NATURAL GAS

Production

The GOI estimates Indonesian gas reserves at 158.3 trillion standard cubic feet (TSCF) or about 27 billion barrels of oil equivalent, of which 92.5 TSCF are proven and 65.8 TSCF are probable. This is equivalent to three times Indonesia's oil reserves and can supply the country for 50 years at current production rates. Over 71 percent of natural gas reserves are located offshore, with the largest reserves found off Natuna Island (33.3 percent), East Kalimantan (30.2 percent), Irian Jaya (15.1 percent), Aceh (6.8 percent) and South Sumatra (6.4 percent). The discoveries by Arco, now BP, in the Wiriagar and Berau fields located offshore Irian Jaya represent some of Indonesia's most promising recent finds.

Natural gas production grew slightly to 3.1 trillion cubic feet in 1999 from 3.0 trillion cubic feet (TCF) in 1998. Most potential gas producers increased gas production except ExxonMobil and Pertamina. ExxonMobil, the largest gas producer in Indonesia, lowered production by nearly 14 percent to 794 billion cubic feet (BCF) from its maturing Arun gas field in North Sumatra. Total Indonesie, a principal supplier of gas to the LNG, LPG and fertilizer plants in East Kalimantan, increased gas output by over 13 percent to 685 BCF. Total has announced plans to double its production to 1.5 TCF in 2000 after the Tunu North and Peciko fields come on line. Mobil and Total produced 26 percent and 22 percent respectively of total gas output. Natural gas production from Vico's Badak field in East Kalimantan was up 4.5 percent to 477 BCF. Vico is a major supplier of gas to the LNG plants in East Kalimantan. BP, the largest supplier of domestic gas after it acquired Arco, increased gas output from its fields offshore Java and Madura by nearly 80 percent to 298.3 BCF to meet the increasing demand for power generation, city gas and petrochemical plants. Unocal increased gas production from its fields in East Kalimantan by 13 percent to 163 BCF to supply the Bontang LNG plant. Gulf Resources increased gas output from its field in Sumatra and West Natuna Sea by 176 percent to 166 BCF. Caltex also increased its gas production by 20 percent to 68.3 BCF, which was entirely used for its power production and steam flood operations.

Natural Gas Production by Major Producers (MMSCF)

Producers	1998	1999	% total
Mobil Oil	921,865	794,299	25.9
Total Ind.	604,447	684,565	22.3
Vico	456,954	477,368	15.6
Arco	165,937	298,327	9.7
Pertamina	270,330	259,132	8.4
Gulf Res.	75,076	166,449	5.4
Unocal	143,764	162,903	5.3
Others	340,479	225,306	7
Total	**2,978,852**	**3,068,349**	**100.0**

Source: MIGAS

Roughly 60 percent of the natural gas was marketed as LNG or liquefied petroleum gas (LPG) for export, 7.9 percent for electricity, 7.0 percent for fertilizer and 1.6 percent for city gas. Less than 6.0 percent of Indonesian natural gas is flared.

Before the economic crisis, the GOI had stated its intention to increase the use of natural gas to provide Indonesians with a clean energy source and conserve crude oil and other petroleum products for export. The greatest obstacle to increasing supplies to the domestic market has been the price to producers. While the price must rise to make supplying gas profitable, the Government argues that it should be low enough to induce industries to convert to gas.

A total of 22 wildcat and appraisal gas wells were drilled in 1999. Oil companies, however, do not actively explore for gas in Indonesia, due to disincentives in the pricing for domestic gas. Rather, as the ratio of gas to oil accumulations is high in Indonesia, most gas fields have been discovered during oil exploration.

With more competitive fiscal terms and a market-based pricing system, there would be an incentive to exploit more of Indonesia's natural gas reserves. Four key areas have been identified by the private sector to increase gas development in Indonesia:

- increase incentives to find and produce natural gas;
- promote private investment and ownership, as well as stability and cost recovery for those firms that invest in major gas facilities;
- encourage multi-buyer and multi-seller gas marketing; and
- establish incentives for domestic gas usage.

Peciko Gas Field Commenced Production

In April 2000, the Government officially inaugurated the operation of the first stage of the Peciko gas field development project, located offshore East Kalimantan. Developed over ten years with a US$560 million investment. the Peciko gas field entered the production stage in December 1999. It will allow Total Indonesie to be the largest gas supplier for LNG/LPG plants and to supplant ExxonMobil as Indonesia's largest gas producer.

Gas reserves at Peciko field combined with even larger reserves at the nearby Tunu field to bring certified proven commercial gas reserves in the Mahakam block to 24.4 TCF, an increase of 19.5 TCF or around 3.5 billion barrels of oil equivalent. Total, with 50 percent interest, is the operator under a PSC in partnership with Inpex of Japan. Production at Peciko started at a rate of around 100 million MMSCF/D and is expected to reach 400 MMSCF/D and to 800 MMSCF/D in 2000. Peciko field will increase Total's daily production to more than 470 MBOE in 2000. At that time the company will supply nearly 60 percent of the Bontang LNG plant's requirements.

Phase IV of Total's Tunu Development Project, which produces and delivers gas to the eighth gas liquefaction train (train "H") at Bontang, was completed in mid-1998.

Other Gas Discoveries and Projects

Makassar Strait

ExxonMobil and Unocal announced on July 30, 1998 that additional oil and gas discovered in the deepwater Merah Besar area, offshore East Kalimantan, will be ready for production by 2001, with oil and gas reserves estimated to be between 100 and 250 million barrels-of-oil-equivalent.

In late 2000, affiliates of ExxonMobil sold a 50-percent working interest in the Makassar Strait PSC and a 30-percent interest in the Rapak Block, which is located to the north of and adjacent to the Makassar Strait PSC, back to Unocal. In May 1999, UK firm Lasmo “farmed in” on the Rapak Block (10 percent). Unocal now has 100-percent ownership of the Makassar Strait PSC and 90-percent of the Rapak Block.

Tangguh

This year saw the coming together of some of the largest players in Indonesia's energy industry: BP Amoco, ARCO, and Castrol. With the BP Amoco and ARCO merger finalized in April and the integration of Castrol three months later, the new "BP" launched its new brand in July 2000. BP is one of the largest foreign investors in Indonesia, and the largest supplier to the Java gas market.

BP's largest project in Indonesia is Tangguh, a world-class LNG project in Papua with proven natural gas reserves of 14.4 TCF and additional probable reserves of 3.9 TCF. The Tangguh LNG project consists of three PSC blocks: Wiriagar, Berau, and Muturi. BP (80 percent) and Kanematsu (20 percent) jointly own Wiriagar. Berau is 48-percent owned by BP, 17.1-percent by Nippon Oil, 12-percent by Kanematsu and 22.9-percent by Occidental Petroleum. BG Exploration and Production holds a 50-percent stake in the Muturi Block; Cairns Ltd., a subsidiary of Malaysia’s Genting Bhd, holds 45 percent; and Nisho Iwai holds the remaining five percent.

BP also has 100 percent working interest in Terang-Sirasun, a one TSCF project in the existing Kangean PSC. The project is expected to begin production in 2004-05.

East Natuna

The Natuna AL gas field (located in the Natuna D-Alpha Block) was discovered in 1973. Its size and location make it a strategic resource for the region. Situated in the Natuna Sea approximately 225 km northeast of Natuna Island, the Natuna AL field is estimated to contain 222 TCF of gas, with an estimated 46 TCF of recoverable hydrocarbon gas. A reserve the size of Natuna will likely be developed in stages to match the demand requirements of gas markets. The phased development of Natuna may ultimately provide sales as pipeline gas or LNG or both. The long term sales target for Natuna is 2,400 MMCF/D or the equivalent of 15.0 MMT of LNG per year, for approximately 40 years.

There are several markets that can be economically reached by pipeline from Natuna: Singapore, Thailand, South China and Java. The Natuna PSC is also looking at traditional LNG markets such as Japan, South Korea, and Taiwan. Natuna was envisioned as an LNG project through the mid-1990’s. Pipeline sales options were assessed from 1997. Thailand and Java were the focus before the regional economic crisis.

The PSC composition consists of ExxonMobil affiliates as operator (76 percent) and Pertamina (24 percent).

The project can be implemented upon market readiness. The reserves are ready to be certified and a detailed development plan has been established. One possible development plan includes initial pipeline gas sales of about 1.0 billion cubic feet per day (BCF/D) of methane for more than 30 years. It includes offshore CO2 separation and CO2 underground disposal as well as floating barges for processing equipment.

There are currently several international pipelines already built or being built by countries such as Malaysia, Thailand, Singapore and Indonesia. In the future and as dictated by the market, the Natuna field could be the main source of supply to the region. The main pipeline from the field to markets would be a key element of the evolving Asian gas pipeline network.

West Natuna Gas Projects

In January 1999, a gas sales agreement and other associated agreements were signed by Pertamina, Singapore-based Sembawang Gas (SembGas) and the West Natuna Group, which includes Conoco of the United States, Canada's Gulf Indonesia Resources and Britain's Premier Oil. The West Natuna Group earlier signed a natural gas supply agreement (GSA) to deliver 325 MMCF/D for 22 years from Indonesia to Singapore (Jurong Island) via a 650-kilometer sub-sea pipeline, with first deliveries scheduled for mid-2001. The GSA is the first of its kind for Indonesia, which traditionally exports gas in the form of LNG. The gas will be used by power generating companies and petroleum and petrochemical plants. Revenues from the gas sales are projected to reach $8 billion over the life of the contract.

The natural gas will be supplied from several fields in West Natuna, which contain an estimated 2.75 TCF, under three PSCs between Pertamina and its operating partners Conoco, Gulf Indonesia Resources and Premier.

In a further development, Pertamina and Malaysian national oil company Petronas signed an agreement in October 2000 for the supply of natural gas from the West Natuna Sea as part of the ASEAN gas grid. Pertamina agreed to supply a total of 1.5 TCF of natural gas to Petronas for 20 years from the B block operated by Conoco. First gas deliveries are expected to commence in July 2002 at 100 million cubic feet per day (MMSCFD), reaching 250 MMSCFD in 2004. Revenues from the gas sales are projected to reach $6.2 billion over the life of the contract. Pertamina and its PSC partners plan to invest $3.5 billion to build production and underwater pipeline facilities. Pertamina expects to sign a second agreement with Petronas for an additional 1.0 TCF of natural gas.

South Sumatra Gas Projects

In September 1999, Devon Energy Corporation subsidiary Santa Fe Energy Resources Jabung signed a Gas Sales and Purchase Letter Agreement for the 20-year sale of natural gas with Pertamina and PowerGas Ltd., a subsidiary of Singapore Power, a Singapore electric and gas utility company.

According to the soon-to-be-signed Gas Sales Agreement, 2.36 trillion cubic feet of natural gas reserves in the PSCs operated by Santa Fe and Gulf Indonesia will be developed for sale to PowerGas Ltd. First deliveries of gas are expected to commence in mid-2003 at 150 million cubic feet per day (MMSCFD) increasing to 350 MMSCFD by 2009. Santa Fe-operated Jabung Block PSC will supply 45 percent of the natural gas for the first 250 MMSCFD of total contract deliveries for the life of the Agreement and 25 percent of the natural gas above 250 MMSCFD.

The deal is subject to the signing of sales and transportation agreements, followed by Indonesia state gas pipeline company PGN's construction of a pipeline to transport the gas from South Sumatra to Singapore via Batam Island, Indonesia. Financing for the construction of the pipeline has been arranged with the Asian Development Bank. PGN, Pertamina and the PSC operators initialed a Gas Transportation Letter Agreement on March 9, 1999. The Transportation Letter Agreement sets forth the methodology to be used to calculate the pipeline tariffs upon finalization of the pipeline cost and based upon the exported gas volume. Final sales and transportation agreements are expected to be signed in the fourth quarter of 2000.

The project is a part of a US $590 million project for construction of an 850-kilometer gas transmission pipeline. Phase one of the pipeline goes from Corridor Block/Gulf Canadian Indonesian Resources Ltd., South Sumatra to Duri. A consortium of five companies led by Mannesmann of Germany completed the construction work.

The 544-kilometer gas transmission pipeline project will transport 310 MMSCFD of natural gas from Grissik, South Sumatra to Duri in Central Sumatra. The project will supply natural gas for Caltex's Duri Steam Flood Project for 15 years.

In March 1998, Nova Gas International Ltd. (NGI), a Canadian company, signed a two-year working contract valued at US $2.26 million with PGN. The contract covers 544 km of gas pipeline operation and maintenance and related services.

For the second phase, a parallel pipeline will go from Grissik to Sakernan (South Jambi B Block PSC) and will pass through Jabung Block/Santa Fe Energy Resources on the way to Batam Island and Singapore. The pipeline should begin operations 30 months after the final contract is signed.

Timor Gap

In October 19, 1999, the People's Consultative Committee repealed its 1978 decree incorporating East Timor into Indonesia. This decision followed an August 1999 UN-sponsored referendum in which the majority of people in East Timor decided in favor of independence from Indonesia. The decree's repeal introduced uncertainty over the status of a bilateral agreement between Indonesia and Australia on exploration of the hydrocarbon resources in the Timor Gap Zone of Cooperation. The Timor Gap area lies south of the deep-water Timor trough and covers some 35,000 square kilometers of the Timor Sea between northern Australia and the island of Timor.

On February 28, 2000, the United Nations announced that Australia and East Timor had signed a "development contract" to jointly exploit oil and gas from the Timor Gas offshore area between Australia and Timor island. The contract to develop the Phillips Petroleum-operated Bayu Undan oil and gas field was signed in Perth. The gas development agreement called for Phillips to invest US $1.4 billion in the first stage of a gas recovery project during which liquid petroleum gas (LPG) and condensate from the field will be removed and processed. The second phase calls for construction of a natural gas pipeline to Darwin. The agreement expires when East Timor achieves independence.

Australian officials traveled to Dili for a first round of negotiations from October 9-11, 2000 on future arrangements for the exploration and exploitation in the Timor Gap. Australia, the UN Transitional Administration in East Timor, and East Timorese representatives seek to reach agreement on a replacement treaty for the Timor Gap to enter into force on East Timor's independence. The new treaty would avoid a legal vacuum upon East Timor's independence and provide commercial certainty for the petroleum industry in the Timor Gap.

Domestic Gas Usage

The World Bank and the Asian Development Bank (ADB) have urged Indonesia to adopt a pricing regime more conducive to providing companies with an incentive to find and produce gas. If gas were able to compete on price with alternative energy forms in the market place, the full value and potential of Indonesia's gas reserves would be realized. Without pricing changes, the domestic gas market is constrained by the economic terms for development, which do not provide exploration incentives, and producers are offered few incentives to develop gas fields too small to support LNG but large enough for domestic gas supplies. A second, major constraint is the absence of a predictable basis for forecasting the future value of gas, such as an indexed price formula. A final constraint has been the subsidy provided for alternative fuels.

Domestic Gas Pricing (Per MMBTU)	
I. FUEL	
1. Fertilizer Plant	\$1.00 – 2.00
2. Steel Industry	\$2.00
3. Electricity	\$2.45 - 3.00
4. Cement Industry	\$2.70 - 3.00
5. Paper Industry	\$1.30
6. Refinery	\$1.49
7. Plywood	\$0.97
8. City Gas	Rp 2,500 - 4,150
II. FEEDSTOCK	
1. Fertilizer	\$1.00 – 2.00
2. Steel Industries	\$0.65
3. Methanol Plant	\$1.42 – 2.00

Under the current system for determining gas prices, price in supply contracts is reached through negotiations on a field-by-field basis between Pertamina and individual producers after the discovery of the gas field. Prices are fixed for a designated supply for the duration of the contract. Hence, the producer price for gas is different for each PSC. Consumer prices are set on a cost-plus basis.

Domestic Gas Initiative

In October 1999, the outgoing Minister of Mines and Energy signed a ministerial decree on a new gas policy for Indonesia that aims to reduce the Government's profit share in natural gas contracts to promote the development of the country's natural gas fields and the domestic use of natural gas. In return, producers are expected to sell gas to consumers at lower prices.

The new policy followed a workshop on a new domestic gas policy held in March 1999. The intent of the workshop, attended by international organizations and private companies, was to develop a strategy for meeting natural gas demand. The GOI is rethinking the role natural gas should play in Indonesia's energy mix in response to stepped up global competition and Indonesian obligations undertaken within the AFTA framework. By the year 2003, Indonesia has committed to open sectors of its economy to the business efforts of its AFTA partners. The rationale for the expansion of natural gas is that gas has lower economic costs than alternative fuels in a number of applications, particularly power generation. For Indonesia to maintain and benefit from the comparative advantage it currently has in oil and gas resources, it must become a competitive producer and marketer as well.

Indonesia has significant gas reserves but much of the gas in non-exportable. There is also a geographical mismatch between location of gas reserves and energy demand location. In addition to geographical constraints, the workshop participants identified other disincentives to developing Indonesia's gas resources, including unattractive fiscal terms, long project lead time, and the lack of incentives to explore and exploit gas reserves. To address these problems, the GOI has proposed to accelerate the time it takes to discover and produce gas by instituting direct buyer/seller negotiations and by reducing red tape. The GOI has also proposed a reduction of its share in gas production sharing contracts.

Until now, Indonesia has focused on exploiting its gas resources in the form of LNG. A substantial portion of Indonesia's gas resources, however, are too remote from liquefaction facilities and/or too small to provide the basis for stand-alone LNG operations. Moreover, recent discoveries and expectations of further discoveries raise the possibility that Indonesia's total resources may exceed any realistic LNG sales target even with an all-out marketing effort. In addition, Indonesia needs to meet growing energy demand at home.

In June 1999, the U.S. Trade and Development Agency (TDA) approved funding of $302,400 to provide assistance to the GOI to develop a Natural Gas Development and Procurement Plan. The objectives of the Plan are to identify investment opportunities for using domestic non-exportable natural gas, and assist in the development of natural gas distribution and transmission infrastructure in West Java and South Sumatra. This project is ongoing.

Electricity Projects

Electric power plants, mainly operated by state electricity company Perusahaan Listrik Negara (PLN) Persero, are the largest consumers of domestic gas. A large percentage of industrial users, however, continue to rely on GOI-subsidized diesel fuel for electricity supply. Introduction of a market mechanism for setting prices and allocating supply would encourage greater use of gas, especially for electricity generation.

In September 1997, as part of the effort to reduce budgetary outlays and contain the current account deficit, the GOI released Presidential Decree (PD) No. 39 listing projects being undertaken by or in conjunction with state-owned entities, including state electricity company PLN. The projects were divided into three categories: continued, postponed or under review. Under PD 39, the GOI postponed or placed under review 16 of the 26 independent power producer (IPP) private power projects. Of the ten power projects allowed to continue, only one gas-fired project, PT Energi Sengkang, was allowed to move forward.

PT Energi Sengkang (U.S. El Paso International, Australian Energy Equity and PT Trihasra Sarana Jaya Purnama) constructed a 135 megawatt combined-cycle gas plant in South Sulawesi which is currently generating power into PLN's South Sulawesi grid. Five other combined-cycle gas projects remain postponed -- Palembang Timur in South Sumatra; Pasuruan in East Java; Samarinda in East Kalimantan; Serpong in West Java; and Batakan in East Kalimantan.

In a related development, Arco (now BP) and Pertamina signed a Memorandum of Understanding on June 26, 1999 with PGN to supply 80-115 MMSCF/D of natural gas to PLN's 2X505 MW combined-cycle power plant at Tambak Lorok in Central Java. The gas will be supplied from BP's Kepondang Muriah gas field in Central Java, which has recoverable natural gas reserves of 600 BSCF over the life of the project. BP agreed to supply the gas for 15 years starting in 2003 when PLN will have converted the Tambak Lorok plant from diesel fuel to natural gas.

Pipeline Projects

State gas company Perusahaan Gas Negara (PGN) is moving forward on an integrated gas transmission pipeline system, known as the Integrated Transmission System (ITS). The first phase to be completed was the Grissik/Duri pipeline. The second, the Grissik/Batam portion, which had been delayed due to the financial crisis, is expected to move forward in late 2000 or early 2001. The ITS is scheduled (in four parts) to eventually link the islands of Sumatra, Java and Kalimantan via a 3,588-kilometer integrated gas pipeline. Reputed to be Southeast Asia's longest, the pipeline is being partially funded by the World Bank, ADB and other institutions. Scheduled to be completed in 2010, PGN's network will flow 2.2 BCFD of natural gas.

PART ONE: GRISSIK/DURI PIPELINE: With a total cost of US $231.7 million, phase one became operational in October 1998. The 544-kilometer Grissik/Duri gas transmission pipeline transports 310 MMSCF/D of natural gas from Gulf Indonesia Resources' fields in South Sumatra, known as the "Corridor Block," to Caltex's Duri field in Central Sumatra. Gulf Indonesia Resources is the gas producer, Caltex is the gas buyer and PGN is the owner of the pipeline network. The Grissik/Duri pipeline project is the first part of a 850-kilometer gas transmission pipeline to link South Sumatra to Singapore. Phase two, which covers the 330-kilometer Sakernan (Jambi) to Singapore leg by way of Batam Island, will be developed at the end of 2000 or early 2001. The $246 million project will transport about 300 MMSCF/D of natural gas to Batam and Singapore. Phase three, the 150-kilometer looping line from Grissik to Sakernan, is projected to cost close to $100 million. (See also "South Sumatra Gas Projects," pages 26-27.)

PROJECT II: SOUTH SUMATRA–WEST JAVA PIPELINE: The first phase is the 174-kilometer West Java distribution pipeline; the second is the 370-kilometer Pagardewa (South Sumatra) to Cilegon (West Java); and the third is the 180-kilometer pipeline from Gulf Indonesia Resources' contract area in South Sumatra to Pagardewa. The project is in the study phase.

PROJECT III: EAST KALIMANTAN-JAVA: The most ambitious of the four projects, the 1,100-kilometer East Kalimantan-Java pipeline includes: phase one, the 600-kilometer Samarinda (Bontang)-Balikpapan-Banjarmasin (South Kalimantan) pipeline; and phase two, the 500-kilometer Banjarmasin-Surabaya (East Java) pipeline. The project will transport about 700 MMSCF/D of natural gas. PGN plans to begin the project in 2005.

PROJECT IV: EAST/WEST JAVA: This project consists of two phases, the 292-kilometer Cirebon (West Java) to Semarang (Central Java) pipeline and the 388-kilometer Semarang to Surabaya link. The project will transport about 700 MMSCF/D of natural gas and is projected for implementation in the 2004-2007 timeframe.