of the Batu Hijau copper and gold mine as well as various discovered resources, several exploration prospects and the supporting infrastructure in the same area. This transaction has affected and we expect will continue to affect our results in a number of respects, which include: (i) primarily as a result of the consummation of this transaction, we recorded a bargain purchase gain of US$467.2 million in 2016, reflecting that the purchase price we paid for our share in AMIV was less than the assessment of the fair value of our share of AMIV's assets based on a valuation report from an independent third party valuer registered with the OJK. In addition, this acquisition affected our balance sheet as our cash balances decreased significantly from the beginning of 2016 to the end of 2016 and our long-term investments increased, primarily due to this acquisition. As part of the transaction, we made a shareholder loan of US$246 million to AMIV for its acquisition of AMNT and also guaranteed certain of AMIV's indebtedness which was incurred in connection with such acquisition. Through this investment, we now operate in the copper and gold mining industry, and expect our share of the results of our joint venture will be significantly affected by AMNT's operating performance in the future.

Oil and Gas Blocks

From time to time, we acquire and divest from, or increase or decrease our effective interests in, oil and gas blocks. For example, in 2016, we increased our interest in the Lematang PSC, a producing asset, to 100% from 74.1%, increased our interest in Block A Aceh, a development asset, from 41.7% to 58.3% and acquired a 40.0% interest in South Natuna Sea Block B. We also agreed to divest our entire interest in the Bawean PSC, a producing asset, in June 2017. The acquisitions of, and divestments from, producing assets affect our production volume, and generally our acquisitions and divestments affect the value of our assets, liabilities and result of operations as we record bargain purchase gains.

Other Businesses

From time to time we have entered into certain businesses, including coal, real estate (through our ownership of The Energy Building) and others. Based on our assessment of our business lines, we decided that it may be in our interests to divest from these businesses and therefore we have reclassified them as assets held for sale. Such reclassification has the effect of such businesses being accounted for as discontinued operations on our income statement until we sell or may reclassify such assets. In particular, in 2017 we reclassified our subsidiary which holds The Energy building as held for sale, which resulted in a significant decrease in investment properties under our non-current assets and increase in our non-current assets classified as held for sale.

Cost Efficiencies

Since 2014, in light of the decreases in oil prices in 2014 and 2015, we have carried out an efficiency drive. In 2015 and 2016, we significantly improved our organizational cost structure. Our 2016 full year unit cash production cost was reduced to US$8.8/BOE compared to US$12.3/BOE in 2015 and US$15.4/BOE in 2014. This reduction was achieved through a number of cost reduction initiatives including (i) changing operating modes, such as revising crew rotation schedules and outsourcing certain non-core activities; (ii) optimizing existing operations and relationships, such as vendor renegotiations to capture deflation and sharing infrastructure with neighboring operators; and (iii) reassessing all operations to apply "fit-for-purpose"

methodologies, such as rescheduling planned maintenance and engine exchanges. The cost reduction programs have targeted both larger scale cost reduction opportunities, such as drilling rig rate reductions, to smaller scale granular opportunities, such as travel and training budgets. We currently are committed to maintaining a unit cash production cost per BOE below US$10 through 2021 through, among others, continuing the aforementioned cost-efficiency initiatives.

Commercial Arrangements

Our PSCs contain cost recovery provisions which permit us to recover approved costs incurred in capital investment for exploration and development, and production and operating expenses against available revenues generated by the PSC after deduction of FTP, and any applicable investment credits. Generally, under the terms of our PSCs, we and the Government are entitled to take and receive FTP amounting to 20% of the total production of oil and gas each year, split between us and the Government, from our production areas in all of our PSCs, before any deduction for cost recovery, and applicable investment credits. Under the terms of ten of our PSCs, including 2 JOBs, after we have recovered all approved costs including incentives, the Government is entitled to a 65.0% to 85.0% profit share of the remaining production and we keep the rest as our profit share.

Because our recoverable costs are customarily settled in oil and gas, the exact amount realizable by us out of these cost recoveries varies depending on the market prices of oil and the contracted prices for gas. For example, if oil prices decrease, our cost recovery portion of production will rise and our net entitlement under our commercial arrangements will therefore also rise. However, despite such increase in our net entitlement, a decline in oil prices will lead to a decline in net revenues.

Our share of profits after tax from our PSCs ranges from 27.5% to 40.0% for gas and 12.5% to 35.0% for oil, depending on the PSCs and without taking into account the impact of cost recovery and DMO for oil and gas. After a period of 60 months commencing from the month of the first delivery of crude oil produced from each new field in a given contract area, the contractor will typically be subject to DMO to sell approximately 3.75% on an after tax basis of the crude oil produced from the contract area at a discounted price, ranging from 10.0% to 25.0% of the market price, depending on the PSC. For the last three years, our DMO have accounted for an average of approximately 3.9% on an after tax basis of our crude oil net production. While we are obliged to sell 25% of the gas we produce in the domestic market, we may do so at market price and as we sell the majority of our entire gas net production in the domestic market, in practice, this obligation does not affect our results of operations. There can be no assurance that we will not be subject to increases in our DMO for oil and gas in the future. See “Risk Factors — Risks Relating to our Industries.” for further information.

Oil and Gas Production Volume

Our oil and gas net production volumes are a key factor that affects our sales and profitability and depend primarily on the terms of our production sharing contracts and the level of developed reserves in the fields in which we have an interest. The level of developed reserves is affected by such factors as:

- our exploration success in making discoveries;
- the speed at which successful exploration is approved for development and then brought into production, and the speed at which reserves are depleted through production;
- the extent to which we acquire or divest interests in producing reserves;
- the expiration and extension of the terms of the production sharing arrangements under which we and our partners produce crude oil and gas;
- operational efficiencies in and the infrastructure available for our production processes; and
- managing declining reserves at mature fields.

In addition to our amount of producing reserve, our level of production is affected by:

- market demand; and
- individual terms of the commercial contracts.

Our Planned Exploration and Development Activities

From January 1, 2014 to March 31, 2017, we incurred US$819.3 million in capital expenditures, which include acquisition costs for exploration and evaluation assets, and development costs for our oil and gas properties. Our total annual non-debt funded capital expenditures necessary to maintain our production levels are expected to remain below US$200 million per year over the next five years, which should allow for a reduction in gearing. Within this total capital expenditure, we intend to cap expenditures for discretionary exploration and managing declines in production to US$60 million per year. We plan to do this by phasing expenditures on our large developments and making carefully selected investments to offset declines in production. We expect that our capital expenditure for drilling and oil and gas infrastructure will be funded by the cost recovery mechanism under our PSCs.

We follow PSAK No. 64, Exploration for Evaluation of Mineral Resources, in recording exploration and evaluation assets. Accordingly, all estimated future costs associated with the acquisition, exploration and development of oil and gas reserves, including directly related overhead costs, are capitalized. All costs arising from production activities are recorded at the time they are incurred. All capitalized costs relating to our oil and gas reserves, including estimated future costs of developing proved reserves and capitalized financing costs, are depreciated and amortized using the unit of production method, based on the total estimated proved reserves, as detailed in Note 2 to our consolidated financial statements.

Investments in unproven reserves and major development projects are not amortized until proved reserves associated with such properties and projects can be determined or until impairments occur.

Our depreciation, depletion and amortization costs for (including depreciation charged to our operating expenses) for the years ended December 31, 2014, 2015 and 2016 were US$89.4 million, US$114.8 million and US$111.4 million, respectively. Our depreciation, depletion and amortization costs for the three month periods ended March 31, 2016 and 2017 were US$26.2 million and US$34.0 million, respectively.

We also conduct workover operations, comprising drilling activities, to maintain our current production capacity, which are accounted for as capital expenditure.

PSC Tax Regime

The calculation of income tax for PSC working interest holders differs from the method generally used in calculating income tax for other Indonesian tax payers. Significant differences between the general income tax regime and the PSC income tax regime include:

- under the PSC tax regime, the taxable value of oil liftings is to be referenced to the net entitlement of oil after deduction of cost recovery (calculated based on ICP, as opposed to the actual sales price), while the taxable value of gas liftings is also referenced to the net gas entitlement, but calculated based on actual sales price;
- under the PSC tax regime, the classifications for intangible and capital costs are not necessarily consistent with general Indonesian income tax rules relating to capital spending;
- under the PSC tax regime, the depreciation and amortization rates applying to intangible and capital costs are not necessarily consistent with the depreciation rates available under the general Indonesian income tax rules;

- under the PSC tax regime, interest costs are not recoverable and not tax deductible, whereas interest is usually fully deductible under general Indonesian income tax rules. However, some of our PSCs provide specific allowances (such as investment credit allowance and interest cost recovery) which are calculated based on approved interest rates on remaining capital expenditure balances, allowing our subsidiaries to recover the amount of such allowances. Such allowance are not tax deductible costs;
- under the PSC tax regime, 20% of the oil and gas production before any deduction for cost recovery can be deferred from tax until the equity split position is reached, which is not necessarily consistent with the how tax is calculated under the general Indonesian income tax rules;
- the PSC tax regime provides for an unlimited carry forward of prior year unrecovered costs, as opposed to a given year restriction under the general Indonesian income tax rules; and
- no tax deductions will arise under the PSC tax regime until commercial production commences, as opposed to a deduction arising from the date of the expenditure being expensed or accrued under the general Indonesian income tax rules.

Due to the above differences, decreases or increases in current tax expenses may not necessarily be in line with decreases or increases in sales. Deductible costs are accordingly required to be calculated in accordance with the PSC tax regime in order to calculate our taxable income and the related tax expense for a given period.

Indonesian income tax rates on our PSCs currently vary from 25% to 35%, depending on the contract terms for the applicable PSC where revenue is generated and the prevailing tax rates in the year in which the PSC is entered into, and this percentage changes our effective tax rate. Our PSCs are also subject to a PSC dividend tax of 15% to 20%. Our income tax expense is significantly influenced by the fact that PSCs cannot be consolidated for Indonesian income tax purposes, as this prevents us from off-setting losses from one PSC from profits from another PSC. Each PSC is taxed individually and no cross deduction is allowed.

Political and Security Conditions in the Countries Where we Operate

While our assets are primarily located in Indonesia, we also operate in Oman, Yemen, Tunisia and Libya. Such operations may be subject to political and security considerations. In 2016, we recorded impairment losses on our oil and gas properties of US$278.5 million, primarily related to impairments of our assets in Libya and Tunisia resulting from our risk assessment related to political conditions in the North African region, which affected our profitability for the year. In addition, our operations in Tunisia were suspended due to labor protests which occurred from April 2017 to June 2017. Operations resumed from June 2017. In Yemen, due to adverse security conditions there has been no activity at our blocks since 2014 and one block is in the process of being relinquished to the Government of Yemen and another is currently under a claim of force majeure. We continue to monitor and assess the conditions in these countries to resume operations.

Overview of Results of Operations

The following table sets forth certain information with respect to our revenues, expenditures and profits, for the years ended December 31, 2014, 2015 and 2016 and the three month periods ended March 31, 2016 and 2017.

	For the Years Ended December 31,			For the Three Month Periods Ended March 31,	
	2014	2015	2016	2016	2017
	(Restated)		(Restated)	(Restated)	
			(US$ in millions)		
Consolidated Statements of Profit or Loss and Other Comprehensive Income					
Net oil and gas sales	**701.9**	**575.3**	**583.0**	**130.8**	**210.3**
Cost of Sales and Other Direct Costs					
Production and lifting costs	281.5	215.3	205.1	39.6	48.4
Depreciation, depletion, and amortization	88.0	113.8	110.2	26.0	33.9
Cost of crude oil purchases	26.3	21.3	13.3	3.0	19.5
Exploration expenses	24.4	6.8	7.0	1.8	3.2
Cost of services	0.5	0.8	0.6	0.2	0.2
Total Cost of Sales and Other Direct Costs	**420.7**	**358.0**	**336.3**	**70.6**	**105.2**
Gross Profit	**281.2**	**217.3**	**246.8**	**60.2**	**105.1**
Selling, general and administrative expenses	(105.2)	(112.1)	(94.7)	(20.3)	(30.8)
Finance costs	(67.0)	(77.2)	(99.6)	(25.2)	(29.4)
Finance income	4.0	4.3	6.0	2.6	7.3
Bargain purchase	—	—	551.7	—	—
Gain on business combination achieved in stages	—	50.2	—	—	—
Impairment loss on assets recognized at fair value less cost to sell	—	—	(11.9)	—	—
Share of net income (loss) of associates and joint venture	7.1	7.2	(27.2)	0.5	10.0
Loss on impairment of assets	(16.2)	(217.2)	(288.9)	—	—
Other income	27.1	18.6	16.7	3.6	17.3
Other expenses	(7.2)	(14.0)	(6.0)	(8.5)	(1.3)
Profit (Loss) Before Income Tax Expense from Continuing Operations	**123.8**	**(122.9)**	**292.8**	**13.0**	**78.2**
Income Tax Benefit (Expense)	**(93.5)**	**(31.3)**	**(62.8)**	**6.3**	**(28.7)**
Profit (Loss) for The Period/Year from Continuing Operations	**30.3**	**(154.2)**	**230.0**	**19.3**	**49.6**
Loss after Income Tax Expense from Discontinued Operations	(21.5)	(32.0)	(43.0)	(8.4)	(4.9)
Profit (Loss) for The Period/Year	**8.8**	**(186.2)**	**187.0**	**11.0**	**44.7**
Other Comprehensive Income That Will Be Reclassified to Profit or Loss	**8.5**	**(1.4)**	**4.5**	**12.0**	**(2.9)**
Other Comprehensive Income That Will Not Be Reclassified to Profit or Loss	**5.2**	**5.8**	**3.4**	**1.0**	**(2.9)**
Total Comprehensive Profit (Loss) for The Period/Year	**22.5**	**(181.8)**	**195.0**	**24.0**	**38.8**
Basic Earnings (Loss) per Share attributable to Equity Holders of the Parent Company (in full amount)	0.00157	(0.05658)	0.05649	0.00311	0.01318

Description of Certain Principal Comprehensive Income Statement Line Items

Net Oil and Gas Sales

Our net oil and gas sales are primarily generated from sales of crude oil and natural gas, which are affected primarily by our net entitlement volume of oil and gas under production sharing arrangements and the prices at which they are sold.

We sell all of our net crude oil entitlement through a competitive tender process, and subject to market conditions, enter into short-term sales contracts with the winning bidder. Crude oil entitlement not sold pursuant to a sales contract is sold in the spot market. Substantially all of our net crude entitlement in Indonesia in 2016 was sold to customers outside of Indonesia (other than oil sold pursuant to our DMO). We currently sell substantially all of our oil produced in Indonesia at prices based on the ICP, subject to adjustment depending on the quality of the crude oil. The cost recovery portion of net crude entitlement is also calculated based upon ICP prices.

Our natural gas sales contracts in Indonesia are typically long-term fixed price contracts, while our gas produced in the United States is sold on the spot market. Our gas production in Indonesia in 2016 was sold to local customers under long-term GSAs. For a summary description of our GSAs, see "Business—Sales and Distribution—Natural Gas".

Cost of Sales and Other Direct Costs

Production and Lifting Costs

Production and lifting costs consist primarily of (i) costs for oil and gas contracts, which consist of costs that are directly attributable to oil and gas activities in international operations, and mainly include manpower and utilities costs, (ii) field operations overhead costs, which consist of several administrative costs such as manpower, equipment rental and utilities costs; and (iii) O&M costs, and to a lesser extent, operational support costs and pipeline and transportation fees.

Cost of Crude Oil Purchases

Our costs of crude oil purchases consist of payments for crude oil (outside of our entitlement) that we purchase from SKK Migas and Pertamina which we then sell to our foreign customers. We settle our lifting position with SKK Migas and Pertamina at the end of each year.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization primarily arises from the depletion of capitalized oil and gas exploration and development costs which are calculated using the unit of production method and depreciation of investment property.

Exploration Expenses

Exploration expenses include dry hole costs, geological and geophysical costs and exploration overheads. Exploration expenses vary with the level of exploration activities and the success rate of such activities. We use the "successful efforts method" of accounting for oil and gas exploration expenses. Accordingly, the costs related to acquisitions of interests in oil and gas properties, the costs of drilling and equipping exploratory wells that locate or result in proved reserves and the costs of drilling and equipping development wells, including the costs of drilling exploratory-type stratigraphic test wells, are initially capitalized and recorded as part of uncompleted wells, equipment and facilities until the exploration is determined to be unsuccessful. Exploration expenses for dry holes are expensed in the year in which the exploration effort is determined to have been unsuccessful.

Cost of Services

Costs of services represents the costs related to our drilling activities in Oman under our Oman service contract for Karim Small Fields where we operate and provide services for the owner, Petroleum Development Oman LLC.

Selling, General and Administrative Expenses

General and administrative expenses consists of salaries, wages and other employee benefits; professional fees; contract charges; service costs; repairs and maintenance; insurance; office supplies and equipment; depreciation; transportation; education; rental and insurance. Selling expenses include export expenses; business travel; advertising and promotion; and entertainment expenses.

Finance Costs

Finance costs primarily consist of interest expenses on our indebtedness.

Finance Income

Finance income primarily consists of interest income on cash deposits at banks.

Bargain Purchase

We record bargain purchase gains when the value of the consideration paid in an acquisition exceeds the fair value of the net assets acquired. In 2016, we recorded a bargain purchase gain of US$551.7 million, which primarily consisted of gains recorded from the purchase of our interest in AMIV, the acquisition of our interest in South Natuna Sea Block B and the increases in our effective interests in Block A Aceh and Lematang PSC.

Gain on Business Combination Achieved in Stages

Gain on business combination achieved in stages consists of a US$50.2 million gain we recognized in 2015 as a result of the remeasurement of our initial 49% equity interest in AMG, which previously had been held at its acquisition date fair value. The 49% interest in AMG, the company that owns The Energy building, was initially acquired in 2013, and the remaining 51% was acquired in December 2015.

Impairment Loss on Assets Recognized at Fair Value less Costs to Sell

Our impairment loss on assets recognized at fair value less costs to sell consists of impairment of net assets that are classified as held for sale, which in 2016 related to the classification of Bawean PSC as held for sale.

Share of Net Income (Loss) of Associates and Joint Venture

Our share of net income (loss) of associates and joint venture primarily consists of our share of the net income or net losses from AMIV and MPI, which we account for using equity accounting. Prior to December 2015, this line item also included income from AMG, which we consolidated starting in December 2015 following our purchase of the remaining 51%, and which prior to December 2015 we accounted for using the equity method.

Loss on Impairment of Assets

Our loss on impairment of assets primarily consists of impairment losses recorded on our oil and gas properties as a result of impairment testing we perform when circumstances indicate that the carrying value of

the asset exceeds its recoverable amount. In 2015, we recorded a loss on impairment of assets of US$217.2 million, primarily due to changes in value of our oil and gas properties resulting from the sharp decrease in oil prices during the year. In 2016, we recorded impairment losses on our oil and gas properties of US$278.5 million, primarily related to our assets in Libya and Tunisia based on our risk assessment related to political conditions in the North Africa region.

Other Income

For the three month period ended March 31, 2017, other income mainly consisted of receipts from insurance claims of US$7.5 million. In 2016, other income mainly consisted of cash receipts from VAT reimbursement amounting to US$5.7 million. In 2015 and 2014, other income mainly consisted of income from short-term investments amounting to US$11.8 million and US$12.8 million, respectively.

Other Expenses

Other expenses primarily consists of foreign exchange losses related to expenses recorded in Indonesian Rupiah.

Income Tax Expense

Income tax expenses primarily consist of our current tax expense net of the deferred tax benefit available to us which is determined in accordance with Statement of Financial Accounting Standards (PSAK) No. 46, "Accounting for Income Taxes". Our current tax expenses are generally determined based on the following: (i) subsidiaries involved in the oil and gas exploration and production are subject to Indonesian corporate income tax at a rate which varies from 25% to 35% and dividend tax which varies from 15% to 20%. Dividend tax is computed from taxable profit after Indonesia corporate income tax; and (ii) the Company and its subsidiaries are subject to corporate tax which varies from 17% to 25%.

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases.

Loss After Income Tax Expense from Discontinued Operations

Loss after income tax expense from discontinued operations represents losses generated by our coal mining business, certain oil and gas blocks and certain other operations, including drilling services, and chemicals production which are held for sale.

Comparison of Three Month Periods Ended March 31, 2017 and 2016

Net Oil and Gas Sales

Our net oil and gas sales increased by 60.7% to US$210.3 million for the three month period ended March 31, 2017 from US$130.8 million for the corresponding period in 2016. The increase in net oil and gas sales was primarily due to increased sales volume, which increased primarily due to our acquisition of our interest in South Natuna Sea Block B in November 2016 and an increase in our average realized prices which was primarily the result of higher oil prices. Our crude oil sales increased to 27.3 MBOPD for the three months period ended March 31, 2017 from 18.9 MBOPD for the corresponding period in 2016. Our average realized prices for oil increased to US$51.6/barrel for the three month period ended March 31, 2017 from US$30.6/barrel for the corresponding period in 2016. Our gas sales increased to 288.6 BBTUPD for the three month period ended March 31, 2017 from 202.1 BBTUPD for the corresponding period in 2016. Our average realized prices for natural gas increased to US$5.5/MMBTU for the three month period ended March 31, 2017 from US$4.1/MMBTU for the corresponding period in 2016.

Production and Lifting Costs

Production and lifting costs increased by 22.4% to US$48.4 million for the three month period ended March 31, 2017 from US$39.6 million for the corresponding period in 2016. This increase was primarily due to production and lifting costs from South Natuna Sea Block B, in which we acquired our interest in November 2016.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by 30.4% to US$33.9 million for the three month period ended March 31, 2017 from US$26.0 million for the corresponding period in 2016, primarily due to depreciation of oil and gas assets at South Natuna Sea Block B, in which we acquired our interest in November 2016.

Cost of Crude Oil Purchases

Cost of crude oil purchases increased by 540.6% to US$19.5 million for the three month period ended March 31, 2017 from US$3.0 million for the corresponding period in 2016, primarily due to additional crude oil purchases at South Natuna Sea Block B in which we acquired our interest in November 2016.

Exploration Expenses

Exploration costs increased by 80.5% to US$3.2 million for the three month period ended March 31, 2017 from US$1.8 million for the corresponding period in 2016, primarily due to an increase of exploration activities in existing PSCs.

Cost of Services

Cost of services for the three month periods ended March 31, 2017 and March 31, 2016 were stable at US$0.2 million.

Total Cost of Sales and Other Direct Costs

As a result of the foregoing, total cost of sales and other direct costs increased by 49.0% to US$105.2 million for the three month period ended March 31, 2017 from US$70.6 million for the corresponding period in 2016.

Gross Profit

Gross profit increased by 74.4% to US$105.1 million for the three month period ended March 31, 2017 from US$60.2 million for the corresponding period in 2016. Gross profit margin increased to 50.0% for the three month period ended March 31, 2017 from 46.0% for the corresponding period in 2016, primarily due to our increased revenues, particularly from South Natuna Sea Block B which as a mature block carries higher margins and higher oil prices. Gross profit margin is derived by dividing gross profit over net oil and gas sales.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by 52.1% to US$30.8 million for the three month period ended March 31, 2017 from US$20.3 million for the corresponding period in 2016. The increase in selling, general and administrative expenses was due to the expenses from South Natuna Sea Block B in which we purchased our interest in 2016.

Finance Costs

Finance costs increased by 16.7% to US$29.4 million for the three month period ended March 31, 2017 from US$25.2 million for the corresponding period in 2016, primarily due to an increase in the average amount of indebtedness in 2017 as compared to 2016.

Finance Income

Finance income increased by 175.7% to US$7.3 million for the three month period ended March 31, 2017 from US$2.6 million for the corresponding period in 2016, primarily due to an increase in interest income from the shareholder's loan to AMIV.

Share Of Net Income Of Associates And Joint Venture

Our share of net income of associates and joint venture increased to US$10.0 million for the three month period ended March 31, 2017 from US$0.5 million for the corresponding period in 2016. The increase was primarily due to our share of net income of AMIV, in which we invested in 2016.

Other Income

Other income increased by 384.2% to US$17.3 million for the three month period ended March 31, 2017 from US$3.6 million for the corresponding period in 2016, which was primary due to cash received from insurance claims in 2017, related to an insurance claim from a 2011 gas flow incident where unintended gas flow occurred in the Lagan Deep-1 exploration well at the South Sumatera PSC.

Other Expenses

Other expenses decreased by 84.9% to US$1.3 million for the three month period ended March 31, 2017 from US$8.5 million for the corresponding period in 2016, primarily due to decreased losses from foreign exchange in the three month period ended March 31, 2017.

Profit Before Income Tax Expense from Continuing Operations

Our profit before income tax expense from continuing operations increased to US$78.2 million for the three month period ended March 31, 2017 from US$13.0 million for the three month period ended March 31, 2016, due to our increase in net oil and gas sales in 2017.

Income Tax Benefit (Expense)

Income tax expense from continuing operations increased by 552.9% to US$28.7 million for the three month period ended March 31, 2017 from income tax benefit of US$6.3 million for the three month period ended March 31, 2016, due to our increased taxable income for the period.

Profit for the Period from Continuing Operations

As a result of the foregoing, profit for the period from continuing operations increased to US$49.6 million for the three month period ended March 31, 2017 from US$19.3 million for the three month period ended March 31, 2016.

Loss After Income Tax Expense From Discontinued Operations

Our loss after income tax expense from discontinued operations decreased to US$4.9 million for the three month period ended March 31, 2017 from US$8.4 million for the corresponding period in 2016, primarily due to income from AMG, the company that owns The Energy building.

Profit For the Period

As the result of the foregoing, profit for the period increased to US$44.7 million for the three month period ended March 31, 2017 from US$11.0 million for the three month period ended March 31, 2016.

Total Comprehensive Profit For the Period

We recorded a total comprehensive profit for the period of US$38.8 million for the three month period ended March 31, 2017 compared to US$24.0 million for the three month period ended March 31, 2016.

Comparison of 2016 and 2015

Net Oil and Gas Sales

Our net oil and gas sales increased by 1.3% to US$583.0 million for the year ended December 31, 2016 from US$575.3 million for the year ended December 31, 2015. The increase in net oil and gas sales was primarily due to increased natural gas sales volume, which increased primarily due to sales from the Tomori field at Senoro, in which full production began in September 2015, partially offset by a decrease in our average realized prices resulting from decreased oil prices and a decrease in oil sales volume which in each case was primarily the result of production declines at maturing blocks. Our crude oil sales decreased to 21.5 MBOPD for the year ended December 31, 2016 from 22.2 MBOPD for the year ended December 31, 2015. Our average realized prices for oil decreased to US$42.3/barrel for the year ended December 31, 2016 from US$49.3/barrel for the year ended December 31, 2015. Our gas sales increased to 212.2 BBTUPD for the year ended December 31, 2016 from 130.8 BBTUPD for the year ended December 31, 2015. Our average realized prices for natural gas decreased to US$4.4/MMBTU for the year ended December 31, 2016 from US$5.2/MMBTU for the year ended December 31, 2015.

Production and Lifting Costs

Production and lifting costs decreased by 4.7% to US$205.1 million for the year ended December 31, 2016 from US$215.3 million for the year ended December 31, 2015. This decrease was primarily due to decreased O&M expenses as well as pipeline and transportation fees primarily resulting from cost efficiency measures and was partially offset by increases in manpower and utility expenses at our international assets.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization decreased by 3.1% to US$110.2 million for the year ended December 31, 2016 from US$113.8 million for the year ended December 31, 2015, primarily due to decreases in production resulting from natural production declines at maturing blocks.

Cost of Crude Oil Purchases

Cost of crude oil purchases decreased by 37.5% to US$13.3 million for the year ended December 31, 2016 from US$21.3 million for the year ended December 31, 2015, primarily due to the decrease in oil prices in 2016.

Exploration Expenses

Exploration costs increased slightly by 3.0% to US$7.0 million for the year ended December 31, 2016 from US$6.8 million for the year ended December 31, 2015, primarily due to additional exploration in existing areas.

Cost of Services

Cost of services decreased by 21.9% to US$0.6 million for the year ended December 31, 2016 from US$0.8 million for the year ended December 31, 2015, primarily due to decreased costs of services in Oman.

Total Cost of Sales and Other Direct Costs

As a result of the foregoing, total cost of sales and other direct costs decreased by 6.1% to US$336.3 million for the year ended December 31, 2016 from US$358.0 million for the year ended December 31, 2015.

Gross Profit

Gross profit increased by 13.6% to US$246.8 million for the year ended December 31, 2016 from US$217.3 million for the year ended December 31, 2015. Gross profit margin increased to 42.3% for the year ended December 31, 2016 from 37.8% for the year ended December 31, 2015, primarily due to our increased revenues and decreases in production and lifting costs and costs of crude oil purchases. Gross profit margin is derived by dividing gross profit over net oil and gas sales.

Selling, General And Administrative Expenses

Selling, general and administrative expenses decreased by 15.5% to US$94.7 million for the year ended December 31, 2016 from US$112.1 million for the year ended December 31, 2015. This decrease was primarily due to, among others, decreased expenses for office supplies and equipment, contract charges relating to manpower supply, export expenses, transportation expenses and salaries, wages and other employee benefits. These decreases were partially offset by increased miscellaneous expenses and professional fees.

Finance Costs

Finance costs increased by 28.9% to US$99.6 million for the year ended December 31, 2016 from US$77.2 million for the year ended December 31, 2015, primarily due to an increased average amount of indebtedness in 2016 as compared to 2015 and to increases in average interest rates for our U.S. dollar-denominated debt.

Finance Income

Finance income increased by 39.4% to US$6.0 million for the year ended December 31, 2016 from US$4.3 million for the year ended December 31, 2015, primarily due to an increase in interest income from the shareholder's loan to AMIV.

Bargain Purchase

In the year ended December 31, 2016, we recorded a bargain purchase gain of US$551.7 million, which primarily consisted of gains recorded from the purchase of our interest in AMIV in the amount of US$467.2 million, and to gains from the acquisition of our interest in South Natuna Sea Block B and from the acquisition of additional effective interests in Block A Aceh and Lematang PSC. In 2015 we did not record any bargain purchase gains.

Gain On Business Combination Achieved In Stages

In the year ended December 31, 2015, we recorded a gain on business combination achieved in stages of US$50.2 million, as a result of the remeasurement of our initial 49% equity interest in AMG, the company that owns The Energy building. Previously, our investment in AMG had been recorded at its acquisition date fair value as we initially acquired a 49% interest in 2013. We acquired the remaining 51% in December 2015. In 2014, we did not record any gains on business combination achieved in stages.

Impairment loss on assets recognized at fair value less cost to sell

Impairment loss on assets recognized at fair value less cost to sell for the year ended December 31, 2016 was US$11.9 million, which consisted of impairment losses related to our classification of Bawean PSC as an asset held for sale.

Share of Net Income (Loss) Of Associates and Joint Venture

In the year ended December 31, 2016, our share of net loss of associates and joint venture was US$27.2 million as compared to our share of net income of associates and joint venture of US$7.2 million for the year ended December 31, 2015. The share of net losses in 2016 was primarily due to our share of net losses of AMIV. The loss in 2016 was partially offset by our share of net income of MPI. AMIV's net loss in 2016 was primarily due to acquisition costs in connection with its acquisition of AMNT. The share of net income in 2015 was primarily the result of our share of net income from MPI.

Loss on Impairment of Assets

Our loss on impairment of assets increased by 33.0% to US$288.9 million for the year ended December 31, 2016 from US$217.2 million for the year ended December 31, 2015. In 2015, the loss on impairment of assets was primarily due to changes in the recoverable value of our oil and gas properties due to the sharp decrease in oil prices during the year. In 2016, the loss was primarily from impairments of our assets in Libya and Tunisia based on our risk assessment related to political conditions in the North African region.

Other Income

Other income decreased by 9.9% to US$16.7 million for the year ended December 31, 2016 from US$18.6 million for the year ended December 31, 2015. In 2016, other income mainly consisted of cash receipts from VAT reimbursement of US$5.7 million and in 2015 other income mainly consisted of income from short-term investments of US$11.8 million.

Other Expenses

Other expenses decreased by 56.9% to US$6.0 million for the year ended December 31, 2016 from US$14.0 million for the year ended December 31, 2015, primarily due to decreased foreign exchange losses.

Profit (Loss) before Income Tax Expense from Continuing Operations

Our profit before income tax expense from continuing operations was US$292.8 million for the year ended December 31, 2016 compared to a loss before income tax expense from continuing operations of US$122.9 million for the year ended December 31, 2015. Our profit in 2016 was primarily due to our bargain purchase gain in 2016, increased gross profit, and decreased selling, general and administrative expenses, which were partially offset by increased impairments of our oil and gas assets as well as increased finance costs. The loss in 2015 was primarily the result of impairment losses on our oil and gas properties.

Income Tax Expense

Income tax expense from continuing operations increased by 100.9% to US$62.8 million for the year ended December 31, 2016 from US$31.3 million for the year ended December 31, 2015, primarily due to increased profit before tax from continuing operations.

Profit (Loss) for the year from Continuing Operations

As a result of the foregoing, we recorded a profit for the year from continuing operations of US$230.0 million for the year ended December 31, 2016 and a loss for the year from continuing operations of US$154.2 million for the year ended December 31, 2015.

Loss After Income Tax Expense From Discontinued Operations

Our loss after income tax expense from discontinued operations increased by 34.4% to US$43.0 million for the year ended December 31, 2016 from US$32.0 million for the year ended December 31, 2015, primarily due to increased finance costs with respect to assets held for sale.

Profit (Loss) For the Year

As a result of the foregoing, we recorded a profit for the year of US$187.0 million for the year ended December 31, 2016 compared to loss for the year of US$186.2 million for the year ended December 31, 2015.

Total Comprehensive Profit (Loss) For the Year

Total comprehensive profit for the year was US$195.0 million for the year ended December 31, 2016 compared to total comprehensive loss for the year of US$181.8 million for the year ended December 31, 2015.

Comparison of 2015 and 2014

Net Oil and Gas Sales

Our net oil and gas sales decreased by 18.0% to US$575.3 million for the year ended December 31, 2015 from US$701.9 million for the year ended December 31, 2014. The decrease in net oil and gas sales was primarily due to the fall in oil prices which began in late 2014 and continued through 2015 and to a lesser extent to a decline in sales volume primarily due to natural production declines at certain of our blocks in 2015, which primarily included Rimau and South Sumatra. Our crude oil sales decreased slightly to 22.1 MBOPD for the year ended December 31, 2015 from 22.2 MBOPD for the year ended December 31, 2014. Our average realized prices for oil decreased to US$49.3/ barrel for the year ended December 31, 2015 from US$97.8/ barrel for the year ended December 31, 2014. Our gas sales decreased to 130.8 BBTUPD for the year ended December 31, 2015 from 141.4 BBTUPD for the year ended December 31, 2014. Our average realized prices for natural gas decreased to US$5.2/ MMBTU for the year ended December 31, 2015 from US$5.6/MMBTU for the year ended December 31, 2014.

Production and Lifting Costs

Production and lifting costs decreased by 23.5% to US$215.3 million for the year ended December 31, 2015 from US$281.5 million for the year ended December 31, 2014, primarily due to decreased production in 2015.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by 29.4% to US$113.8 million for the year ended December 31, 2015 from US$88.0 million for the year ended December 31, 2014, primarily due to depreciation from the Tomori filed at the Senoro PSC which came online in August 2015.

Cost of Crude Oil Purchases

Cost of crude oil purchases decreased by 19.1% to US$21.3 million for the year ended December 31, 2015 from US$26.3 million for the year ended December 31, 2014, primarily due to the decrease in oil prices in 2015.

Exploration Expenses

Exploration costs decreased by 72.1% to US$6.8 million for the year ended December 31, 2015 from US$24.4 million for the year ended December 31, 2014, primarily due to reduced exploration activities in response to the low oil price environment in 2015.

Cost of Services

Cost of services increased by 50.0% to US$0.8 million for the year ended December 31, 2015 from US$0.5 million for the year ended December 31, 2014, primarily due to increased cost of services in Oman.

Total Cost of Sales and Other Direct Costs

Total cost of sales and other direct costs decreased by 14.9% to US$358.0 million for the year ended December 31, 2015 from US$420.7 million for the year ended December 31, 2014, primarily due to the decreases in production and lifting costs and in exploration expenses.

Gross Profit

Gross profit decreased by 22.7% to US$217.3 million for the year ended December 31, 2015 from US$281.2 million for the year ended December 31, 2014. Gross profit margin decreased to 37.8% for the year ended December 31, 2015 from 40.1% for the year ended December 31, 2014, primarily due to the year on year decrease in net oil and gas sales due to the decrease in oil prices and to a letter extent the decrease in sales volume. Gross profit margin is derived by dividing gross profit over net oil and gas sales.

Selling, General And Administrative Expenses

Selling, general and administrative expenses increased by 6.6% to US$112.1 million for the year ended December 31, 2015 from US$105.2 million for the year ended December 31, 2014. This increase was due, among others, to increased rental expenses, office supplies and equipment expenses resulting. Such increase was partially offset, among others, by decreased salaries, wages and other employee benefits, contract charges, and selling expenses.

Finance Costs

Finance costs increased by 15.2% to US$77.2 million for the year ended December 31, 2015 from US$67.0 million for the year ended December 31, 2014, primarily due to increased average amount of indebtedness in 2015 compared to 2014.

Finance Income

Finance income increased by 7.2% to US$4.3 million for the year ended December 31, 2015 from US$4.0 million for the year ended December 31, 2014, primarily due to increased interest income from time deposits.

Gain On Business Combination Achieved In Stages

In the year ended December 31, 2015, we recorded a gain on business combination achieved in stages of US$50.2 million, as a result of the remeasurement of our initial 49% equity interest in PT Api Metra Graha, the company that owns The Energy building. Previously, our investment in AMG had been recorded at its acquisition date fair value as we initially acquired a 49% interest in 2013. We acquired the remaining 51% in December 2015. In 2014, we did not record any gains on business combination achieved in stages.

Share Of Net Income of Associates And Joint Venture

Our share of net income of associates and joint venture increased by 2.0% to US$7.2 million for the year ended December 31, 2015 from US$7.1 million for the year ended December 31, 2014, primarily due to an increase in income from MPI.

Loss On Impairment Of Assets

Our loss on impairment of assets increased to US$217.2 million for the year ended December 31, 2015 from US$16.2 million for the year ended December 31, 2014. In 2015, the loss on impairment of assets was primarily

due to changes in the recoverable value of our oil and gas properties because of a sharp decrease in oil prices during the year. In 2014, our impairments primarily related to impairment of oil and gas properties resulting from our relinquishment of Yemen 83 Block to the government.

Other Income

Other income decreased by 31.5% to US$18.6 million for the year ended December 31, 2015 from US$27.1 million for the year ended December 31, 2014, primarily due to decreased income from short term investments.

Other Expenses

Other expenses increased by 93.2% to US$14.0 million for the year ended December 31, 2015 from US$7.2 million for the year ended December 31, 2014, primarily due to increased foreign exchange losses resulting from the remeasurement of monetary assets which were denominated in Indonesian Rupiah.

Profit (Loss) before Income Tax from Continuing Operations

Our loss before income tax from continuing operations was US$122.9 million for the year ended December 31, 2015 compared to our profit before income tax from continuing operations of US$123.8 million for the year ended December 31, 2014. This was primarily due to the sharp decrease in oil prices which led to decreased revenues and increased losses on impairment of assets in 2015.

Income Tax Expense

Income tax expense from continuing operations decreased by 66.6% to US$31.3 million for the year ended December 31, 2015 from US$93.5 million for the year ended December 31, 2014, primarily due to our decrease in taxable income.

Profit (Loss) for the Year from Continuing Operations

As a result of the foregoing, recorded loss for the year from continuing operations of US$154.2 million for the year ended December 31, 2015 compared to profit for the year from continuing operations of US$30.3 million for the year ended December 31, 2014.

Loss after Income Tax Expense From Discontinued Operations

Our loss after income tax expense from discontinued operations increased to US$32.0 million for the year ended December 31, 2015, from US$21.5 million for the year ended December 31, 2014, primarily due to impairment losses on our downstream assets.

Profit (Loss) For the Year

As a result of the foregoing, we recorded a loss for the year of US$186.2 million for the year ended December 31, 2015 compared to profit for the year of US$8.8 million for the year ended December 31, 2014.

Total Comprehensive Profit (Loss) For the Year

Total comprehensive loss for the year was US$181.8 million for the year ended December 31, 2015 compared to total comprehensive profit of US$22.5 million for the year ended December 31, 2014.

Liquidity and Capital Resources

Our operations, capital expenditures and working capital requirements are primarily funded from cash generated from operations and from borrowings, both short-term and long-term, including banking facilities and bonds. As of March 31, 2017, we had available banking facilities of US$276.1 million, of which US$98.0 million was unutilized.

As of March 31, 2017, we had cash and cash equivalents of US$157.1 million, which comprised cash and time deposits with maturity dates not over three months and which are not used as collateral and short term investments of US$26.6 million.

The following table presents our cash flow data for the years ended December 31, 2014, 2015 and 2016 and the three month periods ended March 31, 2016 and 2017.

Cash Flow Data

	For the Years Ended December 31,			For the Three Month Periods Ended March 31,	
	2014	2015	2016	2016	2017
	(Restated)		(Restated)	(Restated)	
	(US$ in millions, except where otherwise indicated)				
Consolidated Statements of Cash Flows					
Net Cash Provided by Operating Activities	**147.5**	**113.8**	**28.3**	**32.0**	**55.3**
Net Cash Provided by (Used in) Investing Activities	**(306.6)**	**(152.0)**	**(578.5)**	**(77.4)**	**5.9**
Net Cash Provided by (Used in) Financing Activities	**95.5**	**295.9**	**259.6**	**(9.3)**	**(68.7)**

Net Cash From Operating Activities

Three month period ended March 31, 2017. Our net cash provided by operating activities was US$55.3 million for the three month period ended March 31, 2017, primarily comprising cash receipts from customers of US$220.8 million, partially offset by cash paid to suppliers and employees of US$138.8 million and income tax paid of US$26.7 million.

Three month period ended March 31, 2016. Our net cash used in operating activities was US$32.0 million for three month period ended March 31, 2016, which was primarily due to cash receipts from customers US$113.2 million. This was partially offset by cash paid to suppliers and employees of US$77.7 million and income tax paid of US$3.4 million.

Year ended December 31, 2016. Our net cash provided by operating activities was US$28.3 million in 2016, primarily comprising cash receipts from customers of US$514.9 million, partially offset by cash paid to suppliers and employees of US$465.5 million and income tax paid of US$21.0 million. The decrease in net cash provided by operating activities from 2015 to 2016 primarily reflected a significant year on year increase in trade receivables, which were primarily from sales at our newly acquired interest in South Natuna Sea Block B.

Year ended December 31, 2015. Our net cash provided by operating activities was US$113.8 million in 2015, primarily comprising cash receipts from customers of US$604.6 million, partially offset by cash paid to suppliers and employees of US$459.6 million and income tax paid of US$31.2 million.

Year ended December 31, 2014. Our net cash provided by operating activities was US$147.5 million in 2014, primarily comprising cash receipts from customers of US$665.0 million, partially offset by cash paid to suppliers and employees of US$447.8 million and income tax paid of US$69.6 million.

Net Cash Provided Used in Investing Activities

Three month period ended March 31, 2017. Our net cash provided by investing activities was US$5.9 million for the three month period ended March 31, 2017, which was primarily due to proceeds from redemption of short-term investments of US$43.0 million, partially offset by additions to oil and gas properties of US$23.7 million, consisting mostly of additions to Block A and Natuna.

Three month period ended March 31, 2016. Our net cash used in investing activities was US$77.4 million for three month period ended March 31, 2016, which was primarily due to advance for investment of US$110.0 million. This was partially offset by proceeds from redemption of short-term investments of US$39.7 million.

Year ended December 31, 2016. Our net cash used in investing activities was US$578.5 million in 2016, which was primarily due to investments in joint ventures of US$404.0 million, consisting of cash paid for: (i) the acquisition of our interest in AMIV; (ii) the acquisition of subsidiaries for US$261.5 million, which represented acquisitions of our interests in subsidiaries which hold interests in South Natuna Sea Block B and the West Natuna Transportation System, a subsidiary which increased our interest in Block A, Aceh, and our subsidiary which holds our interest in South Sokang PSC; and (iii) additions to oil and gas properties of US$87.9 million consisting of additions of South Natuna Sea Block B and Block A, Aceh. These were partially offset by, among others, proceeds from redemption of short term investments of US$218.9 million, which was previously managed by banks.

Year ended December 31, 2015. Our net cash used in investing activities was US$152.0 million in 2015, which was primarily due to acquisition of subsidiaries of US$157.8 million representing: (i) acquisitions of AMG (our subsidiary that owns The Energy building), (ii) additions to oil and gas properties of US$92.4 million, which mostly represented additions to Senoro-Toili gas facilities and Rimau development drilling, and (iii) advance for investment of US$75.0 million representing an advance to PT AP Investment, which was in relation to our joint acquisition of AMIV in 2016. These were partially offset by reduction in other receivables from related parties of US$122.1 million, representing the cash received from DSLNG.

Year ended December 31, 2014. Our net cash used in investing activities was US$306.6 million in 2014, primarily due to: (i) additions to oil and gas properties of US$142.4 million in Senoro-Toili and (ii) acquisition of subsidiaries of US$126.4 million, which consisted of subsidiaries acquired in connection with the purchase of oil and gas properties, particularly in Tunisia.

Net Cash Flow Provided by (Used in) Financing Activities

Three month period ended March 31, 2017. Our net cash used in financing activities was US$68.7 million for the three month period ended March 31, 2017, primarily due to repayments of bank loans of US$91.3 million.

Three month periods ended March 31, 2016. Our net cash used in financing activities was US$9.3 million for the three month periods ended March 31, 2016, primarily due to payments for financing charges of US$22.4 million. This was partially offset by proceeds from bank loan of US$20.0 million.

Year ended December 31, 2016. Our net cash provided by financing activities was US$259.6 million in 2016, primarily due to proceeds of bank loans of US$330.0 million, representing additional bank loans, and of other long-term debt of US$267.1 million, representing proceeds from Rupiah shelf-registered bonds II Phase I, II and III, partially offset by repayment of bank loans of US$168.4 million, payment of financing charges of US$86.5 million and repayment of other long-term debt of US$80.0 million.

Year ended December 31, 2015. Our net cash provided by financing activities was US$295.9 million in 2015, primarily due to proceeds of bank loans of US$737.6 million, representing additional bank loans, and of other long-term debt of US$70.7 million, representing Singapore dollar medium term notes, partially offset by repayment of bank loans of US$378.3 million, representing settlement of bank loans.

Year ended December 31, 2014. Our net cash provided by financing activities was US$95.5 million in 2014, primarily due to proceeds of bank loans of US$465.0 million, representing additional bank loans, and of other long-term debt of US$80.4 million, representing proceeds from the issuance of our Medium Term Notes IV, partially offset by repayment of bank loans of US$159.9 million, repayments to related parties of US$134.4 million, representing settlement of a term-loan facility to Mitsubishi Corporation, and repayment of other long-term debt of US$79.3 million.

Indebtedness

The following table shows the amount of the Company's total consolidated short-term and long-term debt outstanding as of December 31, 2014, 2015 and 2016 and as of March 31, 2016 and 2017:

	As of December 31,			As of March 31,	
	2014	2015	2016	2016	2017
	(in US$ million)				
Short-term debt					
Short-term bank loans	—	—	16.0	20.0	16.0
Current maturities of long-term bank loans and obligation	183.7	258.3	395.0	329.7	465.4
Long-term debt (net of current maturities)					
Bank loans	544.7	908.2	1,009.6	833.7	906.9
Notes payable	79.8	72.0	127.5	74.9	128.4
US dollar bond	97.4	18.7	—	17.8	—
Singapore dollar bond	—	70.0	68.3	73.4	71.2
Rupiah bond[1]	280.3	252.9	316.9	263.0	236.3
Total debt	1,185.8	1,580.2	1,933.3	1,612.5	1,824.1

Note:

(1) Rupiah amounts were converted to U.S. dollars at an exchange rate: of 0.000080 US$ per Rupiah for amounts as of December 31, 2014; of 0.000072 US$ per Rupiah for amounts as of December 31, 2015; of 0.000074 US$ per Rupiah for amounts as of December 31, 2016; of 0.000075 US$ per Rupiah for amounts as of March 31, 2016; and of 0.000075 US$ per Rupiah for amounts as of March 31, 2017.

Our long-term debt outstanding as of December 31, 2014, 2015 and 2016 and as of March 31, 2017 consisted of both local and foreign currency obligations. Under the terms and conditions of these long-term obligations, we are subject to various restrictive covenants, which restrict us from undertaking certain actions without prior approval of lenders.

Contractual Obligations, Including Long-term Debt

The following table discloses our contractual and other obligations, excluding contingent liabilities, that were outstanding as of March 31, 2017 and the effect such obligations are expected to have on liquidity and cash flow in future periods.

	Payments Due By Period				
	Total	2017	2018	2019	After 2019
	(US$ in millions)				
Bank Loans	1,107.9	161.4	153.1	297.1	496.2
Long-term Debt Obligations (Bonds)	587.8	167.9	183.6	83.9	152.4
Long-term Debt Obligations (Notes payable)	128.4	—	74.8	53.6	—
Total	1,824.1	329.3	411.5	434.6	648.6

Capital Expenditures

The following table sets forth the Company's capital expenditures for the years ended December 31, 2014, 2015 and 2016 and the three month periods ended March 31, 2017.

	For the Years Ended December 31,			For the Three Month period ended March 31, 2017
	2014	2015	2016	
	(US$ in millions)			
Maintenance Capex	124.3	4.6	159.1	10.5
Development Drilling	53.6	35.1	68.0	5.9
Major Projects	129.9	56.1	109.8	19.1
Exploration Program	17.0	14.6	9.1	2.2
Others	0.3	—	0.1	—
Total	**325.1**	**110.4**	**346.1**	**37.7**

Note: The amounts shown represents our expenditure based on our working interest in the project.

Development and exploration drilling accounts for a majority of the capital expenditure for exploration and development activities. The table below sets forth our planned capital expenditure for the periods indicated.

	2017E	2018E	2019E	2020E	2021E
	(US$ in millions)				
Maintenance	42.8	46.4	55.4	36.2	42.8
Development Drilling	54.9	77.9	80.3	18.7	25.3
Major Projects[(1)]	190.4	143.7	79.6	127.9	97.0
Exploration Program	20.8	35.6	39.5	41.6	34.4
MPI and others	30.5	25.5	13.3	13.3	13.5
Total	**339.4**	**329.2**	**268.0**	**237.9**	**213.0**

Note:

(1) Primarily relates to capital expenditure for Block A, Aceh and Senoro Phase II. See "Business—Strategies."

We intend to fund our capital expenditure through a combination of cash generated from the cost recovery portion of our oil and gas sales.

The cost recovery mechanism in each of our producing PSCs allows us to recover capital expenditure within a relatively short period of time. Our capital expenditure for maintenance of equipment and facilities and for drilling is fully recoverable through the cost recovery mechanism under our PSCs. Our capital expenditure at major projects is expected in the short to medium term to be funded primarily through debt and cash from operations. Our capital expenditure for major projects will primarily be focused on the development of Block A Aceh phase I, and subsequent phases of Senoro-Toili and Block A, Aceh. Our total annual capital expenditures funded through our cash from operating, or investing activities (including cost recovery) are expected to remain below US$200 million per year over the next five years, which should allow for a reduction in gearing. Within this total non-debt funded capital expenditure, we intend to cap expenditures for discretionary exploration and low margin in production to US$60 million per year. We plan to do this by phasing expenditures on our large developments and making carefully selected investments to offset declines in production. We cap our discretionary exploration capital expenditure and focus on infrastructure-led, low risk targets and we fund this capital expenditure through cash from operations.

Our ability to obtain adequate financing to satisfy our capital expenditure and debt service requirements may be limited by our financial condition, results of operations and the liquidity of international and domestic financial markets. We may make additional capital expenditures as opportunities or needs arise. In addition, we may increase, reduce or suspend planned capital expenditures or change the timing and use of capital

expenditures from what is currently planned in response to market conditions or for other reasons. The above budgeted amounts do not include any investments we may make in acquisitions of oil and gas properties or other downstream projects, if any.

Our ability to maintain and grow our revenues, net income and cash flows depends upon continued capital spending. Our capital expenditure plans are subject to a number of risks, contingencies and other factors, such as oil and gas prices, geological factors, market demand, acquisition opportunities and the success of our drilling program, some of which are beyond our control. We adjust our capital expenditure plans and investment budget periodically, based on factors deemed relevant by us. Therefore our actual future capital expenditures and investments are likely to be different from its current planned amounts, and such differences may be significant.

Off-Balance Sheet Arrangements

We have various contractual obligations, some of which are required to be recorded as liabilities in our consolidated financial statements, including long-term and short-term loans. We have certain additional commitments and contingencies that are not recorded on our consolidated balance sheet but may result in future cash requirements. These off-balance sheet arrangements are not generally required to be recognized as liabilities on our balance sheet.

Production Sharing Arrangements

				PSA	
Subsidiary	**Block Ownership**	**Country**	**Term**	**Local Government**	**Subsidiary**
Medco Oman LLC.	Karim Small Fields	Oman	25 years	88% of profit from total production	12% of profit from total production
Medco International Venture Ltd.	Area 47	Libya	30 years	86.3% of profit from total production	6.85% of profit from total production
Medco Yemen Amed Ltd	Block 82	Yemen	20 years	80% of profit oil (for production over 25,000 BOPD)	20% of profit oil (for production over 25,000 BOPD)
Medco Yemen Malik Ltd. . . .	Block 9	Yemen	25 years	70% of profit oil (for production over 25,000 BOPD)	30% of profit oil (for production over 25,000 BOPD)
Medco Ventures International (Barbados) Limited	Block Bir Ben Tartar	Tunisia	30 years	65% of profit from total production	35% of profit from total production
Medco Ventures International (Barbados) Limited	Block Cosmos	Tunisia	50 years	50% of profit from total production	50% of profit from total production
Medco Ventures International (Barbados) Limited	Block Yasmin	Tunisia	50 years	50% of profit from total production	50% of profit from total production
Medco Ventures International (Barbados) Limited	Block Sud Remada	Tunisia	11 years	65% of profit from total production	35% of profit from total production
Medco Ventures International (Barbados) Limited	Block Jenein	Tunisia	4 years	70% of profit from total production	30% of profit from total production

Subsidiary	Block Ownership	Country	Term	PSA	
				Local Government	Subsidiary
Medco Ventures International (Barbados) Limited	Block Hammamet	Tunisia	10 years	60% of profit from total production	40% of profit from total production
Medco Sahara Limited	Block Adam	Tunisia	30 years	50% of profit from total production	50% of profit from total production
Medco Sahara Limited	Block Borj El Khadra	Tunisia	25 years	50% of profit from total production	50% of profit from total production

The total remaining commitment for exploration expenditures relating to the above contracts as of March 31, 2017 is US$23.2 million.

Gas Supply Agreements

Our significant GSAs as of March 31, 2017, are as follows.

Company / Counter-party	Date of Agreement	Commitment	Contract Year
PT Medco E&P Indonesia			
PT Pupuk Sriwidjaja (Persero)	Aug 2007	To supply gas at 45 BBTUD	11 years and could be up to 15 years in accordance with terms and conditions as stated in the agreement.
PT Mitra Energi Buana	Jul 2006 and amended December 1, 2012	To supply and sell gas in the quantity of 2.5 BBTUD until November 2012 and 3.7 BBTUD until December 2017.	11 years or until such quantity has been fully supplied, whichever occurs first.
PT Meta Epsi Pejebe Power Generation (MEPPO-GEN)	October 17, 2014 and amended May 25, 2016	To supply 10-16 BBTUD of gas with total gas contract quantity amounted to 15,686 BBTU	2 (two) years since the initial supplies (6,560 BBTU) are met or total amount contract has been fully supplied, whichever occurs first.
Perusahaan Daerah Pertambangan dan Energi (Jakabaring)	August 10, 2011 and amendment through Joint Arrangement dated December 4, 2012.	To supply and sell 3 BBTUD of gas	9 years or until such quantity has been fully supplied, whichever occurs first
PT Sarana Pembangunan Palembang Jaya (SP2J)	April 13, 2010, last amendment dated November 25, 2015	To supply gas involving 450.9 BBTU.	Agreement ends at December 31, 2018 or until such quantity has been fully supplied, whichever occurs first.

Company / Counter-party	Date of Agreement	Commitment	Contract Year
PT Perusahaan Listrik Negara (Persero) Tarakan	April 1, 2010, and amendment through Joint Arrangement dated March 26, 2015.	To supply and sell 10,134 BBTU of gas.	Agreement ends December 31, 2021 or until such quantity has been fully supplied, whichever occurs first. On January 1, 2017, this commitment has already been transferred to PT Perusahaan Listrik Negara (Persero).
Perusahaan Daerah Pertambangan dan Energi	August 4, 2009, and amended through Joint Arrangement dated April 12, 2016.	To supply 0.3 BBTUD of gas. As of April 2013, the gas supply has just commenced due to the recent fulfillment of requirements to supply.	Agreement ends November 30, 2018 or until such quantity has been fully supplied.
Perusahaan Daerah Mura Energi	August 4, 2009 last amendment Dated September 1, 2016.	To supply 1.35 - 2.1 BBTUD of gas with total contract 8,750 BBTU of gas.	12 years and 10 months (estimated until January 2028) from the Start Date or until total amount of the contract fully supplied, whichever occurs first.
Perusahaan Daerah Kota Tarakan	April 6, 2011	To supply gas to meet the needs of household in Tarakan of 0.15 BBTUD.	5 years since June 2011 until such quantity in the agreement has been fully supplied. This commitment has been ended on January 7, 2016 and transferred to PT Perusahaan Gas Negara through a Joint Arrangement.
PD Petrogas Ogan Ilir	May 25, 2016	To supply gas involving 1,820 BBTU.	December 31, 2019 or until the quantity of the contract has been fully supplied, whichever occurs first and could be extended in accordance with terms and conditions as stated in the agreement.
PT Medco E&P Lematang			
PT Perusahaan Listrik Negara (Persero)	March 21, 2007 and amended on December 10, 2014 and 2017	To supply 20 BBTUD (Joint supply with South Sumatera Block)	3 years

Company / Counter-party	Date of Agreement	Commitment	Contract Year
PT Medco E&P Malaka			
PT Pertamina (Persero)	Jan 27, 2015	To supply 58 BBTUD of gas with a total volume of 198 TBTU.	Until 13 years from the date of first gas delivery, or when the total amount of the contract, or gas no longer has an economic value, or the expiration of Block A PSC whichever occurs first.
PT Medco E&P Tomori			
PT Donggi Senoro LNG	Jan 2009	Supply 252 BBTUD of gas with price based on formula expressed in US$ / MMBTU and referred to value of Japan Crude Cocktail (JCC)	15 years (starting at date of commercial operation of LNG plant)
PT Panca Amara Utama	March 13, 2014	To supply 248,200 MSCF of gas with Daily Contract Quantity of 55 MMSCFD	At the time when such quantity in the agreement has been fully supplied or until the termination of the Senoro-Toili PSC (December 3, 2027), whichever occurs first.
PT Medco E&P Simenggaris			
PT Perusahaan Listrik Negara (Persero)	October 17, 2014	To supply gas at 0.5 MMSCFD with total Contracts 805 MMSCF	5 years (starting from the operation date) or until the fulfillment of the total amount of the contract, whichever occurs first.
Medco E & P Natuna Ltd			
PT Pertamina (Persero)	January 15, 1999.	To supply gas with PT Pertamina (Persero) for SembCorp Gas Pte Ltd with the total contract quantities 2,625 TBTU	27 years from the Start Date or until the fulfillment of the total amount of the contract, whichever occurs first
PT Pertamina (Persero)	March 28, 2001 amended on May 8, 2012.	To supply gas with PT Pertamina (Persero) for Petroliam Nasional Berhad (Petronas) with the total contract quantities 1,648 TBTU.	20 years or whichever occurs first as stated in the agreement.

Inflation

The Indonesia rate of inflation was 6.3% in 2015 and 3.5% in 2016 based on the consumer price index. Inflation in Indonesia has not significantly impacted the Company's results of operations in recent years.

Seasonality

Indonesia's wet and dry seasons do not have a material impact on the demand and prices for crude oil and natural gas. During the annual rainy season, typhoons and heavy rain can temporarily limit our ability to continue our oil and gas development activities and reduce AMNT's mine production.

Quantitative and Qualitative Disclosure About Market Risks

Our primary market risk exposures are to fluctuations in oil and gas prices.

Commodity Price Risk

We are exposed to fluctuations in prices of crude oil which is a commodity whose price is determined by reference to international market prices. International oil prices are volatile and this volatility has a significant effect on our revenues and asset values. Due to the cost recovery provided to us in our production sharing arrangements, we do not currently materially hedge market risk resulting from fluctuations in oil and gas prices. See "— Overview" and "Risk Factors — Risks Relating to our Industries — The volatility of prices for crude oil could adversely affect the Group's financial condition and results of operations." AMNT's business is subject to fluctuations in market prices for gold and copper.

Operating Risks

We are exposed to operating risks, including reservoir risk, risk of loss of oil and gas and natural calamities risk in respect of all its installations and facilities. We have, however, insured our installations and facilities. We do not have insurance coverage for lost profits. See "Business — Operating Hazards, Insurance and Uninsured Risks" and "Risk Factors — Risks Relating to our Industries — Our operations are subject to significant operating hazards."

Foreign Exchange Rate Risk

Most of the major contracts entered into by us have historically been denominated in U.S. dollars, and it is anticipated that this will continue to be the case. Such contracts include PSCs, JOBs, agreements with joint venture partners, major construction contracts, drilling leases, service contracts, oil and gas sales contracts and transportation agreements. Consequently, substantially all of our revenues are denominated in U.S. dollars, and a majority of our cash expenses are also denominated in U.S. dollars. Certain expenses comprising the salaries of Indonesian employees, local vendors, local rentals and interest income/expense are normally paid in Rupiah. Given the relatively small currency mismatch, we believe that our exposure to the currency risk of an appreciation of the Rupiah is limited.

We are also exposed to foreign exchange rate risk resulting from fluctuations in exchange rates in the translation of Rupiah-denominated loans, Singapore dollar-denominated notes and U.S. dollar-denominated purchases of diesel, which is later sold in Indonesian Rupiah-denominated sales. As of March 31, 2017, we had foreign currency loans of US$1.2 billion, Singapore dollar borrowings are S$99.5 million (equivalent to US$71.2 million) and Indonesian Rupiah-denominated loans are Rp. 7.6 trillion (equivalent to US$573.8 million).

Our policy for foreign exchange management, swap and hedging was designed to minimize currency risk and maintain cost effectiveness and has the following objectives: ensure that all transactions in currencies other than U.S. dollars (being our functional currency) are sufficiently covered on a timely basis; ensure that we are not adversely affected by foreign exchange, commodity price, interest rate and general market movement in a way that might seriously threaten our viability or undermine the confidence of our customers, staff or debt and equity holders; reduce the actual or anticipated cost of financing; and optimize swap and hedging transactions by maintaining cost effectiveness of such activities and to fairly weigh the cost of risk with possible saving in going unhedged or by engaging in natural hedging.

Interest Rate Risk

We are exposed to interest rate risk resulting from fluctuations in interest rates on our short-term and long-term indebtedness. Upward fluctuations in interest rates increase the cost of new borrowings and the interest cost of our outstanding floating rate indebtedness. As of March 31, 2017, 18.0% of our long-term indebtedness have interest at floating rates which, in the case of U.S. dollar debts, principally are determined in reference to LIBOR and, in the case of Rupiah debts, in reference to the banks' prime lending rate. It is part of our policy to protect any risks related to foreign currency, interest rate, and commodity price using financial hedging instruments. In addition to obtaining cash flow certainty, we enter into cross currency swap transactions to mitigate foreign currency risk for any non-U.S. dollar debts, and interest rates swap to fixed any floating interest rates exposures. We apply hedge accounting to any hedging transactions that meet the criteria for hedge accounting to minimize the volatility of marked-to-market movement on income. Under this policy, we are allowed to enter into hedging transactions for up to 50% of underlying exposures, with special approval required for larger exposures. We monitor the positions through marked to market report distributed by the hedge counterparties.

Critical Accounting Policies and Practices

Our critical accounting policies and practices are those that we believe are the most important to the portrayal of our financial condition and results of operations and that require subjective judgment on behalf of management. In many cases, the accounting treatment of a particular transaction is specifically dictated by generally accepted accounting principles. However, in the preparation of the consolidated financial statements we use judgment to make certain estimates, assumptions and decisions regarding accounting treatments. We believe the policies and practices described below are its critical accounting policies and practices.

Purchase Price Allocation and Goodwill Impairment

Acquisition accounting requires extensive use of accounting estimates to allocate the purchase price to the reliable fair market values of the assets and liabilities purchased, including intangible assets. Under PSAK No. 48 (Revised 2014), "Impairment of Assets", goodwill is not amortized and is subject to an annual impairment testing. Impairment testing is performed when certain impairment indicators are present. In case of goodwill, such asset is subject to annual impairment test and whenever there is an indication that an asset may be impaired; management uses its judgment in estimating the recoverable value and determining the amount of impairment.

Bargain Purchase

Bargain purchase represents the excess of the estimated fair value of the net assets acquired over the cash paid to acquire the assets. The difference is recognized directly in the income statement. Primarily as a result of the acquisition of our interest in AMIV in 2016, we recorded a bargain purchase gain of US$467.2 million in 2016, reflecting that the purchase price we paid for our share in AMIV was less than the assessment of the fair value of our share of AMIV's assets based on a valuation report from an independent third party valuer registered with the OJK. The table below sets forth information about our bargain purchase gain recognized in connection with this transaction:

	Provisional Fair Value As of November 2, 2016[1]
	(US$ in millions)
Assets	
Cash and cash equivalents	377.1
Restricted cash in bank	54.6
Trade receivables	221.9
Other receivables	73.5
Prepaid tax and tax receivables	7.9
Income tax receivable	266.3
Other tax receivables	72.6
Receivables from related parties	230.6
Inventories	170.8
Stockpile	1,520.7
Deferred mine development cost	158.2
Deferred stripping cost	83.8
Debt issuance cost	55.6
Property, plant and equipment	1,302.5
Other assets	54.5
Sub-total	4,650.6
Liabilities	
Trade payable	(79.2)
Other payable to related parties	(246.0)
Accrued expenses	(0.0)
Taxes payable	(113.1)
Other taxes payable	(16.5)
Bank loans	(1,027.8)
Asset abandonment and site restoration obligations and other provisions	(310.1)
Post-employment benefits obligations	(34.8)
Deferred tax liabilities—net	(477.1)
Other payable	(1.7)
Sub-total	(2,306.2)
Other venturer identified asset AMIV	(602.0)
Total identifiable net assets at fair values	1,742.4
Non-controlling interest	(871.2)
Bargain purchase	(467.2)
Total estimation	404.0

Note:

(1) November 2, 2016 is the date of acquisition of AMIV.

Impairment of Non-Financial Assets

Assets that have an indefinite useful life are not subject to amortization but tested annually for impairment, or more frequently if events or changes in circumstances indicate that the carrying amount may not be recoverable based on the fair value assessment using the cash flow projection method that we conduct on a regular basis. When value in use calculations are undertaken, management must estimate the expected future cash flows from the asset or cash-generating unit and choose a suitable discount rate in order to calculate the present value of those cash flows. For the purpose of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows.

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves include:

(i) proved developed reserves: amounts of hydrocarbons that are expected to be retrieved through existing wells, facilities and operating methods; and

(ii) undeveloped proved reserves: amounts of hydrocarbons that are expected to be retrieved following new drilling, facilities and operating methods.

Our historical impairment of oil and gas properties were made where we estimated the recoverable amount of reserves based on value in use using cash flow projections. The calculation of value in use for oil and gas properties cash generating units is mostly sensitive to the following assumptions: (a) lifting, (b) prices, (c) discount rates, and (d) operating and capital expenses. Changes to the assumptions used by the management to determine the recoverable amount, in particular the discount rate, can have significant impact on the result of the impairment assessment.

Reserve Estimates

The accuracy of proved reserve estimates depends on a number of factors, assumptions and variables such as: the quality of available geological, technical and economic data, results of drilling, testing and production after the date of the estimates, the production performance of the reservoirs, production techniques, projecting future rates of production, the anticipated cost and timing of development expenditures, the availability for commercial market, anticipated commodity prices and exchange rates.

As the economic assumptions used to estimate reserves change from year to year, and additional geological data are generated during the course of operations, estimates of reserves may change from year to year. Changes in reported reserves may affect the Group's financial results and financial position in a number of ways, including:

- Depreciation and amortization which are determined on a unit of production basis, or where the useful economic lives of assets change.
- Decommissioning, site restoration and environmental provision may change where changes in estimated reserves affect expectations about the timing or cost of these activities.
- The carrying value of deferred tax assets/liabilities may change due to changes in estimates of the likely recovery of the tax benefits.

Asset Abandonment and Site Restoration Obligations

We have recognized provisions for asset abandonment and site restoration obligations associated with our oil and gas wells, facilities and infrastructure. In determining the amount of the provision, assumptions and estimates are required in relation to discount rates and the expected cost to dismantle and remove all the structures from the site and restore the site. We intend to fulfill these obligations in accordance with the terms of our PSCs or contract areas.

RISK FACTORS

Our business, financial condition and results of operations could be materially and adversely affected by any of these risks.

RISKS RELATING TO OUR BUSINESS AND OPERATIONS

We are dependent on our ability to produce from and/or develop existing reserves, replace existing reserves and find and develop additional reserves for our core oil and gas business.

We must explore for, find, develop or acquire new reserves to replace those depleted and sold in order to grow or maintain production. We face challenges in sustaining production growth due to the maturation and depletion of oil and gas properties. Revenue from Rimau, South Sumatra, Lematang and the South Natuna Sea Block B PSCs, which together contributed 52.2% and 61.9% of our net oil and gas sales for 2016 and the three month period ended March 31, 2017, respectively are entering a mature stage with economic lives of five to 10 years.

The success of presently contemplated exploration and development activities cannot be assured. The decision to explore or develop a property will depend in part on geophysical and geological analyses and engineering studies, the results of which may be inconclusive or subject to varying interpretations. Exploration activities are subject to numerous risks, including the risk that no commercially viable oil or natural gas accumulations will be discovered. If we are unable to find or acquire additional reserves, we would not be able to sustain total production nor grow our core business, and this would have a material adverse effect on our business, prospects, financial condition and results of operations.

The cost of drilling, completing and operating wells is also uncertain. Drilling may be curtailed, delayed or cancelled as a result of many factors, including weather conditions, government requirements and contractual conditions, shortages of or delays in obtaining equipment, reductions in product prices or limitations in the market for products. Geological uncertainties and unusual or unexpected formations and pressures may result in dry wells. Our exploration and production activities may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or the recovery of drilling, completion or operating costs. In addition, we face substantial competition in the search for and acquisition of reserves, which require substantial investment.

Our indebtedness could adversely affect our financial condition.

We have a significant amount of indebtedness. Covenants in agreements governing debt that we may incur in the future may materially restrict our operations, including our ability to incur debt, pay dividends, make certain investments and payments, and encumber or dispose of assets. Our high degree of leverage and ability to incur additional debt may have important consequences to prospective investors, including the following:

- we may have difficulty satisfying our obligations under our indebtedness and, if we fail to comply with these requirements, an event of default could result;
- we may be required to dedicate a substantial portion of our cash flow from operations to required payments on indebtedness, thereby reducing the availability of cash flow for working capital, capital expenditures and other general corporate activities;
- covenants relating to indebtedness may limit our ability to obtain additional financing for working capital, capital expenditures and other general corporate activities;
- covenants relating to indebtedness may limit our flexibility in planning for, or reacting to, changes in our business and the industries;

- we may be more vulnerable than our competitors to the impact of economic downturns and adverse developments in our business; and
- we may be placed at a competitive disadvantage against any less leveraged competitors.

Any of these factors could have a material adverse effect on our business, financial condition, results of operations and prospects.

We face risks related to our joint ventures and other partners.

In November 2016, we acquired a 50% interest in PT Amman Mineral Investama ("AMIV"), which indirectly controls or has an economic interest in all of the shares in AMNT, which operates a copper and gold mine in Sumbawa. AMNT is jointly controlled with a Board of Directors and Commissioners appointed by the two shareholders, us and our joint venture partner. Because we do not wholly control AMNT, we may be unable to fully control decisions relating to operations and strategy, which could adversely affect our ability to obtain benefits from our investment. Furthermore, through our 49% interest in MPI, we have a significant investment in the power generation sector in Indonesia. The remaining interest in MPI is owned by PT Saratoga Power, an unrelated third party, which is majority owned indirectly by PT Saratoga Investama Sedaya Tbk (77.7%), and by the International Finance Corporation (22.3%). We understand that PT Saratoga Investama Sedaya Tbk has been exploring the possibility of selling its interest in PT Saratoga Power. Such process potentially involves certain risks for MPI, including the risk that investment or operational decisions will be delayed during such process.

In addition, a number of our oil and gas blocks have other interest holders, including government entities and a number of MPI's projects have other interest holders. These types of relationships involve special risks associated with the possibility that partner(s) may have economic or business interests or goals that are inconsistent with ours or MPI's; take or omit to take actions contrary to our or MPI's instructions, requests, policies or objectives, good corporate governance practices or the law; be unable or unwilling to fulfill their obligations under the relevant agreements; have disputes with us or MPI as to the scope of their responsibilities; and/or have financial difficulties. For example, our involvement in the downstream sector is through DSLNG, a joint venture company established in 2007 by a consortium consisting of PT Medco LNG Indonesia (a wholly-owned subsidiary of our Group), Mitsubishi Corporation and KOGAS through their joint venture Sulawesi LNG Development Ltd., and Pertamina through its subsidiary PT Pertamina Hulu Energi. Within this scheme, DSLNG purchases gas from the upstream sector, operates the LNG plant, and sells LNG to international customers. We have an 11.1% interest in DSLNG. DSLNG has certain banking facilities that require certain of its shareholders to fulfill certain requirements or reach certain milestones. Although to date we have complied with our obligations under the agreement, we understand that one of our partners may not reach a required milestone on time, which may constitute a default under DSNLG's indebtedness. Although we have been informed that such partner is currently negotiating an extension with DSLNG's lenders, there can be no assurance that our partner will be able to obtain an extension, and the ability of such partner to obtain such extension is outside of our control. If such partner is unable to obtain an extension on time or at all, DSLNG may be considered in default on its indebtedness, which could materially and adversely affect our downstream operations and upstream operations at the Senoro gas field. We have provided a corporate guarantee with respect to such indebtedness in proportion to our 11.1% holding in DSLNG, and we cannot assure you that we will not be liable pursuant to such guarantee. In addition, we or MPI may face stalemates, an inability to finance certain developments, limits on the ability to recoup investments and limits on financial flexibility. Any of the foregoing could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

Our business is subject to significant government regulation.

Oil and gas companies operating in Indonesia are highly regulated. The key terms and conditions applicable to us under Indonesian regulations include cost recovery arrangements and the DMO. For every barrel produced, an oil and gas company that operates under a PSC is entitled to recover costs pertaining to the exploration and

production activities carried out during the year. The cost recovery portion of the annual net entitlement varies with the level of cost incurred, including capital investment for exploration, development and production, annual operating expenses and the realized prices of oil and gas. The DMO specifies the amount of production that must be sold domestically, which can be at lower prices than could be obtained from selling elsewhere. In addition, oil and gas companies are subject to regulation by governments throughout the world. These regulations typically include the requirement to obtain permits to export products. Compliance with government regulations is required to ensure that these permits are, for example, granted, renewed or extended. In the case of exporting pipeline gas, for example, a quarterly permit renewal is required in Indonesia. An inability to obtain the necessary permits may affect exploration and production interests, the costs of safety and health and environmental controls and restrictions on drilling and production. We are also subject to the risk of nationalization, expropriation or cancellation of contract rights by governments. We operate in several countries and are therefore exposed to risks associated with the laws and regulations of each of these countries.

AMNT's copper and gold mining is subject to significant regulation. In 2014, the Indonesian government issued new regulations pertaining to the export of copper concentrate that contain potentially restrictive conditions in respect of obtaining an export permit and impose a new export duty.

The Batu Hijau mine was temporarily shut down from June 2014 through September 2014 due to an inability to export copper concentrate and AMNT's predecessor and its majority shareholder filed claims against the Indonesian government at the International Centre for Settlement of Investment Disputes in July 2014. However in August 2014, AMNT's predecessor withdrew its case, and following the withdrawal, AMNT's predecessor and the government entered into a Memorandum of Understanding in September 2014 in which, among other things, AMNT's predecessor agreed to pay higher royalties and certain export duties and the government agreed to issue permits to allow it to export and sell copper concentrates. The government then issued several six-month export permits commencing in September 2014, March 2015 and November 2015. In 2017, the Indonesian government issued new regulations which amended the 2014 regulations. The 2017 regulations deleted a provision in the previous government regulation that allowed COW holders to export processed minerals and also mandates that COW holders convert their COW to IUPK and refine their minerals domestically. Further in February 2017, under its new ownership, AMNT adopted the Indonesian government's IUPK mining permit which has preserved all economic conditions in the original COW. In February 2017, the Indonesian government issued a twelve month export permit to AMNT. Future export permits will be subject to the government's assessment of progress on AMNT's commitments to comply with the 2014 and 2017 regulations, which include the requirement to build an in-country smelter no later than five years after the issuance of the 2017 regulations. AMNT plans to form a joint venture with another party or parties to develop its smelter. AMNT expects to contribute access to land, the port and its power plant to the joint venture, with the joint venture partner making capital contributions towards project finance needed to construct of the smelter.

The 2014 and 2017 regulations could, notwithstanding the accommodations made by AMNT, result in the inability to export copper concentrate or additional financial obligations, which could adversely impact our future operating and financial results. In addition, AMNT is required to apply for renewals of certain other key permits related to Batu Hijau (such as wastewater permit and explosion utilization permit). The inability to renew such permit, the export permit or other key permits could adversely impact Batu Hijau operations and may adversely impact our business, prospects, financial condition and results of operations.

The power business in Indonesia is highly regulated and certain regulations restrict the price that can be charged for power as well as place other restrictions on the sale of power, which can limit our associated entities' ability to earn revenue. Furthermore, the business is influenced by factors beyond the control of us and our partners such as new market entrants, prices and supply gas as well as operating risks inherent in the industry. Any reduction in the prices received for power would adversely affect our business, prospects, financial condition and results of operations.

The oil and gas reserves data in this document are only estimates and the actual production, revenue and expenditures achievable with respect to our reserves may differ from such estimates; there are no recent reserve estimations or assessments available for a significant portion of our reserves; even for blocks where there are recent third party reserves estimations or assessments, we have not attached these reports to this document.

This document includes estimates of certain of our proved reserves, proved plus probable reserves and proved plus probable plus possible reserves. There are no recent estimations or assessments or no estimations or assessments available for the Rimau, South Sumatra, Tarakan, Lematang and Senoro-Toili (Tiaka, which is Senoro-Toili's oil field) PSCs and for our international blocks, and the reserves estimations have been derived based on prior reserves estimations or assessments which are not recent, with the estimations or assessments for a number of our key producing but maturing blocks being from 2011. Certain of our other blocks were estimated or assessed between 2008 and 2014. Certain reserves figures presented in this document are derived based on reserves estimations or assessments as of December 31, 2016 by NSAI for the Block A Aceh PSC, as of December 31, 2016 by RISC for the South Natuna Sea Block B PSC, and as of November 30, 2016 by GCA for the Senoro-Toili (Senoro Gas Field). Our estimates of reserves at these blocks as at any date which is more recent than the date of the most recent reserve estimations or assessments for the applicable block have been derived by deducting production at the block, without accounting for any reserves appreciation or depreciation, since the dates of the respective estimations or assessments. However, there can be no assurance that a more recent reserves estimation or assessment conducted would result in estimates of the available reserves at these blocks which are consistent with our internal estimates of such reserves.

Approximately 51.9% of our gross proved oil and gas reserves and 54.7% of our gross proved plus probable oil and gas reserves as of March 31, 2017, has not been estimated or assessed since 2014 by any third party, but constitutes our estimates, based on prior reserve estimations or assessments from which production has been deducted.

Even with respect to reserves figures presented in this document that are derived based on independent third party reserves estimations or assessments (namely, the reports as of December 31, 2016 by NSAI for the Block A Aceh PSC; as of December 31, 2016 by RISC for the South Natuna Sea Block B PSC; and as of November 30, 2016 by GCA for the Senoro-Toili (Senoro Gas Field)), we have not attached the reports relating thereto to this document. Accordingly, investors will not have access to such reports provided by these independent consultants, which reports include additional information that may be useful in evaluating the reserves information relating to these blocks.

The Ministry of Energy and Mineral Regulation No. 27/2006 on Management and Use of Data Obtained from General Survey, Exploration and Exploitation of Oil and Gas (the "MEMR Regulation") requires any person that discloses any "data" (as defined therein) relating to oil and gas reserves to obtain consent from the MEMR. The MEMR Regulation does not specify the type of reserves data or information. or reserves report, disclosure that requires consent from the MEMR. Failure to comply with this requirement to obtain consent from the MEMR could result in sanctions of up to 1 year of imprisonment or fines of up to Rp 10 billion. As a public company, under OJK Regulation No. 29/POJK.04/2016 on Annual Report of Issuer or Public Companies as implemented by OJK Circular Letter No. 30/SEOJK.04/2016 on Format and Content of Annual Report of Issuer or Public Companies (the "OJK Regulation"), Medco Energi is required to release an annual report which includes financial statements and other material information, including reserves data and information relating to our operations. In compliance with the OJK Regulation, Medco Energi has been disclosing reserves data and information from time to time in its financial statements and annual reports and other disclosures. Similarly in this document, we have included reserves data and information consistent with disclosures in the Medco Energi's financial statements and annual reports and other disclosures. This notwithstanding, there can be no assurance that the MEMR may take the view that Medco Energi's past disclosures of reserves data and information or disclosures in this document have been made without obtaining their consent as may be required under the MEMR Regulation and impose penalties or sanctions on us, which could have an adverse effect on us.

Determining estimates of reserves is an inexact activity and, accordingly, there can be no assurance that our reserves data accurately reflects actual reserves or will not change. In addition, the basis on which we estimate our reserves differs from SPE guidelines.

Determination of reserves estimates is an inexact interpretive activity generally based upon SPE guidelines and definitions which require estimators to make uncertain forecasts of future production and to analyze incomplete technical and commercial data. There often exist professional interpretive differences of SPE guidelines and reserves classification between companies, independent petroleum engineering consultants and operators. This is often evidenced by different reported reserves between consortium members of the same exploration or producing block. Such differences may include assigning volumes to the categories of proved, probable or possible reserves, based on interpretation of guidelines or on views of the commercial viability of a given oil or gas reserve, at a particular point in time.

There is no assurance that we, independent petroleum engineering consultants or other operators will not change our or their views or interpretations of such guidelines or change our or their interpretation on the commercial viability of given reserves, and thus causing such reserves to be reclassified into another category under SPE or other similar guidelines. Accordingly, there can also be no assurance that the reserves estimates that we have recorded at these blocks accurately reflect the currently available reserves at these blocks.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. The reserves data set forth in this document represent estimates determined by independent petroleum engineering consultants according to current industry practice (where reserves estimations or assessments are applicable), or our own internal review. In general, estimates of economically recoverable oil and gas reserves are based upon a number of variable factors and assumptions, such as geological and geophysical characteristics of the reservoirs, historical production performance from the properties, the quality and quantity of technical and economic data, prevailing oil and gas prices applicable to a company's production, extensive engineering judgments, the assumed effects of regulation by Government agencies and future operating costs. All such estimates involve uncertainties, and classifications of reserves are only attempts to define the degree of likelihood that the reserves will result in revenue for us. For those reasons, estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. In addition, such estimates can be and will be subsequently revised as additional pertinent data becomes available prompting revision. Actual reserves may vary significantly from such estimates. To the extent that actual production is lower than the estimated reserves, our business, prospects, financial condition and results of operations are likely to be materially and adversely affected.

The estimates of gross working interest reserves set out in this document reflect reserves attributable to our effective working interest under the applicable contractual arrangement before consideration of PSC terms. This is a different approach to the method stipulated under SPE guidelines which states that a producer's net entitlement to reserves should be estimated on the basis of the applicable contract terms taking into account project costs and profits. We believe that our approach reflects a common practice in our industry in Indonesia. Our approach may result in higher gross working interest reserves as compared to if such reserves were estimated under SPE guidelines. Estimates of gross working interest reserves are also significantly affected by many factors, including (but not limited to) sales prices, production rates and capital and operating expenses prevailing as of the time such reserves are determined, as well as cost recovery provisions affecting the Government's share of such reserves and the portion of Government take payable to the Government as owner of the reserves. Such estimates may change materially from period to period even in the absence of any new geological information.

Estimates of proven and probable gold and copper reserves are uncertain and the volume and grade of ore actually recovered may vary from estimates.

The reserves stated in this document represent the amount of gold and copper that are estimated at March 31, 2017 that could be economically and legally extracted or produced at the time of the reserve

determination. Such reserves are calculated based on a technical report. Estimates of proven and probable reserves are subject to considerable uncertainty. Such estimates are, to a large extent, based on the prices of gold and copper and interpretations of geologic data obtained from drill holes and other exploration techniques, which data may not necessarily be indicative of future results. Producers use feasibility studies to derive estimates of capital and operating costs based upon anticipated tonnage and grades of ore to be mined and processed, the predicted configuration of the ore body, expected recovery rates or metals from the ore, the costs of comparable facilities, the costs of operating and processing equipment and other factors. Actual operating and capital cost and economic returns on projects may differ significantly from original estimates. Further, it may take many years from the initial phases of exploration until commencement of production, during which time, the economic feasibility of production may change.

In addition, if the price of gold or copper declines from recent levels, if production costs increase or recovery rates decrease or if applicable laws and regulations are adversely changed, we can offer no assurance that the indicated level of recovery will be realized or that mineral reserves can be mined or processed profitably. If AMNT determines that certain of its ore reserves have become uneconomic, this may ultimately lead to a reduction in aggregate reported reserves. The foregoing could cause AMNT to revise its business plans or make asset impairments. Consequently, if AMNT's actual mineral reserves are less than current estimates, AMNT's results would be materially and adversely affected, which in turn would materially and adversely affect our business, prospects, financial condition and results of operations, which could in turn affect its ability to pay dividends to us.

Failure or delay by SKK Migas, our counterparties or us to comply with the terms of PSCs, and the failure to receive SKK Migas and other government approvals on a timely basis, could adversely affect us.

SKK Migas currently regulates Indonesia's petroleum resources on behalf of the Government. SKK Migas enters (and prior to it, BP MIGAS had entered) into production sharing contracts and other forms of cooperation contracts with private sector energy companies, such as us (or in respect of pre-existing production sharing contracts, as the Government contract counterparty of private sector energy companies) whereby such companies explore, develop and market oil and gas in specified areas in exchange for a percentage interest in the production from the blocks in the applicable contract area. To the best of our knowledge, as of the date of this document, we believe we and our partners have been in compliance with the terms of our PSCs.

Most of our reserves are attributable to PSCs. The PSCs to which we are a party contain requirements regarding quality of service, capital expenditures, legal status of the contractors, restrictions on transfer and encumbrance of assets and other restrictions. While there is no specific regulation under Indonesian law which requires the enforcement of a pledge of interests in oil and gas companies that control, directly or indirectly, interests in a PSC, to be approved by SKK Migas, we believe that such enforcement and transfer of interests will, as a matter of policy and market practice, require the approval of SKK Migas. Any failure by us or any private counterparty to comply with the terms of our PSCs could result, under certain circumstances, in the revocation or termination of such arrangements. Such an action by SKK Migas or Pertamina against us could have a material adverse effect on us. Furthermore, SKK Migas may fail to comply with the terms of PSCs. In addition, we must obtain approval from SKK Migas for substantially all material activities undertaken with respect to our PSCs, including acquisitions, divestments, exploration, development, production, drilling and other operations, sale of oil or natural gas and the hiring or termination of personnel. The failure to obtain such approvals or delays in obtaining such approvals, or conditions imposed in connection with the grant of such approvals, would have an adverse impact on us. As part of these PSCs, we finance such activities and facilities and equipment and recover our costs from the sales of the production, if there is successful production, in accordance with the terms of the PSCs. Our business and results of operations are substantially dependent on our relationship with SKK Migas and our counterparties, and any adverse change to these relationships may have a material adverse effect on our business, prospects, financial condition and results of operations.

We have in the past, and may again in the future, engage in acquisitions, which would be subject to risks.

We have in the past, and may in the future, continue to pursue strategic acquisitions that will expand our oil and gas business and our activity in the oil and gas industry generally or in our other lines of business, such as power and mining. We may also seek to increase our interests in existing investments where we own less than the entire business. We may not be able to identify or complete acquisitions or may be unable to obtain financing on acceptable terms, or if we consummate acquisitions, we may not realize any anticipated benefits from such acquisitions. For international acquisitions in jurisdictions where we do not operate, we may face new and different regulatory regimes, environmental requirements and other regulations with which we need to comply. In addition, we are required to comply with covenants under certain of our existing funding agreements which may require written notification to and/or prior consent from the lenders in the event that we would like to consummate any acquisitions should such acquisition fall within the criteria for the covenants. The process of integrating acquired operations into our existing operations may result in unforeseen issues and may require financial resources that would otherwise be available for the ongoing development or expansion of our existing operations. Future acquisitions could result in the incurrence of additional debt, contingent liabilities and increased capital expenditures, interest and other costs, any of which could have a material adverse effect on our business, prospects, financial condition and results of operations by reducing our net profit or increasing our total liabilities, or both.

In addition, we have in the past recorded bargain purchase gains on certain of our acquisitions and in the future may recognize bargain purchase gains or acquisition of goodwill. For example, we recorded a bargain purchase gain of US$467.2 million in 2016 with respect to our investment in AMIV, reflecting that the purchase price we paid for our share in AMIV was less than the assessment of the fair value of our share of AMIV's assets based on a valuation report from an independent third party valuer registered with the OJK. Bargain purchase gains and goodwill we acquire are subject to impairment testing with respect to whether the value of the asset is recoverable, and therefore to the extent such assets decrease in value, we could record impairment losses in the future.

We may experience difficulties in expanding into new businesses and geographic areas.

We have already expanded, and may in the future again expand, our operations or invest in new businesses. For instance, in 2016, we acquired a 50% interest in PT Amman Mineral Investama, which indirectly controls or has an economic interest in all of the shares in AMNT, which operates a copper and gold mine in Sumbawa. In addition, we have in the past expanded into jurisdictions outside of Indonesia, including among others the United States, Oman, Libya, Tunisia, and Yemen. We are also expanding our O&M business activities in the power sector. Prior to making our investment in AMNT, neither we nor our joint venture partner had experience in the gold and copper mining sector. We have also entered into different businesses from time to time which we have subsequently exited or otherwise hold for sale for portfolio rationalization, such as The Energy building. We may have limited or no prior investment or operational experience in areas into which we expand in the future, and there can be no assurance that we will be successful in investing or operating in such areas, or that such activities will not detract the financial and personnel resources from our core business.

A majority of our oil and gas assets and operations is concentrated in Indonesia, and AMNT's copper and gold mining operations are located within one contract area, which geographically exposes us to risks and hazards in those areas.

The concentration of our operations within Indonesia exposes us to the possibility that events could adversely affect the development or production of oil and/or gas, or mining operations in limited geographic areas. Adverse developments with respect to our contract areas could materially and adversely affect our business, prospects, financial condition and results of operations.

The development and expansion of our projects under development involves construction and financing risks that could lead to increased expenses and a loss of opportunities.

As part of our ongoing business, we participate in development projects. Such development projects involve many risks, including:

- the breakdown or failure of plant equipment or processes;
- the inability to obtain required governmental permits and approvals in time;
- work stoppages and other industrial actions by employees or contractors;
- opposition from local communities and special-interest groups;
- engineering and environmental problems;
- construction delays;
- inability to obtain working capital; and
- unanticipated cost overruns.

If we experience any of these or other problems, we may not be able to derive income and cash flows from the projects and investments in a timely manner, in the amounts expected or at all.

Furthermore, the projects we are developing and in which we invest, require substantial capital outlay and a long gestation period before we realize any benefits or returns on investments. For example, first gas discoveries were made at Senoro-Toili in 1999, we signed a GSA in 2009, the final investment decision was made in 2011, and gas deliveries began in 2014. In July 2017 we entered into a facility agreement for up to US$360 million for the development of Block A, Aceh, where first gas production and gas deliveries are expected to begin in 2018. We then plan to focus on Senoro-Toili, where in 2016, a further 880 BCF of gross 100% field 1C contingent resources were estimated or assessed by GCA and where we are now evaluating potential development scenarios and preliminary engineering for Senoro-Toili phase II and the investment decision with respect to the preferred development scenario is expected to be made in the third quarter of 2018. After this Senoro-Toili phase II investment, we plan to focus on our next large development, which is phase II of our Block A Aceh block and the monetization of our other discovered gas resources on this block. Development of Senoro-Toili phase II and Block A Aceh phase II will require additional financing. We cannot assure you that we will be able to obtain such financing on acceptable terms or at all.

In addition, the time and some of the costs required in completing a project may be subject to substantial increases due to factors including shortages, or increased competition or market prices, for materials, equipment, skilled personnel and labor; adverse weather conditions; natural disasters; labor disputes with contractors; accidents; changes in government priorities and policies; changes in market conditions; delays in obtaining the requisite licenses, permits and approvals from the relevant authorities; and other unforeseeable problems and circumstances. We cannot assure you that our projects will be completed on time, within budget or at all, or that their development period will not be affected by any or all of these factors. Any of these factors could materially and adversely affect our business, prospects and financial condition.

We have significant investments in the power generation and gold and copper mining business, which are accounted for using the equity method.

Through our 49% interest in MPI, we have a significant investment in the power generation sector in Indonesia. In addition, in November 2016, we acquired a 50% interest in AMIV, which indirectly controls and has an economic interest in all of the shares in AMNT, which operates a copper and gold mine in Sumbawa. AMNT is jointly controlled with a Board of Directors and Commissioners appointed by the two shareholders, us and our joint venture partner.

MPI and AMIV and their respective subsidiaries have substantial indebtedness. In order to receive cash flows from these entities, we rely on dividends and there can be no assurance that we will receive dividends from AMNT or MPI.

These entities have required our assistance in the past and we expect to make equity contributions of approximately US$88 million to MPI over the next five years to complete the Sarulla geothermal project and Riau IPP prior to an initial public offering of MPI. As part of AMIV's acquisition of AMNT, we provided AMIV with a US$246.0 million shareholder loan. We also have an outstanding guarantee of indebtedness under a US$750 million facility of a subsidiary of AMIV for which we are liable for up to US$375 million (based on our ratable shareholding). See "Business — Copper and Gold Mining" for a description of the AMNT acquisition indebtedness.

In addition, in the short to medium term, we expect that AMNT will undertake a domestic-focused initial public offering, with the proceeds potentially being used for, among other things, repayment of our shareholder loan to AMIV. However, there can be no assurance that the initial public offering will proceed within expected timelines or at all, or even if it proceeds, that proceeds would be used toward repayment of our shareholder loan to AMIV or that such proceeds would be sufficient to support AMNT's needs or be applied to our benefit.

We may suffer uninsured losses or experience losses exceeding our insurance limits.

Our projects could suffer physical damage from fire or other causes, resulting in losses which may not be fully compensated by insurance. The proceeds of any insurance claim may be insufficient to cover rebuilding costs as a result of inflation, changes in building regulations, environmental issues as well as other factors. In addition, there are certain types of losses, such as those due to earthquakes, floods, hurricanes, other natural disasters, terrorism or acts of war, which may be uninsurable or are not insurable at a reasonable premium. We may not carry coverage for timely completion of our projects under development, loss of rent or profit, defects in the quality of materials used, public liability insurance and comprehensive general liability insurance. Should an uninsured loss or a loss in excess of insured limits occur, we may lose the capital invested in and the anticipated revenue from the affected property. We could also remain liable for any debt or other financial obligation related to that property. In addition, any payments we make to cover any uninsured loss may be significant. We may bear the costs associated with any damage suffered by us in respect of these uninsured events. Any of the foregoing could materially and adversely affect our business, prospects, financial condition and results of operations.

Our business is capital intensive, and if we are unable to obtain financing on terms acceptable to us to fund the substantial capital expenditure we expect to incur, we may not be able to implement our development plans.

We require, and will continue to require, substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves. If certain oil and gas projects currently under development do not increase production as quickly as expected or, if, following such increases, revenues subsequently decline, we may be constrained in our ability to secure the capital necessary to undertake or to complete future drilling or other programs. Our ability to obtain required capital on acceptable terms is subject to a variety of uncertainties, including: limitations on our ability to incur additional debt, including as a result of prospective lenders' evaluations of our creditworthiness and pursuant to restrictions on incurrence of debt in our existing and anticipated credit facilities; whether it is necessary to provide credit support or other assurances from our shareholders on terms and conditions and in amounts that are commercially acceptable to them; limitations on our ability to raise capital in the capital markets and conditions of the various capital markets in which we may seek to raise funds; and our future results of operations, financial condition and cash flows. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet our requirements or, if debt or equity financing or loans are available, that it will be on acceptable terms.

To the extent we raise additional debt in order to fund our planned capital expenditures, this may pose additional risks and place restrictions on us which may, among other things:

- increase our vulnerability to general adverse economic and industry conditions;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the availability of our cash flow to fund capital expenditure, working capital requirements and other general corporate purposes; and/or
- limit our flexibility in planning for, or reacting to, changes in our business and our industry, either through the imposition of restrictive financial or operational covenants or otherwise.

Any inability to access financing on acceptable terms and conditions could have a material adverse effect on our business, prospects, financial condition and results of operations.

Increases in interest rates may materially impact our financial condition.

We have entered into certain facility agreements pursuant to which we have indebtedness which is subject to floating rate interest payments. The outstanding indebtedness which is subject to floating interest rate represents 18.0% of our total outstanding indebtedness as of March 31, 2017. Under such facility agreements, we are exposed to interest rate risk in the future depending on the nature of our financing cash flows. We may from time to time enter into interest or other hedging contracts or financial arrangements in the future to minimize our exposure to interest rate fluctuations. These hedging contracts are designed to reduce the risk of exposure to variable interest rates. However, we cannot assure you that we will be able to do so on commercially reasonable terms or that any such agreements we enter into will protect us fully against these risks. Any increase in interest expense of our loan servicing obligations may have a material adverse effect on our business, prospects, financial condition and results of operations.

We rely on equipment provided by third parties.

We compete with other oil and gas companies for equipment and human resources such as drilling rigs, supply vessels and helicopters, which are a limited resource given the competitive market in the Indonesian oil and gas sector. While the current situation is such that there is an excess availability and capacity for oil and gas equipment and services, there is no assurance that this situation will continue. If we are unable to obtain the equipment that we need to carry out our development plans and operations, we may have to delay or restructure our development plans or curtail selected operations, which may have an adverse effect on our ability to commercialize our oil and gas reserves on a timely basis. Further, depending on the complexity of our development projects, the competitive dynamics of the market, and the availability and prices of our contractors and equipment, we may have to pay more than we currently anticipate to implement our development plans. In addition, both MPI and AMNT also compete with third parties for infrastructure and equipment for their respective businesses.

In the event of a disruption or delay in the availability of equipment provided by third parties, we, MPI and AMNT would be unable to sell our respective products until the problem is corrected or until we or they find alternative means to deliver our or their products to our or their customers. Such alternative means, if available, may result in increased costs, and could have a material adverse effect on our or their business, prospects, financial condition and results of operations.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas.

Seismic data is a method used to determine the depth, orientation and configuration of subsurface rock formations. Seismic data is generated by applying a source of energy, from explosives or vibrations, to the

surface of the ground and capturing the reflected sound waves to create two-dimensional ("2D") "lines" or three-dimensional ("3D") grids, the latter of which provides a more accurate subsurface understanding (which includes subsurface maps). Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in interpreting subsurface structures and potential hydrocarbon occurrences and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures or the amount of hydrocarbons. We employ 3D seismic technology to reduce the uncertainty of our projects. However, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. This could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in its returns. Moreover, our drilling activities may not be successful or economical, and our overall drilling success rate, or our drilling success rate for activities in a particular area, could decline.

We are dependent on key personnel as well as the availability of qualified technical personnel.

We are dependent on senior management employees. If we lose the services of any of our key executive officers, it could be time consuming to find, relocate and integrate adequate replacement personnel into our operations, which could harm our operations and the growth of our business. We are also dependent on attracting qualified technical employees to provide services in relation to certain of our oil and gas operations. If we are unable to retain our current workforce or hire qualified technical personnel in the future, it could have a material adverse effect on our business, prospects, financial condition and results of operations.

From time to time, we may be involved in legal, regulatory and other proceedings arising out of our operations, and may incur substantial costs arising therefrom.

From time to time we have been and in the future may continue to be, involved in legal disputes. These disputes may cause us to incur substantial costs, delays in our development schedule, and the diversion of resources and management's attention, regardless of the outcome. If we were to fail to win these disputes, we could incur substantial losses and face significant liabilities. Further, even if we were to win these disputes, we may incur substantial costs in mounting our defense. We may also be subject to regulatory action in the course of our operations, which may subject us to administrative proceedings and unfavorable decisions that could result in penalties and/or delayed construction of new logistics facilities. In such cases, our business, prospects, financial condition and results of operations could be materially and adversely affected.

We may not be able to renew our production sharing or concession arrangements on the same or attractive terms or at all.

Although in the past we have been able to renegotiate economic extensions for our previous expiring Indonesian PSCs, there can be no assurance that we will be able to negotiate new PSCs with SKK Migas, or concessions or other arrangements with other authorities, when existing arrangements expire, or that any new arrangements will be on terms that are satisfactory to us. Among other things, any new arrangements could reduce our production sharing entitlement, royalty or other payments or place other restrictions on our ability to realize economic value from our production entitlement. We also face risks in this regard because new contracts can be less attractive than existing PSCs and so we have increased our focus on older PSCs, which are more likely to require that we obtain extensions thereof. Failure to successfully negotiate any such extensions on favorable terms or at all could result in loss of the ability to carry out activities on the applicable blocks, inability to grow or maintain production levels and otherwise may have an adverse effect on our business, prospects, financial condition and results of operations.

Due to the limited natural gas transmission and distribution infrastructure, failure by us to develop markets for the sale of our natural gas would have an adverse effect on our results of operations.

The limited natural gas transmission and distribution infrastructure within Indonesia and between Indonesia and other countries, including Singapore, has restricted consumption of Indonesian natural gas. There can be no

assurance as to when or if a significant natural gas transmission and distribution system will be constructed. Construction of transmission and distribution pipelines and other infrastructure depends on many factors, many of which are beyond our control, such as government funding, costs of land acquisition, national and local government approvals and timely completion of construction.

Our natural gas is primarily transported through pipes to the off-taker. Due to the limited natural gas delivery infrastructure, we must sell our natural gas to off-takers who are within close geographical proximity to our operations or find other means of monetizing such resources. We must seek to maximize utilization of our natural gas reserves by entering into working alliances as a gas supplier to obtain and secure long-term gas contracts with power plants and industrial users, among others, as new users of natural gas, or by investing interests in or acquiring power plants. Our ability to sustain the planned expansion of our natural gas exploration and production business by continuously finding, developing and maintaining markets for the sale of our natural gas will be subject to many factors, including the ability to obtain funding, regulatory approvals, competition from other regional and international gas producers, downstream market reforms such as reductions of fuel subsidies that could trigger public opposition, environmental regulations, and other operating or commercial risks, some of which are beyond our control. Failure by us to find, develop and maintain markets for the sale of our natural gas would have a material adverse effect on our natural gas business and our business, prospects, financial condition and results of operations.

Fluctuations in the value of the Indonesian Rupiah against foreign currencies may have an adverse effect on our results of operations.

While we report our results in U.S. dollars, a substantial portion of our costs are generated in Rupiah. Our and AMNT's revenues are earned in U.S. dollars, and MPI's revenue is earned in Rupiah. Many of our, and AMNT's and MPI's, operating costs, such as salaries and employee expenses, are denominated in Rupiah. Accordingly, we are exposed to fluctuations in the value of the Rupiah, against the U.S. dollar. In addition, since MPI reports its results in Rupiah, fluctuations of the Rupiah against the U.S. dollar affect our share of MPI's net income. All of our borrowings are either in U.S. dollars or have been swapped to U.S. dollars, although in the future if we earn revenues or dividends from our investments in Rupiah, or have debt exposure in Rupiah or other currencies, fluctuations in the value of the Rupiah or other currencies against the U.S. dollar will affect the U.S. dollar cost to us of servicing and repaying these borrowings. We enter into currency hedging contracts to reduce the exposure to this risk. However, we cannot assure you that we will be able to do so on commercially reasonable terms or that any such agreements we enter into will protect us fully against these risks. Future fluctuations of the U.S. dollar against the Rupiah and other foreign currencies may adversely impact our business, prospects, financial condition and results of operations.

AMNT may be unable to replace gold and copper reserves as they become depleted.

Our gold and copper mining operations are carried out by our joint venture, AMNT. AMNT plans to continue the development of its Batu Hijau mine, and to engage in further appraisal on other discovered resources, including at Elang, which is its largest discovered resource. AMNT also plans further exploration activities in the future. There can be no assurance that AMNT's development plans will be successful or that its appraisal and exploration activities will result in the discovery or development of mineable reserves. With respect to exploration activities, if a viable commercial deposit is discovered, it can take several years and capital expenditure from the initial phases of exploration until production commences during which time the capital cost and economic feasibility may change. Furthermore, actual results upon production may differ from those anticipated at the time of discovery. In order to maintain gold and copper production beyond the life of AMNT's current proved and probable gold and copper reserves, additional gold and copper reserves must be appraised and developed. AMNT's appraisal and exploration programs may not result in the replacement of such gold reserves or result in new commercial mining operations, this outcome would adversely impact its business and our prospects.

Current mining at Batu Hijau is focused on ore production from Phase 6, which is expected to be completed during 2017. Waste development for Phase 7 is expected to commence in 2017. This waste stripping is required to access the ore in Phase 7 and is expected to take three years. During this hiatus in ex-pit ore production, Batu Hijau will feed its processing plant from existing long-term stockpiles of lower grade ore resulting in lower metal production during the Phase 7 waste development period. Predominantly low to medium grade ore has been accumulated on stockpiles since the start of operations in 2000 until the present day. AMNT believes there is sufficient stockpiled material for up to 10 years of concentrate production. AMNT believes that grade control from blasthole sampling and the precise spatial tracking of the placement of each truckload of this material on the stockpile has resulted in an accurate physical geo-model of the stockpile. However these stockpiles have been classified as a "Probable Mineral Reserve" in order to reflect some uncertainty regarding the degree of oxidation of the copper minerals over time, which affects metal recovery. In addition, Phase 7 could also experience unexpected problems and delays during development arising from such factors as unseasonal or exceptional wet weather and localized pit wall disturbance.

The interests of our controlling shareholders may differ from those of our Group.

Encore Energy Pte. Ltd. ("Encore") owns 35.71% of the Shares of Medco Energi. As a result, Encore has the power to significantly influence the management and policies of Medco Energi. Encore is a corporation incorporated in Singapore and 100% owned by Mr. Hilmi Panigoro, a member of the Panigoro family and the President Director of Medco Energi. In addition, according to our share register as of June 30, 2017, PT Medco Duta is the registered holder of 8,305,500, or 0.25%, of the outstanding Shares and PT Multifabrindo Gemilang is the registered holder of 2,000,000, or 0.06%, of the outstanding Shares. Such entities are also, to the knowledge of Medco Energi, controlled by members of the family of Mr. Hilmi Panigoro. Under Indonesian regulations, an affiliate transaction is a transaction entered between a company and its affiliates or affiliates of a member of the board of directors of a company, a member of the board of commissioners or a substantial shareholder who owns at least 20% of total issued and paid up capital of such company. An affiliate transaction does not require prior approval by a company's independent shareholders. Subject to certain exemptions, the company must publicly disclose the transaction, including providing a fairness opinion from an independent appraiser. An affiliate transaction may, however, be a conflict of interest transaction if such transaction could raise a conflict between the economic interests of the company and the personal economic interests of a member of the board of directors or board of commissioners or substantial shareholder or any of their affiliates. If the transaction is considered to be a conflict of interest transaction, it will be subject to the approval of Medco Energi's independent shareholders, which could affect our ability to enter into such transactions even if such a transaction may be in our interests.

The interests of Medco Energi's controlling shareholders may differ from ours, and such shareholders may vote their shares in a way which prioritizes their interests over ours. To the extent that we enter into affiliate transactions without public disclosure and providing the fairness opinion or enter into conflict of interest transactions without independent shareholder approval, Medco Energi may be subject to administrative sanctions under OJK regulations, such as written notices, fines, restrictions of business activity, ceasing business activity, revocation of license, cancellation of approval and/or cancellation of registration. In addition, Encore is subject to certain covenants and restrictions with respect to its shareholding in Medco Energi pursuant to financing arrangements with its lenders, including having to provide a pledge over Encore's shares in Medco Energi.

Indonesian law contains provisions which may cause us to forego transactions that are in our best interests.

In order to provide more legal certainty and protection to shareholders, in particular the independent shareholders, in connection with affiliated party transactions or conflict of interest transactions conducted by an issuer or an Indonesian public company, in November 2009, BAPEPAM-LK issued Rule No. IX.E.1 on Affiliated Party Transaction and Conflict of Interest of Certain Transaction which replaced the previous rule issued in 2008 ("Rule No. IX.E.1").

Rule No. IX.E.1 requires the issuer or the Indonesian public company to disclose information to the public or to submit a report to OJK of its affiliated party transaction by the end of the second working day following such a transaction and further stipulates that any conflict of interest transaction conducted by Indonesian public companies would require prior independent shareholders' approval of the issuer or the said Indonesian public company, unless such affiliated party transaction or conflict of interest transaction meets certain exemptions stipulated under this rule.

Transactions between us and other persons could constitute an affiliated party transaction or conflict of interest transaction under Rule No. IX.E.1. If such a transaction falls under the conflict of interest transaction, the approval of holders of a majority of shares owned by the independent shareholders would have to be obtained prior to conducting such a transaction. OJK has the power to enforce this rule and our shareholders may also be entitled to seek enforcement or bring enforcement actions based on Rule No. IX.E.1.

The approval of independent shareholders is designed to be a control to stop abuse by controlling shareholders. However the requirement to obtain independent shareholder approval could be burdensome to us in terms of time and expense and could cause us to forego entering into certain transactions which we might otherwise consider to be in our best interests. Moreover, we cannot assure you that approval of the independent shareholders would be obtained if sought.

Indonesian corporate and other disclosure and accounting standards differ from those in other jurisdictions, such as the United States and countries in the European Union.

There may be less publicly available information about Indonesian public companies, such as Medco Energi, than is regularly made available by public companies in the United States and other countries. In addition, our financial statements have been prepared in accordance with Indonesian Financial Accounting Standards, which differs in certain material respects from U.S. GAAP. Further, although we are required to comply with the requirements of OJK with respect to corporate governance standards, these standards may differ materially from those applicable in other jurisdictions, such as the United States.

Political and social instability in the countries where we operate could adversely affect us.

While our assets are primarily located in Indonesia, we also have assets or operations in Oman, Tunisia, Yemen and Libya. Exploration and development activities in these countries may require protracted negotiations with host governments, national oil companies and third parties and may be subject to economic and political considerations such as the risks of war, actions by terrorist or insurgent groups, community disturbances, renegotiation, forced change or nullification of existing contracts or royalty rates, unenforceability of contractual rights, changing taxation policies or interpretations, adverse changes to laws (whether of general application or otherwise) or the interpretation thereof, foreign exchange restrictions, inflation, changing political conditions, the death or incapacitation of political leaders, local currency devaluation, currency controls, and governmental regulations that favor or require awarding contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. Any of the factors detailed above or similar factors or the occurrence of any of the foregoing events in Indonesia or the other countries where we operate could have a material adverse effect on our business, results of operations and financial condition.

In 2016, we recorded impairment losses on our oil and gas properties of US$278.5 million, primarily related to impairments of our assets in Libya and Tunisia resulting from our risk assessment related to political conditions in the North African region. Due to political conditions in Libya and Yemen, we have ceased activities at, and in the case of Yemen, relinquished our rights to, certain of our oil and gas blocks in these countries. In addition, exploration activities at our onshore exploration blocks in Tunisia are currently suspended under force majeure. There can be no assurance that our rights to these blocks will not be impaired or terminated as a result, including, for example, because we are deemed not to have fulfilled our development or other obligations relating thereto.

If a dispute arises in connection with our operations, it may be subject to the exclusive jurisdiction of courts in those countries or arbitration tribunals or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to more favorable jurisdictions. Further, we may also be adversely affected by increased action by non-governmental organizations opposed to the oil and gas exploration and production industry.

Political and related social developments in the countries where we operate have been unpredictable in the past and there can be no assurance that social and civil disturbances will not occur in the future and on a wider scale, or that any such disturbances will not, directly or indirectly, have a material adverse effect on our business, financial condition, result of operations and prospects.

Our operations could be disrupted by community or labor issues.

We are subject to risks associated with community and workforce unrest. For example, AMNT's Batu Hijau operations faced demonstrations including protests and roadblocks by the local community in 2011 and again in 2015 relating to a worker recruitment process by AMNT. The local community believed that AMNT conducted an unfair recruitment process by accepting the workers from families of the local village and sub-district officials. Batu Hijau also faced temporary work stoppages in 2011 and 2012. In addition, development of the geothermal facility at Sarulla, which is not operated by us, was also impacted by social unrest, including riots, which delayed commercial operation of the first facility there. In addition, our operations in Tunisia were suspended due to labor protests from April to June 2017. We cannot predict whether similar or more significant incidents will occur and the recurrence of significant opposition from the local community could disrupt exploration, development or operational activities and, thereby, adversely affect our assets and operations or our other operations. Indonesia has seen greater worker and union activism in recent times, and a strike or other labor disputes could adversely affect our operations and assets. Strikes and labor disputes can have various causes including wages, benefits, work conditions and job security, as well as layoffs, which can result from, among other things, reduced labor needs during the lifecycle of our projects, such as at AMNT where a labor rationalization program is planned to reduce excess workforce headcount by approximately 30%. Any of the foregoing could have a material adverse effect on our business, prospects, financial condition and results of operations.

Oil and gas facility and pipeline, mine closure and remediation costs and abandonment costs and environmental liabilities may exceed the provisions we have made.

Natural resource extractive companies are required to close their operations and rehabilitate the lands that they mine in accordance with a variety of environmental laws and regulations in accordance with the obligations in their PSCs, contracts of work, or IUPK, and a variety of implementing environmental laws and regulations, as applicable. Under the Indonesian mining law, mining companies are required to submit reclamation plans and post-mining activity plans to Directorate General of Minerals, Coal and Geothermal ("DGMCG"). Mining companies are also required to provide reclamation and post-mining guarantees as a commitment to implement the reclamation and post-mining activities as stipulated in the plan. The amount of guarantee itself is determined by the DGMCG based on its assessment and valuation of the plan submitted by the mining company. Estimates of the total ultimate closure and rehabilitation costs may be significant and based principally on current legal and regulatory requirements and closure plans that may change materially. Any underestimated or unanticipated rehabilitation costs could materially affect our or AMNT's business and prospects. The laws and regulations governing oil and gas facilities and pipelines, mine closure and remediation are subject to review at any time and may be amended to impose additional requirements and conditions which may cause our or AMNT's provisions for environmental liabilities to be underestimated and could materially affect our financial position or results of operations.

The exploration, development, and operation of the Sarulla geothermal power project is subject to geological risks and uncertainties.

The Sarulla geothermal power project, in which MPI owns an 18.6% interest, is subject to various uncertainties, such as potential dry holes, flow-constrained wells and uncontrolled releases of pressure and temperature decline. In addition, the high temperature and high pressure in geothermal energy resources requires special resource management and monitoring. Because geothermal resources are complex geological structures, there can be no assurance that MPI's estimates of their geographic area are accurate. The viability of geothermal projects depends on different factors directly related to the geothermal resource, such as the heat content (the relevant composition of temperature and pressure) of the geothermal resource, the useful life (commercially exploitable life) of the resource and operational factors relating to the extraction of geothermal fluids. Although MPI believes its geothermal resources will be fully renewable if managed appropriately, the geothermal resources that MPI intends to exploit may not be sufficient for sustained generation of the anticipated electrical power capacity over time. Further, MPI's geothermal resources may suffer an unexpected decline in capacity. Any of these factors could adversely affect MPI's development of the Sarulla geothermal power project and, in turn, our business, financial condition and results of operations.

RISKS RELATING TO OUR INDUSTRIES

The volatility of prices for crude oil could adversely affect the Group's financial condition and results of operations.

Our future revenues will be highly dependent upon the prices of, and demand for, oil and natural gas. Our profitability is determined in large part by the difference between the prices received for the oil and natural gas and the costs of exploring for, developing, producing and selling these products. We currently sell most of our oil at prices based on the Indonesian Crude Price. Currently, we sell all of our natural gas under long-term contracts. Some of our contracts, representing 54% of sales volume in the three month period ended March 31, 2017 contain pricing linked to oil prices, such as the Senoro GSA and one of the South Natuna Sea Block B GSAs. The remaining 46% was sold domestically within Indonesia under fixed price or inflation linked long-term contracts with no linkage to oil price, and accordingly, our revenue from natural gas sales is not subject to as much price volatility as with sales of oil.

There have recently been significant fluctuations in the prices of crude oil, with oil prices having dropped significantly in 2015. In 2015, our average realized crude oil price was US$49.29 per barrel, representing a 49.6% decline from our average realized crude oil price in 2014 of US$97.83 barrel, which impacted our revenues and profitability and impacted the value of our assets as we recorded an asset impairment of US$203.9 million in 2015. The average monthly ICP-SLC ranged from US$45/bbl to US$132/bbl from January 1, 2009 to December 31, 2014 and more recently, the average monthly ICP-SLC dropped from US$60/bbl in December 2014 to US$45/bbl in June 2017.

The market prices of crude oil are subject to a variety of factors beyond our control. These factors, among others, include:

- international events and circumstances, as well as political developments and instability in petroleum producing regions, such as the Middle East (particularly the Persian Gulf, Iraq and Iran), Latin America and Western Africa;
- the ability of the Organization of Petroleum Exporting Countries ("OPEC") and other petroleum-producing nations to set and maintain production levels and therefore influence market prices;
- market prices and supply levels of substitute energy sources, such as coal;
- domestic and foreign government regulations with respect to oil and energy industries in general;
- the level and scope of activity of oil speculators;

- weather conditions and seasonality; and
- overall global economic conditions.

In the event of sustained low oil prices we attempt to reduce our cost of production and curtain exploration activities. In the event that the price of oil falls below the cost of production, we may reduce oil production to a level where we can produce oil economically. These circumstances could lead to further decreases in our revenues, net income and cash flows. We do not materially hedge our exposure to movements in oil prices Volatility and any significant decreases in the price of oil and gas could have a material adverse effect on our financial condition and results of operations.

A substantial or extended decline in gold or copper prices would have a material adverse effect on AMNT.

AMNT's business is dependent on the prices of gold and copper, which fluctuate on a daily basis and are affected by numerous factors beyond our control. Factors tending to influence prices include:

- gold sales, purchases or leasing by governments and central banks;
- speculative short positions taken by significant investors or traders in gold or copper;
- the relative strength of the U.S. dollar;
- the monetary policies employed by the world's major central banks;
- the fiscal policies employed by the world's major industrialized economies;
- expectations of the future rate of inflation;
- interest rates;
- recession or reduced economic activity in the United States, China, India and other industrialized or developing countries;
- decreased industrial, jewelry or investment demand;
- increased import and export taxes;
- increased supply from production, disinvestment and scrap;
- forward sales by producers in hedging or similar transactions; and
- availability of cheaper substitute materials.

Any decline in AMNT's realized gold or copper price could adversely impact our net income. In addition, sustained lower gold or copper prices can:

- reduce revenues further through production declines due to cessation of the mining of deposits, or portions of deposits, that have become uneconomic at sustained lower gold or copper prices;
- reduce or eliminate the profit that we currently expect from ore stockpiles and ore on leach pads and increase the likelihood and amount that AMNT might be required to record as an impairment charge related to the carrying value of its stockpiles;
- halt or delay the development of new projects;
- reduce funds available for exploration and advanced projects with the result that depleted reserves may not be replaced; and
- reduce existing reserves by removing ores from reserves that can no longer be economically processed at prevailing prices.

Our operations are subject to significant operating hazards.

Our oil and gas exploration, development and production operations are subject to significant risks normally associated with such activities, including drilling blowouts, pipeline ruptures, explosions, oil spills and fires. Any of these risks could result in environmental pollution, damage to or destruction of wells, production facilities or other property, or injury to persons or fatalities. While we aim to prepare for, and train our personnel to deal with, such emergencies, if we are unable to quickly fix the damage resulting from such accidents, our financial condition and results of operation could be materially and adversely impacted. In addition, drilling hazards or environmental damage could increase the cost of operations, and various field operating conditions may adversely affect our production levels from successful wells. These conditions include delays in obtaining government approvals or consents, shut-in of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to materially and adversely affect revenue and cash flow to varying degrees. Offshore production facilities are subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, collision and damage from severe weather or tidal conditions. These hazards can cause substantial damage to facilities and interrupt production. Offshore oil activities can also be affected by ocean conditions arising from occurrences such as typhoons and tsunamis.

In addition, the exploration and development of natural resources and the development and production of oil and gas, mining or power operations are activities that involve a high level of uncertainty. These can be difficult to predict and are often affected by risks and hazards outside of our control. These factors include, but are not limited to:

- environmental hazards, including discharge of metals, concentrates, pollutants or hazardous chemicals;
- industrial accidents, including in connection with the operation of mining transportation equipment, milling equipment and/or conveyor systems and accidents associated with the preparation and ignition of large-scale blasting operations, milling, processing and transportation of chemicals, explosives or other materials;
- surface or underground fires or floods;
- unexpected geological formations or conditions (whether in mineral or gaseous form);
- ground and water conditions;
- fall-of-ground accidents in underground operations;
- failure of mining pit slopes and tailings dam walls;
- seismic activity; and
- other natural phenomena, such as lightning, cyclonic or tropical storms, floods or other inclement weather conditions.

The occurrence of one or more of these events in connection with our businesses or investments may result in the death of, or personal injury to, employees, other personnel or third parties, the loss of equipment, damage to or destruction of properties or production facilities, monetary losses, deferral or unanticipated fluctuations in production, environmental damage and potential legal liabilities, all of which may adversely affect our reputation, business, prospects, results of operations and financial position.

The mining industry faces continued geotechnical challenges.

The mining industry and AMNT's mining operations are facing continued geotechnical challenges due to aging of mines and a trend toward mining deeper pits and more complex deposits. This leads to higher pit walls and increased exposure to geotechnical instability and hydrological impacts. As AMNT's operations are maturing, open pits get deeper and AMNT has experienced certain geotechnical failures at the Batu Hijau mine

in the past. In addition, the pit design for Phase 7 was developed based on the same geotechnical and hydrological strategies that have been developed over the 20-year life of the Batu Hijau operation to date. The pit walls will be depressurized with horizontal drainage holes and pre-split blasting will be used to maximize wall competency but, based on experience at Batu Hijau, the pit walls are still anticipated to fail on a localized scale. The operation is well-practiced in monitoring and managing such confined failures and there is no reason to expect the additional depth in Phase 7 will present any additional issues to what the mine has experienced in the past.

No assurances can be given that unanticipated adverse geotechnical and hydrological conditions, such as landslides and pit wall failures, will not occur in the future or that such events will be detected in advance. Geotechnical instabilities can be difficult to predict and are often affected by risks and hazards outside of AMNT's control, such as severe weather and considerable rainfall, which may lead to periodic floods, mudslides, wall instability and seismic activity, which may result in slippage of material. Geotechnical failures could result in limited or restricted access to mine sites, suspension of operations, government investigations, increased monitoring costs, remediation costs, loss of ore and other impacts, which could cause mining operations to be less profitable than currently anticipated and could result in a material adverse effect on our business, financial condition, results of operations and prospects.

We operate in a competitive environment.

The Indonesian oil and gas, mining and power industries are highly competitive. Key areas in which we face competition include the acquisition, renewal and negotiation of licenses, evaluating, bidding for and acquiring assets, and securing the resources necessary for our operations as well as selling our products. Many of our competitors have greater financial and personnel resources available to them than we do. The size, infrastructure, wide-ranging experience and close relationships with the Government of some state-owned, international, or other energy companies may provide them with competitive advantages over other companies operating in Indonesia or the other countries where we operate, including us. Our ability to develop our business will depend upon our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Our business operations may be adversely affected by current and future environmental regulations.

Our business is subject to certain laws and regulations on environmental and safety matters relating to the exploration for, and development and production of, oil and gas, conducting mining operations and power generation, which may have a material adverse effect on our financial condition and results of operations. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities which may require us to incur costs to remedy such discharge and pay penalties or fines. Any change in Indonesian laws and regulations applicable to us, including environmental laws and regulations and increased governmental enforcement of environmental laws or other similar developments in the future may require us to make additional capital expenditure or incur additional operating expenses in order to maintain our current production, development, exploration and other operations activities, curtail our production activities or take other actions that could materially and adversely affect us.

On October 3, 2009, the Government enacted Law No. 32 of 2009 regarding Environmental Protection and Management ("Environmental Law"), in place of the previous Law No. 23 of 1997 ("Law 23/1997"), which required that all current environmental management licenses be integrated into the environmental permit issued pursuant to the Environmental Law and introduced more stringent penalties for breaches of environmental laws and regulations. As an implementation of the Environmental Law, the Government enacted Government Regulation No. 27 of 2012 on Environmental License, dated February 23, 2012 ("Regulation No. 27") and State Minister of Environmental Affairs Regulation No. 5 of 2012 on Types of Planned Businesses and/or Activities Subject to Mandatory Environmental Impact Analysis which requires that in addition to an environmental impact analysis (*Analisa Mengenai Dampak Lingkungan*) ("AMDAL") approval, an environmental management effort

plan (*Upaya Pengelolaan Lingkungan*) ("UKL") or an environmental monitoring effort plan (*Upaya Pemantauan Lingkungan*) ("UPL"), an environmental permit from the State Ministry of Environmental Affairs or governor or mayor/head of regent of their respective areas would need to be obtained. However, all environmental documents (AMDAL, UKL and UPL) obtained before the implementation of Regulation No. 27 would be accepted as valid environmental permits. The Environmental Law requires us to obtain environmental licenses (*Izin Lingkungan*) as a pre-requisite to obtaining the relevant business licenses, and if obligations in the AMDAL approval, UKL or UPL are not met, one of the sanctions that could be imposed is the revocation of our environmental permit. Revocation of environmental licenses may lead to nullification or termination of the corresponding business license, which may require us to cease certain operations and may have a material adverse effect on us. In addition to environmental licenses, under Law No. 32/2009, each holder of an environmental license is required to effect a cash deposit in a designated state-owned bank; however, no government regulation has been issued which stipulates the amount of such cash deposit, and accordingly we have not made any such deposit as of the date of this document. If, in the future, government regulations are issued which stipulate the amount of the cash deposit, we would be required to make such a deposit in order to comply with Law No. 32/2009. The enactment of further implementing regulations relating to the Environmental Law could cause us to incur significant additional costs or delay in the completion of our projects under development in order to comply with such new regulations. See "Business—Environmental".

While we have generally received Blue, Green and Gold PROPER awards from the Environmental & Forestry Ministry for certain of our Indonesian assets, in 2016, we received a Red rating from the Environmental & Forestry Ministry for our Bawean PSC (which we sold in June 2017), due, among other things, to the Government's request for a wastewater treatment facility to be constructed. A Red rating means that although the facility was making efforts to be in compliance with relevant regulations, such facility is not in full compliance.

We operate the South Natuna Sea Block B PSC as well as the West Natuna Transportation System ("WNTS") pipeline to an onshore receiving facility in Singapore through which we distribute approximately 30% of our total gas sales. It has been reported that the Singapore government may consider implementing regulations aimed at limiting the amount of mercury in gas supplied to Singapore. There can be no assurance regarding the extent or effect of such regulations, which have not yet been promulgated. While a mercury removal unit has been implemented at the South Natuna Sea Block B PSC, which we believe would allow us to be in compliance with such prospective regulations, the actual implementation of such regulations in a manner different from our expectations could have an adverse effect on our business, prospects, results of operations and financial condition if we are not in compliance.

In addition, certain discoveries on our blocks, such as Block A Aceh, have high carbon dioxide levels. The future developments of such resources which will need to be considered, designed and managed by us in light of prevailing regulations.

Given the possibility of unanticipated regulatory or other developments, including more stringent environmental laws and regulations, the amount and timing of future environmental compliance expenditures could vary substantially from their current levels. These changes could limit the availability of our funds for other purposes. We cannot predict what additional environmental legislation or regulations will be enacted in the future or the potential effects on our business, financial condition, results of operations and prospects.

Shortages of critical parts and equipment may adversely affect us.

The industries in which we operate and invest have been impacted, from time to time, by increased demand for critical resources such as input commodities, drilling equipment, trucks, shovels and tires. These shortages have, at times, impacted the efficiency of operations, and resulted in cost increases and delays in production and construction of projects, thereby impacting operating costs, capital expenditures and production and construction schedules.

RISKS RELATING TO INDONESIA AND CERTAIN OTHER COUNTRIES WHERE WE OPERATE

Medco Energi is incorporated in Indonesia and most of its commissioners and directors are based in Indonesia. A substantial majority of our operations and assets are also located in Indonesia. As a result, future political, economic, legal and social conditions in Indonesia, as well as certain actions and policies the Government may take or adopt, or omit to take or adopt, could have a material adverse effect on our business, financial condition, results of operations and prospects.

Political and social instability in Indonesia may adversely affect us.

Following the collapse of President Suharto's regime in 1998, Indonesia experienced a process of democratic change. Despite Indonesia having successfully conducted its first free elections for parliament and president in 1999, as a new democratic country, Indonesia continues to face various socio-political issues and has, from time to time, experienced political instability and social and civil unrest.

Since 2000, thousands of Indonesians have participated in demonstrations in Jakarta and other Indonesian cities both for and against former President Wahid, former President Megawati, former President Yudhoyono and current President Widodo as well as in response to specific issues, including fuel subsidy reductions, privatization of state assets, anti-corruption measures, decentralization and provincial autonomy and the American-led military campaigns in the middle-east. Although these demonstrations were generally peaceful, some have turned violent.

Political and related social developments in Indonesia have been unpredictable in the past. There can be no assurance that this situation or future sources of discontent will not lead to further political and social instability. Social and civil disturbances could directly or indirectly, materially and adversely affect our business, financial condition, results of operations and prospects. In addition, as a significant oil producer and consumer market of great potential, Indonesia remains a key investment location, though corruption, policy drift and collapsing infrastructure, as well as insecurity in the region, present risks to business operations in that country.

Increased scope of regulation by Government agencies may have a material adverse effect on our business, financial condition and results of operations.

The evolving roles of SKK Migas and the Ministry of Energy and Mineral Resources, coupled with political changes in Indonesia, have allowed other Government agencies to increase their roles in administering and regulating the oil and gas industry in Indonesia.

BP MIGAS (currently known as SKK Migas), via a letter dated June 10, 2009 in relation to the Regulation of the Minister of Energy and Mineral Resources No. 22 Year 2008 on "Type of Activities Cost of Business Upstream Oil and Gas which cannot be recovered to Contractor of Production Sharing Contract" (*Kontraktor Kontrak Kerja Sama*) and Government Regulation of Republic of Indonesia No. 27 of 2017 regarding Amendment of Government Regulation of Republic Indonesia No. 79 of 2010 on "Cost Recovery and Income Tax Treatment in the Upstream Oil and Natural Gas Business Sector," added to the categories of costs that could not be recovered under contract.

Also, the Indonesian tax authorities have recently initiated additional tax audits and implemented measures to increase tax revenues from the oil and gas industry. Further, the treatment of taxation under the new tax laws may conflict with the approach currently adopted for PSCs. Continued expansion of the role of these governmental agencies may have a material adverse effect on companies operating in the oil and gas industry, including us.

Increased regulation by governments and governmental agencies may increase the cost of regulatory compliance and limit our access to new exploration properties.

The oil and gas industry is generally subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production interests, the imposition of specific drilling obligations, environmental, health and safety controls, controls over the development and decommissioning of a field (including restrictions on production) and possibly, nationalization, expropriation, cancellation or non-renewal of contract rights.

Within Indonesia, where our operations are primarily located, the evolving roles of SKK Migas and the Ministry of Energy and Mineral Resources, coupled with political changes in Indonesia, have allowed other Government agencies such as the Minister of Trade, the Ministry of Forestry and State Ministry for Environmental Affairs to increase their roles in administering and regulating the oil and gas industry in Indonesia. The continued expansion of the roles of governmental agencies may result in the adoption of new regulations, legislation and practices that we would be required to comply with.

In addition, new regulations, legislation and practices may be adopted by the Government and other governments or governmental agencies in countries in which we have operations in response to evolving practices or specific incidents, such as the Gulf of Mexico oil spill, which may result in more stringent regulation of oil and gas activities in the United States and elsewhere, particularly relating to environmental, health and safety controls and oversight of drilling operations, as well as access to new areas. Any new regulations, legislation and practices could increase the cost of compliance and may require changes to our drilling operations, exploration, development and decommissioning plans and could impact our ability to capitalize on our assets and limit our access to new exploration properties or operatorships.

The oil and gas industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities, and we operate in certain tax jurisdictions that have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, or we could incur additional costs.

Indonesia is subject to significant geological risk that could lead to natural disasters and economic loss.

Because of its location in a geologically active part of the world, Indonesia is subject to various forms of natural disasters. These include earthquakes, tsunamis, volcanic eruptions, floods and landslides that can result in major losses of life and property, such as the 2004 Indian Ocean Tsunami that devastated the province of Aceh, and can therefore have significant economic and developmental effects.

If the Government is unable to timely deliver foreign aid to affected communities, political and social unrest could result. Any such failure on the part of the Government, or declaration by it of a moratorium on its sovereign debt, could trigger an event of default under numerous private-sector borrowings including ours, thereby materially and adversely affecting our business, financial condition, results of operations and prospects.

In addition, the future geological or meteorological occurrences, may significantly harm the Indonesian economy. A significant earthquake or other geological disturbance or weather-related natural disasters in any of Indonesia's more populated cities and financial centers could severely disrupt the Indonesian economy and thereby materially and adversely affect our business, financial condition, results of operations and prospects.

Terrorist attacks and terrorist activities and certain destabilizing events have led to substantial and continuing economic and social volatility in Indonesia, which may materially and adversely affect our business.

Terrorist attacks and associated military responses have resulted in substantial and continuing economic volatility and social unrest in the world. In Indonesia during the last several years and as recently as May 2017,

there have been various terrorist attacks directed towards the Government, foreign governments and public and commercial buildings frequented by foreigners, which have killed and injured a number of people.

There can be no assurance that further terrorist acts will not occur in the future. Any of the foregoing events, including damage to our infrastructure or that of our suppliers and customers, could materially and adversely affect international financial markets and the Indonesian economy, interrupt parts of our business and materially and adversely affect our financial condition, results of operations and prospects.

Any outbreak of infectious disease, or fear of an outbreak, or any other serious public health concerns in Indonesia or elsewhere may have an adverse effect on the Indonesian economy and may adversely affect us.

An outbreak of infectious diseases (including avian flu, SARS, swine flu, the H7N9 virus) or another contagious disease or the measures taken by the governments of affected countries, including Indonesia, against such potential outbreaks, could seriously interrupt our operations or the services or operations of our suppliers and customers, which could have a material adverse effect on our business, financial condition, results of operations and prospects. The perception that an outbreak of infectious diseases or another contagious disease may occur may also have an adverse effect on the economic conditions of countries in Asia, including Indonesia.

Regional or global economic challenges may materially and adversely affect the Indonesian economy and our business.

The economic crisis which affected South East Asia, including Indonesia, from mid-1997 was characterized in Indonesia by, among others, currency depreciation, a significant decline in real gross domestic product, high interest rates, social unrest and extraordinary political developments. As a result of the economic crisis in 1997, the Government has had to rely on the support of international agencies and governments to prevent sovereign debt defaults. The economic difficulties Indonesia faced during the Asian economic crisis that began in 1997 resulted in, among other things, significant volatility in interest rates, which had a material adverse impact on the ability of many Indonesian companies to service their existing indebtedness.

Indonesia's economy remains significantly affected by economic conditions which resulted in a decrease in Indonesia's real GDP growth from 6.0% in 2012, to 5.6% in 2013 and 5.0% in 2014. These conditions had a material adverse effect on Indonesian businesses. The global financial markets have experienced, and may continue to experience, significant turbulence originating from the liquidity shortfalls in the U.S. credit and sub-prime residential mortgage markets since 2008, which have caused liquidity problems resulting in bankruptcy for many institutions, and resulted in major government bailout packages for banks and other institutions. The global economic crisis has also resulted in a shortage in the availability of credit, a reduction in foreign direct investment, the failure of global financial institutions, a drop in the value of global stock markets, a slowdown in global economic growth and a drop in demand for certain commodities. The global financial markets have also recently experienced volatility as a result of concerns over the debt crisis in the Eurozone. Uncertainty over the outcome of the Eurozone governments' financial support programs and worries about sovereign finances generally are ongoing.

The Government continues to have a modest fiscal deficit and a high level of sovereign debt, its foreign currency reserves are modest, the Rupiah continues to be volatile and has poor liquidity, and the banking sector is weak and suffers from high levels of non-performing loans. The inflation rate (measured by the year on year change in the consumer price index) remains volatile. The Indonesia rate of inflation was 6.3% in 2015 and 3.5% in 2016 based on the consumer price index. Interest rates in Indonesia have also been volatile in recent years, which have had a material adverse impact on the ability of many Indonesian companies to service their existing indebtedness.

The current global economic situation could further deteriorate or have a greater impact on Indonesia and our business. Any of the foregoing could materially and adversely affect our business, financial condition, results of operations and prospects.

Indonesian accounting standards differ from those in other jurisdictions.

We prepare our financial statements in accordance with Indonesian FAS, which differs from U.S. GAAP. As a result, our financial statements and reported earnings could be significantly different from those that would be reported under U.S. GAAP. This document does not contain a reconciliation of our financial statements to U.S. GAAP, and there can be no assurance that such reconciliation would not reveal material differences.

We are subject to corporate disclosure and reporting requirements that differ from those in other countries.

We are subject to corporate governance and reporting requirements in Indonesia that differ, in significant respects, from those applicable to companies in certain other countries. The amount of information made publicly available by issuers in Indonesia may be less than that made publicly available by comparable companies in certain more developed countries, and certain statistical and financial information of a type typically published by companies in certain more developed countries may not be available. As a result, investors may not have access to the same level and type of disclosure as that available in other countries, and comparisons with other companies in other countries may not be possible in all respects.

Downgrades of the credit ratings of Indonesia and Indonesian companies could materially and adversely affect us.

As of the date of this document, Indonesia's sovereign foreign currency long-term debt is rated "Baa3/positive outlook" by Moody's, "BBB-/stable outlook by Standard and Poor's and "BBB-/positive outlook" by Fitch, and its short-term foreign currency debt is rated "P-3" by Moody's, "A-3" by Standard & Poor's and "F3" by Fitch with a stable outlook from Moody's, a positive outlook from Standard & Poor's and a stable outlook from Fitch. These ratings reflect an assessment of the Government's overall financial capacity to pay its obligations and its ability or willingness to meet its financial commitments as they become due.

Any downgrade to credit ratings of Indonesia or Indonesian companies could have an adverse impact on liquidity in the Indonesian financial markets, the ability of the Government and Indonesian companies, including us, to raise additional financing and the interest rates and other commercial terms at which such additional financing is available and could have a material adverse effect on us.

We may be subject to changes in taxation.

Our subsidiaries engaged in oil and gas operations in Indonesia are subject to taxation and are faced with increasingly complex tax laws. The amount of tax we pay could increase substantially as a result of changes in, or new interpretations of, these laws, which could have a material adverse effect on our liquidity and results of operations. Taxes have increased or been imposed in the past and may increase or be imposed again in the future. In addition, taxing authorities could review and question our tax returns leading to additional taxes and penalties which could be material.

Certain recent changes to Indonesian tax laws may adversely affect us. We have interests in a number of PSCs in Indonesia. On December 20, 2010, the Indonesian Government enacted Government Regulation 79/2010 ("GR 79/2010"), which changes the regime governing cost recovery under PSCs and the taxation of oil and gas activities. GR 79/2010 generally applies to PSCs entered into or extended after December 20, 2010. PSCs entered into or extended before December 20, 2010 will continue to be governed by the regulations prevailing at the time such PSCs were executed, unless it is determined that such PSCs have not expressly or sufficiently provided for the areas mentioned in the list below, in which case the provisions of GR 79/2010 will apply and such PSCs must be adjusted within three months of the effective date of GR 79/2010 (being December 20, 2010). It is not yet clear who will make such determinations or how they will be made.

The transitional provisions in GR 79/2010 list eight areas that makes GR 79/2010 applicable to PSCs entered into before December 20, 2010 including:

- government share;
- requirements for cost recovery and the norms for claiming operating non-allowable costs;
- non-recoverable operating costs;
- the appointment of independent third parties to carry out financial and technical verifications;
- the issuance of income tax assessments;
- the exemption of customs duty and import tax on the importation of goods used during exploitation and exploration activities;
- contractor's tax in the form of oil and gas from the contractor's share; and
- income from outside the PSC in the form of uplifts and/or the transfer of PSC interests.

On June 15, 2017, the Indonesian government enacted Government Regulation No. 27 of 2017 regarding the Amendment of Government Regulation No. 79 of 2010 regarding Operating Costs that may be Recovered and Income Tax Treatment for Upstream Oil and Gas Activities ("GR 27/2017"), which was put into effect on June 19, 2017. GR 27/2017 applies to PSCs entered into or extended after June 19, 2017. PSCs entered into or extended: (i) prior to the enactment of Oil and Gas Law; (ii) after the enactment of Oil and Gas Law and prior to enactment of GR 79/2010; and/or (iii) after the enactment of GR 79/2010, will continue to be governed by the regulations prevailing at the time such PSCs were executed, unless it is determined that such PSCs have not expressly or sufficiently provided for the eight areas mentioned in the transitional provisions of GR 27/2017 which are the same as the eight areas mentioned in the transitional provisions of GR 79/2010 above.
GR 27/2017 introduced new tax facilities which previously were not available in GR 79/2010:

- domestic purchase of certain goods on which VAT is applicable and utilization of certain intangible goods and services from overseas during exploitation and exploration period are exempted from VAT;
- 100% reduction of land and building tax during exploitation period which can be granted by Ministry of Finance upon consideration of the economics of the project;
- facility cost sharing and parent company overhead charges are exempted from withholding tax and VAT; and
- income from outside the PSC in the form of uplifts and/or the transfer of PSC interests after deduction of final income tax, is exempted from branch profit tax.

PSCs entered into or extended prior to enactment of GR 27/2017 which aim to utilize benefits from GR 27/2017 may choose to adjust the PSC in full with the terms of GR 27/2017 within a period of no more than six months after the effective date of GR 27/2017 (being June 19, 2017). It is not yet clear who will make such determinations or how they will be made.

Further changes to the taxation and tax laws that may result in higher taxes and operating costs in Indonesia could have a material adverse effect on our business, results of operations, financial condition and prospects.

We are exposed to the risk of adverse sovereign action.

The oil and gas industry is a significant contributor to the Indonesian economy and the economies of the other countries where we operate and is therefore a key government focus. Potential future changes in government policy, regulations or PSC fiscal regimes and taxes could have an adverse effect on our business, financial results or prospects.

Our assets may be subject to sovereign immunity risk.

Indonesia has a constitution and laws which entrench and vest all of the rights over its natural resources in the state, including oil and gas resources, which are regarded as sovereign state assets. Indonesia has also established a state-owned agency which enters into commercial contracts with oil and gas exploration and production companies in relation to the exploration, development and production of oil and gas resources. Accordingly, the natural resources discovered within a contract area are ultimately owned by the state and the exploration and production agency only has contractual rights of exploration, development and production. As our contracts in Indonesia are with a state-owned agency, in the event of a dispute, it is uncertain if the state-owned agency will be able to invoke the principles of sovereign immunity. We are subject to similar risks with respect to our international operations. The invocation of such immunity may limit our ability to enforce our rights, which in turn adversely affects our business, results of operations, financial condition and prospects.

Labor laws and regulations in Indonesia or other countries where we operate and labor unrest may materially adversely affect our results of operations.

Laws and regulations which facilitate the forming of labor unions, combined with weak economic conditions, have resulted and may continue to result in labor unrest and activism in Indonesia. In 2000, the Government issued Law No. 21 of 2000 regarding Labor Unions (the "Labor Union Law"). The Labor Union Law permits employees to form unions without intervention from an employer, the government, a political party or any other party. On March 25, 2003, President Megawati enacted Law No. 13 of 2003 regarding Employment (the "Labor Law") which, among other things, increased the amount of severance, pension, medical coverage, life insurance, service and compensation payments payable to employees upon termination of employment. The Labor Law requires further implementation of regulations that may substantively affect labor relations in Indonesia. The Labor Law requires companies with 50 or more employees establish bipartite forums with participation from employers and employees. The Labor Law also requires a labor union to have participation of more than half of the employees of a company in order for a collective labor agreement to be negotiated and creates procedures that are more permissive to the staging of strikes. Following the enactment, several labor unions urged the Indonesian Constitutional Court to declare certain provisions of the Labor Law unconstitutional and order the Government to revoke those provisions. The Indonesian Constitutional Court declared the Labor Law valid except for certain provisions, including relating to the right of an employer to terminate its employee who committed a serious mistake and criminal sanctions against an employee who instigates or participates in an illegal labor strike. Our international operations are also subject to the labor laws in the jurisdictions where we operate, and our international operations are affected by such laws.

Labor unrest and activism in Indonesia could disrupt our operations, our suppliers or contractors and could affect the financial condition of Indonesian companies in general, depressing the prices of Indonesian securities on the Jakarta or other stock exchanges and the value of the Rupiah relative to other currencies. Labor disruptions outside of Indonesia in the markets in which we operate have affected and could in the future affect our operations. For example, our operations in Tunisia were suspended due to labor protests from April 2017 to June 2017. Such events could materially and adversely affect our business, financial condition, results of operations and prospects.

GLOSSARY

Certain Defined Terms

"1C"	means with respect to contingent resources, in the "low estimate" scenario of contingent resources, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is at least 90%
"Alpha"	means adjustment to the dated Brent price to accommodate crude quality, international oil price, and national energy security.
"AMG"	means PT Api Metra Graha.
"BAPEPAM-LK"	means Badan Pengawas Pasar Modal (or Capital Market Supervisory Agency).
"Block A PSC"	means the PSC between Pertamina and Asamera Oil (Indonesia) Ltd. dated July 6, 1989, which expired on August 31, 1991, and the amended and restated PSC between Pertamina, PT Medco EP Malaka, Premier Oil Sumatra (North) BV. and Japex Block A Ltd. dated October 28, 2010 that became effective as of September 1, 2011, as may be amended from time to time.
"BPHMigas"	means Badan Pengatur Hilir Minyak Dan Gas Bumi, the non-profit Government-owned operating board that is succeeding to Pertamina's role as regulator of downstream oil and gas activities under the Oil and Gas Law.
"BP Migas"	means Badan Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi, the non-profit Government-owned operating board that is succeeding to Pertamina's role as regulator of upstream oil and gas activities under the Oil and Gas Law.
"CAGR"	means compounded annual growth rate.
"Company"	means Medco Energi and its consolidated subsidiaries.
"ConocoPhillips"	means ConocoPhillips Indonesia.
"CPI"	means Consumer Price Index.
"Custodian"	has the same meaning as set forth in the Indonesian Regulation PER-10/PJ/2017.
"Energi Sengkang"	means PT Energi Sengkang.
"EPC"	means engineering, procurement and construction.
"Financial Sector Incentive"	has the same meaning as set forth in the Indonesian Regulation PER-10/PJ/2017.

"FSO"	means floating storage and offloading vessel.
"Government"	means the Government of Indonesia.
"GSA"	means Gas Sale Agreements.
"HOAs"	means binding heads of agreements.
"HSFO"	means High Sulphur Fuel Oil 180 CST.
"IDR"	means Indonesian Rupiah.
"IDX"	means the Indonesia Stock Exchange (formerly known as the Jakarta Stock Exchange or JSX).
"Indonesia"	means the Republic of Indonesia.
"Indonesian FAS"	means Indonesian Financial Accounting Standards.
"Indonesia Income Tax"	has the same meaning as set forth in the Indonesian Regulation PER-10/PJ/2017.
"ISO"	means International Organization for Standardization.
"ISRS"	means International Stereotactic Radiosurgery Society.
"Itochu"	means Itochu Petroleum Co., (Singapore) Pte. Ltd.
"Lematang PSC"	is the production sharing contract between Pertamina and Enim Oil Company Ltd dated April 6, 1987, as may be amended from time to time.
"LIBOR"	refers to the London Interbank Offering Rate.
"MEB"	means to PT Mitra Energi Batam.
"Medco E&P Indonesia"	means PT Medco E&P Indonesia (formerly PT Exspan Nusantara).
"Medco Energi"	means PT Medco Energi Internasional Tbk.
"Medco Madura"	means Medco Madura Pty Limited, a subsidiary of Medco Energi.
"Medco Simenggaris"	means Medco Simenggaris Pty Ltd., a subsidiary of Medco Energi.
"MEGS"	means PT Mitra Energi Gas Sumatera
"MEM"	means PT Medco Energi Menamas.
"Menamas"	means PT Menamas.
"MGI"	means PT Medco Gas Indonesia.
"Ministry"	means Ministry of Energy and Natural Resources, Indonesia.

"MIV"	means Medco International Ventures Ltd.
"MTN"	means medium term notes.
"Non-Bank Corporations"	has the same meaning as set forth in the No. 16/22/PBI/2014 regarding the Reporting of Foreign Exchange Activity and Reporting of Application of Prudential Principles in Relation to an Offshore Loan Management for Non-Bank Corporation.
"OCBC"	means Overseas-Chinese Banking Corporation.
"Offshore Debt Plan"	has the same meaning as set forth in the No. 16/22/PBI/2014 regarding the Reporting of Foreign Exchange Activity and Reporting of Application of Prudential Principles in Relation to an Offshore Loan Management for Non-Bank Corporation.
"OHSAS"	means Occupational Health and Safety Assessment Series.
"Oil and Gas Law"	refers to the new oil and gas law enacted on November 23, 2001 by the Government.
"OPEC"	means the Organization of Petroleum Exporting Countries.
"O&M"	means Operations and maintenance.
"Pertamina"	means Perusahaan Pertambangan Minyak Dan Gas Bumi Negara, the Indonesian state-owned oil and gas company.
"PGN"	means PT Perusahaan Gas Negara (Persero) Tbk.
"PJB"	means PT Pembangkitan Jawa-Bali.
"PLN"	means PT Perusahaan Listrik Negara (Persero).
"PLN-E"	means PT Prima Layanan Nasional Enjiniring.
"PLN WS2JB"	means PT PLN (Persero) Wilayah Sumetera Selatan Jambi dan Bengkulu.
"PSAK"	means *Pernyataan Standar Akuntansi Keuangan* or Indonesian Statement of Financial Accounting Standards
"Rimau PSC"	means the PSC between Pertamina and PT Stanvac Indonesia dated April 23, 1973, as may be amended from time to time, and the renewal and extension PSC between Pertamina, Exspand Airsenda Inc. and Exspan Airlimau Inc. dated December 7, 2001 that became effective as of April 23, 2003, as may be amended from time to time.
"Rp." or "Rupiah"	means Indonesian Rupiah.
"SCB"	means Standard Chartered Bank.

"Senoro-Toili JOB-PSC"	means the PSC between Pertamina and Union Texas Tomori, Inc dated December 4, 1997, as may be amended from time to time.
"SGD Bonds"	means the S$100.0 million 5.90% Notes due 2018 issued by Medco Energi Global Pte. Ltd. under the S$500.0 million Multicurrency Medium Term Note Programme unconditionally and irrevocably guaranteed by Medco Energi.
"SIBOR"	means the Singapore Interbank Offering Rate.
"Simenggaris JOB-PSC"	means the PSC between Pertamina and Genindo Western Petroleum Pty. Ltd. dated February 24, 1998, as may be amended from time to time.
"South Natuna Sea Block B PSC"	means the PSC between Pertamina and Conoco Indonesia Inc., Texaco Block B South Natuna Sea Inc, Chevron International Ltd. and Inpex Natuna Ltd. dated August 3, 1990, signed on October 16, 1968, as may be amended from time to time, and the renewal and extension PSC between Pertamina and Conoco Indonesia Inc., Texaco Block B South Natuna Sea Inc, and Inpex Natuna Ltd. dated January 15, 1999 that became effective as of October 16, 2018 as may be amended from time to time.
"South Sokang PSC"	means the PSC between BP MIgas and Medco South Sokang BV dated December 17, 2010, as may be amended from time to time.
"South Sumatera Block PSC"	means the PSC between Pertamina and PT Stanvac Indonesia dated July 6, 1989 that became effective as of November 28, 1993, as may be amended from time to time, and the renewal and extension PSC between BP Migas and PT Medco E&P Indonesia dated October 28, 2010, as may be amended from time to time.
"SPE"	means the Society of Petroleum Engineers.
"Tarakan PSC"	is the production sharing contract between Pertamina and Tesoro Tarakan dated January 14, 1982, as may be amended from time to time, and the renewal and extension production sharing contract between Pertamina and PT Medco E&P Tarakan (formerly PT Exspan Tarakan) dated December 7, 2001, as may be amended from time to time.
"U.S. GAAP"	means generally accepted accounting principles in the United States, which is the accounting standards adopted by the United States Securities and Exchange Commission
"U.S."	means the United States of America.
"US$"	means United States dollars.
"United States"	means the United States of America.
"VAT"	means value-added tax.
"YPU PLN"	means Yayasan Pendidikan dan Kesejahteraan PT PLN (Persero)

"WNTS"	means the West Natuna Transportation System.
"Wood Mackenzie"	means Wood MacKenzie Ltd., an international energy research and consulting company.
"YPK PLN"	means Yayasan Pendidikan dan Kesejahteraan PLN.

Oil and Gas Terms

"Brent price"	means Brent crude oil price.
"contract area"	means a specified geographic area that is the subject of a production sharing arrangement pursuant to which an operator and its partners provide financing and technical expertise to conduct exploration, development and production operations.
"delineation well" or "appraisal well"	means a well drilled in a newly discovered or known discovery to gain further information.
"development well"	means a well that is drilled to exploit the hydrocarbon accumulation defined by an appraisal or delineation well.
"DMO"	means domestic market obligations.
"dry well" or "dry hole"	is an exploratory, development or appraisal well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
"EPSA"	means Exploration and Production Sharing Agreement.
"exploration well"	means a well that is designed to test the validity of a seismic interpretation and to confirm the presence of hydrocarbons in an undrilled formation.
"FTP"	means first tranche petroleum.
"gross working interest production"	represents the sum of the oil and gas production from each of the Company's blocks multiplied by the effective interest in such block.
"gross working interest reserves"	represents reserves attributable to the Company's effective interest prior to deduction of Government take payable to the Government as owner of the reserves under the applicable contractual arrangement.
"ICP-SLC"	means the Indonesian Crude Price-Sumatra Light Crude/Minas, a reference price calculated using a formula determined by the Government.
"Indonesian participant"	means an Indonesian entity which must be offered a certain specified percentage undivided interest in the total rights and obligations under a production sharing arrangement.
"JOB"	means Joint Operating Body.

"KOGAS"	means Korea Gas Corporation.
"lead"	means preliminary interpretation of geological and geophysical information that may or may not lead to prospects.
"lifting cost" or "production cost"	means, for a given period, cost incurred to operate and maintain wells and related equipment and facilities.
"LNG"	means liquefied natural gas.
"LPG"	means liquefied petroleum gas.
"Net production" or "net entitlement"	represents the Company's share of gross working interest production after deducting the share payable to the Government pursuant to the terms of the relevant production sharing arrangement.
"Net reserves"	represents reserves attributable to the Company's effective interest, after deduction of Government take payable to the Government as owner of the reserves under the applicable contractual arrangement.
"Petronas"	means Petroliam Nasional Berhad.
"Platts"	means S&P Global Platts.
"Proved plus probable reserves"	are proved reserves plus those reserves that are unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable.
"Proved reserves"	represents those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and Government regulations.
"PSC"	means Production Sharing Contract.
"RIM"	means RIM Intelligence Co.
"SembCorp"	means SembCorp Industries.
"Sembgas"	means SembCorp Gas Pty. Ltd.
"TAC"	means Technical Assistance Contract.
"Upstream Regulation"	refers to the Government Regulation No. 35 of 2004 on October 14, 2004 with respect to Upstream Oil and Gas Business Activities.

Units of Measurement

"Bbls"	means barrels.
"BBTU"	means billion BTU.
"Bcf"	means billion cubic feet.

"BOE"	means barrels of oil equivalent; natural gas is converted to BOE using the ratio of one Bbls of crude oil in the range of 5.19 - 6.54 Mcf of natural gas.
"BOPD"	means barrels of oil production.
"BTU"	means British Thermal Unit, the standard measure of the heating value of natural gas.
"GW"	means gigawatt.
"GWh"	means gigawatt hour.
"KWh"	means kilowatt hour.
"MBbls/d"	means thousand barrels per day.
"MBOE/d"	means thousand barrels of oil equivalent per day.
"MBOPD"	means million barrels gross oil production.
"MBTU"	means thousand BTU.
"Mcf"	means thousand cubic feet.
"MMBbls"	means million barrels.
"MMBbls/d"	means million barrels per day.
"MMBOE"	means million barrels of oil equivalent.
"MMBTU"	means million BTU.
"MMBTUD"	means million BTU per day.
"MMSCFD"	means million standard cubic feet per day.
"MW"	means megawatts.
"Tcf"	means trillion cubic feet.