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1.1 INTRODUCTION

Pendawa USA has been retained by PT. Perusahaan Gas Negara (Persero) Tbk. (PGN) for the Small-to-Medium Scale (SMS) Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Distribution Study, which encompasses an assessment of the market for and economic viability of Small-to-Medium Scale (SMS) CNG and LNG use in gas transmission/distribution infrastructure deficient markets in place of oil based fuels (OBF), a technical and economic feasibility study of the optimal CNG/LNG supply chain to selected markets, an estimation of the pace of market capture, a determination of the economic and environmental benefits of replacing OBFs with CNG/LNG, an implementation plan for projected domestic CNG/LNG usage and identification of the associated U.S. export potential.

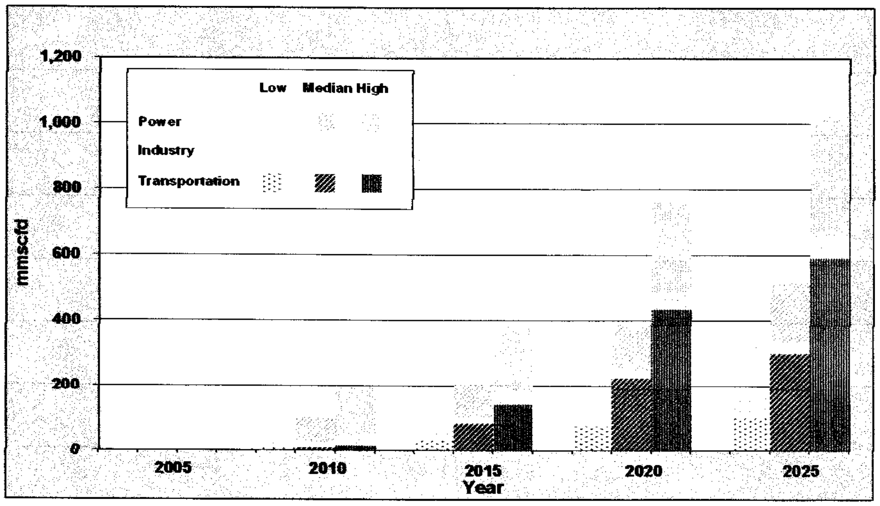
This Final Report follows from the Inception Report and Interim Reports #1 and #2 and reports the outcomes of all 17 tasks set out in the terms of reference of the Study.

1.2 OBF MARKETS

The potential for replacement of OBFs by CNG/LNG is confined to the small scale electric power generation, industrial and transportation markets.

Assuming 10, 25 and 50% CNG/LNG penetration of identified OBF markets not already served by pipeline gas, Figure 1.1 below shows potential nationwide OBF replacement by CNG/LNG ranging from 44-197 mmscfd by 2010 rising to 188-1,027 MMCFED by 2025. Small scale power generation constitutes 75% of the potential OBF market capture by 2010, while transportation (natural gas vehicles) accounts for 55% of a quintupled, potential market by 2025.

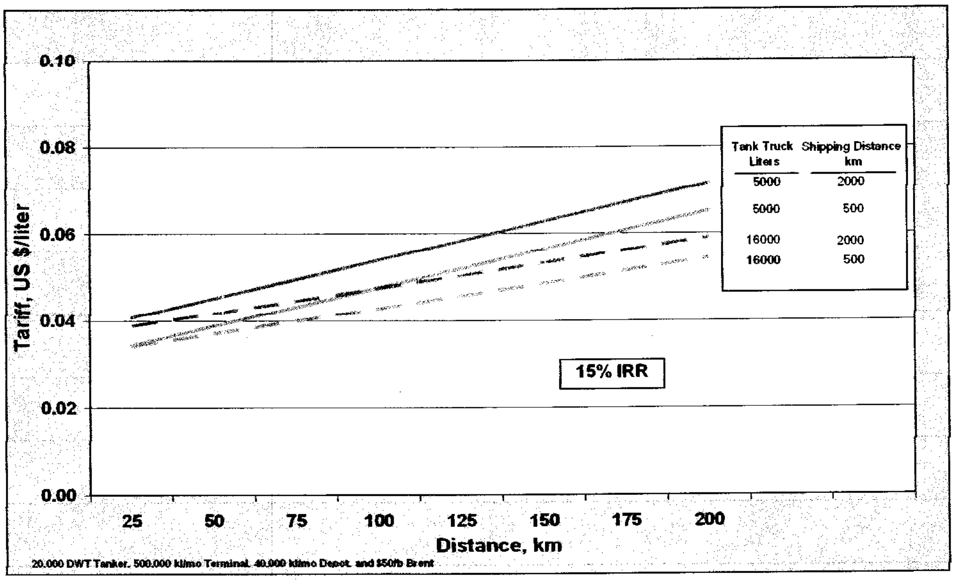
Figure 1.1 Potential Nationwide Replacement of OBF by CNG/LNG



1.3 OBF COST OF DELIVERY

The Study team developed a general model for determining the cost of OBF products shipping/storage/distribution as functions of refinery-to-retail distance and volume for use in subsequent determinations of the overall cost of OBF supply to remote markets. Figure 1.2 shows the correlation between OBF delivery tariffs, distance and volume for a 15% investor's rate of return. The correlation shows delivery costs ranging from about US$0.04-0.06 per liter.

Figure 1.2 OBF Product Delivery Costs



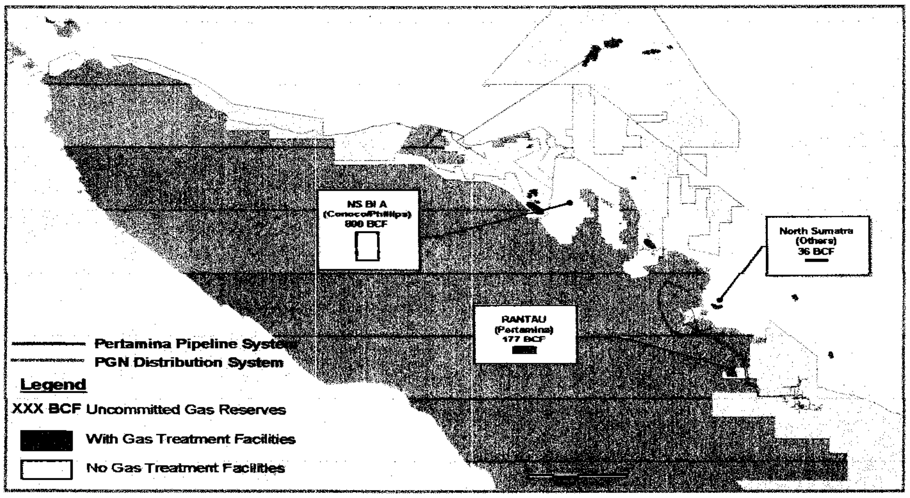
1.4 SOURCES OF CNG/LNG FEED GAS SUPPLY

CNG/LNG feed gas quality, quantity and sourcing in Indonesia have been reviewed. While feed gas quality requirements are stringent, state-of-the-art industrial processes are available to reduce impurities to acceptable levels. In most instances, pipeline quality gas available at the producer boundary or at transmission/distribution network off-take points constitutes suitable sources of CNG/LNG feed gas.

Given the generally low volumes of CNG/LNG supply chains, the gas reserve requirements are low by Indonesian standards.

The locations of uncommitted gas reserves for potential use in CNG/LNG-based gas supply have been mapped throughout Indonesia. A sample map for the provinces of Aceh and Northern Sumatra is shown in Figure 1.3 .

Figure 1.3 Uncommitted Gas Reserves in Aceh and Northern Sumatra



1.5 SMS CNG/LNG SUPPLY MODES

Terrestrial SMS CNG/LNG supply systems are in widespread use throughout the world, while marine SMS LNG supply systems are embryonic and marine SMS CNG supply systems in the conceptual stage of development.

Diagrammatic sketches of typical terrestrial SMS CNG and LNG supply chains are shown in Figures 1.4 and 1.5 below.

The main drawback of the CNG supply chain is the weight of the cylindrical storage/transport vessels carrying compressed gas at pressures of up to 3,600 psia. Hence, current development efforts are aimed at lowering cylinder weight by replacing steel with high-strength composite materials, thereby increasing the gas carrying capacity of axle-load limited truck-trailer transportation. The estimated gas carrying gains are illustrated in Table 1.1 below, although composite high density polyethylene (HDPE) cylinders are not yet in production.

Figure 1.4 Terrestrial CNG Supply Chain

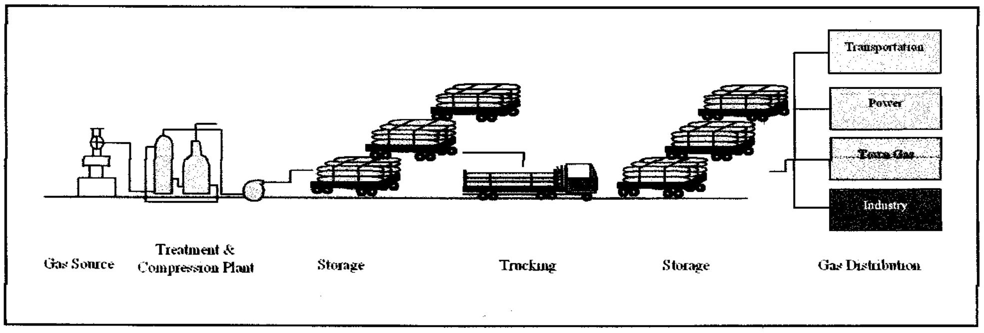


Figure 1.5 Terrestrial LNG Supply Chain

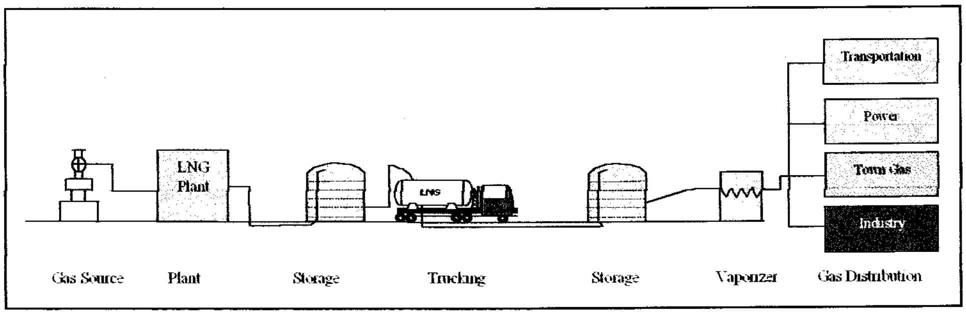


Table 1.1 CNG Cylinder Characteristics

Cylinder Type	Gas Pressure, psia	Total Weight, tonnes	Cylinder Weight, tonnes	Gas Weight, tonnes	Gas Volume, scf
All Steel	3600	30	26.4	3.6	172,500
Composite Steel/Carbon Fiber			24.8	5.2	247,600
Composite HDPE/Carbon-epoxy			22.5	7.5	359,000

1.6 CNG/LNG COST OF DELIVERY

Discounted cash flow based CNG/LNG/pipeline supply chain tariff models were developed correlating tariffs at a specified investor's rate of return with delivered volume and distance to market. Sample tariff correlations for terrestrial and marine CNG/LNG/pipeline gas supplies are presented in Figures 1.6 through 1.9 below.

Figure 1.6 Terrestrial CNG/LNG/PL Gas Supply Tariff vs Distance

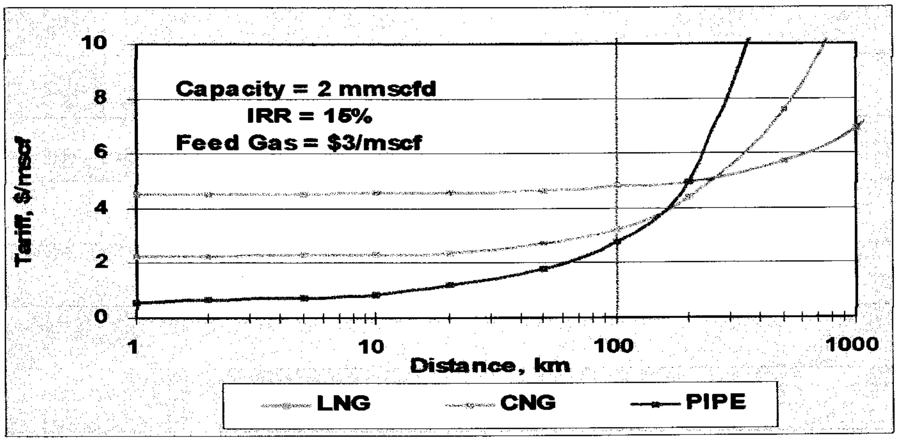


Figure 1.7 Terrestrial CNG/LNG/PL Gas Supply Tariff vs Volume

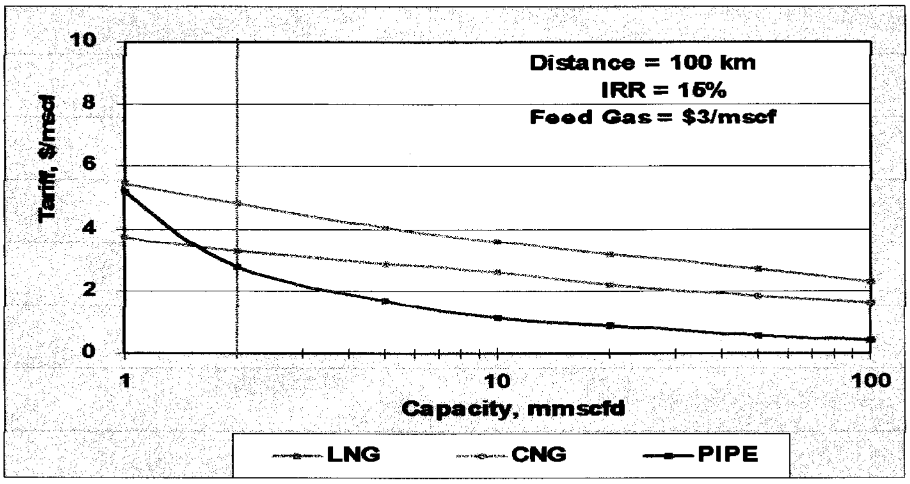


Figure 1.8 Marine CNG/LNG/PL Gas Supply Tariff vs Distance

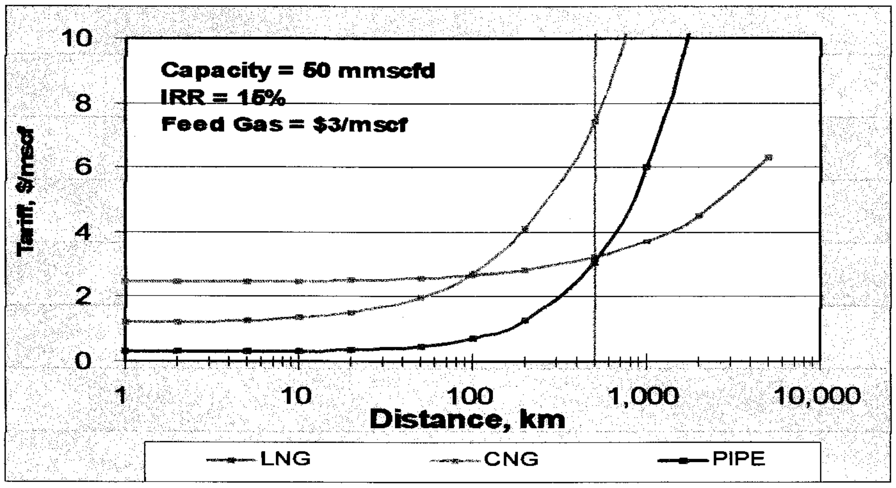
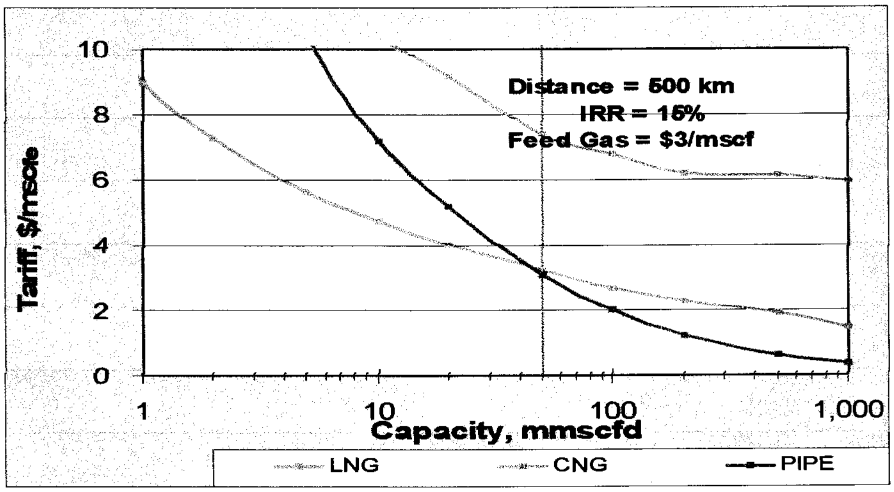
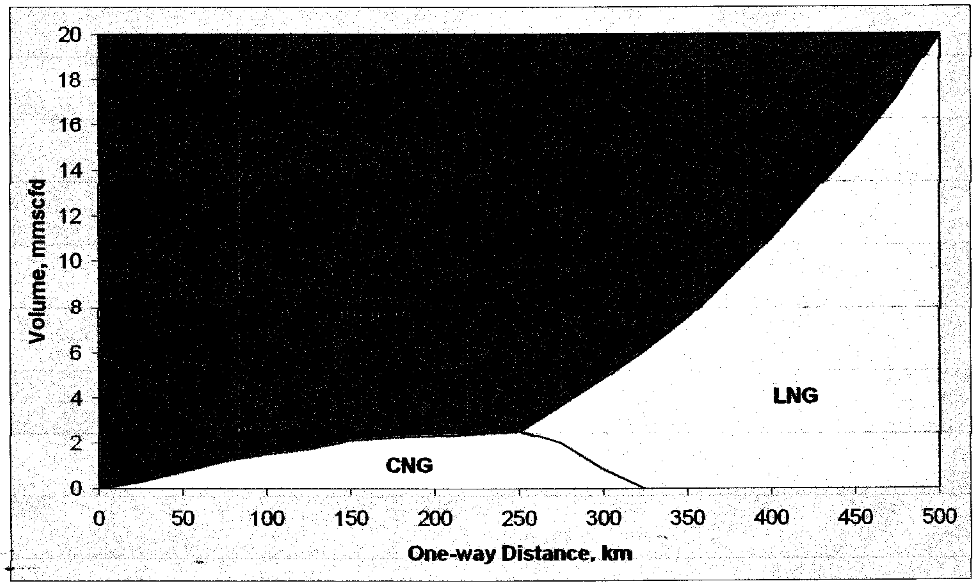


Figure 1.9 Marine CNG/LNG/PL Gas Supply Tariff vs Volume



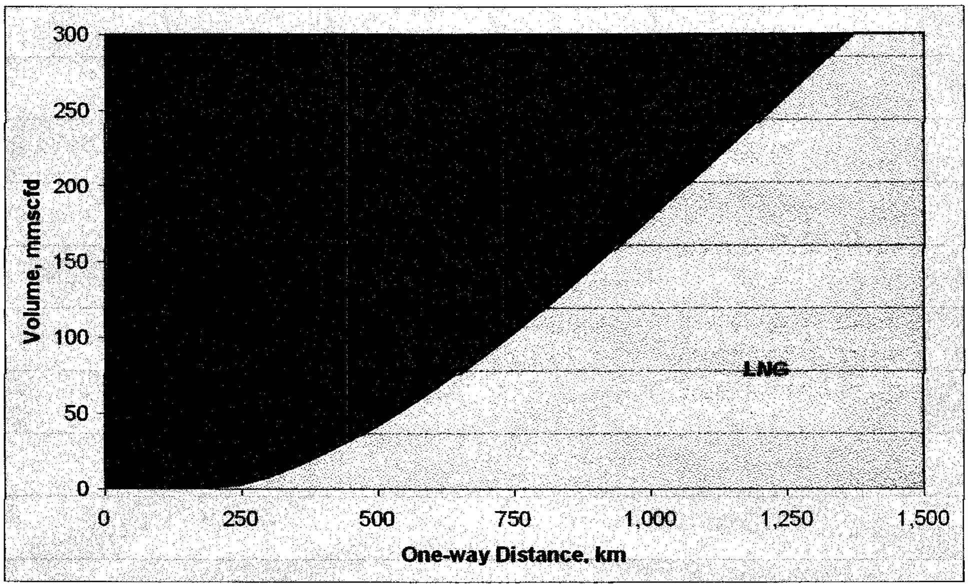
Using the CNG/LNG/pipeline tariff models developed in this project, lowest cost gas supply was determined for both terrestrial and marine transportation as functions of distance and volume. The results are shown in Figures 1.10 and 1.11 below.

Figure 1.10 Lowest Cost Terrestrial CNG/LNG/PL Gas Supply @ 15% IRR



CNG is the lowest cost terrestrial gas supply mode for volumes up to 2.5 mmscfd and distances up to 250 km. For larger volumes and longer distances, LNG and pipeline gas are the lowest cost modes of transportation.

Figure 1.11 Lowest Cost Marine CNG/LNG/PL Gas Supply @ 15% IRR



For one-way distances up to 250 km, pipeline gas is the lowest cost mode of gas transportation. Beyond 250 km, LNG becomes the lowest cost mode of marine gas transportation for low volumes, say up to 50 mmscfd for distances up to 500 km and up to 100 mmscfd for distances in excess of 750 km. CNG is not competitive for any combination of volume and distance due to low boat speed and high cost of gas storage.

1.7 TEFS OF MARINE CNG TRANSPORTATION

A technical and economic feasibility study (TEFS) of maritime CNG transportation was subcontracted to Enersea. Their estimates of costs of service (compression/storage/shipping/receiving) are shown in Table 1.2 below along with Enersea's estimates adjusted by the Study Team to reflect Indonesian conditions and generic transportation tariffs determined by the Marine CNG Supply Tariff model developed as part of this study.

Table 1.2 CNG Cost-of-Service Tariff Comparison, $/mscf

Mode	Volume	Distance	Enersea		This Study	
	mmscfd	km	Findings	Adjusted	15% IRR	20% IRR
Barge	15	56	2.33	3.21	2.58	3.19
	40	370	1.95	2.73	2.33	2.93
Ship	100	1,235	2.45	2.93	2.43	3.03
	200		1.90	2.34	1.95	2.45

Given the uncertainty of the required investor's rate of return, the Enersea results are reasonably bracketed by the model predictions of this Study suggesting marine CNG tariffs of $2.45-3.05 per mscf for low volume, short distance transportation declining to $2.20-2.75 per mscf for large volume, long distance delivery.

1.8 CNG/LNG COMPETITIVENESS IN OBF MARKETS

To ascertain economically viable market penetrations, gas netback values (NBV) in each potential OBF market were determined for underlying crude oil prices of $40, 60 and 80 per barrel and compared to the CNG/LNG cost of supply from nearest gas sources based on feed gas prices of $3, 4 and 5 per mmBtu. Tables 1.3 through 1.5 below illustrate the application of the methodology to selective electric power generating, industrial and transportation locations, respectively, supplied by either LNG or CNG.

Table 1.3 Competitiveness of CNG/LNG-in-Power in Selective Locations

Fuel	Region	From	To	Generating Technology	CF**	Volume	Gas NBV, $/mmBtu***			Cost of CNG/LNG Supply, $/mmBtu		
							Oil Price, $/B			Feed Gas Price, $/mmBtu		
				DE/TTOC*	%	mmscfd	40	60	80	3	4	5
LNG	Aceh	Arun	Banda Aceh	DE	55	7.07	7.84	12.07	16.31	5.33	6.41	7.49
		Arun	Meulaboh	DE	47	1.4	7.72	11.95	16.20	5.49	6.57	7.64
	Riau	Batam	P. Pinang	DE	59	9.93	8.07	12.32	16.55	7.89	9.11	10.34
		Batam	PP/Mentok	DE	47	0.78	7.72	11.95	16.20	8.76	9.98	11.21
	E.Java/Bali	Bontang	Gilimanuk	TTOC	11	37.3	9.54	14.04	18.56	5.74	6.85	7.97
		Bontang	Gilimanuk/ Pemaron	TTOC	21	7.64	9.28	13.79	18.30	6.37	7.48	8.60
	Kalimantan	Bontang	Pontianak	DE	50	9.51	7.77	12.00	16.24	7.18	8.33	9.49
		Bontang	Singkawang	DE	50	2.58	7.77	12.00	16.24	7.89	9.05	10.20
	Papua	Tangguh	Jayapura	DE	52	5.21	6.84	10.84	14.85	7.83	9.00	10.17
CNG	Jambi	Duri PL	Payo Selincah	DE	50	5.31	7.77	12.00	16.24	5.38	6.40	7.41
	Lampung	Bandar L	Tarahan	DE	50	8.86	7.77	12.00	16.24	5.16	6.18	7.19

* DE = Diesel Engine: TTOC = Turbine Technology Open Cycle
** Capacity Factor
*** 50/50 = Conversions/New Units

Economically viable $40/B and higher oil prices
Economically viable $60/B and higher oil prices
Economically viable $80/B and higher oil prices

Generally, CNG/LNG replacement of OBFs is economically justifiable in most small scale, electric power generation markets at an oil price of $40 per barrel (yellow cells), while some markets required an oil price of $60 per barrel (orange cells). Only a few small remote offshore markets require an oil price of $80 per barrel or more.

Table 1.4 Competitiveness of CNG-in-Industry in Selective Locations

Region	To	Fuel	Volume (mmscfd)			Gas NBV, $/mmBtu*			Cost of CNG/LNG Supply, $/mmBtu**		
						Oil Price, $/B			Feed Gas Price, $/mmBtu		
		CNG/LNG	Low	Med	High	40	60	80	3	4	5
W. Java	Bandung	CNG	1	1.5	2	11.03	15.87	20.72	8.34	8.92	9.73
	Sukabumi								9.04	9.64	10.48
	Majalengka								7.74	8.12	9.04
C. Java	Solo								7.79	8.50	9.47
	Kudus								7.21	8.08	8.78
	Yogyakarta								7.79	8.5	9.47
E. Java	Malang								7.64	8.48	9.15
	Jember								7.64	8.48	9.15
	Blitar								8.68	9.35	10.15

* 50/50 = Conversions/New Units
** Including a $1/mmBtu distribution tariff

Economically viable $40/B and higher oil prices

Replacement of OBFs by CNG/LNG is economically justified in all identified industrial markets at crude oil prices of $40 per barrel or higher, since the gas NBVs are considerable higher in industry than in small scale electric power generation.

Table 1.5 Competitiveness of CNG/LNG in Transportation, OEM NGV

Vehicle Type	Fuel Switch		Gas NBV, $/mmBtu			CNG/LNG COS, $/mmBtu		
			Crude Oil Price, $/B			Feed Gas Price, $/mmBtu		
	From	To	40	60	80	3	4	5
Large Bus	ADO	CNG	6.01	9.56	13.10	5.60	6.60	7.60
Metromini Bus			3.73	7.27	10.82	5.60	6.60	
Small Truck			-2.54	1.00	4.54	5.60	6.60	7.60
Medium Truck			1.52	5.06	8.60			
Large Truck			6.01	9.56	13.10	5.60	6.60	7.60
Small Truck	Gasoline		6.38	11.28	16.19	5.60	6.60	7.60
Taxi			8.41	13.32	18.22	5.60	6.60	7.60
Mikrolet			8.16	13.07	17.98	5.60	6.60	7.60
Large Bus	ADO	LNG	6.01	9.56	13.10	7.21	8.42	
Metromini Bus			3.91	7.46	11.00	7.21		
Small Truck			-0.99	2.55	6.10	7.21	8.42	9.63
Medium Truck			1.80	5.34	8.88			9.63
Large Truck			6.01	9.56	13.10	7.21	8.42	

Economically viable at $40/B or higher oil prices

Economically viable at $60/B or higher oil prices

Economically viable at $80/B or higher oil prices

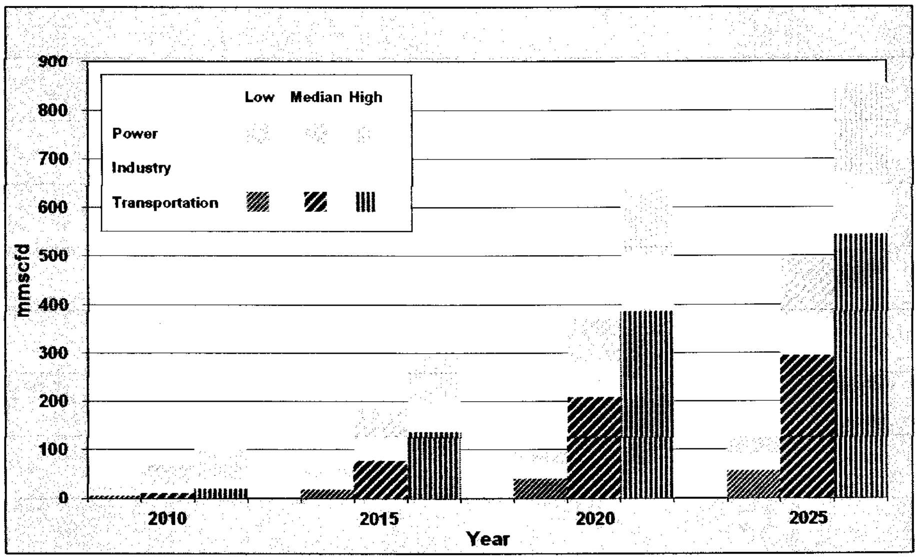
At $3 per mscf feed gas, 60% of the OEM NGV types require a $40 per barrel or higher oil price for CNG usage to be economically viable, while 12% require an oil price of $60 per barrel or higher and another 12% an oil price of $80 per barrel or higher. At $5 per mscf feed gas, 25% of the vehicle types require $40 per barrel or higher oil prices for CNG usage to be economically viable, while 37% require $60 per barrel or higher and 25% require $80 per barrel or higher oil prices. For LNG fueled OEM NGVs, 60% of the vehicle types require an oil price of $80 per barrel or higher, while the remaining vehicles types require oil prices in excess of $100 per barrel for economic viability.

1.9 OBF MARKET CAPTURE BY CNG/LNG

Projected replacements of OBFs by CNG/LNG in the small scale electric power generation, industrial and transportation sectors were determined based on gas netback value vs cost of CNG/LNG supply for three oil and feed gas price scenarios.

Figure 1.12 below shows projected OBF replacements to range from 29-101 mmscfd by 2010 growing to 125-853 mmscfd by 2025. The low end of the ranges reflects $40/B crude oil and $3/mmBtu CNG/LNG feed gas prices, while the high end of the ranges reflects $80/B crude oil and $5/mmBtu CNG/LNG feed gas prices.

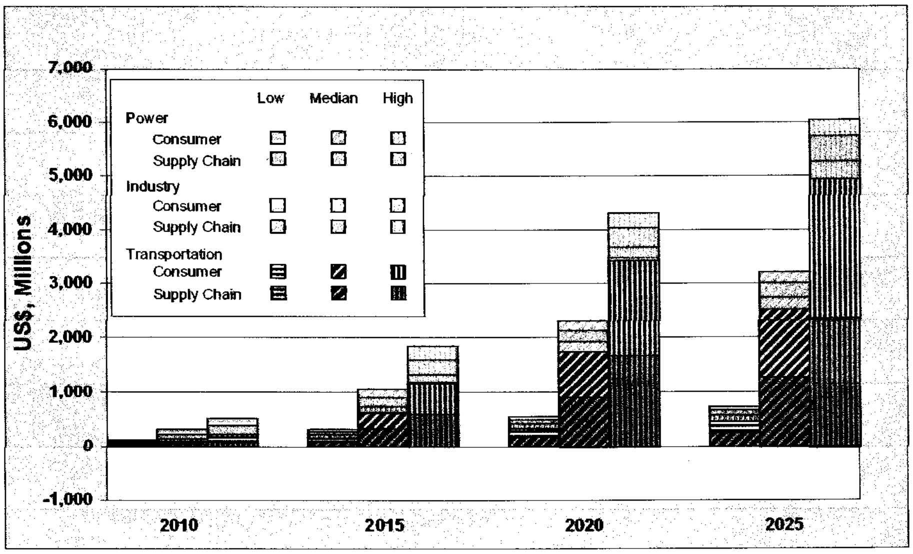
Figure 1.12 Projected CNG/LNG Replacements of OBFs, Indonesia



1.10 SWITCHING CAPITAL REQUIREMENTS

As highlighted in Figure 1.13 below, the cumulative incremental capital investments required to reach the projected levels of OBF replacement by CNG/LNG in small scale power generation, industry and transportation range from \$124-519 MM by 2010 growing to \$0.7-6 billion by 2025 depending on crude oil and CNG/LNG feed gas prices.

Figure 1.13 Cum. Incr. CNG/LNG Switching Capital Needs, Indonesia



In the Low scenario, 63% of the investments are projected to occur in or associated with the transportation sector, while the small scale power generation sector accounts for 21%. In the High scenario, the transportation sector investments grow to account for 82% of total investments, while that of the power generation sector declines to 13% reflecting the leveraging impact of OBF prices on the economic viability of NGVs.

1.11 CNG/LNG DISTRIBUTION SYSTEM TEFS

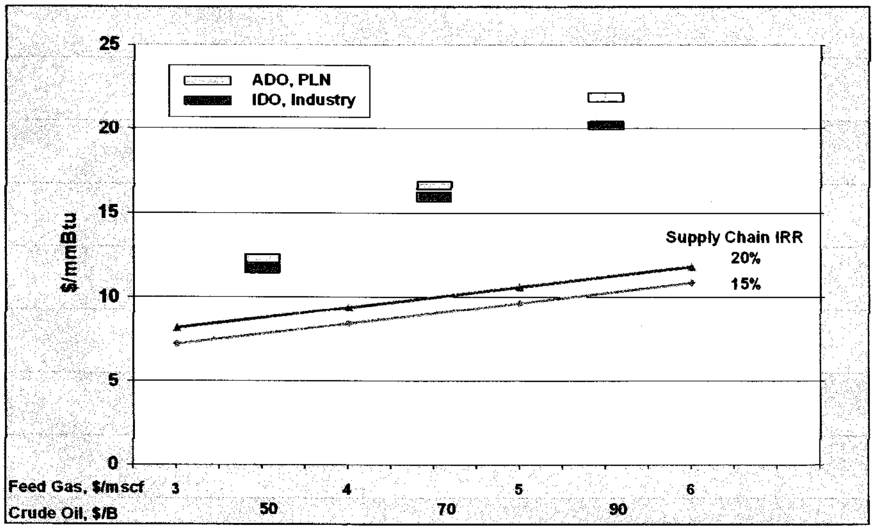
Two technical and economic feasibility case studies were prepared for conceptual CNG/LNG distribution systems, namely

- Case 1. CNG/LNG supply to three regional power plants involving terrestrial and marine transportation; and
- Case 2. LNG production and marine transportation to a pipeline system for power and industry use..

For Case 1. LNG delivery to the three regional power plants by both marine and terrestrial transport is shown to be practical and economically viable at crude oil prices of $40 per barrel or higher and less costly than CNG delivery.

For Case 2. as shown in Figure 1.14, LNG supply by ship to the Case 2 pipeline system is technically feasible and economically viable for OBF product prices in excess of $50 per barrel crude oil equivalent.

Figure 1.14 LNG Cost of Supply to Case 2 pipeline vs Cost of Alternative Fuels



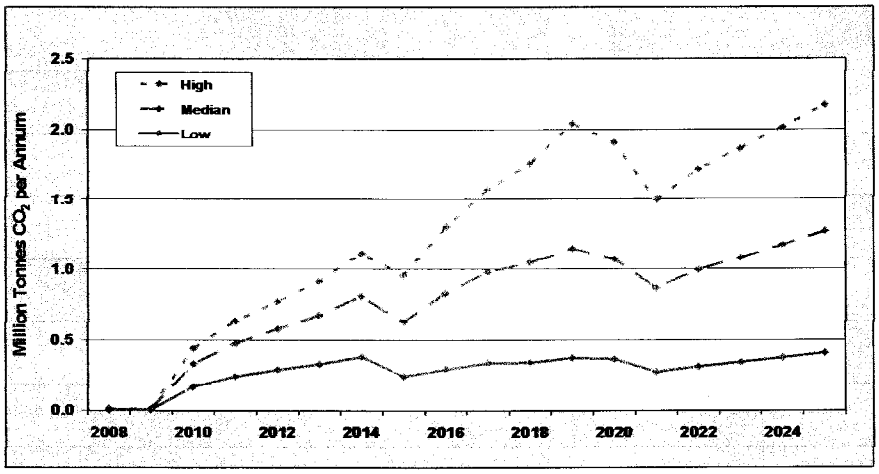
1.12 DOMESTIC SMS CNG/LNG REGULATORY ENVIRONMENT

Indonesia has a set of broad, business conducive regulations for CNG and LNG manufacturing, transportation, storage and distribution, but lacks specific, detailed regulations setting minimum technical and safe operational standards. Japan and the United States of America have complete technical, health, safety and environmental regulations covering small-to-medium scale CNG/LNG manufacture, storage, terrestrial and marine transportation, which, with minor adaptation, would serve Indonesia well.

1.13 POLLUTANT AND GREENHOUSE GAS EMISSION REDUCTIONS

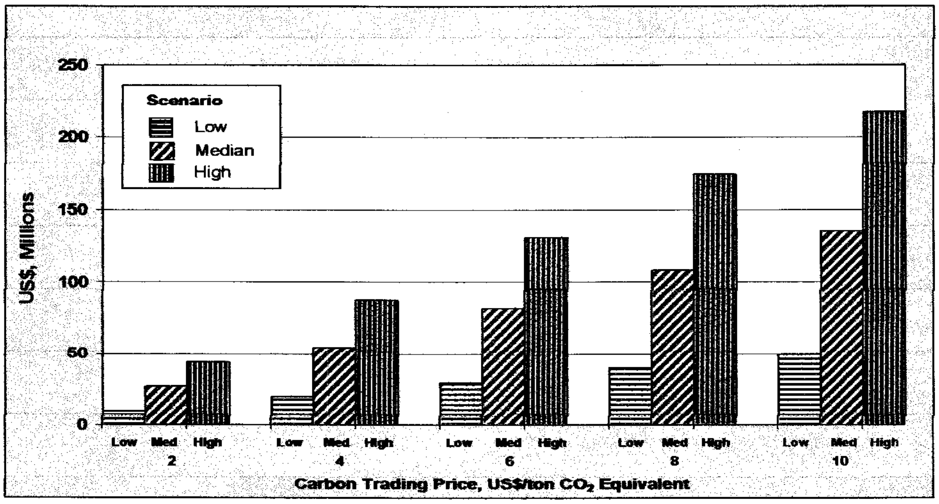
As shown in Figure 1.15 below, the projected levels of OBF replacement by CNG/LNG result in rapidly rising CO_2 emission reductions reaching 0.4, 1.3 and 2.2 million tons of CO_2 per annum by 2025. The one-year emission reduction retreats are caused by projected declines in CNG/LNG consumption as pipeline gas replaces CNG/LNG usage as a result of projected gas infrastructure build-out.

Figure 1.15 Projected CO_2 Emission Reductions



The project stands to qualify for Clean Development Mechanism "certified emission reduction", or carbon, credits under the Kyoto Protocol. As shown in Figure 1.16, the project's life time (2008-2025) carbon credit trading value ranges from \$10-43 million at a carbon trading price of \$2 per ton CO_2 equivalent, \$30-130 million at \$6 per ton, and \$50-217 million at \$10 per ton. Carbon prices have recently traded at as high as \$16 per ton due to Japan's projected need to purchase \$2+ billion dollars worth of carbon credits by 2012.

Figure 1.16 2008-25 Carbon Credit Trading Values of Projected GHG Emission Reductions



1.14 MONETARY GAINS FROM SWITCH TO CNG/LNG

National foreign exchange savings and consumer savings resulting from the projected levels of OBF replacement by CNG/LNG are presented in Figures 1.17 and 1.18 below, respectively.

Cumulative foreign exchange savings from replacing OBFs with CNG/LNG in small scale power generation, industry and transportation are estimated at a negative $15 to 171 MM by 2010 growing to $2.6-33 billion by 2025.

Figure 1.17 Cum. Foreign Exchange Savings from Switch to CNG/LNG

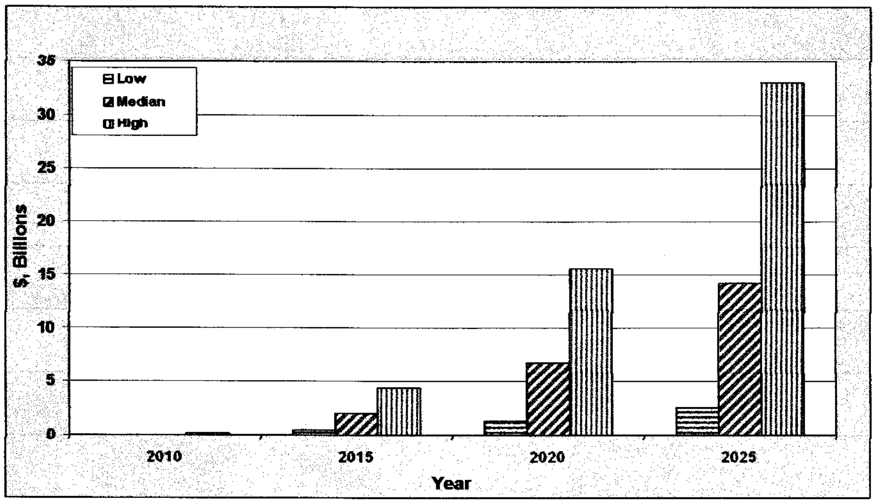
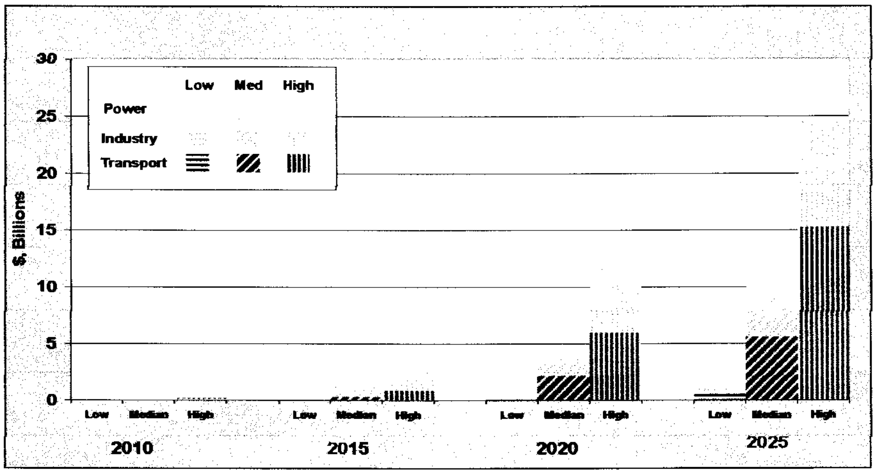


Figure 1.18 Cum. Consumer Savings from Switch to CNG/LNG



Cumulative consumer savings derived from the projected replacement of OBFs are forecasted to reach a negative $8 to185 MM by 2010 growing to $1.4-25 billion by 2025 depending upon future crude oil and CNG/LNG feed gas prices. The greatest cumulative savings by 2025 are experienced by the transportation sector accounting for more than half of total projected consumer savings followed by the electric power generation sector with 25-30 percent.

1.15 DEVELOPMENT IMPACT

Using a national 66 sector I/O model, the future impacts of OBF-to-CNG/LNG investments on macro-measures of the national economy were ascertained. As shown in Table 1.6 below, only in the Median and High scenarios were the projected impacts material, especially on national income and national employment, since the transportation sector is very labor intensive. Thus, the corresponding national employment additions by 2025 are estimated at 0.4-2.6 million to a current work force of 106 million.

Table 1.6 Cum. Impact of OBF-to-CNG/LNG Investment on National Economy

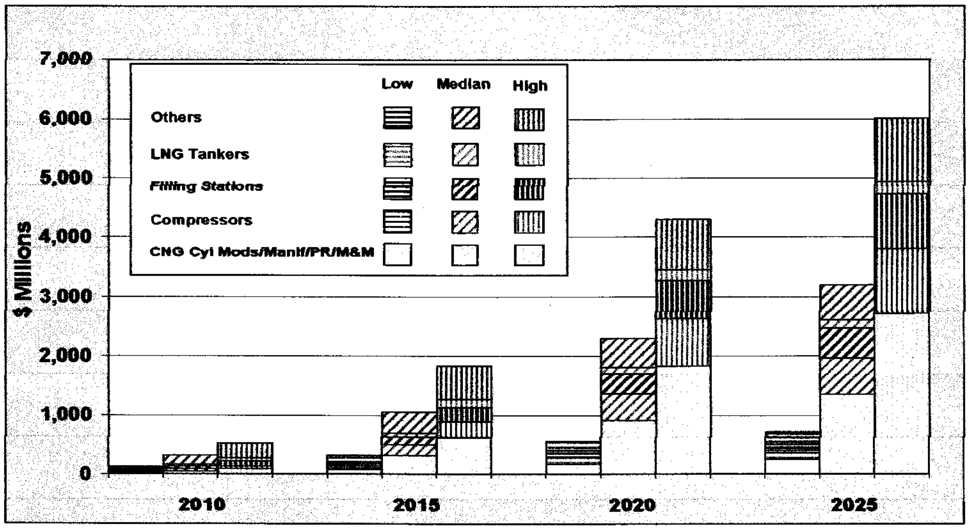
Measure	Scenario	2010	2015	2020	2025
GDP	Low	0.01%	0.02%	0.04%	0.05%
	Median	0.02%	0.06%	0.12%	0.17%
	High	0.03%	0.09%	0.22%	0.30%
National Income	Low	0.59%	1.54%	2.84%	3.55%
	Median	1.12%	3.52%	7.33%	10.08%
	High	1.71%	5.84%	13.20%	18.38%
National Employ-ment	Low	0.04%	0.13%	0.27%	0.36%
	Median	0.07%	0.35%	0.92%	1.31%
	High	0.10%	0.61%	1.71%	2.45%

The projected replacement of OBFs by CNG/LNG also has multiple, "soft" ancillary developmental benefits in the areas of infrastructure build-out, market reform, human capacity building/technology transfer and demonstration effects.

1.16 CNG/LNG IMPLEMENTATION PLAN

The projected levels of OBF replacement by CNG/LNG entail the capital spending profiles presented in Figure 1.19 below, i.e., cumulative spending of $124-519 MM by 2010 growing to $0.7-6 billion by 2025. The spending profiles for the four largest equipment categories are also highlighted in Figure 1.19, showing nearly 50% of capital outlays in the Median and High scenarios being on CNG cylinder modules and ancillary equipment.

Figure 1.19 Cum. Incr. Capital Spending by Equipment/Facility Category



1.17 FUNDING OF SWITCH TO CNG/LNG

This study assumes OBF replacement by CNG/LNG to result from a large number of small, independent, economically grounded investment decisions by individuals and enterprises with the amounts constituting small fractions of their on-going operating budgets. Such investments typically do not lend themselves to project packaging and financing in the capital markets. Also, the interchangeability and transient nature of most of the supply chain facilities, as lower cost gas pipeline service over time replaces CNG/LNG delivery, make project packaging and project financing difficult.

Only marine transportation, i.e., LNG service, and public CNG based transport offer the scope of segregation into special purpose vehicles with multiple funding options.

A wide range of financing possibilities on favorable terms is typically available for ship and bus construction, including lease-back options.

A potential source of funding for OBF replacing projects is Carbon Trading Credits, which in individual cases can contribute as much as 20% of the required capital investment.

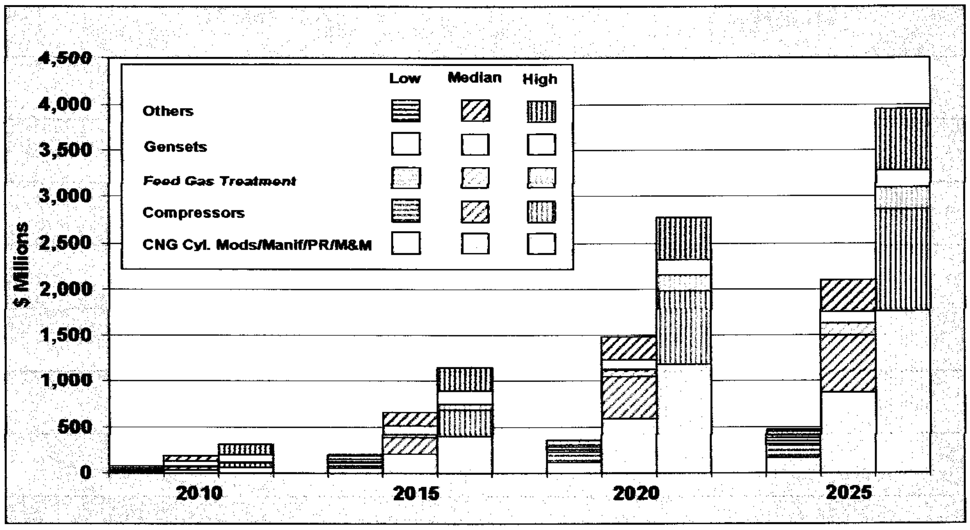
1.18 U.S. EXPORT POTENTIAL

The estimated U.S. export potential associated with the projected levels of OBF replacement by CNG/LNG is presented in Table 1.7 below. The export potential ranges from $74-308 MM by 2010 increasing to $0.5-4 billion by 2025 depending upon future crude oil and CNG/LNG feed gas prices. As highlighted in Figure 1.20, the largest equipment export opportunities for U.S. vendors and suppliers are in CNG cylinder modules and peripherals, compressors, CNG/LNG feed gas treatment and gensets comprising about 80% of the identified U.S. export potential.

Table 1.7 U.S. Export Potential, $MM

Scenario	2010	2015	2020	2025
Low	74	199	351	475
Median	185	658	1,483	2,098
High	308	1,157	2,776	3,951

Table 1.20 U.S. Export Targets by Equipment/Services Category



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Pendawa has been retained by PT. Perusahaan Gas Negara (Persero) Tbk. (PGN) to undertake the Small-to-Medium Scale (SMS) Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Distribution Study, which encompasses an assessment of the potential CNG/LNG demand in Indonesia's geographically dispersed fuel markets currently dominated by Oil Based Fuel (OBF) products, the economic viability of Small-to-Medium Scale (SMS) CNG and LNG usage in such markets, estimation of the pace of market capture, determination of the economic and environmental benefits of such fuel switching, an implementation plan for projected domestic CNG/LNG-based gas usage and identification of the associated U.S. export potential.

The contract was awarded by PGN in March, 2006, and a project kick-off meeting was held in Jakarta with PGN on 29 March, 2006. The outcomes of that meeting were reported in the Inception Report, which provides the following:

- Relevant background information
- Objectives of the study
- Initial identification of issues
- Approach and methodologies to be followed
- Project Structure
- Proposed work schedule and deliverables

Following submission of the Inception Report on April 21, 2006, Pendawa developed industrial OBF consumption data and OBF/CNG/LNG/pipeline supply chain models, collected and analyzed model input data and formulated preliminary results. These findings were compiled in the Interim Report #1, submitted to PGN on September 7, 2006, which addressed:

- OBF products consumption (for potential switching to natural gas) by sector at the regency level (Task 1);
- Cost of OBF products shipping, storage and distribution (Task 2);
- Location, magnitude and quality of potential sources of CNG/LNG feed gas supply (Task 3);
- Alternative modes of CNG and LNG transportation (Task 4); and
- Cost of CNG and LNG delivery as functions of distance and volume (Task 5).

In accordance with the terms of reference under the contract and the work program set out in the Inception Report, Pendawa continued work on Tasks 6 through 10 as well as expanded coverage under Task 1 to site-by-site small scale power generation and transportation. Submitted to PGN on March 2, 2007, the results were presented in Interim Report #2 covering:

- Analysis of OBF markets for potential replacement by CNG/LNG-based gas (Task 2);
- Technical and Economic Feasibility Study of marine CNG transportation short and long distance (Task 6);
- Price competitiveness of CNG/LNG in domestic OBF markets (Task 7);
- OBF market capture by CNG/LNG (Task 8)
- Switching capital requirements (Task 9); and
- Technical and Economic Feasibility Study of two CNG/LNG Delivery systems (Task 10), namely
  - CNG distribution to three regional electric power generation stations; and
  - LNG distribution in support of heavy duty vehicle use.

In accordance with the work program, Pendawa has completed work on the remaining seven tasks, which are reported in this "Final Report", along with updated and edited write-ups of the tasks previously reported in Interim Reports #1 and #2. The last seven tasks completed and documented in this "Final Report" are:

- CNG/LNG Regulatory Environment (Task 11)
- Pollutant and Greenhouse Gas Reductions (Task 12)
- Monetary Gains from Switch to CNG/LNG (Task 13)
- Development Impact (Task 14)
- CNG/LNG Implementation Plan (Task 15)
- Funding of Switch to CNG/LNG Usage (Task 16)
- U.S. Export Potential (Task 17)

The "Final Report" incorporates comments and suggestions by PGN following their review of an early draft of the "Final Report".

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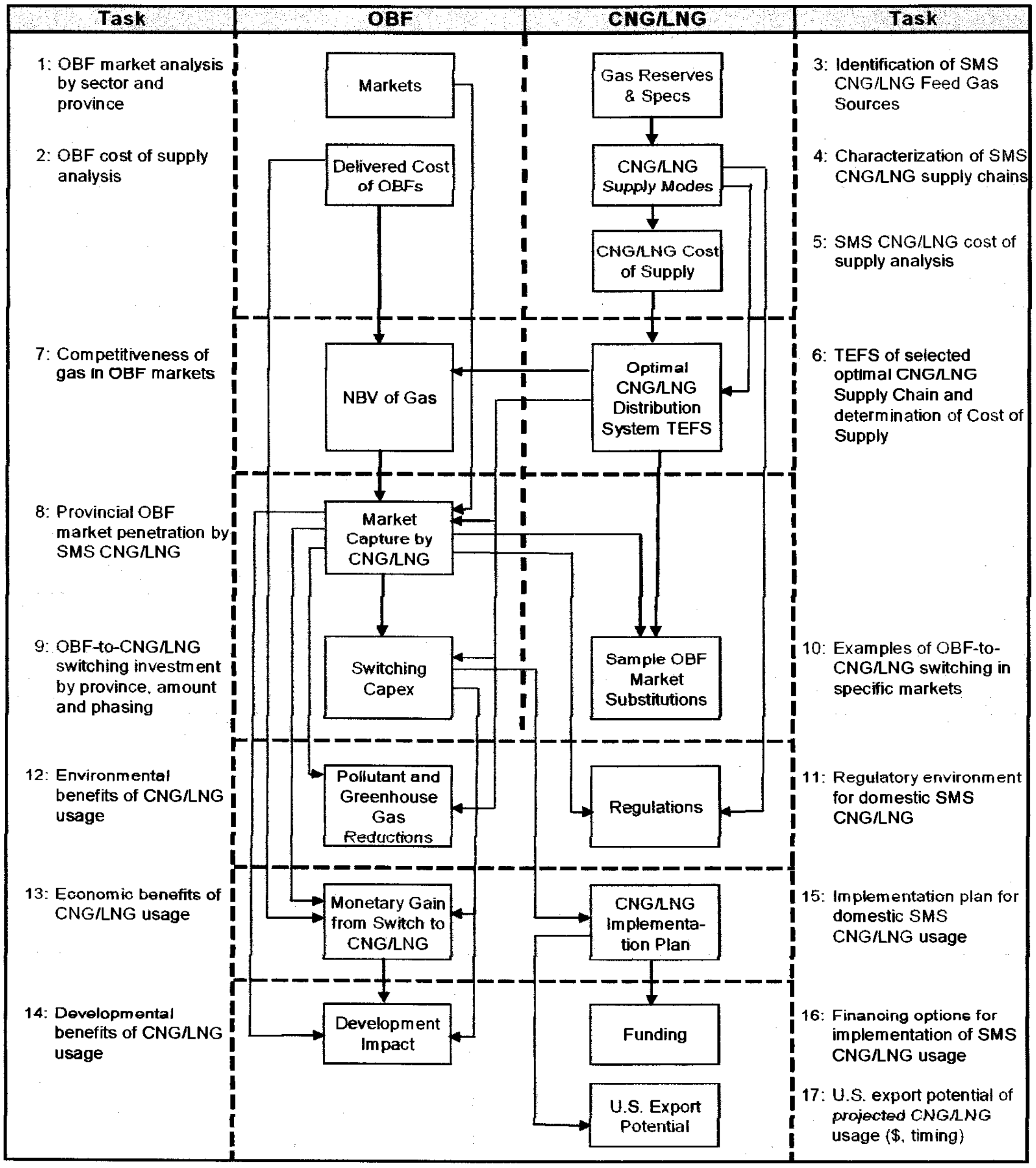
The study methodology was designed to take into account the interdependencies of activities to be undertaken in the study, whereby outputs of previous tasks become inputs to subsequent tasks. By optimizing linkages between interdependent tasks, the study methodology ensures overall analytical consistency.

Figure 3.1 Project Approach



The OBF products market is assessed by sector at the regency level throughout Indonesia in Task 1 focusing on the small-to-medium scale (SMS) power generation, industrial and transportation OBF markets for potential switching to CNG/LNG-based natural gas. The cost of OBF products supply to geographical disparate markets is determined in Task 2. Potential SMS CNG and LNG feed gas sources within Indonesia are identified and described in Task 3. Alternative SMS CNG and LNG supply chains are characterized in Task 4, while the costs of SMS CNG/LNG-based gas delivery are quantified in Task 5 as functions of distance and volume. Work on these five tasks was reported in Interim Report #1.

A detailed examination of the technical and economic viability of marine CNG transportation is undertaken in Task 6, while Task 7 calls for determination of the price competitiveness of CNG/LNG-based gas in OBF product markets vis-à-vis alternative fuels.

The pace and degree of OBF product market capture by CNG/LNG-based natural gas is quantified by fuel type and location in Task 8, while Task 9 comprises estimation of the investment requirements to effect the projected OBF products market capture by SMS CNG/LNG-based gas. Task 10 examines market examples of OBF-to-CNG/LNG conversion, specifically conversion to LNG usage in small power generating stations and LNG fuelled heavy duty vehicles. Task 11 sets out the regulatory environment for domestic SMS CNG/LNG manufacture, transportation, distribution and marketing.

Task 12 calls for quantification of the environmental benefits of the projected OBF-to-CNG/LNG conversion and its monetary value under the Clean Development Mechanism of the Kyoto Protocol. Task 13 requires estimation of the economic benefits to Indonesia and Indonesian consumers of switching to CNG/LNG, while Task 14 quantifies and discusses the developmental impacts of such a switch. An implementation plan for SMS CNG/LNG utilization is described in Task 15, while Task 16 discusses its associated funding plan.

Task 17 identifies the U.S. export potential associated with the projected implementation of SMS CNG/LNG-based gas usage.

Administrative tasks not listed in Figure 3.1 above include preparations of the Inception Report, Interim Reports #1 and #2, a Draft Final Report and the Final Report along with submittal of Monthly Progress Reports and client liaison and training.

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4.1.1 INTRODUCTION

This section examines the potential for replacing Oil Based Fuels (OBFs) by CNG/LNG-based natural gas in energy markets throughout Indonesia. The scope for replacement was confined to potential replacement of OBF in the small scale power generation, industrial and transportation sectors. Other OBF markets, such as non-energy and large scale power generation, either do not lend themselves to replacement by CNG/LNG, since they require large volumes of low priced gas, which is the domain of pipeline gas, or, in the case of the household and commercial markets, are too small, typically constituting only 1% of the industrial market.

The magnitudes of potential OBF replacement by CNG/LNG-based gas have been determined throughout Indonesia by reference to current and projected OBF usage in small scale electric power generation, industry and transportation in areas within reach of CNG/LNG delivery from known feed gas sources. The actual economic viability of supplying CNG/LNG to specific markets is determined in Task 7 (CNG/LNG Competitiveness in OBF Markets) and the projected degree of market capture is estimated in Task 8 and reported in Sections 10 and 11 of this report, respectively.

4.2 OBF REPLACEMENT OPPORTUNITIES IN POWER MARKET

4.2.1 Approach to Identification and Quantification

Using PLN data[1], the Study Team identified all PLN-operated, OBF fuelled electric power generating units of less than 100 MW as to location, generating technology, current (at times de-rated) output capacity, capacity (utilization) factor and fuel type. Non-PLN, captive power generating capacity, a small percentage of PLN's generating capacity, was identified and characterized by province only, since individual unit locations were not provided.[2]

Among the OBF fired power generating units identified, those units (plus allocated captive power capacities) outside the reach of existing gas transmission and distribution networks, but within a distance of about 400 km overland and 1,600 km by sea of known CNG/LNG feed gas sources were identified as potential targets for conversion to CNG/LNG. Their current OBF consumption was determined and future consumption assumed to escalate at 6% per annum, i.e., the assumed average annual rate of electric power consumption growth throughout Indonesia and equal to the underlying GDP growth rate of this study.

[1] "Rencana Penyediaan Tenaga Listrik (RPTL) 2004-2013" published by PLN in October, 2004
[2] "Statistik PLN 2005" published by PLN in July, 2006.

4.2.2 OBF Replacement Opportunities in Small Scale Power Generation

Following the methodology described in subsection 4.2.1, the opportunities for future replacement of OBF by CNG/LNG in small scale and captive electric power generating units throughout Indonesia have been compiled and tabulated by province and geographical location within each province in Appendix A. For purpose of illustrating the approach, the details of identifying current and projected future opportunities for OBF replacement by CNG/LNG in the electric power generation sector are shown in Table 4.1 below for the Province of Aceh only, while corresponding details for all other provinces are contained in Appendix A. Future fuel consumption in identified opportunities for OBF replacement is assumed to increase at the rate of real GDP growth, i.e., 6% p.a.

Table 4.1 Opportunities for CNG/LNG Replacement of OBF in Power Generation, Aceh

Location	Gen. Techn.*	MW	GWh	CF	Eff	MMCFED				
						2005			2010	2025
						PLN Power	Captive Power	Total		
Banda Aceh	DE	28.9	140.4	55%	40%	3.3	2.0	5.3	7.1	16.9
Sigli	DE	9.8	37.5	44%	40%	0.9	1.0	1.9	2.5	6.0
Takengon	DE	6.5	15.0	26%	40%	0.4	0.1	0.5	0.6	1.4
Meulaboh	DE	9.8	40.4	47%	40%	0.9	0.1	1.0	1.4	3.3
Blangpidie	DE	5.4	22.4	47%	40%	0.5	0.1	0.6	0.8	2.0
Tapaktuan	DE	3.1	12.9	48%	40%	0.3	0.1	0.4	0.5	1.3
Subussalam	DE	4.5	19.9	50%	40%	0.5	0.1	0.6	0.8	1.8
Total		**68**	**289**			**7**	**4**	**10**	**14**	**33**

Table 4.2 below summarizes the opportunities for future OBF replacement by CNG/LNG in the electric power generation sector throughout Indonesia based on detailed province-by-province analyses analogous to that of Aceh described above. The details are contained in Appendix A.

Assuming 6% p.a. growth in small scale electric power generation output, Table 4.2 shows present day opportunities for OBF replacement in power generation of 229 mmscfd almost tripling by 2025. The largest opportunity for OBF market capture appears in the provinces of North Sumatra, Bali and South and Southeast Sulawesi, which are characterized by a large number of small, distributed OBF fuelled power generation stations, inadequate or non-existent gas transmission and distribution systems and the presence of nearby sources of CNG/LNG-feed gas.

Keep in mind that "opportunities for OBF replacement" here means the total identified OBF consumption of the small scale electric power generation market, which could be captured by CNG/LNG based on technology and locations of currently known CNG/LNG feed gas sources relative to market locations. How much of that market is likely to be captured by CNG/LNG based on economic and practical delivery considerations will be addressed cursorily later in this section and in considerable detail in Section 11.

Table 4.2 Opportunities for CNG/LNG Replacement of OBF in Power Generation, mmscfd

Province	2005	2010	2015	2020	2025
NAD Aceh	10.2	14	18	25	33
N. Sumatra	57.9	77	104	139	186
W. Sumatra	7.4	10	13	18	24
Riau	13.5	18	24	32	43
Jambi	4.0	5	7	10	13
S. Sumatra	0.0	0	0	0	0
Bangka Belitung	7.4	10	13	18	24
Bengkulu	3.6	5	6	9	12
Lampung	7.7	10	14	18	25
Bali	27.9	37	50	67	89
W. Nusatenggara	7.4	10	13	18	24
E. Nusatenggara	2.7	4	5	6	9
West Kalimantan	11.8	16	21	28	38
S. & C. Kalimantan	13.7	18	25	33	44
East Kalimantan	0.0	0	0	0	0
S. & SE. Sulawesi	35.5	47	64	85	114
Central Sulawesi	4.9	7	9	12	16
North Sulawesi	5.9	8	11	14	19
Gorontalo	0.0	0	0	0	0
Maluku & N. Maluku	3.2	4	6	8	10
Papua	3.9	5	7	9	12
Total	**229**	**306**	**409**	**548**	**733**

4.3 OBF REPLACEMENT OPPORTUNITIES IN INDUSTRIAL MARKET

4.3.1 Approach to Identification and Quantification

This study assumes that industrial CNG/LNG usage outside the island of Java will only occur, where OBF consuming industries are located in the vicinity of electric power generating plants convertible to CNG/LNG-based gas, i.e., those identified in subsection 4.2.2 above. In other words, low volume industrial CNG/LNG consumption will "piggyback" on CNG/LNG burning electric power generating units to achieve the supply economies of scale, which allows manufacture and delivery of CNG/LNG to be economically viable. This study assumes that 10 percent of regency-wide industrial OBF consumption constitutes the opportunity for conversion to CNG/LNG, if opportunities for CNG/LNG replacement of OBF in regency power generating units have been identified.

Only in Java does the study assume that CNG/LNG will make in-roads into the industrial OBF market without the benefit of concomitant CNG/LNG delivery to the electric power generation sector. Electrification is very high in Java and few OBF fired, small scale power plants are used other than in captive power production, usually as "back-up" with a low utilization factor. However, the concentration of industrial, non-transportation OBF consumption is quite high in a number of major cities throughout Java, which constitute the opportunities for OBF replacement by CNG/LNG.

4.3.2 OBF Replacement Opportunities in Industry

Following the methodology described in subsection 4.3.1, the current and future opportunities for replacement of OBF by CNG/LNG in industry throughout Indonesia have been tabulated by province and geographical location within the province in Appendix A. For illustrative purposes, Table 4.3 below shows the details of the process of identifying current and projected future opportunities for CNG/LNG replacement of industrial OBF use in the Province of Aceh only.

Table 4.3 Opportunities for CNG/LNG Replacement of OBF in Industry, Aceh

Location	MMCFED				
	2005	2010	2015	2020	2025
Banda Aceh	0.14	0.19	0.2	0.3	0.4
Meulaboh	0.07	0.10	0.1	0.2	0.2
Sigli	0.07	0.09	0.1	0.2	0.2
Blangpidie & Tapak Tuan	0.07	0.09	0.1	0.2	0.2
Takengon	0.06	0.08	0.1	0.1	0.2
Subussalam	0.02	0.03	0.0	0.1	0.1
Total	0.4	0.6	0.8	1.0	1.4

Table 4.4 below presents the future opportunities for replacement of OBF by CNG/LNG in the industrial sector throughout Indonesia based on analogous, detailed province-by-province analyses presented in Appendix A.

As with CNG/LNG replacement of OBF in electric power generation addressed in the previous subsection, Table 4.4 shows present day opportunities for CNG/LNG replacement of OBF in industry of 43 mmscfd more than tripling by 2025, although still constituting no more than 20% of estimated potential OBF replacement in electric power generation. Of the 43 mmscfd of present day opportunities, two-thirds are associated with industry in the vicinity of small scale power plants in areas outside Java, while one-third is attributed to industrial usage in Java.

Again, keep in mind that "opportunities for OBF replacement" here means the total identified industrial OBF market, which could be captured by CNG/LNG based on current technology and known CNG/LNG feed gas supply sources. How much of that market is likely to be captured by CNG/LNG based on economic and practical delivery considerations will be addressed cursorily later in this section and in considerable detail in Section 11.

Table 4.4 Opportunities for CNG/LNG Replacement of OBF in Industry

Region	Province	MMCFED				
		2005	2010	2015	2020	2025
Outside Java	NAD Aceh	0.4	0.6	0.8	1.0	1.4
	N. Sumatra	3.9	5.2	6.9	9.2	12.4
	W. Sumatra	0.5	0.6	0.8	1.1	1.5
	Riau	2.7	3.6	4.8	6.5	8.6
	Jambi	0.7	0.9	1.2	1.7	2.2
	S. Sumatra	0.0	0.0	0.0	0.0	0.0
	Bangka Belitung	2.7	3.6	4.8	6.5	8.7
	Bengkulu	0.2	0.3	0.4	0.5	0.7
	Lampung	1.2	1.6	2.1	2.9	3.8
	Bali	0.4	0.6	0.8	1.1	1.4
	W. Nusatenggara	0.1	0.1	0.1	0.2	0.2
	E. Nusatenggara	0.0	0.0	0.0	0.0	0.0
	West Kalimantan	5.4	7.2	9.6	12.9	17.2
	S. & C. Kalimantan	4.3	5.8	7.8	10.4	13.9
	East Kalimantan	0.0	0.0	0.0	0.0	0.0
	S. & SE. Sulawesi	3.1	4.2	5.6	7.5	10.1
	Central Sulawesi	0.8	1.1	1.4	1.9	2.5
	N. Sulawesi	0.7	0.9	1.2	1.7	2.2
	Gorontalo	0.0	0.0	0.0	0.0	0.0
	Maluku & N. Maluku	0.3	0.4	0.6	0.8	1.1
	Papua	0.2	0.3	0.4	0.5	0.6
	Subtotal	**28**	**37**	**49**	**66**	**89**
Java	DKI Jakarta	0.0	0.0	0.0	0.0	0.0
	West Java	8.2	11.0	14.7	19.7	26.3
	Central Java	1.5	2.0	2.7	3.6	4.8
	DI Yogyakarta	0.4	0.5	0.7	0.9	1.2
	East Java	4.9	6.6	8.8	11.8	15.8
	Subtotal	**15**	**20**	**27**	**36**	**48**
	Grand Total	**43**	**57**	**76**	**102**	**137**

4.4 OBF REPLACEMENT OPPORTUNITIES IN TRANSPORTATION MARKET

Another opportunity for CNG/LNG replacement of OBFs is in transportation, i.e., natural gas vehicles (NGV), either through conversion of current rolling diesel and gasoline fuelled stock or future purchase of Original Equipment Manufacture (OEM) NGVs in ongoing replacement and expansion of existing rolling stock.

There are currently two NGV markets in Indonesia, namely

- in Jakarta consuming 0.3 mmscfd of compressed gas in 71 (OEM) city buses and about 50 (converted) taxis; and
- in Surabaya consuming 0.03 mmscfd of compressed gas in taxis.

This study assumes development of NGV markets in 13 other major cities throughout Indonesia currently served by pipeline gas or scheduled to be provided natural gas supply in the foreseeable future.

Current CNG-based NGV technology is characterized by bulky and heavy (thick-walled) fuel cylinders with limited capacity suggesting CNG be the preferred NGV mode of transportation in and around cities, where payload is less critical and refueling stations aplenty, while LNG-based NGV technology characterized by smaller and lighter fuel tanks with capacities comparable to those of diesel vehicles will be the preferred NGV mode for long distance, scheduled, heavy duty transportation, such as buses and trucks, where payload is at a premium and refueling stations infrequent, but in known locations.

The subsection below explains the methodology adopted to estimate future opportunities for CNG-in-transportation demand in the city of Jakarta and its extension as a model for the evolution of CNG-in-transportation demand in other cities targeted for NGV use. Opportunities for OBF replacement for three levels of vehicle market penetration by NGV have been estimated.

The estimated opportunities for OBF replacement in transportation presented in this section are order-of-magnitude estimates based on assumed levels of NGV market penetration. In Section 11 of this report, titled "OBF Market Capture by CNG/LNG", gas netback values vis-à-vis costs of CNG/LNG supply for three different combinations of oil and CNG/LNG feed gas prices are used to project economically justified degrees of market penetration by CNG/LNG fuels in the fifteen cities according to vehicle type and in long distance busing/trucking and ensuing estimated CNG/LNG-in-transportation demand.

4.4.1 Approach to Identification and Quantification

The most developed NGV market in Indonesia, Jakarta's, is used as a model for the evolution of NGV markets in 14 other cities in Indonesia. The latest data on the Jakarta motor vehicle population[1] are presented in Table 4.5 below along with salient vehicle type characteristics, such as vehicle population growth rate, average daily travel distance, fuel efficiency and "guesstimated" degree of NGV market penetration at maturity. Three different levels of NGV market capture have been assumed to occur by 2016, defined as Low, Median and High.

[1] "Natural Gas Vehicle Study" (2002) by Pendawa Sejati Consultama

Table 4.5 Jakarta Motor Vehicle Population, Characteristics and NGV Targets

Vehicle Type	Jkt Vehicle Population in 2000	Annual Growth	Fuel	In Use	km/day	km/LGE	% NGVs 10 years after introduction to city		
							Low	Median	High
Large Bus	6,000	4%	Diesel	85%	350	4	10%	25%	50%
Metromini	8,678	4%	Diesel	85%	250	5	10%	25%	50%
Small Truck (D)	16,572	4%	Diesel	70%	150	8	0%	5%	10%
Truck	65,957	4%	Diesel	70%	200	6	0%	5%	10%
Large Truck	7,789	4%	Diesel	85%	350	4	10%	25%	50%
Small Truck (G)	74,574	4%	Gasoline	70%	150	8	0%	5%	10%
Taxi	26,656	4%	Gasoline	85%	250	9	10%	25%	50%
Mikrolet	16,775	4%	Gasoline	85%	200	8	10%	25%	50%

The methodology for estimating future NGV penetration of the Jakarta motor vehicle market assumes that the specified percentage of NGVs for each vehicle type will be achieved in 2016, and that the NGV population will grow between 2006 and 2016 at a constant percentage rate. A model was prepared to track vehicle conversions to CNG as well as introduction of OEM NGVs into the vehicle population assuming an average 14-year vehicle life. The total of conversions and OEMs was assumed to reach the specified targets by 2016, i.e., 0-10% for the Low scenario, 5-25% for the Median scenario and 10-50% for the High scenario.

The evolution of NGV markets in other major cities in Indonesia is assumed to mirror that of Jakarta, only delayed in time to reflect later introduction of CNG refueling stations. The cities with present and future NGV markets are listed in Table 4.6 along with estimated time of introduction of CNG refueling stations and NGVs as well as time of NGV market maturity, i.e., 10 years after introduction. Since no data are available on motor vehicle populations in other cities, the study assumes that they are proportional to population, both in total as well as to type of vehicle.

Note that cities currently served by gas distribution networks but without CNG NGVs will start seeing NGVs in 2008, while CNG NGVs are assumed to have been introduced in all 15 cities by 2012.

Table 4.6 NGV Market Introduction and Maturity by City

	Population, '000	% of Jakarta	Year of Introduction of NGV to Metropolis (x) and achievement of NGV Target (o), respectively																	
			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jakarta	10,212	100%	x																	
Bandung	2,740	27%							x											
Cirebon	2,061	20%			x															
Semarang	1,495	15%							x											
Surabaya	2,977	29%	x																	
Medan	2,187	21%			x															
Pekanbaru	952	9%			x															
Palembang	1,818	18%			x															
B. Lampung	1,137	11%				x														
Pontianak	1,058	10%							x											
Banjarmasin	622	6%							x											
Balikpapan	548	5%			x															
Samarinda	809	8%					x													
Manado	500	5%							x											
Makassar	1,354	13%							x											
Total	30,470																			

4.4.2 OBF Replacement Opportunities in Transportation

4.4.2.1 Potential OBF Replacement by CNG in Transportation

The detailed modeling of potential CNG/LNG replacement of OBFs in transportation is contained in Appendix A. A summary of the modeling results for each of three assumed levels of NGV penetration of the motor vehicle population (listed in Table 4.5 above) is presented in Tables 4.7 through 4.9 below.

Table 4.7 Potential CNG Replacement of OBFs in Transportation, Low Case

MMCFD	2004	2005	2006	2008	2010	2015	2020	2025
Jakarta	0.2	0.2	0.3	2.4	3.8	13.9	22.2	27.2
Bandung	0.0	0.0	0.0	0.0	0.0	0.8	2.8	5.7
Cirebon	0.0	0.0	0.0	0.1	0.5	1.6	4.1	5.1
Semarang	0.0	0.0	0.0	0.0	0.0	0.4	1.5	3.1
Surabaya	0.0	0.0	0.0	0.1	0.2	3.2	6.5	7.9
Medan	0.0	0.0	0.0	0.1	0.5	1.7	4.3	5.4
Pekanbaru	0.0	0.0	0.0	0.0	0.2	0.8	1.9	2.3
Palembang	0.0	0.0	0.0	0.1	0.4	1.4	3.6	4.5
B. Lampung	0.0	0.0	0.0	0.0	0.1	0.7	2.1	2.7
Pontianak	0.0	0.0	0.0	0.0	0.0	0.3	1.1	2.2
Banjarmasin	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.3
Balikpapan	0.0	0.0	0.0	0.0	0.1	0.4	1.1	1.3
Samarinda	0.0	0.0	0.0	0.0	0.0	0.4	1.5	1.8
Manado	0.0	0.0	0.0	0.0	0.0	0.1	0.5	1.0
Makassar	0.0	0.0	0.0	0.0	0.0	0.4	1.4	2.8
Total	0.2	0.2	0.3	3	6	26	55	74

Table 4.8 Potential CNG Replacement of OBFs in Transportation, Median Case

MMCFD	2004	2005	2006	2008	2010	2015	2020	2025
Jakarta	0.2	0.2	0.3	3.7	7.0	39.1	69.3	84.7
Bandung	0.0	0.0	0.0	0.0	0.0	1.4	7.3	17.8
Cirebon	0.0	0.0	0.0	0.1	0.8	3.9	12.7	15.8
Semarang	0.0	0.0	0.0	0.0	0.0	0.7	4.0	9.7
Surabaya	0.0	0.0	0.0	0.1	0.4	8.8	20.2	24.7
Medan	0.0	0.0	0.0	0.1	0.8	4.1	13.5	16.8
Pekanbaru	0.0	0.0	0.0	0.0	0.3	1.8	5.9	7.3
Palembang	0.0	0.0	0.0	0.1	0.7	3.4	11.2	14.0
B. Lampung	0.0	0.0	0.0	0.0	0.1	1.5	6.7	8.4
Pontianak	0.0	0.0	0.0	0.0	0.0	0.5	2.8	6.9
Banjarmasin	0.0	0.0	0.0	0.0	0.0	0.3	1.7	4.0
Balikpapan	0.0	0.0	0.0	0.0	0.2	1.0	3.4	4.2
Samarinda	0.0	0.0	0.0	0.0	0.0	0.8	4.5	5.7
Manado	0.0	0.0	0.0	0.0	0.0	0.2	1.3	3.2
Makassar	0.0	0.0	0.0	0.0	0.0	0.7	3.6	8.8
Total	0.2	0.2	0.3	4	10	68	168	232

Table 4.9 Potential CNG Replacement of OBFs in Transportation, High Case

MMCFD	2004	2005	2006	2008	2010	2015	2020	2025
Jakarta	0.2	0.2	0.3	6.1	8.2	71.6	136.9	167.7
Bandung	0.0	0.0	0.0	0.0	0.0	1.5	12.2	35.0
Cirebon	0.0	0.0	0.0	0.1	1.2	5.9	25.1	31.3
Semarang	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.8*	*6.7*	*19.1*
Surabaya	0.0	0.0	0.0	0.1	0.5	16.4	39.9	48.9
Medan	0.0	0.0	0.0	0.1	1.3	6.3	26.7	33.2
Pekanbaru	0.0	0.0	0.0	0.0	0.6	2.7	11.6	14.5
Palembang	0.0	0.0	0.0	0.1	1.1	5.2	22.2	27.6
B. Lampung	0.0	0.0	0.0	0.0	0.1	2.1	13.2	16.6
Pontianak	0.0	0.0	0.0	0.0	0.0	0.6	4.7	13.5
Banjarmasin	0.0	0.0	0.0	0.0	0.0	0.3	2.8	8.0
Balikpapan	0.0	0.0	0.0	0.0	0.3	1.6	6.7	8.3
Samarinda	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*1.0*	*9.0*	*11.4*
Manado	0.0	0.0	0.0	0.0	0.0	0.3	2.2	6.4
Makassar	0.0	0.0	0.0	0.0	0.0	0.7	6.0	17.3
Total	0.2	0.2	0.3	6	13	117	326	459

The assumptions for NGV market penetration listed in Table 4.5 above suggest the potential OBF replacement by CNG in transportation to increase from a current 0.3 mmscfd to 6-13 mmscfd by 2010 and 74-459 mmscfd by 2025, depending upon degree of market penetration. These levels of OBF replacement correspond to a 0.05% share of the identified motor vehicle markets in 2006 rising to 1-2% in 2010 and 6-35% in 2025.

As mentioned in subsection 4.4 above, LNG-fueled, rather than CNG-fueled, NGVs are likely to be employed in scheduled, long distance, heavy duty hauling of people and goods by bus and truck, where payload is at a premium and refueling stations infrequent, but in known locations. Market maturity is assumed to be reached ten years after introduction of LNG refueling stations, i.e., in 2018, and will be the only LNG consumption in transportation in Indonesia. Assuming 4% p.a. growth in the bus and truck population and various levels of market penetration, the estimated potential LNG replacement of OBF in transportation is set out in Table 4.10 below. The underlying detailed calculations are contained in Appendix A.

Table 4.10 Potential LNG Replacement of OBF in Transportation

MMCFED	Mkt Share	2005	2010	2015	2020	2025
Low	10%	-	2	8	22	27
Median	25%	-	2	16	55	67
High	50%	-	3	25	110	133

4.4.2.2 Potential OBF Replacement by CNG/LNG in Transportation

The potential replacement of OBF by CNG/LNG-based gas in transportation is the sum of the opportunities for replacement by CNG and LNG set out in the immediately prior subsections. Potential OBF replacements in transportation for the three previously defined levels of market penetration by NGVs are presented in Tables 4.11 through 4.13 below.

Table 4.11 Potential CNG/LNG Replacement of OBF in Transportation, Low Case

MMCFD	2006	2008	2010	2015	2020	2025
CNG	0.3	3	6	26	55	74
LNG	-	1	2	8	22	27
Total	0.3	4	8	35	77	101

Table 4.12 Potential CNG/LNG Replacement of OBF in Transportation, Median Case

MMCFD	2006	2008	2010	2015	2020	2025
CNG	0.3	4	10	68	168	232
LNG	-	1	2	16	55	67
Total	0.3	5	12	84	223	299

Table 4.13 Potential CNG/LNG Replacement of OBF in Transportation, High Case

MMCFD	2006	2008	2010	2015	2020	2025
CNG	0.3	6	13	117	326	459
LNG	-	1	3	25	110	133
Total	0.3	7	16	142	435	592

Tables 4.11 through 4.13 show potential CNG/LNG replacement of OBFs in the transportation sector ranging from 8-16 mmscfd in 2010 and growing to 101-592 mmscfd by 2025. CNG is estimated to command a 3-4 fold market share lead over LNG.

4.5 POTENTIAL OBF REPLACEMENT BY CNG/LNG

The total potential for replacement of OBFs by CNG/LNG-based gas in small scale power generation, industry and transportation is summarized below based on the analyses of individual sector replacement opportunities presented in the subsections above.

Since subsections 4.2 and 4.3 above assumed CNG/LNG replacing OBF in all qualifying, OBF burning electric power generating and industrial facilities, three cases are developed below based on levels of market penetration: A Low Case reflecting 10% penetration of these two OBF markets, a Median Case representing 25% penetration, and a High Case assuming 50% penetration.

The estimated total potential OBF replacements by CNG/LNG over time are presented below numerically in Tables 4.14 through 4.16 and graphically in Figure 4.1.

While the current OBF replacement is only 0.2 mmscfd, preliminary market penetration assumptions suggest potential CNG/LNG replacement of OBFs of 44-197 mmscfd by 2010, rising to 188-1,027 mmscfd by 2025. While projected absolute levels of OBF replacements only appear significant after 2020 in the Median and High cases, they still constitute a mere 2.8-5.5% of the 2025 OBF consumption projected by the Department of Energy Mineral Resources under the "Business as Usual" scenario and less than 2.6-5.1% of the 2025 OBF consumption under its "Optimal Scenario"[1].

Table 4.14 Potential CNG/LNG Replacement of OBF, Low Case

MMCFED	2005	2010	2015	2020	2025
Power	-	31	41	55	73
Industry	-	6	8	10	14
Transportation	0.2	8	35	77	101
Total	0.2	44	84	142	188

Table 4.15 Potential CNG/LNG Replacement of OBF, Median Case

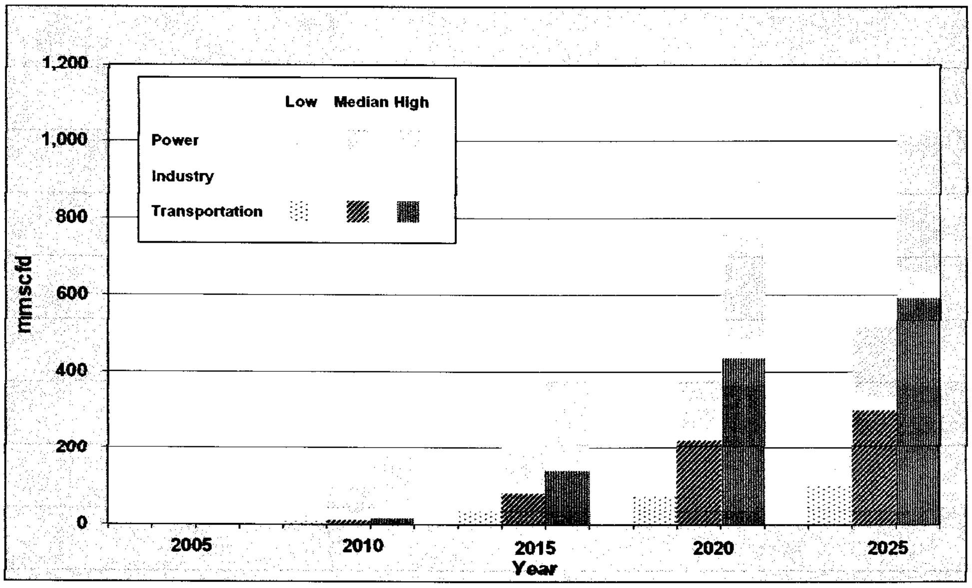
MMCFED	2005	2010	2015	2020	2025
Power	-	76	102	137	183
Industry	-	14	19	26	34
Transportation	0.2	12	84	223	299
Total	0.2	103	205	385	516

Table 4.16 Potential CNG/LNG Replacement of OBF, High Case

MMCFED	2005	2010	2015	2020	2025
Power	-	153	205	274	366
Industry	-	29	38	51	68
Transportation	0.2	16	142	435	592
Total	0.2	197	385	760	1027

[1] "Energy Industry Development", Blueprint of April 1, 2005 by the Department of Energy and Mineral Resources.

Figure 4.1 Potential CNG/LNG Replacements of OBFs



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5.1 INTRODUCTION

This section presents generalized costs of Oil Based Fuel (OBF) products delivery as functions of refinery-to-retail distance and volume. The cost of delivery is the sum of the transportation charges associated with shipping from the refinery gate to a storage terminal, storage at the terminal, transportation from terminal to depot and distribution from depot to retailers/consumers in different domestic market locations in Indonesia. The cost of delivery added to the cost of the OBF product at the refinery gate constitutes the cost of OBF supply, which is a reference in the determination of gas netback values and thereby the competitiveness of CNG/LNG supply in OBF markets (Task 7) and OBF market capture (Task 8).

5.2 APPROACH

The approach to determining the cost of OBF supply comprises:

i. Identifying the links of a generic OBF products supply chain;

ii. Quantifying investments in and operating costs of each link;

iii. Calculating shipping/storage/distribution tariffs as functions of distance and volume by discounted cash flow analysis to provide a specified investor's rate of return; and

iv. Determining the delivered cost of OBF products in selected fuel market locations within Indonesia by adding the price of OBF product at the refinery gate to the calculated shipping/storage/distribution tariffs.

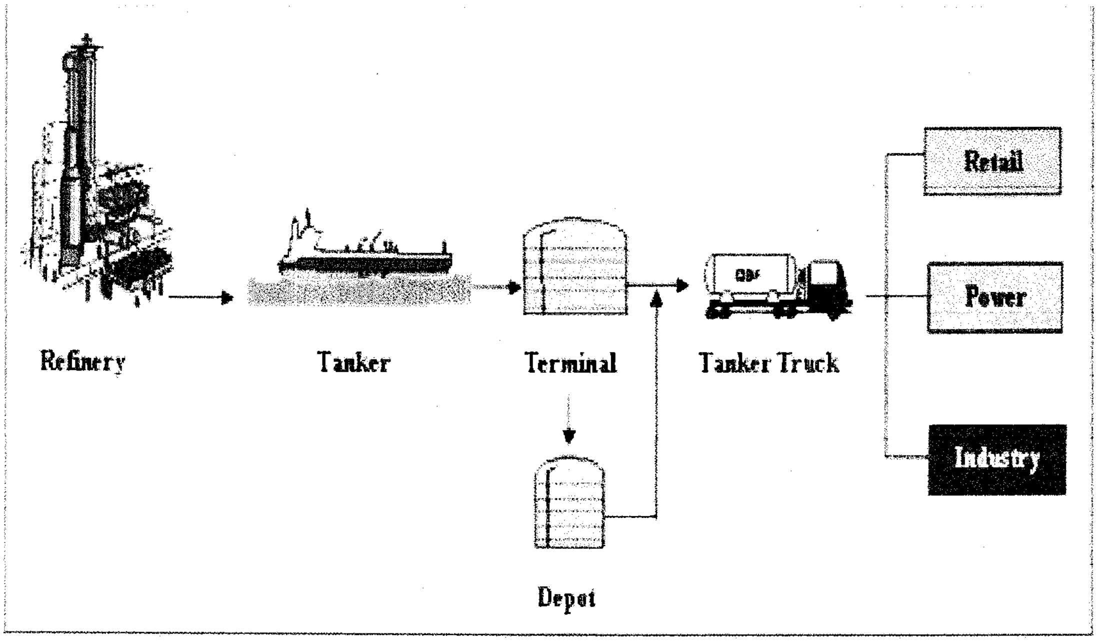
The cost of OBF delivery determined in this manner will be compared with current and projected future practice.

5.3 OBF PRODUCT SUPPLY CHAIN

The generic OBF products supply chain employed in this study is shown diagrammatically in Figure 5.1 below.

The generic OBF products supply chain commences at a refinery gate in Indonesia or Singapore. Transportation to a receiving terminal/tank farm/main depot is assumed to be by product tanker. The OBF products are then delivered by pipeline to subsidiary depots, from where distribution to retail outlets takes place by trailer trucks. In any specific situation, one or more of the legs/nodes may not apply, e.g., distribution directly from a refinery tank farm/terminal to retailers skips marine shipping, pipelining and subsidiary depot storage. Likewise, certain products may be shipped directly to the end user skipping the retail station.

Figure 5.1 OBF Products Supply Chain



5.4 OBF DELIVERY COST

The cost of OBF delivery as a function of volume and distance is determined as the sum of the costs, or tariffs, of the individual links in the supply chain. Tariffs are determined for each link in the supply chain allowing for a 15% investor's rate of return. The findings are summarized in the subsections below, while assumption and calculation details are contained in the Appendix B.

5.4.1 Shipping Costs

The key assumptions underlying OBF product tanker freight tariff determinations are listed in Table 5.1 below.

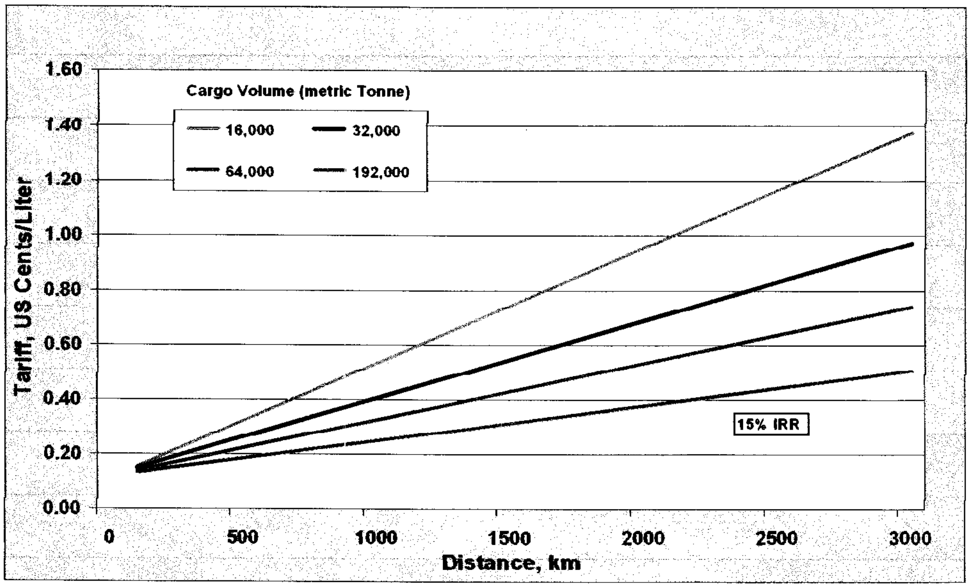
Based on these assumptions, freight tariffs for shipment of OBF products were calculated as functions of distance and volume to yield a 15% investor's rate of return using a discounted cash flow model. The cash flow model and sample freight tariff determinations are contained in Appendix B. There is no significant variance in the tanker freight tariffs for different OBF products. Rather, smaller tankers tend to be hired for IDO and HFO shipments than for HSD (High Speed Diesel), also sometimes called Automotive Diesel Oil (ADO), shipments due to lower volumes of demand. HSD is typically freighted by 40,000-80,000 DWT tankers, while 20,000-40,000 DWT tankers are usually used for IDO and HFO shipments.

Table 5.1 Tanker Freight Tariff Assumptions

Table of Assumptions			
Size Ship (DWT)	40,000	80,000	240,000
Investment, $MM	35	52	96
Manning, $MM/Year	0.83	0.91	1.23
Stores & Lubes, $ MM/Year	0.50	0.55	0.64
M&R, $ MM/Year	0.29	0.33	0.49
Speed avg, kts/h	15	15	14.6
Port Costs $MM/Year	0.50	0.65	1.80
Fuel Cons, T/d	27	46	91
Admin&Other, $MM/Year	0.21	0.23	0.29
Load/Disch., days	*0.64*	*0.93*	*1.40*
Delay, days	0.08	0.14	0.60
P&I, $ MM/Year	0.10	0.16	0.39
H&M, $MM/Year	0.34	0.51	0.95

Figure 5.2 below shows graphically the tanker freight tariffs as functions of shipping distance and tanker size. They range from U.S. Cents 0.3 per liter for a shipping distance of 500 km to U.S. Cents 0.8-1.10 per liter for a distance of 2,500 km. Current tanker freight tariffs are higher than those shown in Figure 5.2 due to a shortage of product tankers.

Figure 5.2 OBF Products Tanker Freight Tariffs



5.4.2 Terminal/Depot Costs

The key assumptions underlying OBF products terminal/depot tariff determinations are listed in Table 5.2 below.

Table 5.2 Terminal and Depot Tariff Assumptions

Item	Unit	Terminal Capacity		
Throughput	kl/month	400,000	500,000	600,000
Design Storage	kl	460,000	575,000	690,000
Capital Expenditure	$ MM	34	40	45
Annual Operating Expense	$ MM	2.74	3.18	3.59
Harbor - Terminal Pipeline				
Capital Expenditure	$ MM	8	8.8	10
Annual Operating Expense	$ MM	0.24	0.26	0.29

Item	Unit	Depot Capacity		
Throughput	kl/month	20,000	40,000	60,000
Design Storage	kl	23,000	46,000	69,000
Capital Expenditure	$ MM	4.6	7.3	9.6
Annual Operating Expense	$ MM	0.37	0.59	0.77
Terminal - Depot Pipeline				
Capital Expenditure	$ MM	16	20	22
Annual Operating Expense	$ MM	0.48	0.6	0.66

Based on these assumptions, OBF product storage tariffs were calculated as a function of throughput volume to yield an investor's rate of return of 15% using a discounted cash flow model. The cash flow model and sample storage tariff determinations are contained in Appendix B. There is no material difference in storage tariffs for different OBF products.

Figures 5.3 and 5.4 present graphically the terminal and depot tariffs as functions of throughput volume. Terminal tariffs range from U.S. Cents 0.25 – 0.22 per liter, while depot tariffs vary from U.S. Cents 1-2 per liter as throughput increases over the ranges examined.

As shown in Figure 5.5 below, total OBF terminal and depot tariffs range from U.S. Cents 1.5-2.5 per liter dependent on the depot size, but essentially independent of the terminal size, at least for the throughput range of 400,000-600,000 kiloliters per months.

Figure 5.3 OBF Products Terminal Tariffs

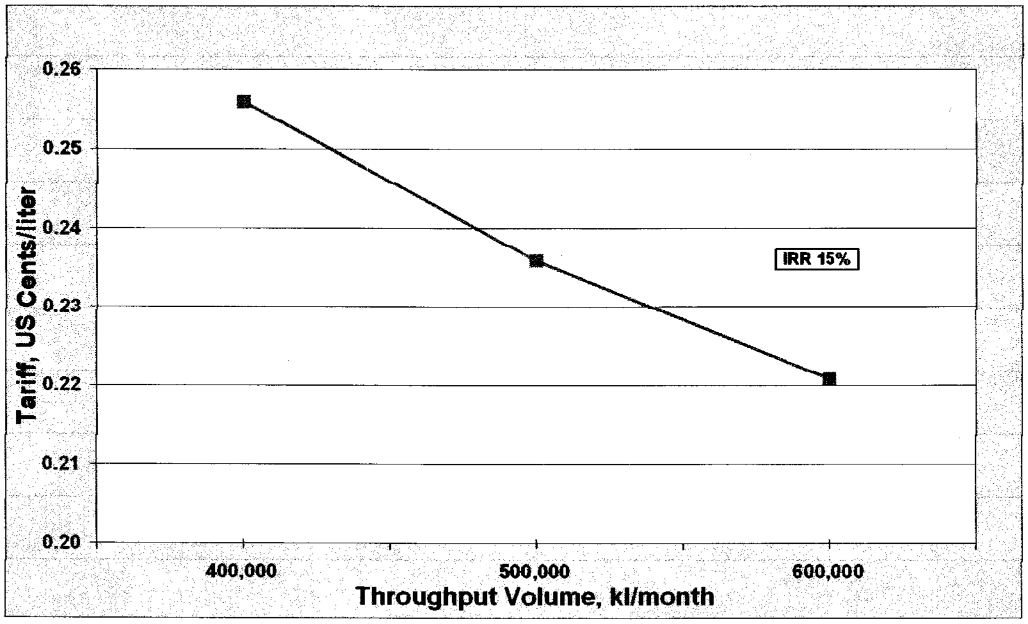


Figure 5.4 OBF Products Depot Tariffs

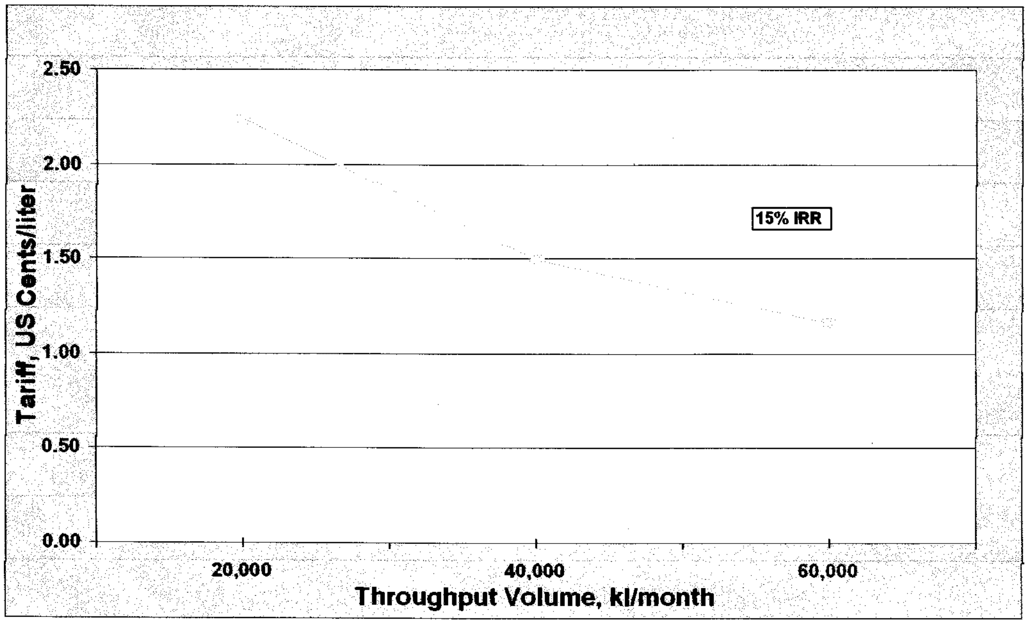
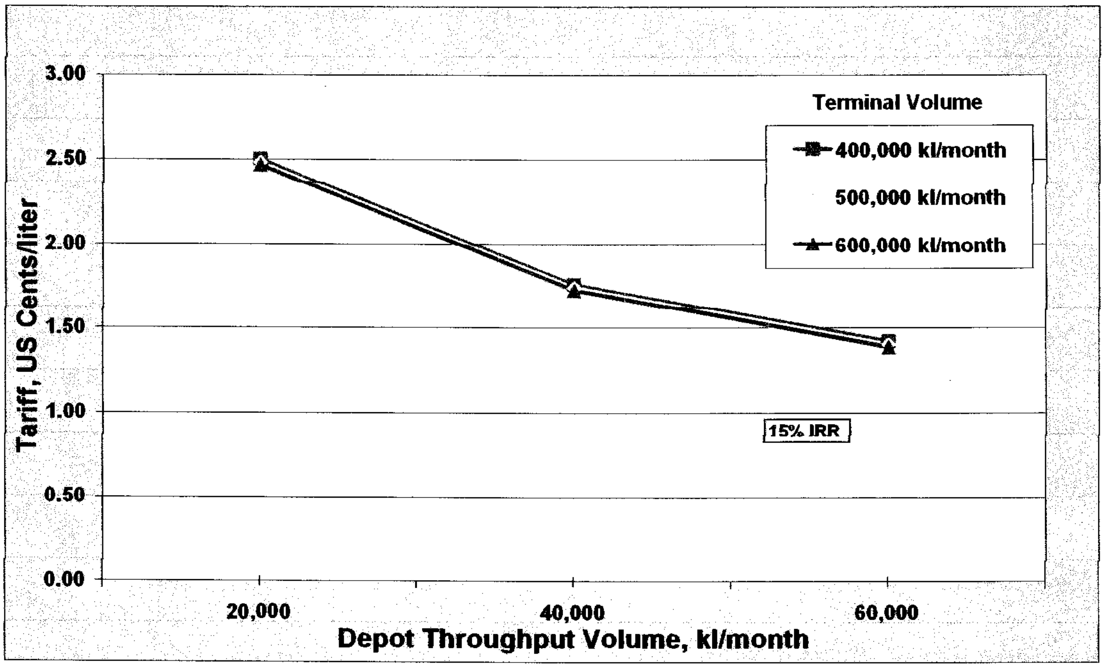


Figure 5.5 OBF Products Terminal & Depot Tariffs



5.4.3 Distribution Costs

The key assumptions underlying OBF products distribution tariff determinations are listed in Table 5.3 below.

Table 5.3 Distribution Tariff Assumptions

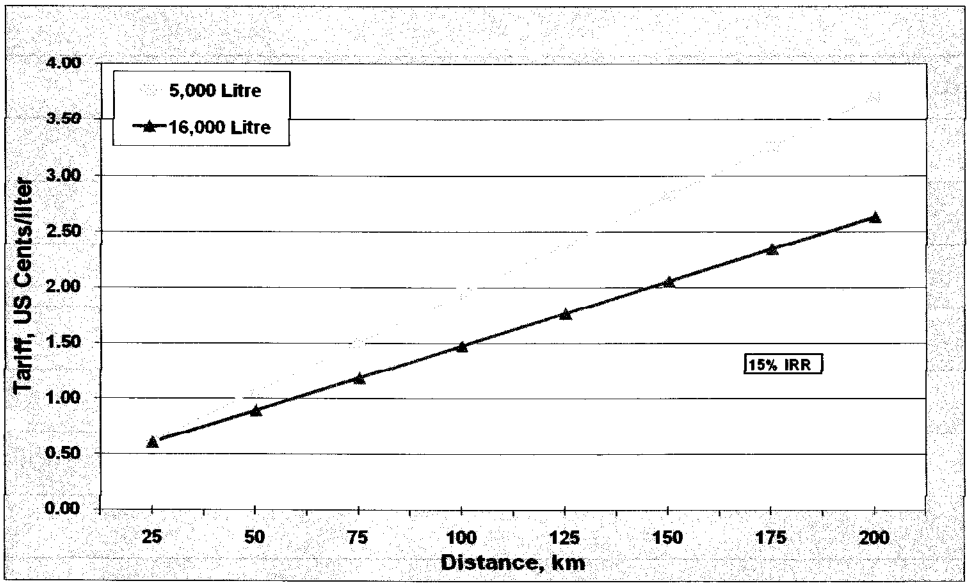
Item	Unit	Vehicle Size (liters)	
		5,000	16,000
Capital Expenditure (per vehicle)	$ M	28	61
Annual operating expenses	$ M	32	59
Operating Days per year (per vehicle)	day	280	280

Based on these assumptions, OBF distribution tariffs were calculated as functions of distance to retail outlet and volume to yield an investor's rate of return of 15% using a discounted cash flow model. The cash flow model and sample distribution tariff determinations are contained in Appendix B. There is no material difference in distribution tariffs for different OBF products, although distribution charges for HFO usually are slightly higher than for HSD and IDO due its more viscous nature.

Figure 5.6 shows graphically the distribution tariff as functions of distance and throughput volume. The tariff ranges from U.S. Cents 0.6 per liter for a distance of

25 km to U.S. Cents 2.5-3.7 per liter for a distance of 200 km. 16,000 liter tanker trucks represent the lower end of the range.

Figure 5.6 OBF Products Distribution Tariffs



5.4.4 Carrying Costs

This model of the OBF products supply chain assumes that the OBF products distributor incurs "carrying" costs as a result of the lag time between payment for products received at the refinery gate and receipt of payment from retailers. The key assumptions underlying carrying cost determinations are listed in Table 5.4 below. *Carrying time and cost of funds were assumed the same for all OBF products.*

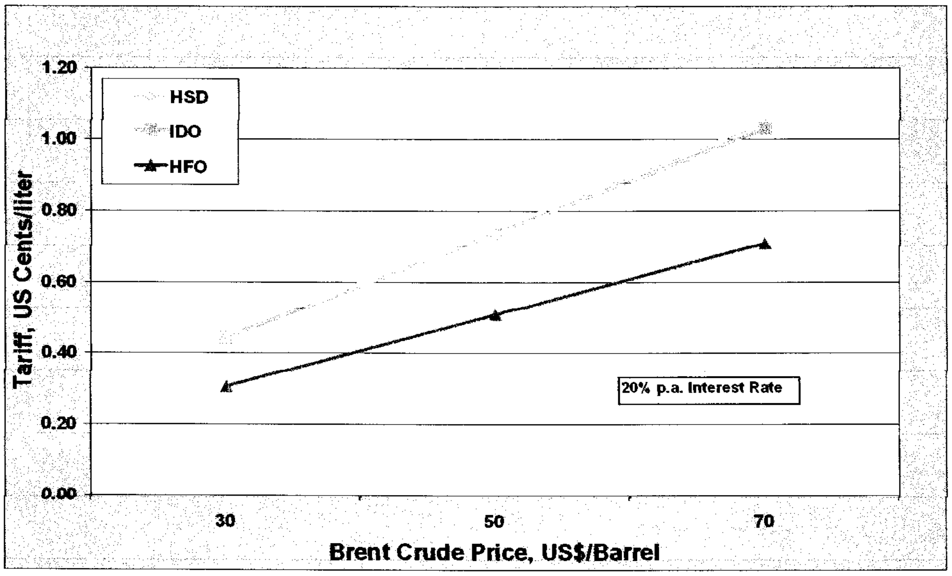
Table 5.4 Carrying Cost Assumptions

Item		Unit	
Characteristics			
	Singapore –	Days	4
	Storage	Days	30
	Distribution	Days	1
Brent Crude Price		**$/barrel**	30, 50, 70
OBF – Brent Multiplier			
	ADO		1.15
	IDO		1.11
	HFO		0.83
Interest Rate		**%**	**20**

Based on these assumptions, carrying charges were calculated for different product price levels, the details of these calculations being presented in Appendix B.

Figure 5.7 below shows graphically the carrying costs as functions of different levels of OBF product prices ex. refinery.

Figure 5.7 OBF Products Carrying Costs



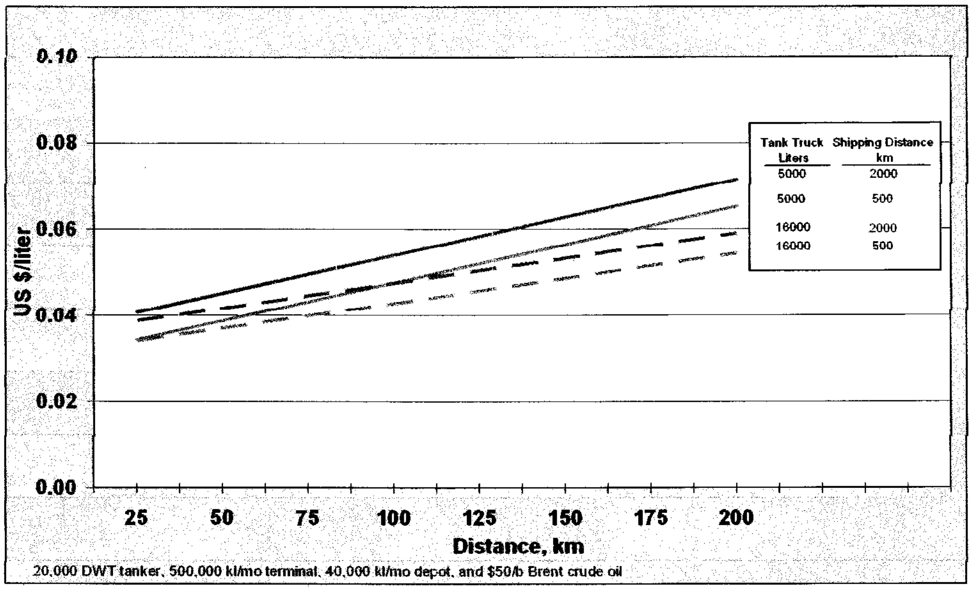
The carrying charges for HFO range from U.S. Cents 0.3-0.7 per liter, while those of HSD and IDO range from U.S. Cents 0.45-1.05 per liter, both ranges reflecting an underlying $30-70 per barrel crude oil price range.

5.4.5 OBF Products Shipping/Storage/Distribution/Carrying Charges

The cost of delivering OBF products to retail outlets as functions of volume and distance are presented below as the sum of the corresponding shipping, terminal/depot, distribution and carrying charges presented in the previous subsections. The summation details are contained in Appendix B, while Figure 5.8 below presents them graphically.

The cost of OBF delivery ranges from about $0.04 per liter for a distribution distance of 25 km to about $ 0.55- 0.70 per liter for a distribution distance of 200 km. The lower end of the range reflects a larger tank truck size. While the cost of OBF delivery is quite independent of shipping distance, the larger tanker truck size of 16,000 liters shaves $0.01 off the delivery cost at distribution distances above 150 km.

Figure 5.8 OBF Products Shipping/Storage/Distribution/Carrying Charges



5.4.6 OBF Cost of Delivery Comparisons

The generic costs of IDO delivery developed in the previous subsections are compared with published delivery charges in Table 5.5 below.

Table 5.5 IDO Transportation and Distribution Cost Comparisons, US Cents/Liter

T&D Costs[1] Only	T&D Costs Plus Retail Margin		
This Study	1999 Actuals[2]	MOPS[3]	2006 Actuals[4]
4.3 - 5.9	1.95	6.5	6.5 - 8.1

[1]Transportation and Distribution costs [2]Petrominer, May 15, 1999

[3]Mid Oil Platts Singapore, i.e., 15% of Singapore IDO at $69/B

[4]Public Service Obligation "alphas" granted to Pertamina for 2006 by BPH Migas. Source: Petrominer, August 15, 2006

The OBF delivery costs developed in this study compare favorably with current imputed transportation and delivery costs represented by the MOPS formula and the "Public Service Obligation" supply and distribution charge granted Pertamina for 2006 considering that the latter includes a retail margin and that the 8.1 cents/liter "alpha" applies to Pertamina's remote West and East Nusa Tenggara marketing districts. The "1999 Actuals" date back to a point in time, when Pertamina was under political and public pressure to demonstrate efficiency in fuel distribution and went to great lengths to explain its "best of class" performance.

5.5 OBF COST OF SUPPLY

The delivered cost of OBF products to retail outlets as functions of volume and distance have been determined as the sum of the price of the relevant OBF product at the refinery gate and applicable shipping/terminal/depot/carrying charges presented in the previous subsection. Three different levels of OBF product prices were used corresponding to $30, $50 and $70 per barrel of Brent crude oil. Detailed results are contained in Appendix B.

As industrial HSD/IDO consumption is the main target for replacement by SMS CNG/LNG-based gas, only the costs of HSD supply are presented in Table 5.6 below for the three different levels of crude oil price and distribution distances of 75 and 200 km.

Table 5.6 HSD Costs of Supply, $/mmBtu

Crude Oil, $/B	30		50		70	
Depot-Retail, km	75	200	75	200	75	200
HSD T&D[1]	1.16	1.60	1.16	1.60	1.16	1.60
HSD @ Refinery	5.87		9.79		13.71	
Delivered Cost of HSD	7.03	7.47	10.95	11.39	14.87	15.31
T&D Cost, % of Delivered Cost	16%	21%	11%	14%	8%	10%

[1]Transmission and Distribution

T&D costs represent 8-21% of the cost of supply of HSD depending upon the price of HSD at the refinery gate.

These HSD costs of supply will be used in Task 7 to determine the price competitiveness of CNG/LNG-based gas in OBF markets.

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6.1 INTRODUCTION

This section reviews the feed gas quality requirements for CNG/LNG manufacture and transportation, discusses briefly gas treatment processes to meet such specifications, sets out the volume requirements for typical SMS CNG/LNG delivery projects and identifies potential sources within Indonesia.

6.2 CNG/LNG FEED GAS SPECIFICATIONS

Natural gas used in CNG and LNG manufacture must meet certain minimum specifications to avoid equipment damage and hazards either in manufacturing, storage, transportation or eventual end-use. The requirements will be discussed below by product.

6.2.1 CNG Feed Gas Specifications

Regulations on feed gas requirements for CNG manufacture, transportation and storage are provided by the U.S. Department of Transportation (DOT). The DOT specifications for gas transported as CNG in steel cylinders are contained in Table 6.1 below.

Table 6.1 CNG Feed Gas Specifications

Component	Maximum Value
H_2O	0.5 lbs/MMscf
H_2S	0.1 grains/100 scf
O_2	1.0% vol
CO_2	3.0% vol
All non-HC gases listed above	4.0% vol

All wellhead and most transmission pipeline gas avails in Indonesia would need to be treated prior to use in CNG manufacture, as they would not meet these specifications in their native state. The presence of hydrogen sulfide in a gas stream is uniquely field-specific.

6.2.2 LNG Feed Gas Specifications

Minimum feed gas specifications for LNG manufacture, transportation and storage are provided by the liquefaction equipment manufacturers to protect the process equipment from corrosion and failure. The amount of C_2+ hydrocarbons in the LNG feed gas stream is usually constrained by the end-user. Table 6.2 below provides generally accepted feed gas specifications for LNG manufacture and end-usage.

Table 6.2 LNG Feed Gas Specifications

Component	Maximum Value
CO_2	100 ppm
H_2S	5 ppmv
H_2O	1 ppmv
Mercury	10 nanograms/Nm3
Benzene	10 ppmv
C_5+	0.1 mol%

All wellhead and most transmission pipeline gas avails in Indonesia would need to be treated for use in LNG manufacture, as they would not meet these specifications in their native state. The low level of mercury is dictated to prevent corrosion of the aluminum heat exchangers at the heart of the liquefaction process.

6.2.3 CNG/LNG Feed Gas Pre-treatment

Dependent upon gas composition, feed gas pre-treatment prior to entering the compression/liquefaction stage consists of up to four steps:

- Separation of free liquids and solids;
- CO_2 and H_2S removal;
- Dehydration; and
- Chemical binding of mercury

An inlet filter separator is needed to remove any free liquid or solids entering the plant with the feed gas. These devices generally contain filter cartridges and sufficient volume for liquid separation and handling. Using a filter separator protects the downstream treating units from contaminants that would cause operating problems.

After inlet scrubbing, CO_2 is removed from the gas stream, often called "sweetening", usually with an amine based solvent system. Methyldiethanol amine (MDEA) is the most popular solvent currently in use capable of removing CO_2 to below 100 parts per million by volume (ppmv). CO_2 and any H_2S present in the feed gas stream are removed concurrently in the amine unit.

The amine unit is followed by a molecular sieve or glycol dehydration system, dependent upon the scale of operation. The molecular sieve system can be designed to also remove CO_2. However, that is usually only economically viable for smaller gas volumes, typically less than 5 mmscfd.

Mercury, if present in the feed gas, is removed with a guard bed downstream from the dehydration unit. This bed is a sulfur impregnated carbon or alumina catalyst, which reacts with the mercury for near complete removal.

6.3 CNG/LNG VOLUME REQUIREMENTS

CNG and LNG feed gas sources range from wellhead to transmission pipeline outlets and the gas quality varies accordingly. As will be shown in the subsection below, wellhead gas and transmission pipeline gas compositions vary considerably in Indonesia and in consequence hereof so do gas reserve requirements for SMS CNG and LNG projects. However, a range of 5 to 30 percent impurities covers about 85% of reported Indonesian gas reserves, excluding Alpha-D gas reserves in the Natuna Sea. For this range of gas impurities, the gas requirements for SMS terrestrial and marine CNG and LNG projects are presented in Figure 6.1 and 6.2 below. The details of the calculations are contained in Appendix C.

The difference between the cases displayed in Figures 6.1 and 6.2 reflects the varying efficiencies of converting natural gas to CNG and LNG on a small and a large scale, ranging from a 5% loss for marine CNG manufacture to 25% for terrestrial (small scale) LNG manufacture.

Figures 6.1 and 6.2 show gas requirements ranging from 20-60 Bscf for small scale terrestrial CNG and LNG projects to 200-300 Bscf for larger scale marine CNG and LNG projects.

Figure 6.1 Gas Requirements for Terrestrial SMS CNG & LNG Projects

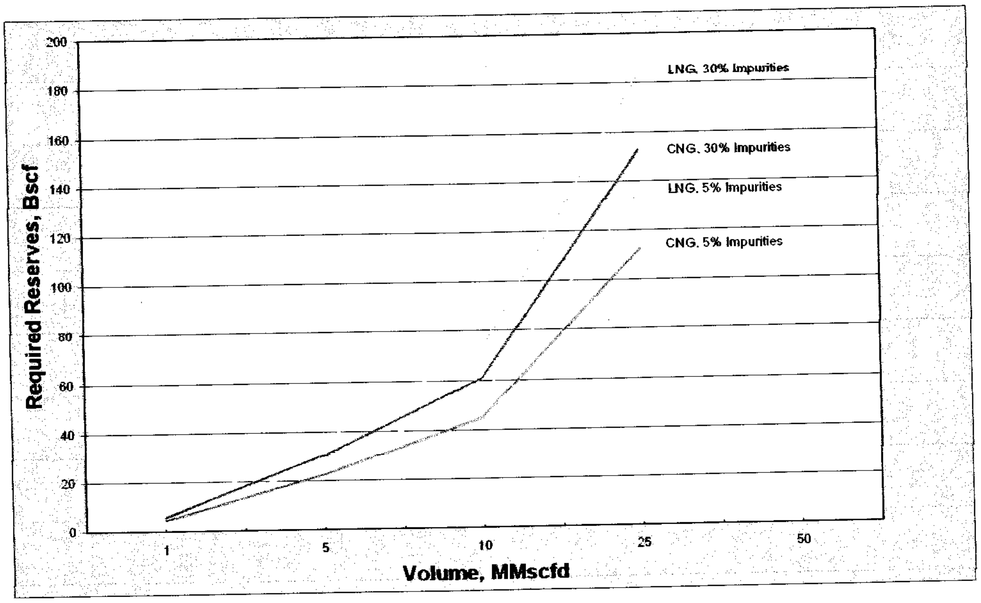
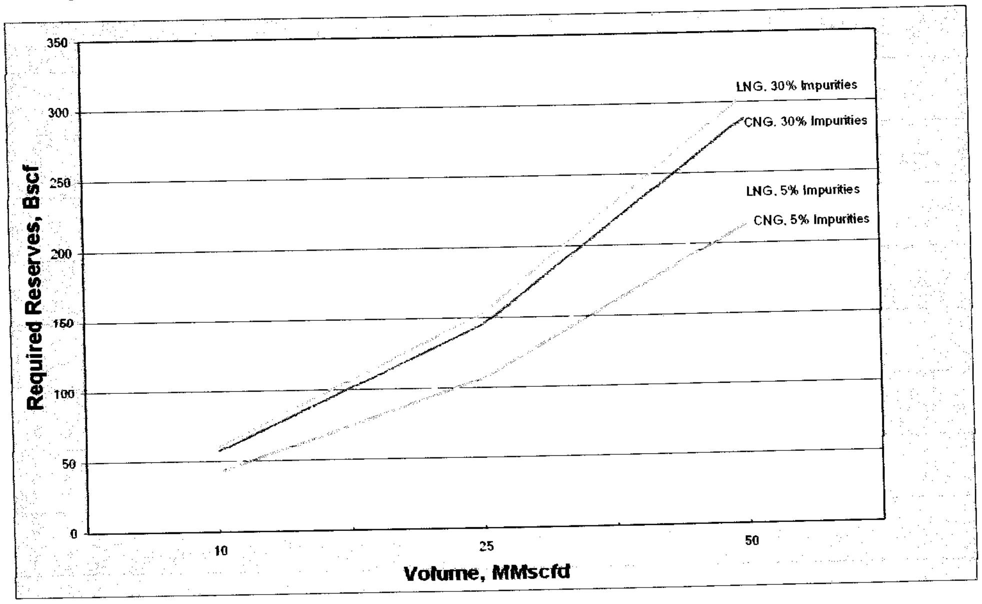


Figure 6.2 Gas Requirements for Marine SMS CNG & LNG Projects



6.4 POTENTIAL SOURCES OF CNG/LNG FEED GAS SUPPLY

Any point along the natural gas supply chain is a potential source of SMS CNG or LNG feed gas provided appropriate pre-treatment of the gas supply. Depending upon the nature of the impurities and their concentrations, certain, usually wellhead, gas sources with high levels of CO_2 or H_2S may be uneconomic as feed gas for SMS CNG and LNG manufacture and transportation. However, after field processing to typically less than 5% CO_2 and essentially complete removal of H_2S, even such gas becomes viable sources of CNG and LNG manufacture.

Uncommitted natural gas reserves, i.e., gas not already contracted for sale as either pipeline gas or LNG, potentially suitable for CNG/LNG manufacture have been compiled for all Production Sharing Contract (PSC) areas in Indonesia along with their wellhead composition and other relevant characteristics. The detailed data are contained in Appendix C. Figures 6.3 through 6.8 contain maps showing the locations and magnitudes of such uncommitted gas reserves along with existing and planned gas transmission and distribution networks. Table 6.3 lists uncommitted gas reserves by province.

Figure 6.3 Uncommitted Gas Reserves in Northern Sumatra

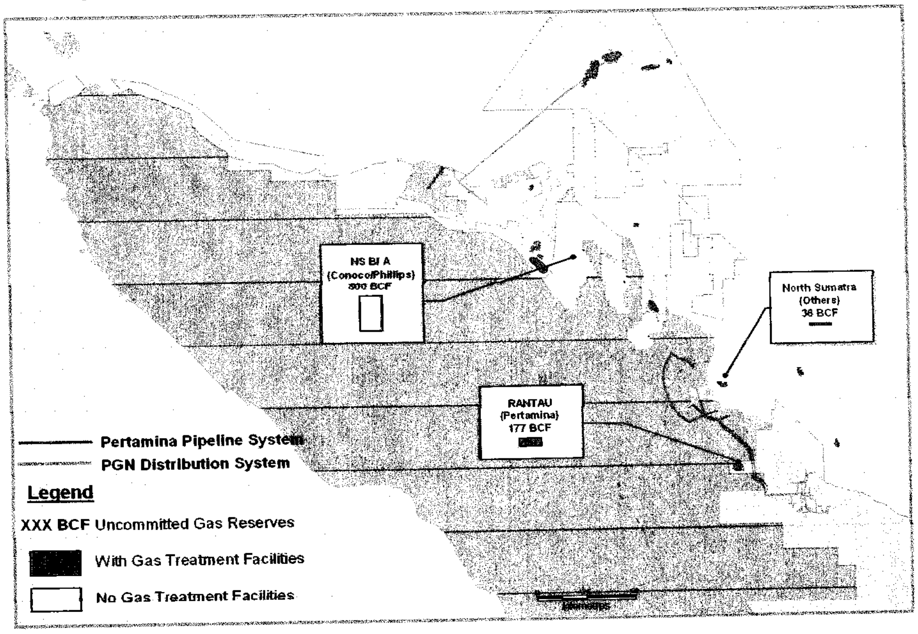


Figure 6.4 Uncommitted Gas Reserves in Central and Southern Sumatra

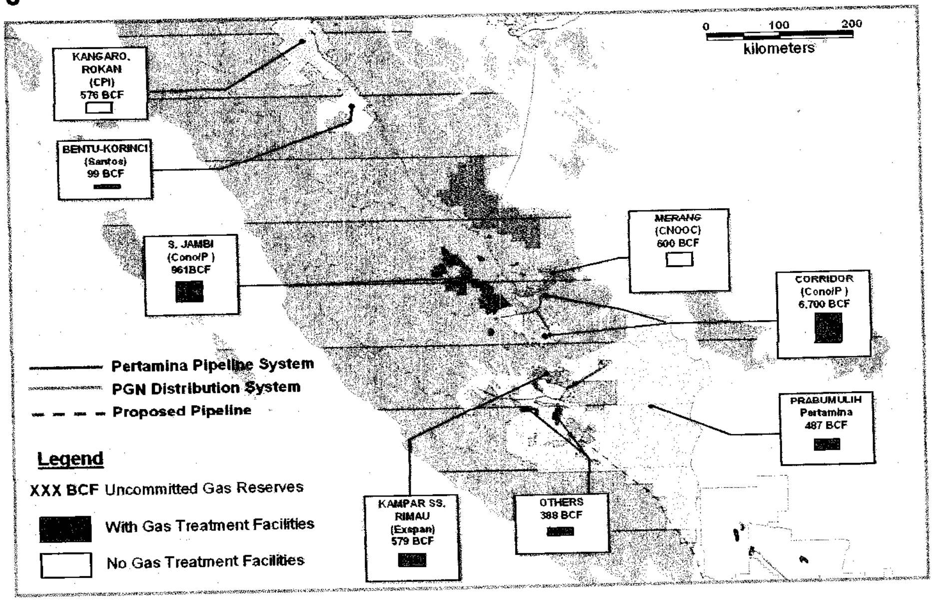


Figure 6.5 Uncommitted Gas Reserves in Java

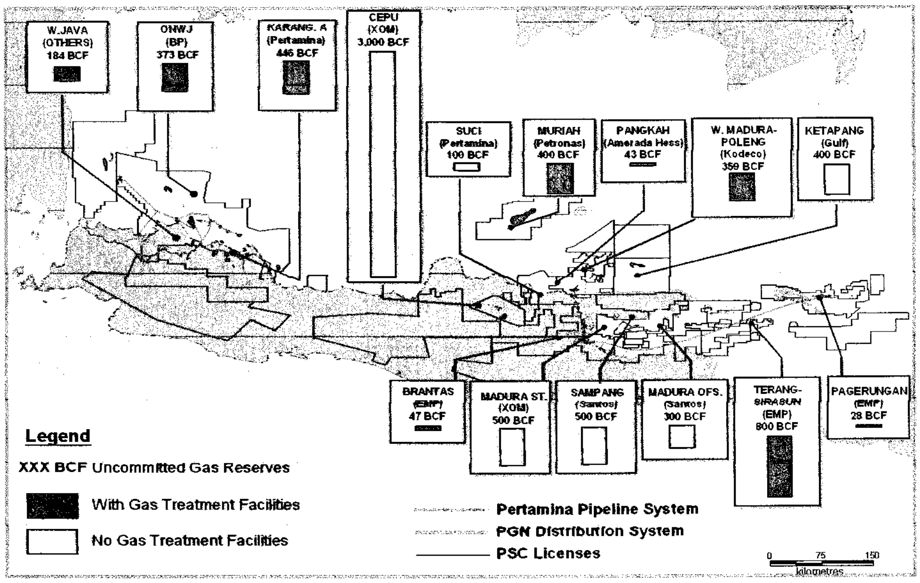


Figure 6.6 Uncommitted Gas Reserves in East Kalimantan

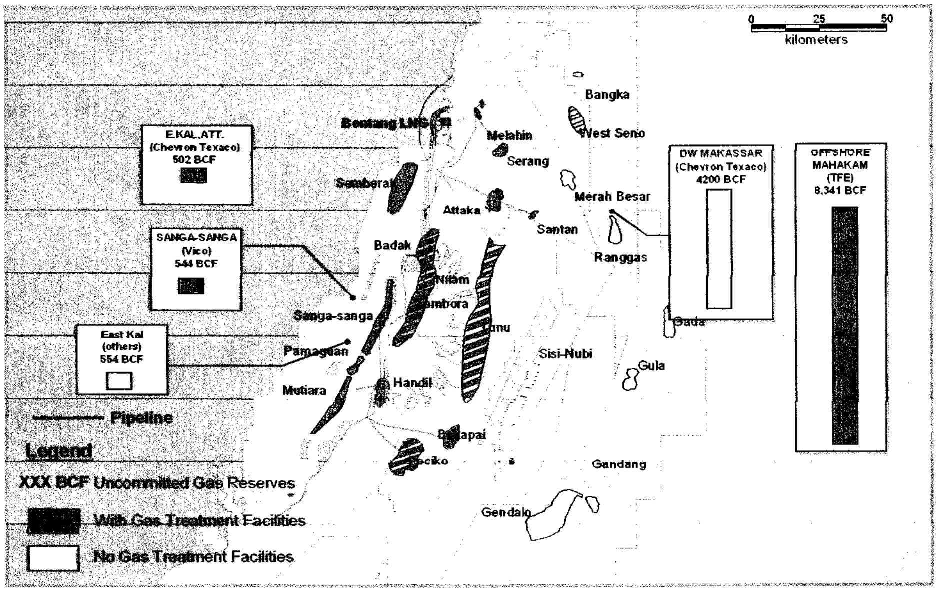


Figure 6.7 Uncommitted Gas Reserves in Sulawesi

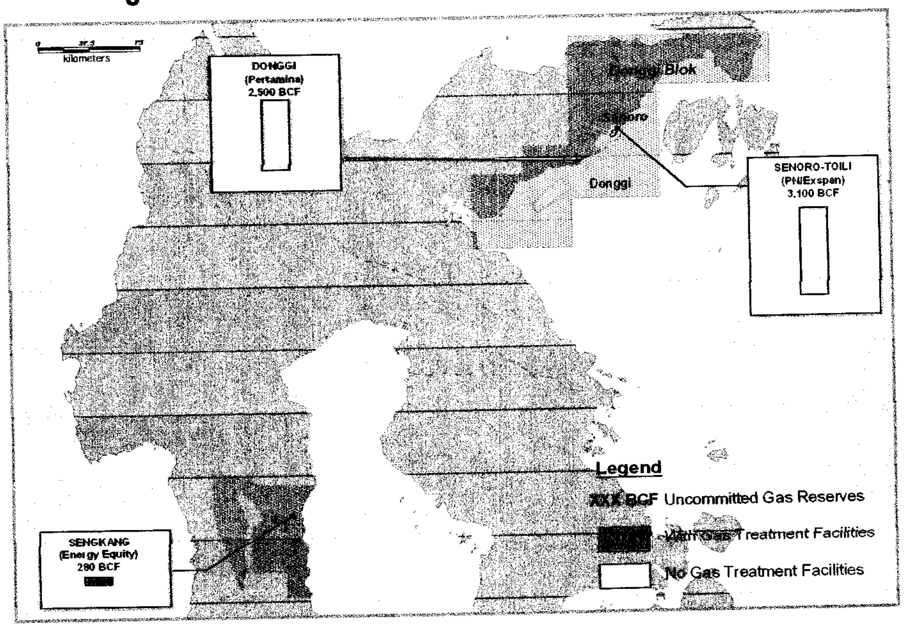


Figure 6.8 Uncommitted Gas Reserves in West Papua

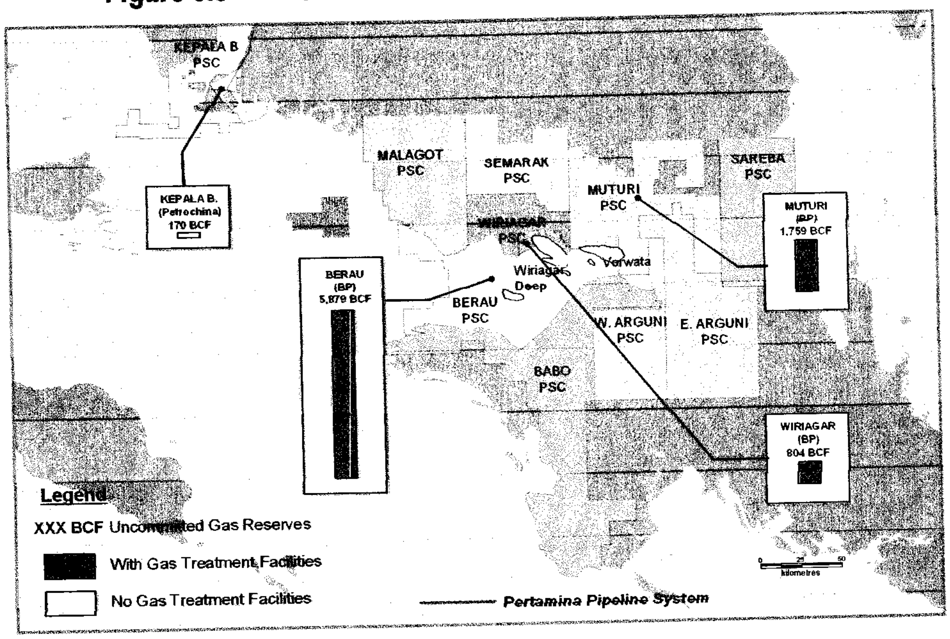


Table 6.3 Uncommitted Indonesian Gas Reserves

Province	Gas Reserves, Wellhead, bscf		
	Risked	Committed	Uncommitted
Aceh	3,237	2,412	825
North Sumatra	350	137	213
Riau (Onshore)	776	620	99
South Sumatra	11,400	7,951	3,449
Jambi	2,495	1,439	1,056
West Java	3,800	2,784	1,016
East Java	7,200	973	6,227
Central Java	486	0	486
East Kalimantan	30,854	16,703	14,151
South Sulawesi	400	120	280
Central Sulawesi	5,600	0	5,600
Maluku	11	0	11
Papua	16,970	8,359	8,611
Total Indonesia	**82,803**	**40,878**	**41,925**

Thus, the potential sources of SMS CNG/LNG feed gas supplies are:

- Wellhead gas in PSCs with undeveloped, uncommitted gas reserves;
- Pipeline quality gas in PSCs with developed, uncommitted gas reserves; and
- Pipeline quality gas along the transmission and distribution networks backed up by uncommitted gas that can be connected to the transmission/distribution networks.

Pipeline quality gas is the preferred source of CNG/LNG feed gas, since its pre-treatment cost is lower.

These maps along with the cost of CNG/LNG supply correlations developed in subsequent Task 5 and the cost of OBF supply data developed in Task 2 are employed in Task 7 (CNG/LNG Competitiveness in OBF Markets) to determine, which of the potential OBF power generation, industrial and transportation market opportunities identified in Task 1 can be supplied economically with CNG/LNG sourced from uncommitted gas reserves.

--oOo--

7.1 INTRODUCTION

This section reviews processes, facilities and technologies used in Small-to-Medium Scale (SMS) manufacture and transportation of Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG).

CNG and LNG are the alternative gas transportation forms utilized, when a pipeline is either not warranted or not yet available.

The single main characteristic of natural gas, which challenges delivery logistics and economics, is its low density (mass-to-volume ratio). Compression to CNG and liquefaction to LNG both improve the weight-to-volume ratio, but each comes with extensive processing and a high price tag, especially compared to liquid fuel, such as diesel. The volume and weight effects are demonstrated in Table 7.1, which shows volumes and weights of LNG and CNG tanks as multiples of a tank of diesel tank with equivalent heating value.

Figure 7.1 Fuel Tank Comparisons

CHARACTERISTIC	LNG:DIESEL	CNG:DIESEL
Heating Value	1:1	1:1
Volume	1.7:1	4.8:1
Weight, incl. tank	1.6:1	17:1

The subsection below reviews the operational and functional parameters of terrestrial and marine supply chains based on two alternative modes of gas transportation, namely as CNG or LNG. The aim is to identify key supply chain stages, describe their relevant operational characteristics, relate the interaction of one stage with the next, and examine the current status of transportation schemes.

The objective is to provide an understanding of the logistics of CNG and LNG operations in support of comprehensive economic analyses, which are presented later.

SMS gas transportation covers deliveries up to 25-50 mmscfd. SMS terrestrial transportation of CNG/LNG is dealt with in more detail than marine transportation, since it relies on established technology and enjoys significantly greater world-wide activity. Marine CNG transportation is a newly emerging concept still in its developmental stage and is constrained by lack of standards and regulations, while, on the other hand, large scale marine transportation of LNG is a well-established, international operation. It is the economic aspects of down-scaling LNG operations to SMS levels, which presents the main challenge.

7.2 STAGES IN THE GAS SUPPLY CHAIN

For purposes of this review, the gas supply chain for both CNG and LNG is considered to comprise five stages, each stage being reviewed in sequence. Gas transportation over land is covered first followed by water-born gas transportation.

The five supply chain stages are:

i. Feed Gas Source and Treatment;
ii. Compression or Liquefaction;
iii. Site Storage;
iv. Transportation; and
v. Customer Storage and Delivery.

7.3 TERRESTRIAL SMS GAS SUPPLY CHAINS

Figures 7.1 and 7.2 show the components that make up the supply chains for *terrestrial CNG and LNG delivery.*

Figure 7.1 Terrestrial CNG Supply Chain

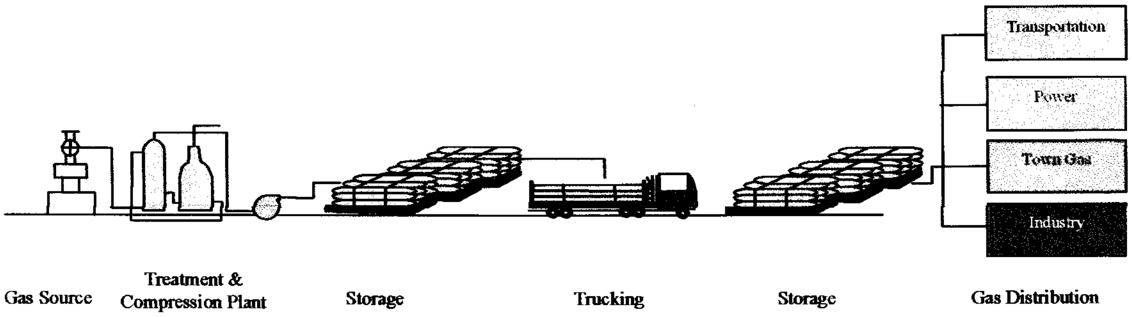
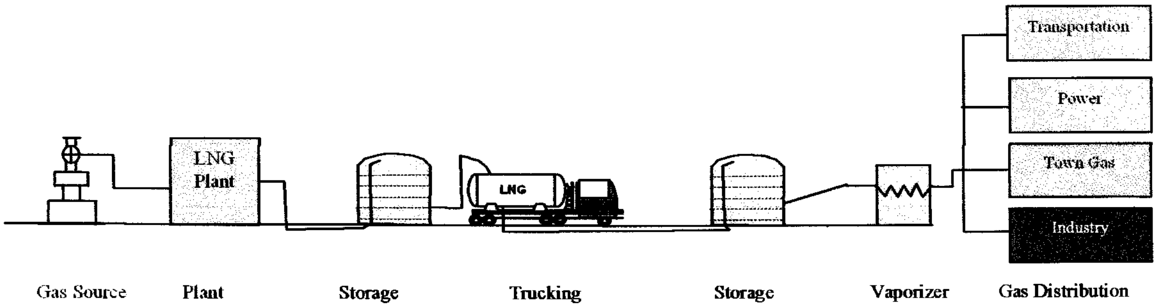


Figure 7.2 Terrestrial LNG Supply Chain



7.3.1 Gas Supply Source and Treatment

A gas supply source can be either a pipeline or wellhead. Pipeline gas usually already meets minimum pipeline quality specifications, whereas wellhead gas may have widely varying compositions. In both cases, further treatment, or purification, is usually needed before compression or liquefaction can be undertaken.

The governing principle of treating feed gas for processing into CNG or LNG is the removal of components that liquefy under compression, solidify under refrigeration or attack working-parts of the system.

7.3.1.1 Gas Specification for CNG

In addition to the need for removal of components that liquefy under compression, quality limits of gas for CNG are often additionally and more stringently determined by the regulations applicable to road transportation of CNG in high pressure containers.

For example, the U.S. Department of Transport (DOT) CFR 49 re Requirements for Steel Cylinders sets limits aimed at preventing internal corrosion of the cylinder. These limits are shown in Table 7.2.

Table 7.2 Allowable CNG Impurities by U.S. DOT[1]

H_2O	0.5 lbs per MMscf
H_2S	0.1 grains per 100 scf
O_2	1.0% vol
CO_2	3.0% vol
All non-hydrocarbon gases (incl. above) but excluding N_2	4.0% vol max.

In the event that DOT or other transportation standards do not need to be met (non-steel containers or lower pressure), the end-use application may determine the gas quality requirements provided they are not less than those that prevent liquefaction under compression.

7.3.1.2 Gas Specification for LNG

The limits on feed gas composition for LNG manufacture are set by liquefaction plant operational requirements. Most plants have similar limits on impurities. Table 7.3 lists typical allowable levels of impurities in feed gas for LNG manufacture.

[1] US Department of Transport (DOT) – SP 8009 Rev 15; CFR 49 Exemption SPO 8009; Cylinder specification 3AAX from 4130X steel.

Excessive levels of certain components, such as CO_2, water and aromatics, can freeze on exchanger surfaces reducing efficiency and causing blockages. Mercury, a common trace element, attacks aluminum, which is a favored heat exchanger material. These impurities must be removed to allowable levels.

Table 7.3 Typical Allowable Levels of Impurities in LNG Feed Gas[2]

CO_2	50-100 ppmv.
H_2S	5 ppmv.
H_2O	1 ppmv
Mercury	10 nanograms/Nm^3
Benzene	1 – 10 ppmv.*
Pentanes and heavier	*0.1 mol%.*

*Depends on overall composition.

Table 7.4 below shows a range of export LNG compositions by country.

Table 7.4 Compositions of LNG Exports by Country[3]

Origin	Methane C1 %	Ethane C2 %	Propane C3 %	Butane C4%	Nitrogen N2 %
Algeria	87.6	9.0	2.2	0.6	0.6
Australia	89.3	7.1	2.5	1.0	0.1
Malaysia	89.8	5.2	3.3	1.4	0.3
Nigeria	91.6	4.6	2.4	1.3	0.1
Oman	87.7	7.5	3.0	1.6	0.2
Qatar	89.9	6.0	2.2	1.5	0.4
Trinidad & Tobago	96.9	2.7	0.3	0.1	0.0

7.3.2 Compression and Liquefaction

This section defines CNG and LNG parameters. It describes the compression and liquefaction processes and in the case of LNG outlines the cryogenic properties as part of a hazard review.

7.3.2.1 Compression – CNG

CNG is natural gas compressed to a high pressure, commonly 245-265 bars (3,600-3900 psi), to reduce its volume and thereby making transportation in containers more cost effective. Compression from atmospheric pressure to 245 bars reduces the volume by a factor of approximately 245:1.

[2] Source: Black & Veatch Prichard Inc. Overland Park Kansas
[3] Source: Groupe International Des Importateurs De Gaz Natural Liquide.

The most commonly used compressor type for CNG is a reciprocating, positive displacement, multi-stage compressor driven either by an electric motor or gas engine depending on the reliability of the electricity supply and operating costs.

A compressor must receive gas at a regulated, fixed inlet pressure. It raises the gas pressure and delivers it into a high pressure storage facility that shuts down the compressor once the required pressure has been reached.

The number of stages required depends on the available inlet pressure and the required outlet pressure. High gas inlet pressures (27 bars/400 psi and above) allow significant savings on compressor costs and power requirements by reducing the number of needed compression stages.

Generally, multiple compressor units are used to meet load demands, because they provide supply security, permit rotational maintenance and load matching.

7.3.2.2 Liquefaction – LNG

LNG is natural gas chilled to the point of liquefaction at -160°C (-260°F). Its volume is reduced in the process by a factor of approximately 600:1. Natural gas will not liquefy by compression alone.

The process of producing LNG can be divided into two parts:

- Contaminants removal.
- Liquids recovery.

The main differences among most LNG processes are contaminants removal methods and refrigerants used in the chilling cycle. Figure 7.3 below contains a typical LNG plant flow chart.

A number of different chilling cycles are used; some are more suited to SMS production than others. An SMS liquefaction plant will generally trade operational energy efficiency for simplicity and reliability

In a typical liquefaction unit, treated gas is fed into a main heat exchanger, where it is initially cooled to between -45°C (-50°F) and –73°C (-100°F). Gas and heavy hydrocarbons, which might solidify at LNG temperatures, are removed from the heat exchanger at this point and sent to a separator. Cold gas is then returned to the heat exchanger, where it is liquefied and sub-cooled. LNG exits at -151 to –160 °C (-240 to -255°F) and is sent to storage at near-atmospheric pressure.

The increasing demand for SMS LNG plants is being satisfied by using standardized modular designs, simplified operating schemes and optimized LNG storage facilities, all of which help to minimize capital costs.

Figure 7.3 LNG Plant Schematic

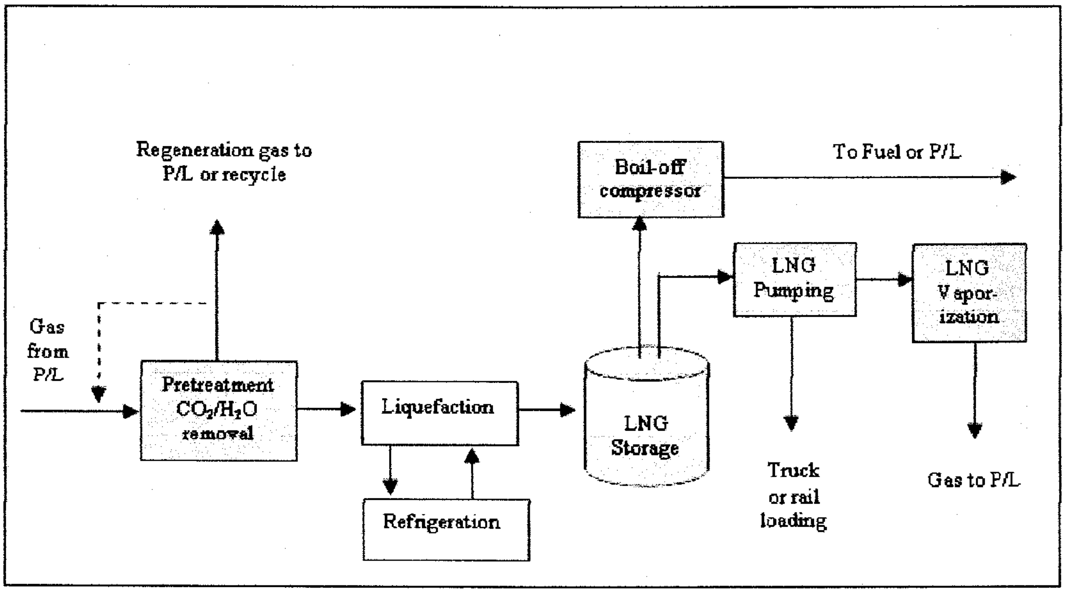


Table 7.5 lists a number of process cycle types, along with typical energy consumption levels.

Table 7.5 Process Cycle Types and Energy Use per Unit of LNG Produced

Process	Abbrev.	kw/ton-day	HP/kg
Typical for SMS			
Turbo-expander	TEX	15.5	0.506
Pre-cooled mixed refrigeration	PCMR	13.0	0.418
Single mixed refrigeration	SCMR	16.8	0.55
Typical for large scale.			
Propane pre-cooled mixed refrigeration	C_3MR	12.2	0.396

- The TEX process is a single cycle turbo-expander refrigeration process that uses the boil-off gas as the refrigerant;
- The PCMR process is a mixed refrigerant process using nitrogen, methane, ethane and butanes as a mixed refrigerant with a conventional refrigeration cycle (ammonia or propane) for pre-cooling;
- The SCMR process is a single cycle mixed refrigerant process using nitrogen, methane, ethane (or ethylene), butanes and pentanes as a mixed refrigerant; and
- The C3MR process, typical of those used in large scale production, is a mixed refrigeration process that uses propane for pre-cooling.

Generally, pentane and heavier components must be removed to protect the system from solids formation. The propane and butane portions may also have to be removed depending on the heating value required for the LNG end product. However, the feed gas to most SMS LNG plants usually contains insufficient liquids to require further processing to meet marketable quality.

7.3.2.2.1 LNG Hazards

LNG is odorless, colorless, non-corrosive, non-toxic, non-flammable and non-explosive in its liquid state. If LNG is spilled, however, it presents two hazards:

1. A rapid, nearly spontaneous transition (Rapid Phase Transition) from the liquid state to the vapor state driven by the heat gained from the underlying spill surface. The effect is a physical explosion caused by the rapid expansion as the phase change takes place; and
2. A thermal explosion, if the vapor mixes with air and comes into contact with an ignition source.

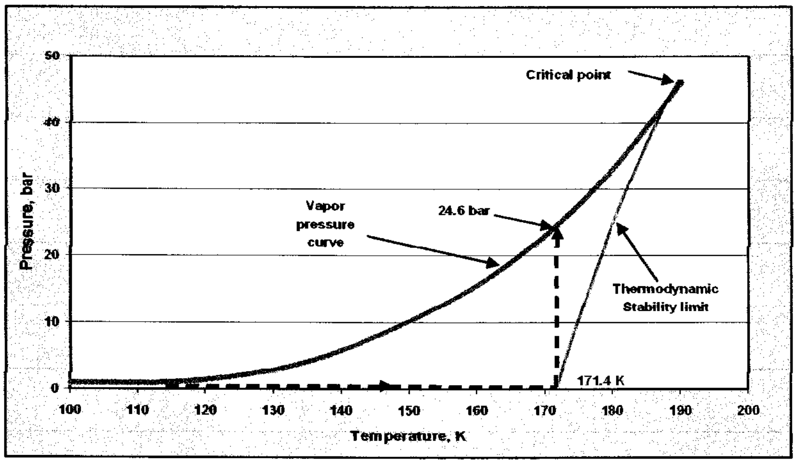
A rapid phase transition is also referred to as a physical explosion, because it does not involve combustion or chemical reaction to create mechanical explosion energy.

Pure liquid methane (CH_4) at ambient pressure boils at 111.6°K (-160°C, -258.8°F). Rapid heating at ambient pressure, as occurs during a spill, quickly causes liquid CH_4 to reach its thermodynamic stability limit of 171.4°K (-102°C, -151.3°F) at the liquid spill surface interface. At this temperature, liquid CH_4 becomes a superheated liquid that can no longer exist as a liquid and has to give up its superheat by expanding rapidly. In theory, the expansion follows the Thermodynamic Stability Limit line shown in Figure 7.4, also called the Rapid Phase Transition. In practice, the reaction path followed is shown by the dashed line. The reason for the path deviation is that the amount of energy in a RPT is quite small and a considerable proportion of this expansion energy is lost to turbulence. The result is that the maximum vapor pressure reached in practice is much lower than theory suggests. As shown in Figure 7.4 below, the practical maximum vapor pressure that can be reached as a result of the RPT is 24.6 bars (361.6 psi) at 171.4°K.

Once the liquid is transformed to a vapor, the rate of heat transfer is very much slower, because the heat transfer is from air (low specific heat content) to the vapor leading to a much lower rate of vapor expansion.

The pressure forces resulting from a RPT are small compared to those released during a combustion reaction of CH_4 and air. The pressure forces generated as a result of a RPT of 1 kg of CH_4 is equivalent to the energy released during combustion of only 0.56 grams of CH_4. In other words, combustion of 1 kg of CH_4 releases 1,780 times more energy than the RPT.

Figure 7.4 LNG Temperature – Vapor Pressure Curve



Thus, the greatest risk from an LNG spill is vapor mixing with air and igniting. Preventing such admixing of air is the focus of safety precautions applied in transportation, storage and handling of LNG.

Physical handling of LNG by personnel must be undertaken with care to avoid contact with the skin. LNG contact with skin can result in serious "cold burns" (frostbite).

7.3.3 Site Storage

This section describes the principle functions of site storage and the different storage methodologies utilized for CNG and LNG as determined by their handling characteristics.

7.3.3.1 Site Storage of CNG

The function of storage at the CNG compressor site is to act as a receiving buffer between the compressor, which produces continuously, and a transportation system that operates in batch mode.

It is usual that portable storage cylinder units act as site storage for CNG, receiving gas directly from the compressors. There are usually three (or more) sets of gas transport modules (canisters/bottles): One at the filling site; one in transit with/on the barge/ship; and one at the user end.

Stationary storage at the compressor site is not used, because decanting from a stationary storage to a mobile storage would result in pressure equalization, i.e., for stationary storage and mobile cylinders of the same size an initial pressure of 265 bars (3,900 psi) in a stationary cylinder would balance to 133 bars (1,950 psi) in each cylinder after decanting. The mobile cylinder would thus be only partially filled.

7.3.3.2 Site Storage of LNG

Storage at the LNG plant site acts as a buffer between the continuously producing LNG plant and a batch transportation system. Normally, storage is sized to equal demand/off-take multiplied by time between tanker arrivals plus 50%.

LNG storage is a cryogenic container designed as two separate pressure vessels one inside the other. The inner vessel stores the cold LNG in its liquid form. It is wrapped with multiple layers of non-combustible insulation and reflective foil (super insulation) and then sealed within the outer vessel. The space between the inner and outer vessels is evacuated to produce a superior insulation.

The inner vessel is protected from over-pressurization by two safety relief valves. The first to open is the primary relief valve. It is designed to safely vent excess pressure from the inner vessel due to normal heat leakage through the insulation and support system or accelerated heat leakage due to loss of vacuum or a fire condition. The second relief valve with a higher set point provides protection in the event the primary relief valve malfunctions or is blocked.

The outer vessel is protected from over-pressurization by an annular space evacuation plug.

LNG is usually stored and then shipped at a temperature slightly below its boiling point and at pressures between 0 barg (0 psig) and 17 barg (250 psig). At these pressures, the LNG temperature is -160°C (-260°F) and -109°C (-65°F), respectively.

Being a liquid, LNG can be pumped (using a cryogenic pump) from the stationary site storage into the transportation tanker for delivery to customers. Loading time for a 33,000 liter tank trailer (a maximum road transportable load) is about one hour.

7.3.4 Terrestrial Transportation

This section on terrestrial transportation of CNG and LNG focuses on the legal weight limits that apply to road movement of all goods, because it is this restriction that most affects the transportation function. It reviews the types and impacts of container weights on maximum, allowable net payload. Comparisons are made with liquid fuel (diesel) net payloads.

7.3.4.1 Terrestrial Transportation of CNG

The challenge in CNG transportation is to carry the largest amount of gas in the lightest possible container.

The most common pressure ranges used for transporting CNG is 205-245 bars (3,000-3,600 psi). At these pressures, a very strong pressure vessel is required and all-steel containers are lowest cost, but also heaviest in weight. The gas volume reduction ratio is 245:1 at 3,600 psi, but the ratio of container-weight to gas-weight is 7.4:1. In other words, the container is more than seven times heavier than the gas content.

Lighter composite cylinders using metal and carbon fiber materials and hoop-wrapping techniques are available and improve the weight ratio, but they are also more expensive.

Full composite, non-metal cylinders from exotic materials with even lower weight ratios are due for release in 2008, but costs are as yet unknown. Table 7.6 shows the ratio of cylinder weights to gas weight for a range of cylinder types

Table 7.6 Weight Ratios of Different Cylinder Types

No.	Cylinder type	Weight of gas, tons	Weight of cylinder, tons	Gas pressure, psi
1	All steel	1	7.4	3,600
2	Composite: Steel with carbon fiber wrapping	1	4.8	3,600
3	Full composite-HDPE with carbon-epoxy over wrap.	1	3.0	3,600

For land transportation, legal limits on truck weights control how much gas can be delivered per shipment.

The combined maximum weight limit for a tractor, trailer and load on first class roads in Indonesia is 44 - 45 metric tons. A typical truck/trailer load arrangement is shown in Figure 7.5 below comprising 9 tons for the prime mover/tractor and 6 tons for the trailer leaving 30 tons available for the load container and the gas. The weight limit is based on allowable axle load limits plus load distribution.

Figure 7.5 Allowable Axle Load Distributions

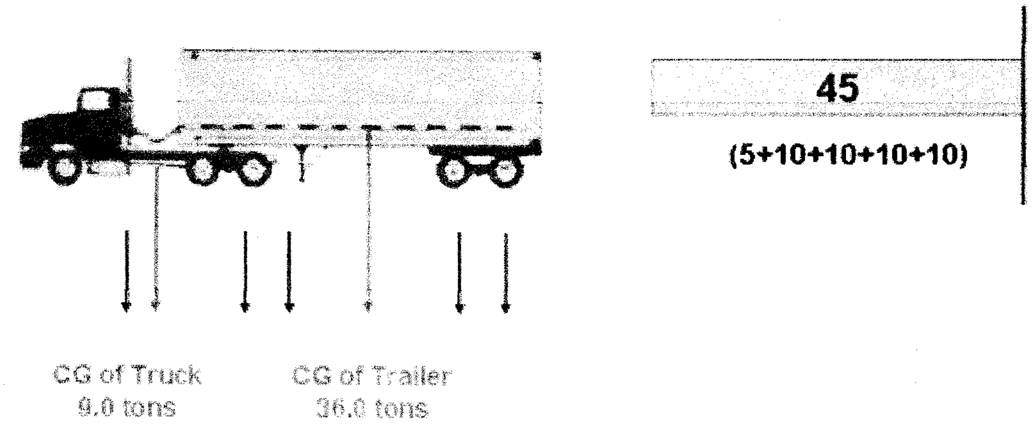


Table 7.7 below shows the amounts of CNG that can be transported in a single load within legal weight limits for the three different types of cylinders listed in Table 7.6 above. To show energy transported in relationship to diesel, the energy content of the CNG is converted into equivalent liters of diesel and listed in the last column of Table 7.7.

Table 7.7 Fuel Quantities and CNG Cylinder Types[4]

Cylinder type	Combined weight, tons	Cylinder weight, tons	Gas weight, tons	Gas, SCF	Diesel, liter equiv.
1	30	26.4	3.6	172,500	4,662
2	30	24.8	5.2	247,600	6,691
3	30	22.5	7.5	359,000	9,703

7.3.4.2 Terrestrial Transportation of LNG

Because of its liquid form, LNG is easier to transport and transfer than CNG and has a much higher energy density. It is transported at near atmospheric pressure resulting in much lighter containers than for CNG.

However, as a cryogenic substance, LNG must be transported in well-insulated containers and use appropriate pumping and safety facilities.

Table 7.7 showed the combinations of container and CNG weights for three different cylinder types, which meet the allowable 30 ton load limit. Table 7.8 below expands Table 7.7 to include LNG. The intent is to show two things: Firstly, the relative gain in net payload weight of LNG transported compared to CNG; and, secondly, the transportation advantage that diesel has over both CNG and LNG.

Table 7.8 Fuel Quantities and CNG/LNG Cylinder Types

Cylinder type	Combined weight, tons	Cylinder weight, tons	Gas (Diesel) weight, tons	Gas, SCF (liter)	Diesel, liter equiv.
CNG 1	30	26.4	3.6	172,500	4,662
CNG 2	30	24.8	5.2	247,600	6,691
CNG 3	30	22.5	7.5	359,000	9,703
LNG cryogenic	30	16.1	13.9	761,300 (33,000)	18,760
Diesel	33.8	4	29.8		32,000

This comparison is made because diesel is often the alternative to CNG and LNG, and transportation cost is a significant factor.

Latest diesel delivery tankers make extensive use of aluminum and optimize tractor designs to reduce non-payload weight. The result is a payload of 29.8 tons of diesel compared with 13.9 tons for LNG, as shown by Table 7.8.

[4] Gas vs diesel energy equivalency based on gas at 1000 Btu/scf and diesel at 37,000 Btu/liter

As shown by Table 7.9 below, while LNG has higher energy content on a mass basis (Btu/kg) than diesel, the larger payload of a volume delimited truck/trailer delivery system means supply of 1.7 times as much energy per diesel delivery compared to LNG delivery.

Table 7.9 Fuel Form Equivalents

Fuel	Kg/liter	Btu/liter	Btu/kg
CNG at 245 bars	0.226	10,950	
LNG at -161°C	0.455	22,336	49,090
Diesel	0.93	36,939	39,780

7.3.5 *Customer Storage and End-use Facilitation*

The function of storage at the end user site is two-fold:

1. Act as a buffer between the periodic deliveries and the utilization rate; and
2. Provide security of supply in the event of interruption to deliveries.

The different physical characteristics of CNG and LNG determine the type of facilities employed. In the case of CNG, the end-use application can have significant impact on gas quantities deliverable. These aspects are discussed in this section.

7.3.5.1 Customer Storage of CNG

Trailer mounted transportation cylinder units are generally used as the means of providing CNG storage at the customer site. When one trailer unit is emptied, it is exchanged for a full unit. Providing security of supply may require the use of more than one parked trailer unit. This has significant impact on site storage costs.

The reasons for exchanging cylinder units were explained in Subsection 7.4.3.1, "Site Storage of CNG".

7.3.5.2 CNG Use Facilitation

CNG is delivered to the customer site at a pressure of around 3,600 psi and must be regulated down to the pressure required by the application. If the application is an industrial establishment, and the gas is to be used for process heating and/or on-site power generation via reciprocating engine, a pressure regulation station is required to reduce the gas to pipeline pressure. Normal distribution pressure inside an industrial establishment ranges from 0.06 to 0.7 bar (1-10 psi) above atmospheric pressure. Because this is a low pressure relative to the delivered pressure, greater than 99% of the gas from the trailer cylinders can be delivered, i.e., there will be very little residual pressure, and thus residue gas, left in the delivery cylinders.

The receiving and regulating station, distribution pipe size and pressure regulators must be designed to accommodate falling inlet pressures as delivery cylinders are emptying.

Because pressure reduction from a high level to a low level causes cooling, the Joule-Thompson effect, additional facilities may be required to prevent malfunction of the regulating equipment due to ice formation and metering errors due to temperature variation.

If the application is a gas turbine, which requires gas at a pressure of 17 bar (400 psi), a residual amount of approximately 11% of delivered gas will remain in the cylinders, thereby reducing the effective delivery quantity.

CNG for Natural Gas Vehicles (NGV) use requires a special approach. The NGV fuel gas cylinder (fuel tank) is filled to a maximum of about 205 bar (3,000 psi.) from the supply source. To maximize extraction of the CNG delivered in the trailer cylinders (initially at 245 bar 3,600 psi), an NGV refueling station usually has a three-bank storage cylinder and compressor arrangement. High, medium and low pressure bank storage cylinders sequentially fill the NGVs, and an on-site compressor maintains the high pressure bank at a margin above the maximum NGV fuel tank pressure. Trailer-mounted storage cylinders are connected to and form an integral part of this system.

Using such a three-bank system and an on-site compressor allows 94% of the gas from trailer cylinders to be emptied out. Without an on-site compressor, even using a sequential filling system, only about 50% of the gas from the trailer unit can be transferred.

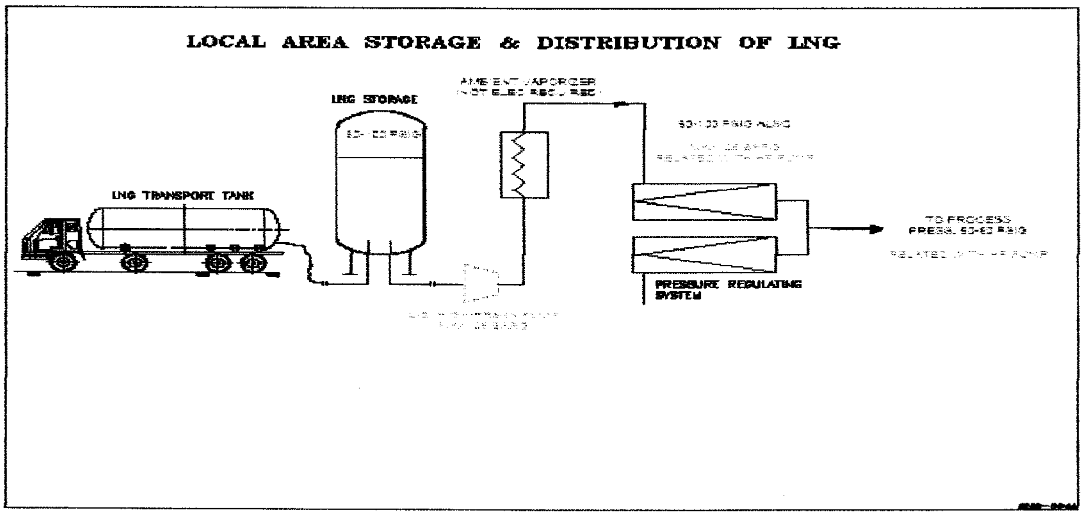
7.3.5.3 Customer Storage of LNG

LNG storage at the customer's site is generally sized to meet 2 days of demand. The receiving facility will consist of:

- A receiving area for the delivery vehicle to safely park while unloading the LNG. A cryogenic transfer pump is usually mounted on the delivery vehicle;
- Stationary cryogenic vessels for LNG storage;
- Vaporization units to convert LNG back to gaseous form; and
- A pressure regulating station to control gas supply into customer pipeline.

A typical LNG receiving station arrangement is shown in Figure 7.6 below.

Figure 7.6 Local Area Storage and Distribution of LNG



The receiving area may be subject to local and government regulations regarding access and vehicle escape routes in the event of emergency. Such regulations usually apply to all types of fuel deliveries. In other parts of Asia, e.g., in Thailand, LPG Delivery Codes are being used in the absence of an LNG-specific Delivery Code.

Regulations regarding vessel positioning usually follow the requirements of NFPA 59A. The key points are: A requirement of 20 m clearance between the vessels and any building or point of ignition and a surrounding containment barrier with a volume equal to that of the largest vessel.

The customer site cryogenic storage vessels are, in principle, the same as those described in Subsection 7.3.4.2 above, except that LNG vaporizing equipment will be part of the facilities.

The vaporization units for SMS operations in Asia generally use ambient air heat through a natural convection heat exchanger eliminating the need for electrical power. Exchangers are sized according to customer gas demand rates. The pressure of the gas exiting the vaporizer depends on the LNG input pump pressure (and pressure rating of the vaporizer). If the application is a NGV refueling station dispensing compressed gas, high pressure LNG pumps allow gas to be vaporized into bulk CNG storage without need for additional compression. Common bulk CNG storage pressure is 250 bar (3600 psi).

Once LNG is in its gaseous state, normal pressure regulating station design principles and equipment can be utilized.

7.4 SMS MARINE CNG AND LNG SUPPLY CHAINS

The supply chain components for marine operations are basically the same as for terrestrial operations, except that transportation is by ship or barge rather than truck/trailers.

This section, therefore, discusses only those aspects that are different from terrestrial operations. Furthermore, SMS marine transportation of CNG is still at the developmental stage, while small scale LNG transportation based on proven technology is embryonic. Reviews of their current status, therefore, form a considerable part of this subsection.

The equipment and facilities making up marine CNG and LNG supply chains are shown schematically in Figures 7.7 and 7.8 below.

Figure 7.7 Marine Based CNG Supply Chain

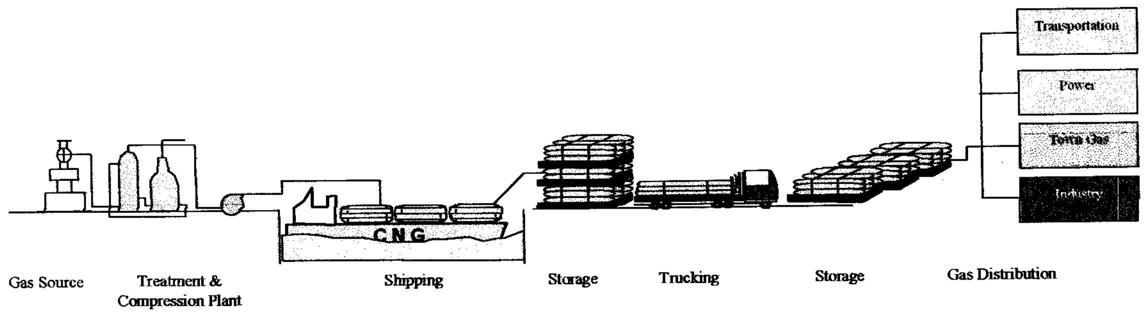
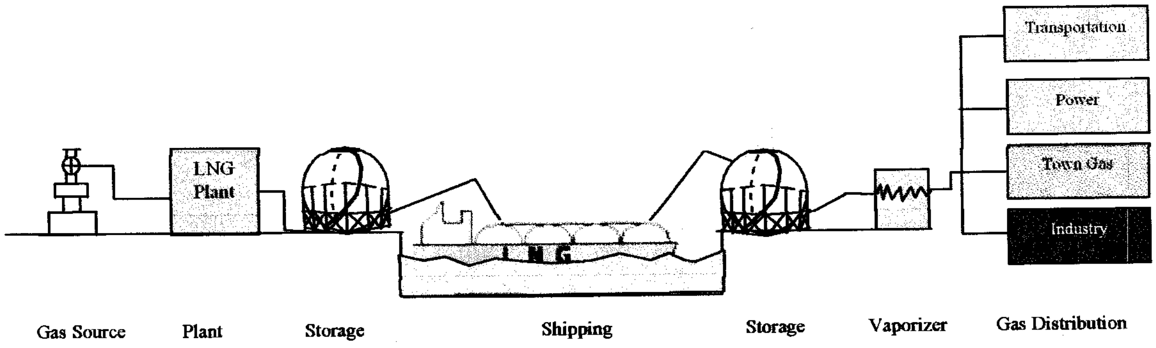


Figure 7.8 Marine Based LNG Supply Chain



7.4.1 SMS Marine Transportation

This subsection reviews the state of development of SMS marine CNG and LNG transportation methods, technologies and attendant regulations

7.4.1.1 Development of SMS Marine CNG Transportation

Marine CNG transportation principles and means are quite different from those of LNG. There are currently no marine CNG transportation regulations. Formulation and adoption of regulations covering the shipping of CNG are needed before marine CNG transportation can progress. Entry into ports, unloading of cargo and insurance coverage all require certification.

However, regulations and standards for marine transport of CNG are in the process of being formulated and CNG shipping is expected to be given a significant boost now that two leading marine certification societies have become involved, namely:

- *American Bureau of Shipping (ABS); and*
- Det Norske Veritas (DNV).

They are being guided in the formulation of regulations by the following:

- IGC Code. (International code for ships carrying liquefied gases in bulk);
- *Class Rules;*
- ASME/ANSI PV and piping codes; and
- FSA (Formal Safety Assessment).

There are currently five different onboard containment systems under development and there is strong competition between U.S., Canadian, and Norwegian enterprises.

Some of these are:

- Coselle by Williams Company, U.S.A. Small diameter pipe (6”) in large coils. Stores 100,600 m3 (3.55 mmscf) at 205 bars (3,000 psi) in the cargo hold;
- Volume Optimized Transport and Storage (VOTS) by EnerSea, U.S.A. Vertical, large diameter pipes in insulated cold-storage. Pressure 88-125 bars (1,300-1,850 psi) and temperature -40°C.
- Knutsen CNG Norway. Vertical thick walled pipe-type bottles. Pressure 240 bars (3,530 psi) and higher.
- TransCanada Pipelines. Gas Transportation Modules (GTM). Fiber glass wrapped steel pipe, 65% of the weight of all-steel cylinders. Storage pressure of 205 bars (3,000 psi).
- Trans Ocean Gas, Canada. Fiber reinforced plastic cylinders. One-third to one-sixth of the weight of all-steel cylinders.

Systems for shipment of CNG by both barge and ship are under development.

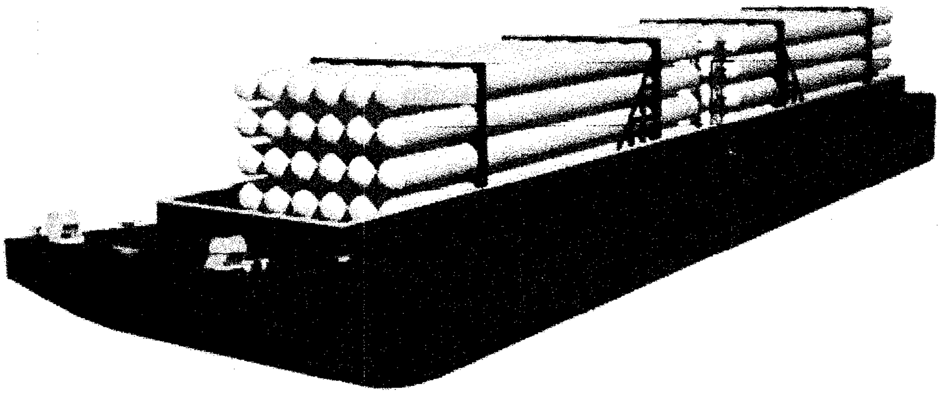
7.4.1.2 SMS CNG Transportation by Barge

Recent developments in barge-mounted CNG cylinders for short distance shipment of gas in inland or costal waters show considerable promise.

One system under development by TransCanada uses Gas Transportation Modules (GTM). These are conventional high strength, low alloy (HSLA) pipeline pipe with thicker steel heads welded at each end overlaid circumferentially with a high performance laminate extending past the transition. Typically, individual tubes are 42 inches in diameter, 76 ft long and hold 172,000 scf of gas at 3,000 psi.

A number of tubes are assembled into tube bundles within a frame that allows them to be lifted on and off the barge. Typically, a barge would carry 180 tubes that together contain 25 mmscf of gas at 3,000 psi (See Figure 7.9).

Figure 7.9 Barge-mounted GTMs



On reaching port, however, transporting the tube assemblies will be subject to road weight limitations. Thus, utilizing the barge as floating storage and discharging gas directly into a pipeline system appears an attractive option for such applications as island resorts currently using diesel fueled power generation. Barriers include port facility requirements, safety regulations, barge movement due to tidal and wave effects and onshore pipeline distances.

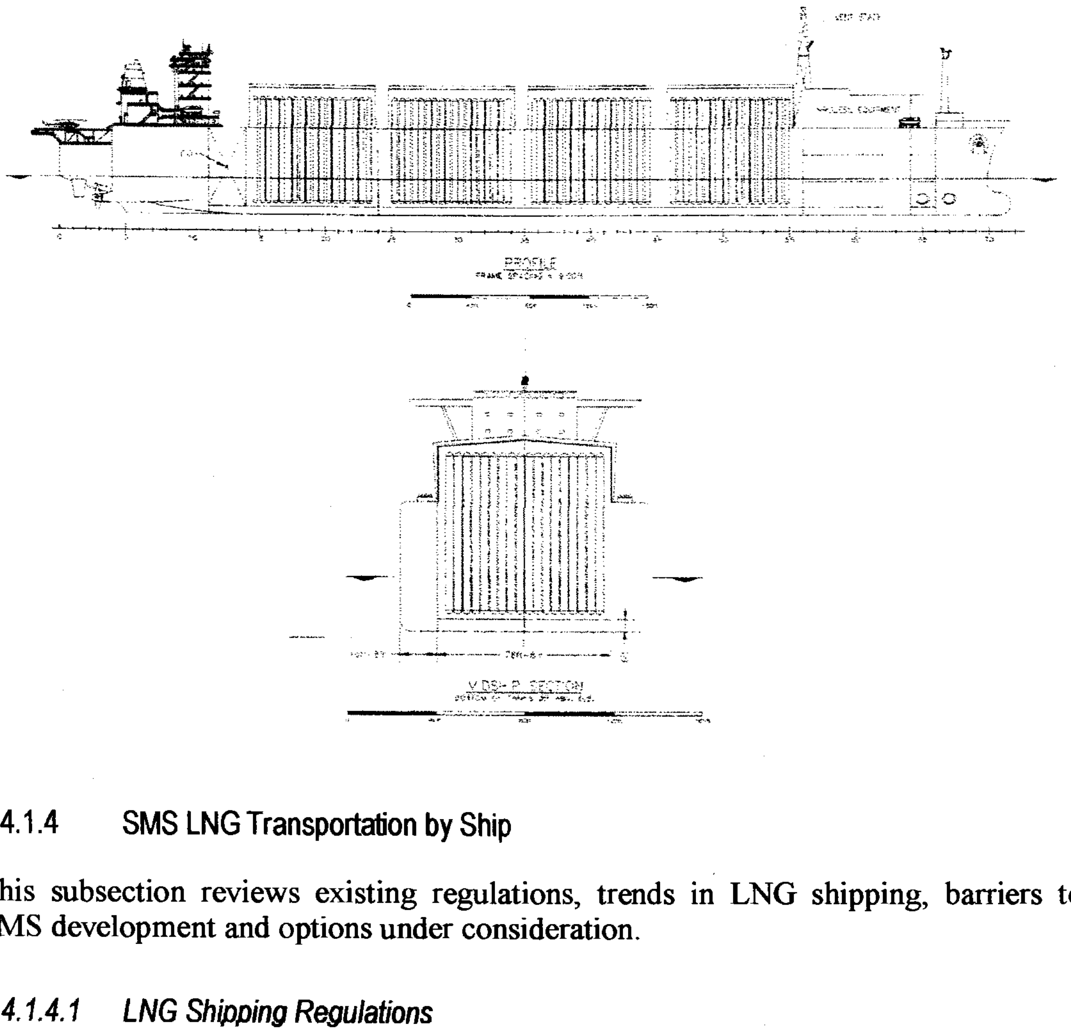
7.4.1.3 SMS CNG Transportation by Ship

A development by EnerSea Transport for open sea operation proposes 120 bar pressure (1,700 psi.) CNG chilled to – 40°C transported by ship in refrigerated holds using vertically mounted bottles grouped 36 bottles per tank. The ship's four holds can accommodate a total of 12 tanks. The total volume of gas to be transported is 220 mmscf. Refrigerating the gas increases its density and thus the mass of gas carried. A conceptual ship is shown in Figure 7.10 below.

One unloading system now under development utilizes a liquid pumped into the gas bottles to force the gas out into a stationary storage thereby retaining the original pressure. A small amount of compressed gas is left in the bottle and allowed to expand to force the liquid back out of the bottles, when transfer has been completed.

The advantage of this system is that the gas storage bottles in the ship can be fixed permanently simplifying ship design, and the ship's turnaround time is relatively short. The disadvantage is the necessity for a pump unloading system and stationary storage.

Figure 7.10 Conceptual CNG Ship



7.4.1.4 SMS LNG Transportation by Ship

This subsection reviews existing regulations, trends in LNG shipping, barriers to SMS development and options under consideration.

7.4.1.4.1 LNG Shipping Regulations

Large volume marine LNG transportation is already a mature market with steady expansion.

In 2005, the fleet consisted of 177 vessels with about 20 MM m^3 (LNG) (approx. 0.42 tscf gas) capacity. Average vessel size is 116,000 m^3 (equivalent to approximately 2.5 bscf of natural gas). Another 104 ships with an average capacity of 150,000 m^3 per vessel are on order at shipyards leading to an overall capacity increase of 75% within 5 years.

Mandatory shipping standards are in place and can be applied to small scale LNG vessels considered to be in the range 1,000 to 10,000 m^3. The development of SMS LNG shipping is therefore not limited by lack of regulation or lack of interest.

7.4.1.4.2 Development of SMS Marine LNG Transportation

The development of SMS marine transportation of LNG depends on logistical and commercial factors, such as:

- LNG supply source;
- Economies of scale;
- Fixed vs. variable costs;
- Price of LNG vs. alternative;
- Buyers with smaller credit capacity;
- Can small ships be dedicated to LNG?
- Capital requirements/unit volume;
- Operational flexibility;
- Interactions at the import terminal;
- Storage tanks; and
- Jetty trade-offs.

Fortunately, the commercial factors of LNG project barriers are shrinking and small projects are becoming more attractive:

- Small scale LNG plants are becoming more affordable;
- Economies of scale and fixed vs. variable costs less formidable;
- Prices of alternative fuels escalating with a perception of long term permanency;
- Growing number of small, short term sales;
- Shipping becoming more flexible; and
- Destination restrictions being reduced.

7.4.1.4.3 Small LNG Ships for Coastal Transportation

The design approach to small LNG carriers is derived from that of liquid ethylene carriers, in which ethylene is carried at -104°C vs -160°C for LNG. Designs focus on minimizing the capex and maximizing flexibility. Combined LNG/ethylene/LPG carriers (termed LEG carriers) are being considered to enhance profitability. Cylindrical and bi-lobe tanks are being used. Bi-lobe cylinders are basically two cylindrical tanks joined together. Typically, such cylindrical tanks hold 6,000 m^3 each with maximum ship capacity of about 15,000 m^3. Bi-lobe tanks are sized up to 7,500 m^3, each with maximum ship capacities of about 30,000 m^3. Design pressures are 5-7 bars. Bi-Lobe tanks are shown in Figures 7.11 and 7.12.

Figure 7.11 Bi-Lobe Tank

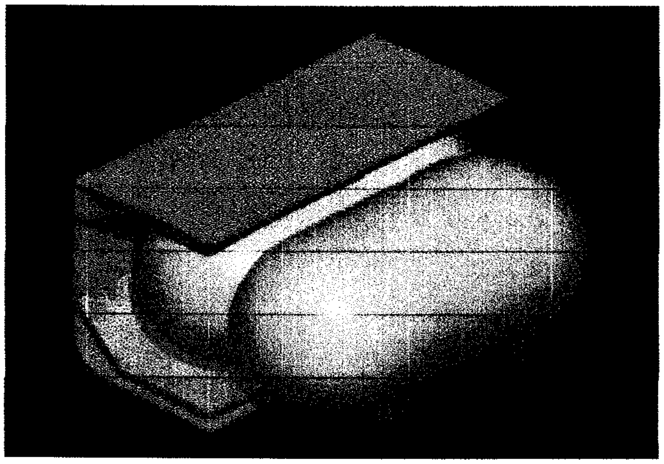
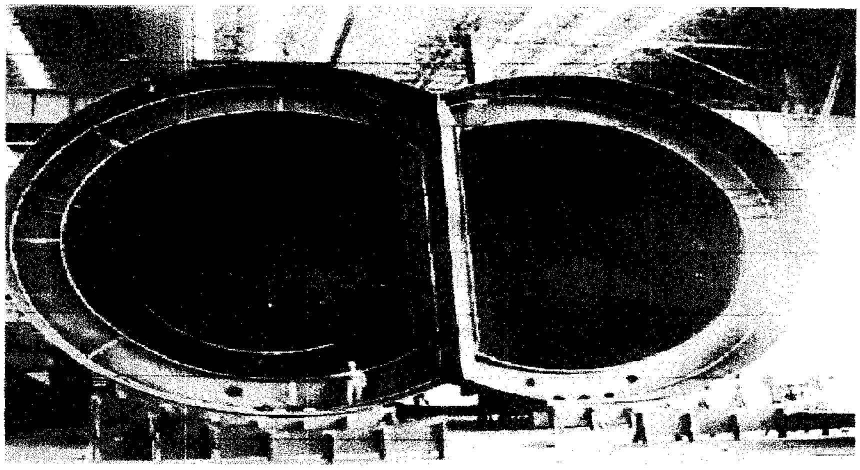


Figure 7.12 Bi-lobe Tank Cross-section



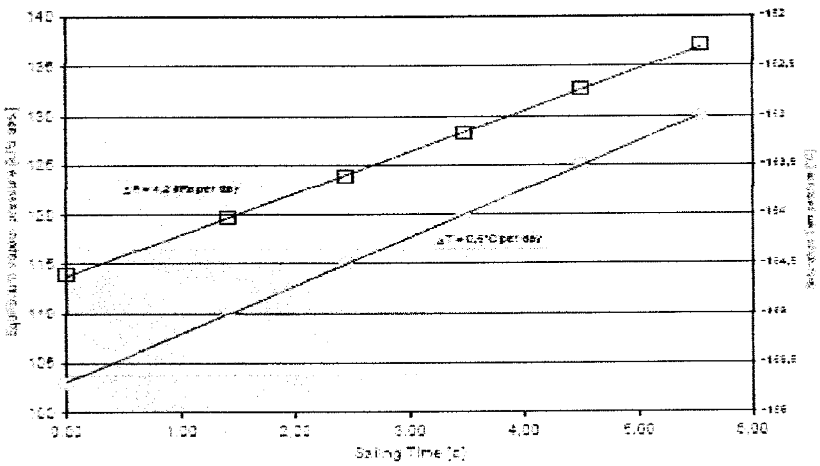
The same tank insulation used for ethylene can be applied to LNG. Due to its lower temperature (than ethylene), additional expansion joints must be allowed for in LNG ships. Shrinkage is 34 mm in a 15 m diameter tank.

- Re-liquefaction of LNG boil-off is not economical for short voyages. Hence, the options are to:
    - Accept the increase in pressure during the voyage assuming the receiving terminal can accept it;
    - Flare the vapor; or
    - *Use the vaporized LNG as part of the ship's propulsion fuel.*

The typical boil-off rate in a 30,000 m^3 ship is 0.23% per day amounting to about 32 tons of LNG equivalent. At US$6/MMBtu, this represents about US$9,000/day.

Figure 7.13 shows the increases in pressure and LNG temperature due to heat transfer *for short sailing times of up to 6 days. The increases are typically* 4.2 kPascal *and* 0.5°C per day.

Figure 7.13 Pressure and Temperature Increase vs Sailing Days



The cost of small LNG tankers vs those of ethylene tankers can be summarized as follows:

- *Only small changes in the ship's hull construction are required, mainly in the steel* grade of tank supports;
- Tanks and cargo handling are more expensive; and
- Overall capex is approximately 10-50% more than for a corresponding ethylene carrier.

The normal speed of an LNG tanker is 16 knots per hour (18.4 mph).

Loading/unloading time for a 30,000 m^3 LNG tanker is about 5-7 hours.

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8.1 INTRODUCTION

This section introduces discounted cash flow models for determining the cost of terrestrial and marine CNG, LNG and pipeline based gas delivery as functions of distance from source to market, volume to be delivered and investor's rate of return. These tariff setting models are then used to determine the lowest cost mode of gas delivery for relevant ranges of distances and volumes.

By comparing the costs of gas supply (producer price plus the lowest cost of delivery) with the netback price of gas in OBF markets currently not served by natural gas (Task 7), the study will identify those OBF markets, where CNG/LNG based gas supply can compete economically.

8.2 CNG/LNG/PL TARIFF MODELS

The tariff models used to determine the cost of CNG/LNG/Pipeline service comprise three components:

- Logistics equations, which for each mode of transportation determine the number and size of units in the supply chain for a given distance from source to market and a given volume of supply;
- Cost correlations, which govern the relationship between unit size and cost for each constituent link in a supply chain; and
- A discounted cash flow model determining the cost of service, i.e., the tariff, yielding a specified investor's rate of return on the capital investment in the supply chain characterized by distance and volume and mode of transportation.

These three components of the tariff models will be discussed in more detail below for each of the three modes of gas transportation, namely CNG, LNG or pipeline.

Since the equipment and modus operandi differ dependent upon whether transportation is overland or water-born, the applicable tariff models will be discussed separately.

8.2.1 Terrestrial CNG/LNG/PL Tariff Models

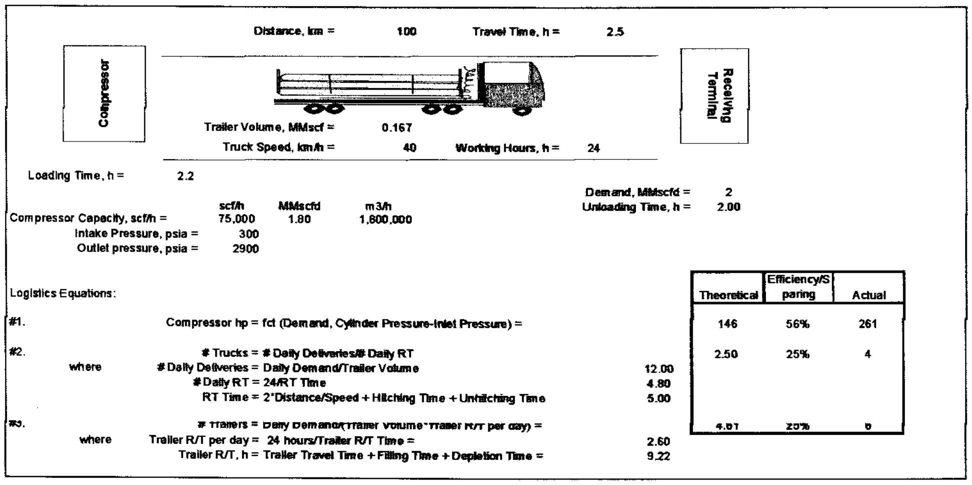
This subsection presents the principles of the terrestrial CNG, LNG and pipeline transportation tariff models.

8.2.1.1 Terrestrial CNG Tariff Model

The terrestrial CNG transportation model and supporting logistics equations are presented in Figure 8.1 below.

The underlying principle in the terrestrial CNG supply chain is use of the trailer cylinder module as storage both at the receiving terminal as well as the compressor station. Thus, a full trailer cylinder module is hitched to the truck (prime mover) at the compressor station and hauled to the receiving terminal, where it is unhitched and acts as storage and source of supply for further distribution. An empty trailer cylinder module at the receiving terminal is hitched to the truck and hauled to the compressor station, where it is unhitched and loaded with compressed gas. In the meantime, a loaded trailer cylinder module is hitched to the truck for return to the receiving terminal, thereby completing the cycle. This system minimizes CNG storage requirements and optimizes unloading.

Figure 8.1 Logistics Equations for Terrestrial CNG Transportation



The logistics equations address the three components of the CNG supply chain:

1. Compressor horsepower, which is determined by the intake gas pressure, transportation cylinder pressure and compressor capacity (mmscfd);

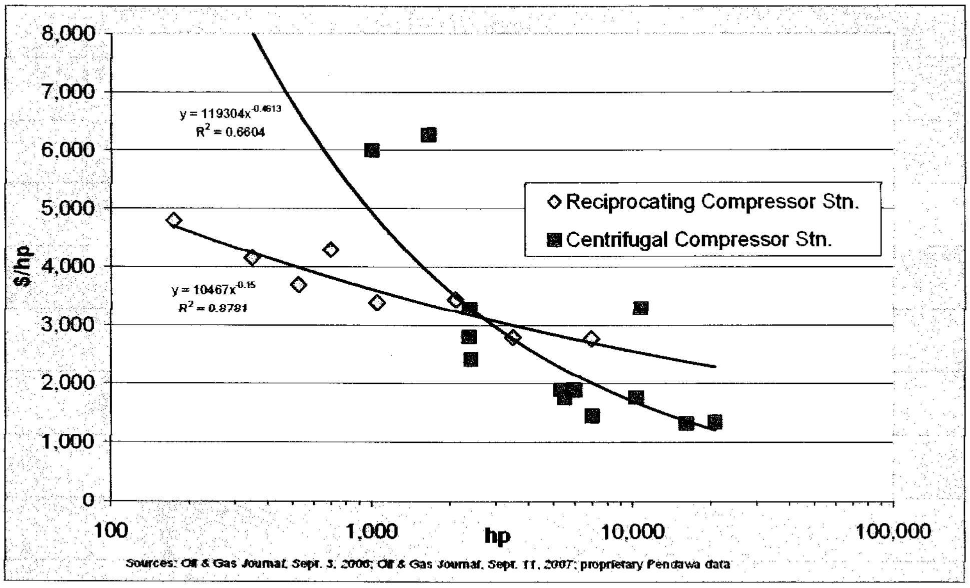
2. Required number of trucks, which is determined by roundtrip time (a function of truck speed and hitching/unhitching times) and daily delivery requirement (a function of gas demand at the receiving terminal and trailer cylinder module volume); and

3. Required number of trailers and associated cylinder modules, which is determined by trailer cylinder module roundtrip time (a function of trailer travel time and loading and unloading times) and daily delivery requirement (a function of gas demand at the receiving terminal and trailer cylinder module volume).

All values determined by the logistics equations are adjusted for efficiency and sparing to arrive at practical operating requirements.

Cost correlations provide the unit capital costs for each component of the supply chain, while the logistics equations determine the number of units required. All cost correlations are contained in Appendix D. A sample cost correlation is shown in Figure 8.2 below relating total compressor station cost to installed horsepower for reciprocating and centrifugal compressor stations.

Figure 8.2 Compressor Station Cost vs Horsepower



The other important capital cost parameters in terrestrial CNG transportation are the characteristics and cost of the trailer cylinder module used in storage and transportation. In conformance with the guideline set out in the previous section for maximum truck/trailer weight based on road considerations, the trailer cylinder specifications and cost used in this report are presented in Table 8.1 below.

Table 8.1 CNG Trailer Cylinder Module Specifications

Item	Type	Specification
Cylinder Vessel	DOT -3AAX-2900	22" OD x 0.647" MW x 36' L
Service Pressure		2900 psig (200 bars)
Skid Configuration	ISO	8-cylinder module
Skid Capacity		167,000 scf @ 2900 psig
Skid Weight		25,051 kg (empty)
Skid Size		40' L x 8' W x4'3" H
Trailer + Skid Cost		$263,000

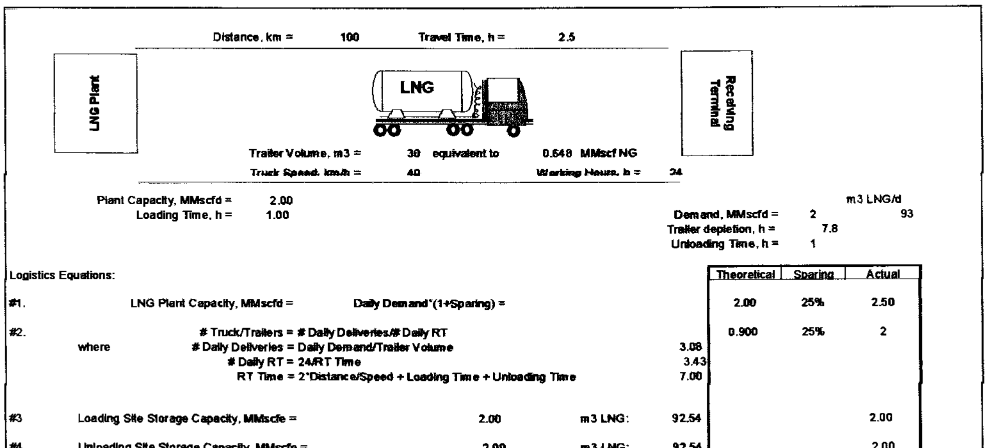
Operating cost assumptions for the compressor station, trucking and receiving terminal are presented in Appendix D.

A discounted cash flow model is used to determine the cost of service, i.e., the delivery tariff, as a function of investor's rate of return for a CNG supply chain defined by demand volume and distance from gas source to receiving terminal. The tariff is calculated on an after-tax basis, i.e., after allowance for tax depreciation of assets and payment of taxes (at a rate of 30%). The detailed cash flow model is presented in Appendix D.

8.2.1.2 *Terrestrial LNG Tariff Model*

The terrestrial LNG transportation model and supporting logistics equations are shown in Figure 8.3 below.

Figure 8.3 Logistics Equations for Terrestrial LNG Transportation



Since LNG is a liquid, the underlying principle in the terrestrial LNG supply chain is site storage of LNG at both the LNG plant as well as the receiving terminal. A truck/trailer hauls liquefied natural gas from the LNG plant to the receiving terminal followed by an empty return to the LNG plant for refilling. Stored LNG at the receiving terminal is vaporized for retail distribution.

The logistics equations address the three components of the LNG supply chain:

1. LNG plant capacity, which is determined by daily demand at the receiving terminal (mmscfd);

2. Required number of trucks/trailers, which is determined by roundtrip time (a function of truck speed and loading/unloading times) and daily

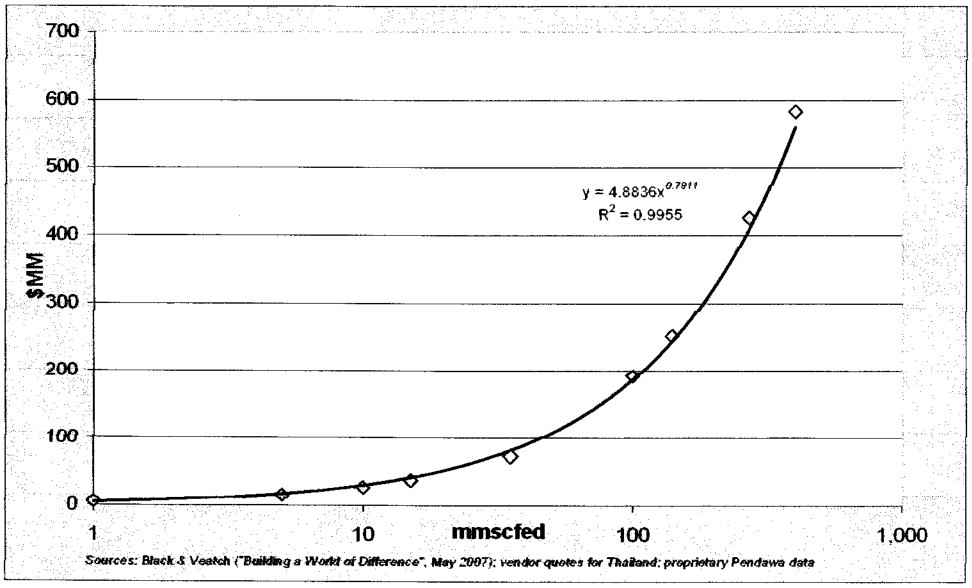
delivery requirement (a function of gas demand at the receiving terminal and trailer capacity/volume); and

3. Storage capacities at the sites of the LNG plant and the receiving terminal, which are based on supply chain reliability considerations and daily peak demand.

All values determined by the logistics equations are adjusted for efficiency and sparing to arrive at practical operating requirements.

Cost correlations provide the unit capital costs for each of the components of the supply chain, while the logistics equations determine the number of units required. All cost correlations are contained in Appendix D. Sample cost correlations for LNG plant, storage tanks and vaporization facilities versus capacity are presented in Figures 8.4 through 8.6 below.

Figure 8.4 LNG Plant Cost[1] vs Capacity



[1]LNG feed gas cleaning and liquefaction, excluding storage

Figure 8.5 LNG Storage Tank Cost vs Capacity

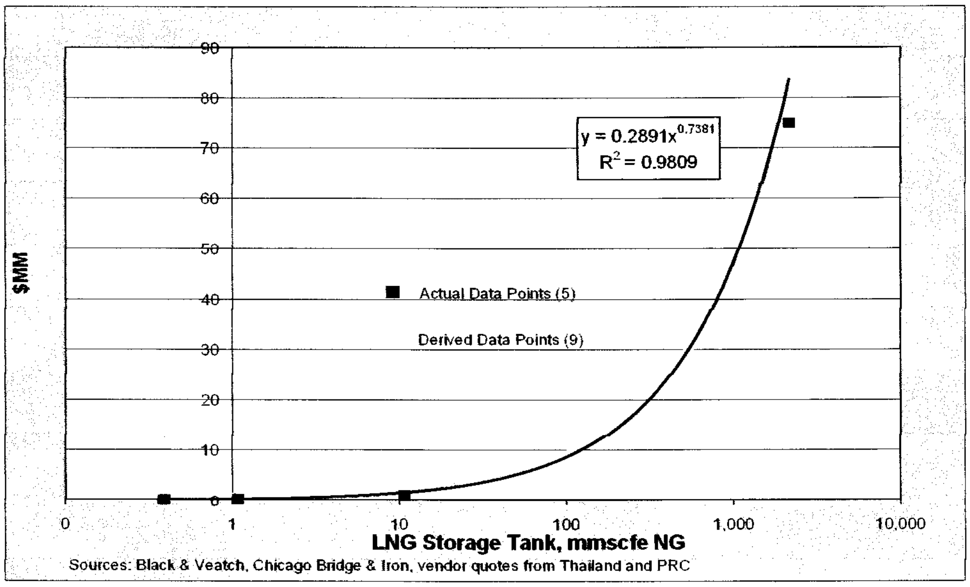
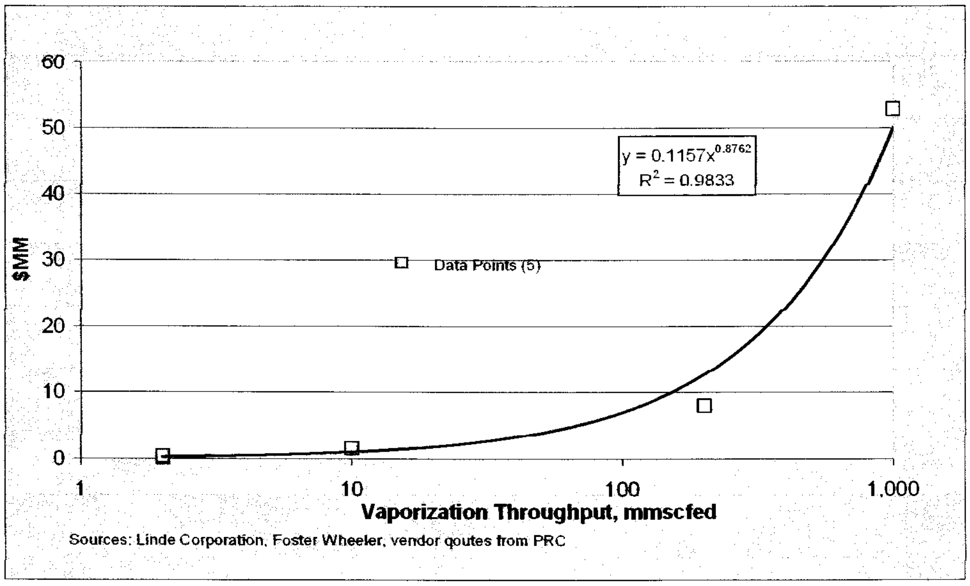


Figure 8.6 LNG Vaporization Cost vs Capacity



The other important capital cost parameters in terrestrial LNG transportation are the characteristics and cost of the LNG truck/trailer used in transportation. In conformance with the guideline set out in the previous section for maximum truck/trailer weight based on road considerations, the LNG truck/trailer specifications and cost used in this report are presented in Table 8.2 below.

Table 8.2 LNG Truck/Trailer Specifications

Item	Type	Specification
Vessel	Insulated, Pressurized	30 m^3 (0.648 MMscfe)
Service Pressure		Max 200 psig
Vessel Size		20' L x 8' 3" OD
Weight (truck/trailer/vessel)		41 tonnes
Cost		$309,000

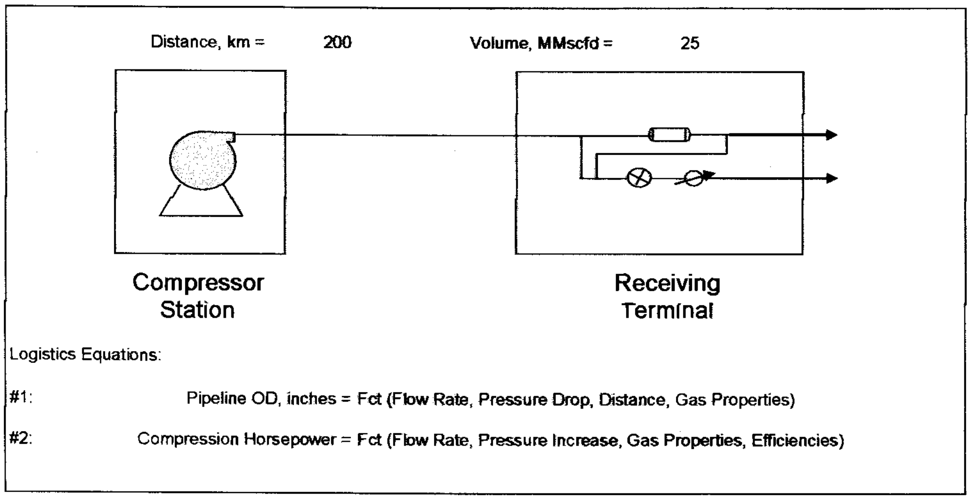
Operating cost assumptions for the LNG plant, trucking and receiving terminal are presented in Appendix D.

As for the CNG Tariff Model, a discounted cash flow model is used to determine the cost of terrestrial LNG service, i.e., the delivery tariff, as a function of investor's rate of return for an LNG supply chain specified by demand volume and distance from liquefaction plant to receiving terminal. The tariff is calculated on an after-tax basis, i.e., after allowance for tax depreciation of assets and payment of taxes (at a rate of 30%). The detailed cash flow model is presented in Appendix D.

8.2.1.3 *Terrestrial Pipeline Tariff Model*

The terrestrial pipeline transportation model and supporting logistics equations are shown schematically in Figure 8.7 below.

Figure 8.7 Logistics Equations for Terrestrial Pipeline Transportation



The model for transportation of natural gas by pipeline comprises compression of gas to a pressure sufficient to enable it to flow through a pipeline of specified diameter arriving at its destination at a specified pressure.

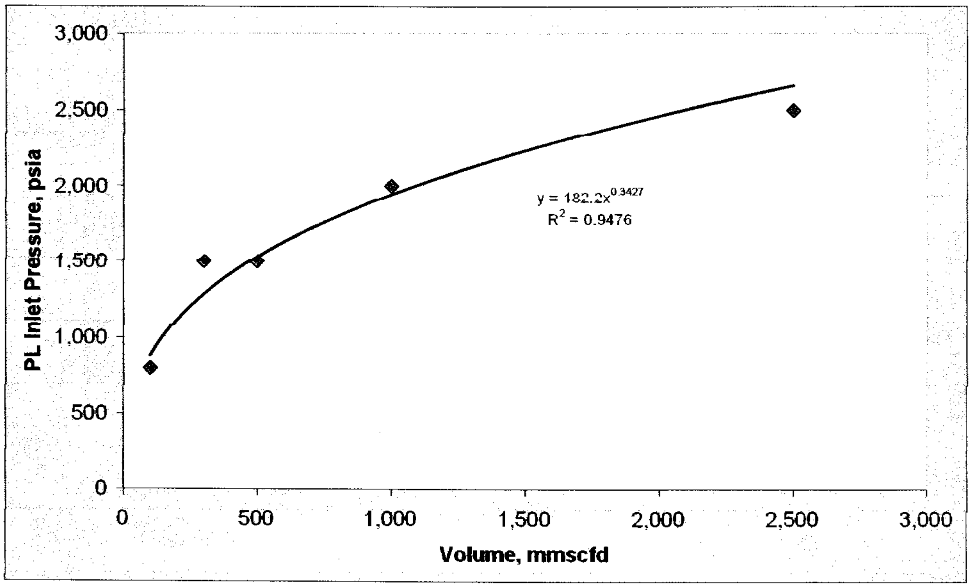
The logistics equations for the pipeline supply chain address:

1. Pipeline diameter, which is determined by formulae, such as the "El Paso Pipeline Flow Equation", as a function of flow rate, pressure drop, distance, and gas properties;

2. Required compression horsepower, which is determined by flow rate, pressure drop through the pipeline and gas properties.

To approximate prevailing pipeline system operating conditions, additional decision variable were introduced into the logistics equations, such as maximum pipeline operating pressure (shown in Figure 8.8 below), pipeline pressure decline before recompression and maximum distance between compressor stations.

Figure 8.8 Maximum Pipeline Operating Pressure



All values determined by the logistics equations are adjusted for efficiency and sparing to arrive at practical operating requirements.

Cost correlations provide the unit capital cost of each component in the supply chain sized by the logistics equations. Detailed cost correlations are contained in Appendix D. The compressor cost correlation with capacity is the same as that used in the CNG supply model, while unit installed pipeline cost, expressed in \$/(km*in), is assumed correlated with pipeline OD as shown in Figure 8.9 below. Also, an onshore pipelay set-up charge as a function of pipeline OD shown in Figure 8.10 below was included.

Figure 8.9 Installed Pipeline Cost vs Pipeline OD

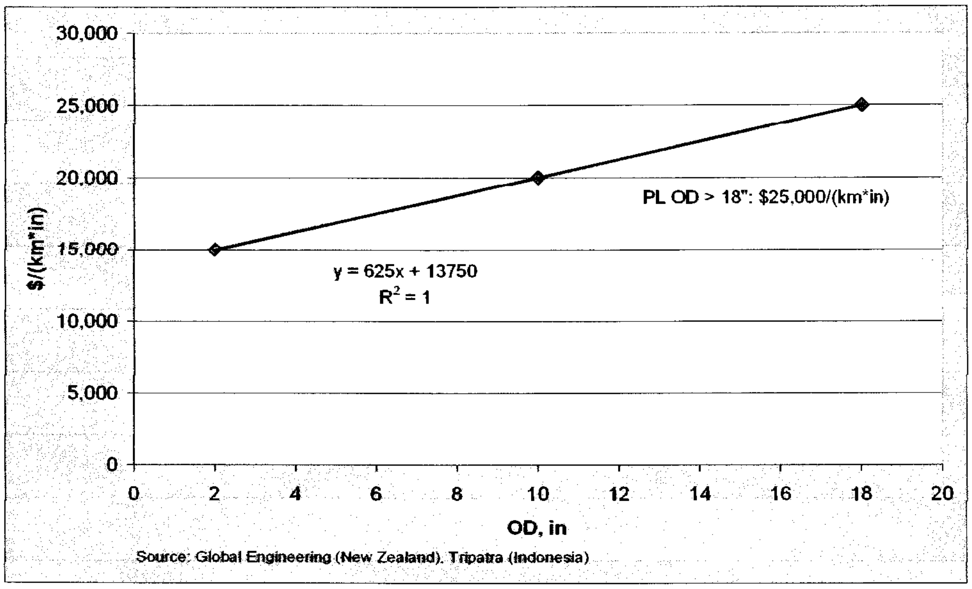
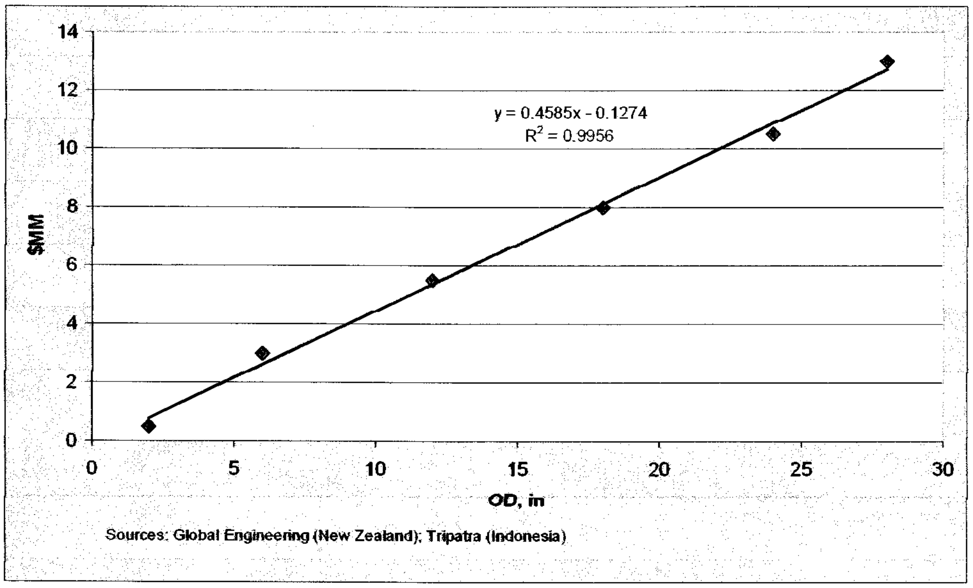


Figure 8.10 Onshore Pipe-lay Set-up Cost vs Pipeline OD



Operating cost assumptions for the terrestrial pipeline transportation chain are presented in Appendix D.

As for the CNG and LNG tariff models, a discounted cash flow model is used to determine the cost of terrestrial pipeline transportation service, i.e., the delivery tariff, as a function of investor's rate of return for a pipeline supply chain specified by demand volume and distance between source of supply and receiving terminal. The tariff is calculated on an after-tax basis, i.e., after allowance for tax depreciation of assets and payment of taxes (at a rate of 30%). The detailed cash flow model is presented in Appendix D.

8.2.2 Marine CNG/LNG/Pipeline Tariff Models

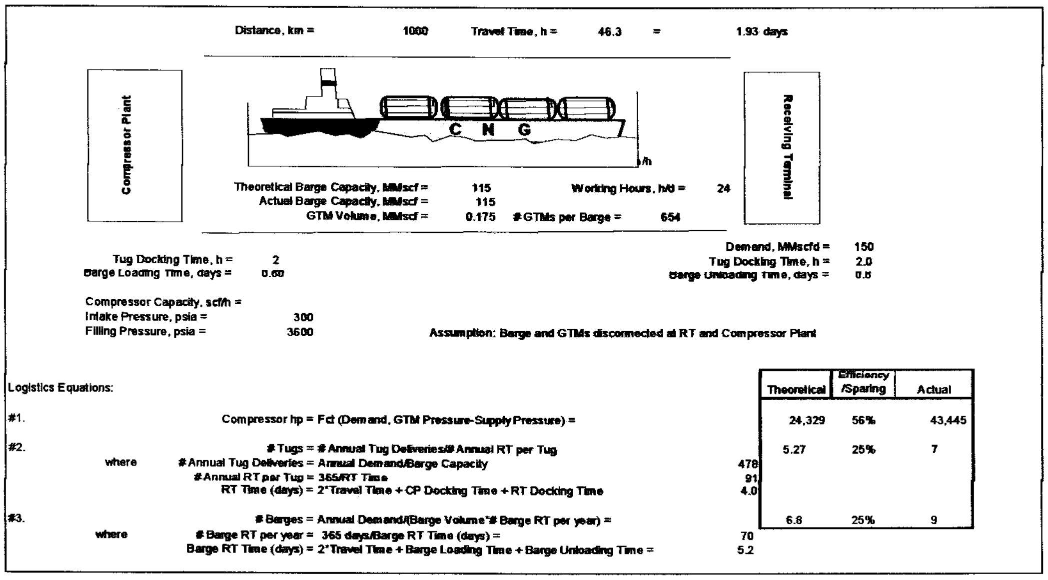
This subsection presents the underlying principles of the marine CNG, LNG and pipeline transportation tariff models.

8.2.2.1 Marine CNG Tariff Model

The marine CNG transportation model and supporting logistics equations are shown in Figure 8.11 below.

The underlying principle in the marine CNG supply chain is the use of barge-mounted, high pressure Gas Transport Modules (GTM) for transportation as well as storage at the compressor station as well as the receiving terminal. Thus, a GTM-barge module is filled at the Compressor Station and pushed by a tug boat to the receiving terminal, where it is unhitched from the tug boat acting as storage, and, when needed, connected to the send-out system for distribution of its gas content. A depleted GTM barge module is picked up at the receiving terminal and hauled back to the compressor station by the tug boat for refilling, where a full GTM-barge module is awaiting the tug for another round trip. This system minimizes CNG storage requirements and optimizes unloading.

Figure 8.11 Logistics Equations for Marine CNG Transportation



The logistics equations address three components of the marine CNG supply chain:

1. Compressor horsepower, which is determined by the intake gas pressure, GTM pressure and compressor capacity (mmscfd);

2. Required number of tug boats, which is determined by roundtrip time (a function of tug boat speed and docking times) and daily delivery requirement (a function of gas demand at the receiving terminal and GTM-barge module capacity); and

3. Required number of GTM-barge modules, which is determined by GTM-barge module roundtrip time (a function of tug boat travel time and loading/unloading times), daily delivery requirement (a function of gas demand at the receiving terminal and GTM-barge module capacity) and desired storage redundancy at both the compressor station and the receiving terminal, subject to a maximum GTM-barge capacity of 134 mmscf. Larger GTM-barge capacity requirements are assumed met by multiple 134 mmscf GTM-barges.

The specifications for the maximum GTM-barge capacity are set out in Table 8.3 below.

Table 8.3 Marine CNG Barge Specifications

Item	Type	Specification
Vessel Size		135m L x 23.5m W
# of GTMs		765
Capacity		134 MMscf
Cost		$12.9 MM

All values determined by the logistics equations are adjusted for efficiency and sparing to arrive at practical operating requirements.

Cost correlations provide the unit capital cost for each component of the supply chain sized by the logistics equations. All cost correlations are presented in Appendix D. The compressor station cost correlations are the same as applied in the Terrestrial CNG Tariff Model. Sample cost correlations for tugs and barges vs GTM carrying capacity (mmscf) are presented in Figures 8.12 and 8.13 below.

Figure 8.12 CNG Tug Boat Cost vs Capacity

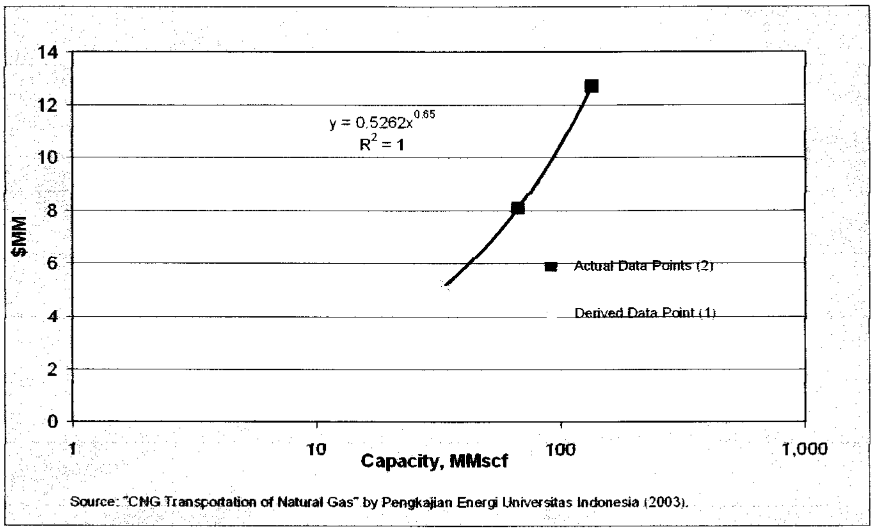
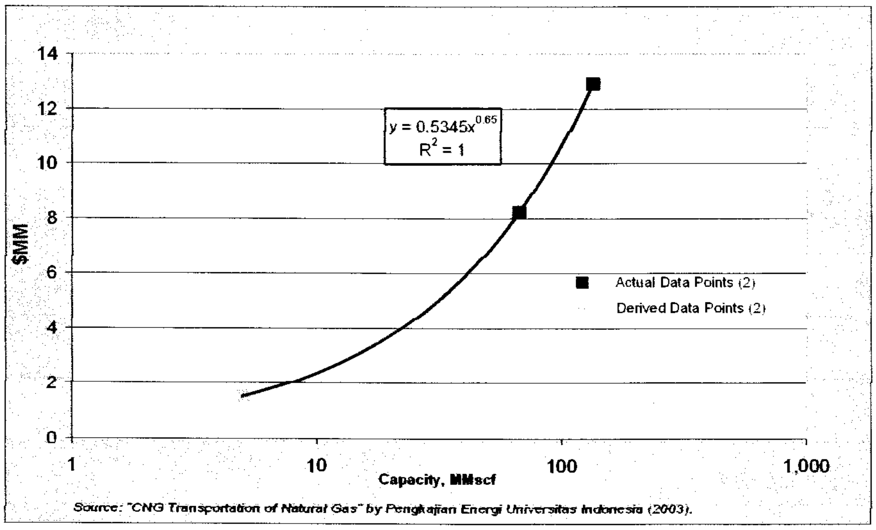


Figure 8.13 CNG Barge Cost vs Capacity



A third important component in marine CNG transportation is the GTMs, the transportation and storage containers for CNG. Their characteristics and cost are set out in Table 8.4 below.

Table 8.4: CNG GTM Specifications

Item	Type	Specification
Gas Transport Module Size	TransCanada	80' L x 42" OD
Service Pressure		3600 psig (245 bars)
Weight		17.5 tonnes
Capacity		175,000 scf @ 3600 psig
Cost		$60,000

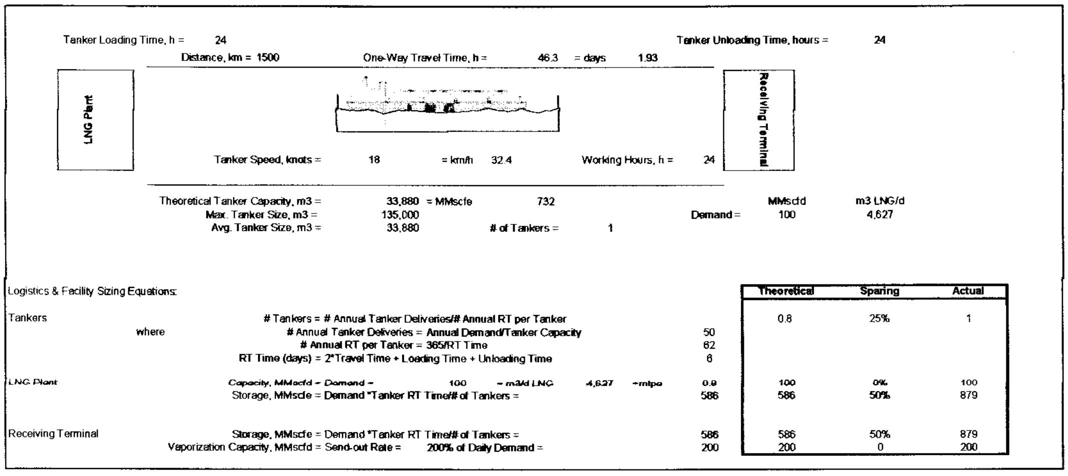
Operating cost assumptions for the marine CNG supply chain are presented in Appendix D.

A discounted cash flow model analogous to the one for terrestrial CNG/LNG/PL transportation is used to determine the cost of service, i.e., the delivery tariff. The detailed cash flow model is presented in Appendix D.

8.2.2.2 *Marine LNG Tariff Model*

The marine LNG transportation model and supporting logistics and facilities sizing equations are shown in Figure 8.14 below.

Figure 8.14 Logistics Equations for Marine LNG Transportation



The underlying principle in the marine LNG supply chain is the employment of LNG liquefaction capacity, on-site storage at both LNG plant and receiving terminal, LNG tanker(s) and vaporization capacity sized to meet maximum demand load. The LNG tanker size is limited to 135,000 m^3.

The logistics equations address three components of the marine LNG supply chain:

1. LNG plant capacity assumed to equate to demand plus a sparing allowance;

2. On-site storage at both the LNG plant and the receiving terminal assumed to equal demand (mmscfd) multiplied by the period (days) between tanker arrivals plus an allowance; and

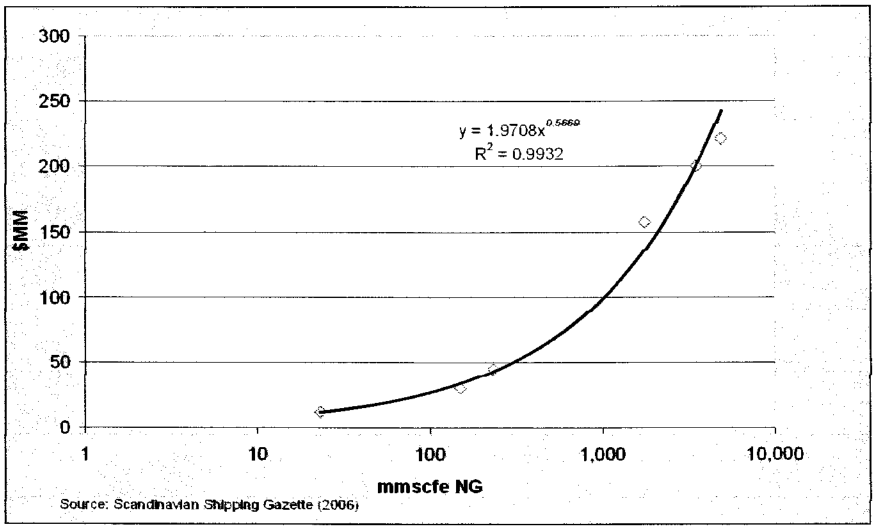
3. Vaporization capacity at the receiving terminal assumed to be twice demand.

All values determined by the logistics equations are adjusted for sparing to arrive at practical, operating requirements.

Cost correlations provide the unit capital costs for components of the supply chain sized by the logistics equations. All cost correlations are contained in Appendix D.

The cost correlations for LNG plant vs throughput and LNG storage facilities vs capacity are the ones applied in the Terrestrial LNG Tariff Model. A sample cost correlation for LNG tankers vs capacity is presented in Figure 8.15 below.

Figure 8.15 LNG Tanker Cost vs Capacity



Operating cost assumptions for the marine LNG supply chain are presented in Appendix D.

A discounted cash flow model analogous to the one for terrestrial CNG/LNG/PL transportation is used to determine the cost of service, i.e., the delivery tariff. The detailed cash flow model is presented in Appendix D.

8.2.2.3 Marine Pipeline Tariff Model

The marine pipeline transportation model and supporting logistics equations are identical to those for terrestrial pipeline transportation described in subsection 8.2.1.3 above.

Cost correlations provide the unit capital costs of the components in the supply chain sized by the logistics equations. Detailed cost correlations are found in Appendix D.

The compressor cost correlations with capacity are the same as for the CNG supply and terrestrial pipeline models, while installed offshore pipeline costs and pipelay set-up costs as functions of pipeline OD are presented in Figures 8.16 and 8.17 below, respectively.

Figure 8.16 Installed Offshore Pipeline Cost vs Pipeline OD

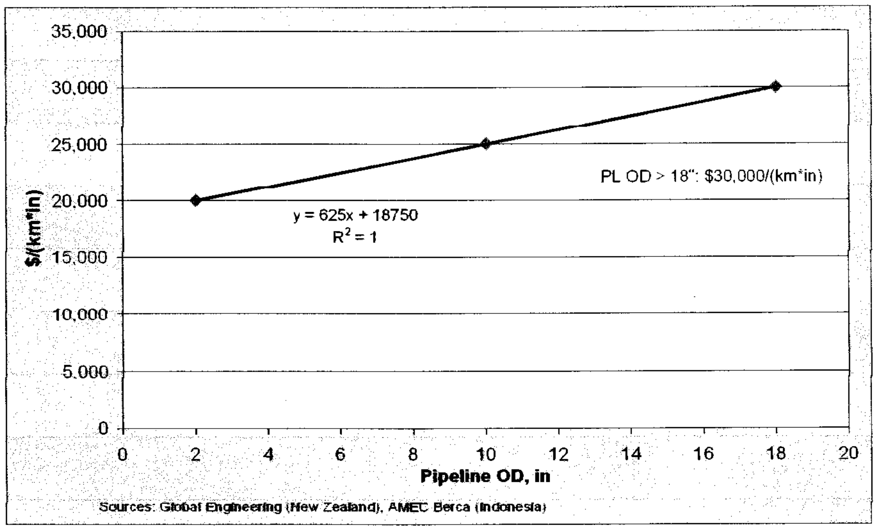
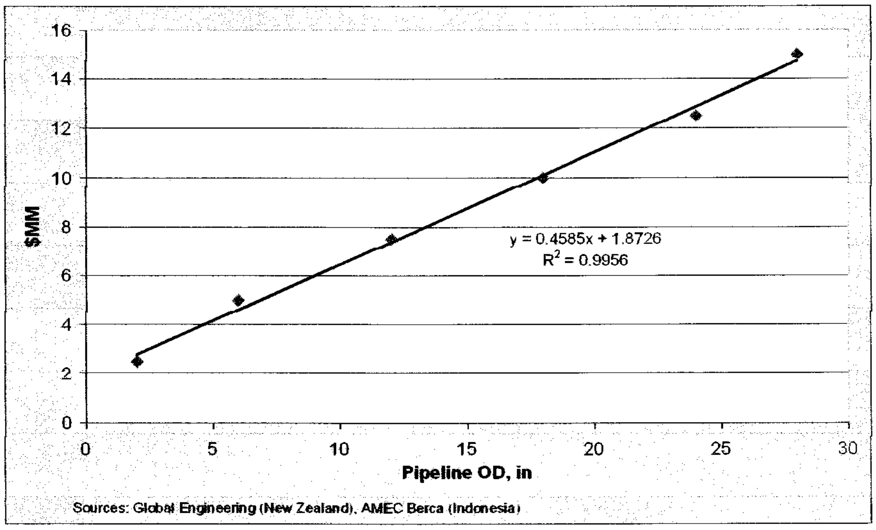


Figure 8.17 Offshore Pipe-lay Set-up Cost vs Pipeline OD



Operating cost assumptions for the marine pipeline transportation chain are presented in Appendix D.

A discounted cash flow model analogous to the one for other transportation models is used to determine the after-tax cost of service, i.e., the delivery tariff. The detailed cash flow model is presented in Appendix D.

8.3 COST OF CNG/LNG/PL GAS DELIVERY

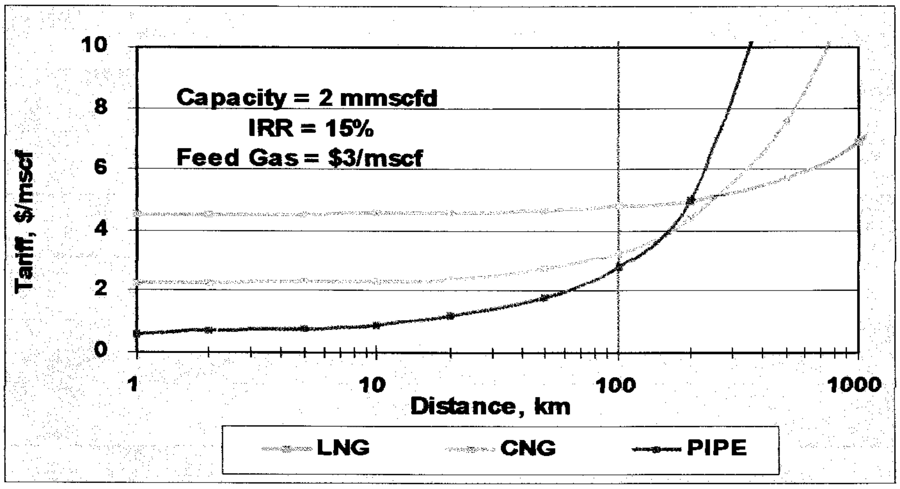
This subsection presents single variable, sample cost-of-delivery determinations for terrestrial and marine transportation using the tariff models introduced in the preceding subsection. In each instance, comparisons are made between the different modes of transportation to identify the lowest cost of delivery.

8.3.1 Terrestrial CNG/LNG/PL Tariffs

Figures 8.18 and 8.19 present the impacts of distance on terrestrial CNG/LNG/pipeline tariffs for a given demand volume and demand volume on tariffs for a given distance, respectively, both at a 15% investor's rate of return.

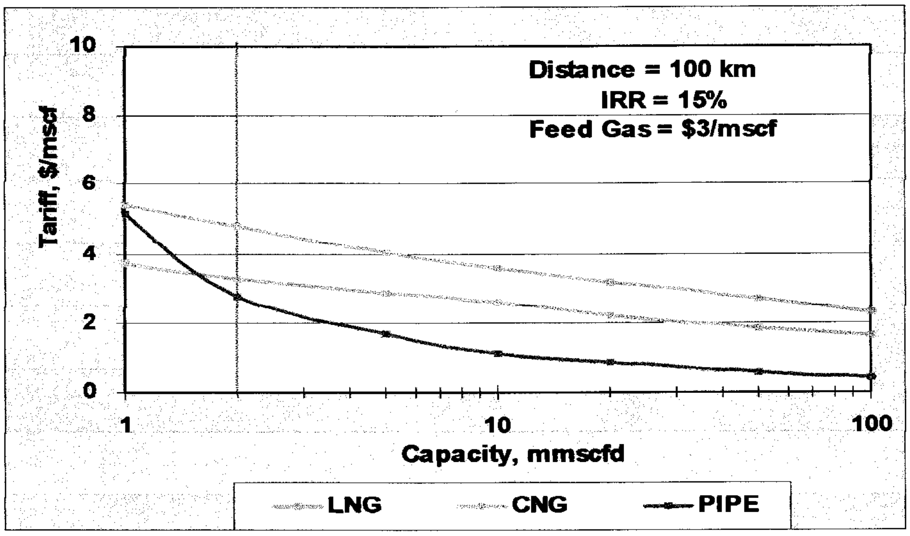
For a demand volume of 2 mmscfd, Figure 8.18 shows pipeline to be lowest cost terrestrial gas delivery mode up to a distance of about 180 km, whereupon CNG delivery is lowest cost up to a distance of about 270 km. Thereafter, LNG transportation offers lowest delivery cost. Up to a distance of 10 km, the lowest cost tariff is about $0.75/mscf gradually rising to nearly $4.00/mscf for a distance of 270 km. When LNG transportation becomes lowest cost supply mode at 270 km, the tariff is nearly $5/mscf.

Figure 8.18 Terrestrial CNG/LNG/PL Gas Delivery Cost vs Distance at 15% IRR



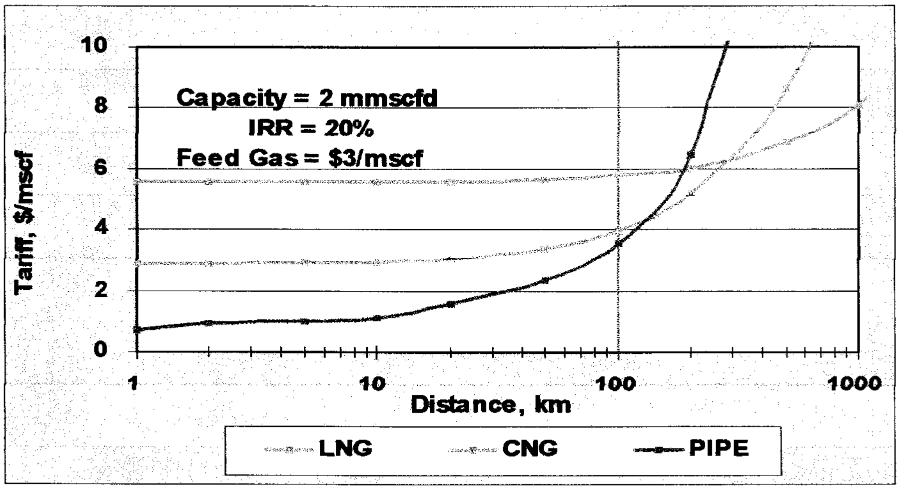
For a delivery distance of 100 km, Figure 8.19 shows CNG to be the lowest cost terrestrial transportation mode up to a volume of about 1.5 mmscfd, whereupon pipeline transportation takes over with rapidly declining tariffs due its economies of scale.

Figure 8.19 Terrestrial CNG/LNG/PL Gas Delivery Cost vs Volume at 15% IRR



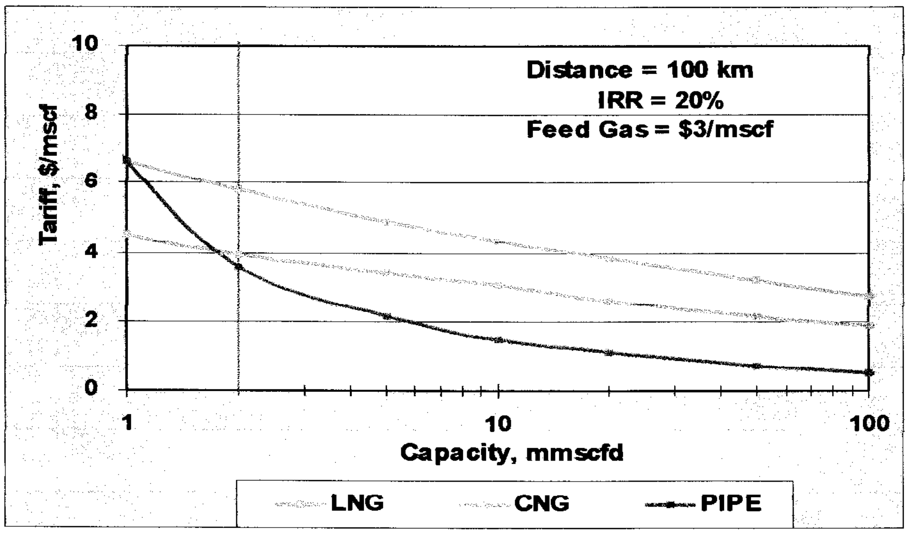
Figures 8.20 and 8.21 below present the analogous single variable tariff determinations, but at a 20% investor's rate of return. For a 2 mmscfd market located 100 km from a gas source, the tariff for the lowest cost mode of transportation, pipeline, increases to $3.56/mscf, or about $0.80/mscf more than for a 15% IRR.

Figure 8.20 Terrestrial CNG/LNG/PL Gas Delivery Cost vs Volume at 20% IRR



Pipeline transportation being less capital intensive than CNG transportation results in a marginal extension of the cross-over point from pipeline to CNG to 1.7 mmscfd at the higher IRR (Figure 8.21)

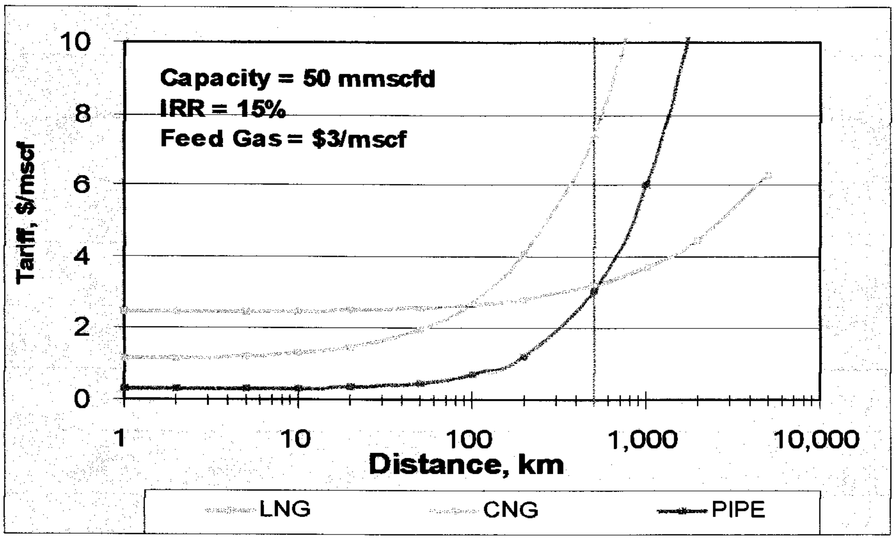
Figure 8.21 Terrestrial CNG/LNG/PL Gas Delivery Cost vs Distance at 20% IRR



8.3.2 Marine CNG/LNG/PL Tariffs

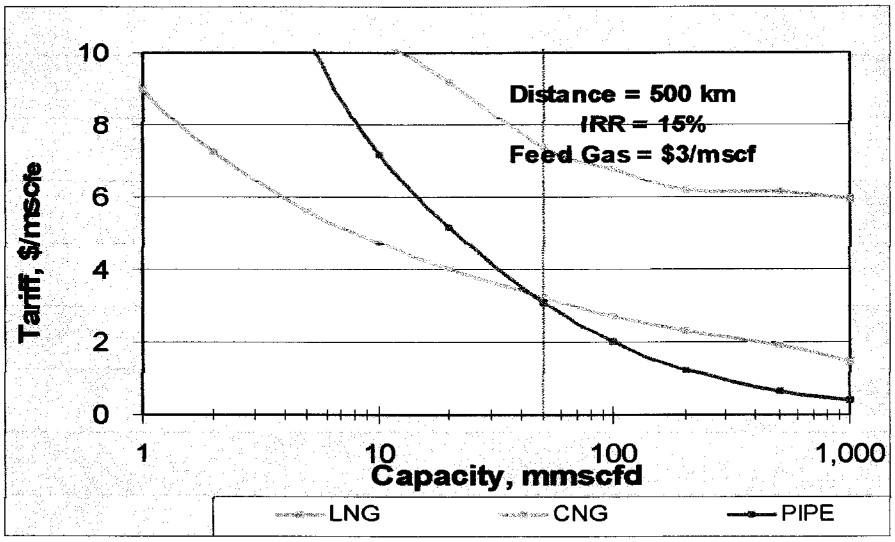
Figures 8.22 and 8.23 below present the impacts of distance on marine CNG/LNG/pipeline tariffs for a given demand volume and demand volume on tariffs for a given distance, respectively, both at a 15% investor's rate of return.

Figure 8.22 Marine CNG/LNG/PL Gas Delivery Cost vs Distance at 15% IRR



For a demand volume of 50 mmscfd, Figure 8.22 shows pipeline to be lowest cost marine gas transportation mode up to a one-way distance of 500 km, whereupon LNG delivery is lowest cost. CNG offers higher cost delivery than both pipeline and LNG by a wide margin. The lowest cost tariff gradually increases with distance to about \$3/mscf at 500 km, where LNG becomes lowest cost mode of transportation.

Figure 8.23 Marine CNG/LNG/PL Gas Delivery Cost vs Volume at 15% IRR



For a delivery distance of 500 km, Figure 8.23 shows LNG to be the lowest cost marine transportation mode up to a volume of about 45 mmscfd, whereupon pipeline transportation takes over for a one-way distance of at least 1,000 km with declining tariffs due to its economies of scale.

Figures 8.24 and 8.25 below present the analogous single variable marine tariff determinations, but at a 20% investor's rate of return.

Figure 8.24 Marine CNG/LNG/PL Gas Delivery Cost vs Distance at 20% IRR

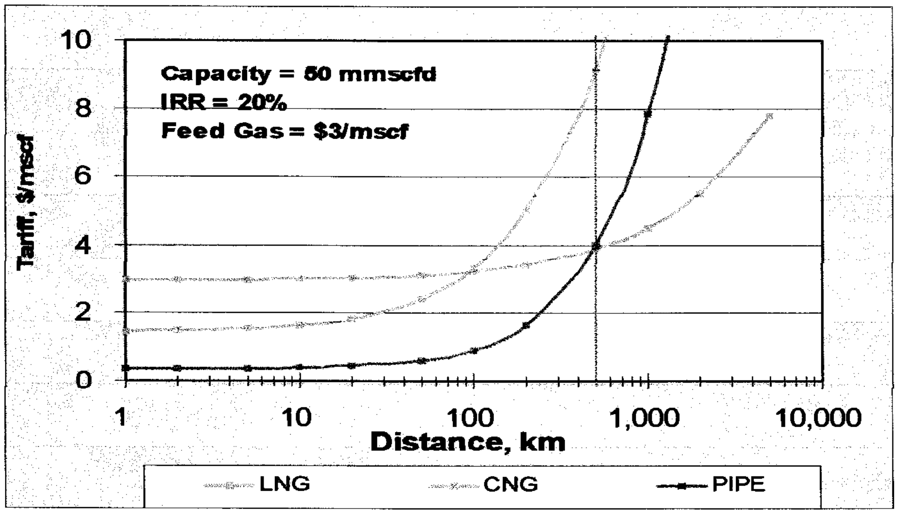
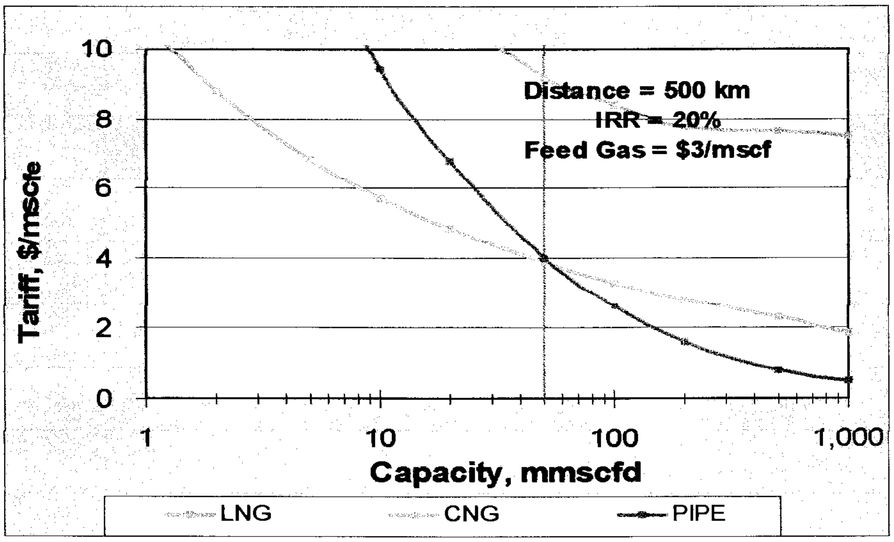


Figure 8.25 Marine CNG/LNG/PL Gas Delivery Cost vs Volume at 20% IRR



At an investor's rate of return of 20%, the tariff for the lowest cost mode of transportation of 50 mmscfd to a market located 500 km from the gas source increases by nearly 30% to $3.85/mscfd. The higher investor's rate of return results in the cross-over point for lowest cost transportation extending from 45 mmscfd at 15% IRR (Figure 8.23) to 55 mmscfd at 20% IRR (Figure 8.25).

8.4 LOWEST COST GAS DELIVERY

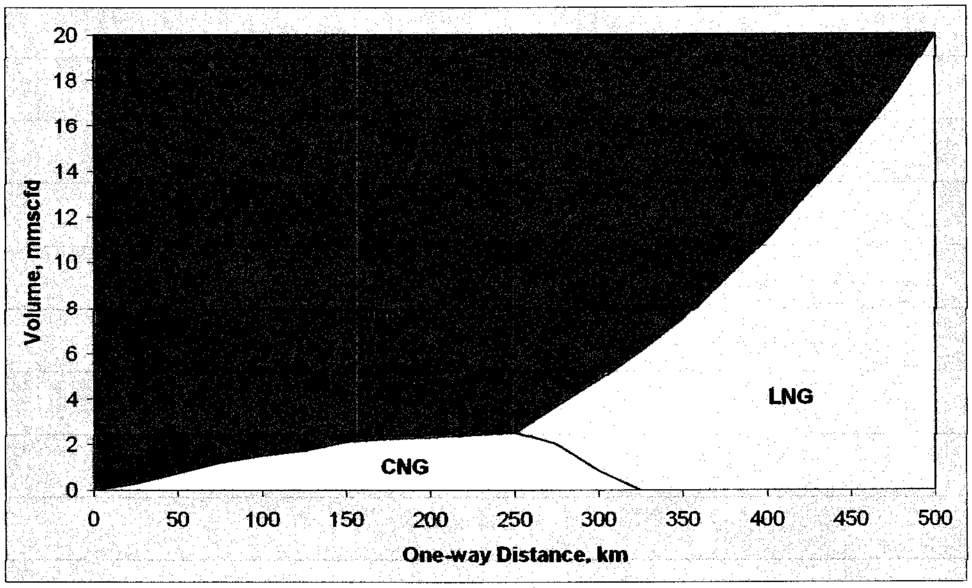
This subsection presents area charts of lowest cost terrestrial and marine gas delivery as functions of volume and distance for the three transportation mode alternatives of CNG/LNG/pipeline. These charts are useful as an initial screening tool to find lowest cost gas transportation for use in determining the cost of gas supply as an alternative to OBF products in infrastructure-deficient markets.

The terrestrial and marine CNG/LNG/pipeline tariff models described above were used to identify the lowest cost mode of transportation for any combination of distance and volume.

8.4.1 Lowest Cost Terrestrial CNG/LNG/PL Gas Delivery

Figure 8.26 below presents the results for terrestrial gas transportation at a 15% investor's rate of return and a feed gas price of $3/mscf.

Figure 8.26 Lowest Cost Terrestrial CNG/LNG/PL Gas Delivery @ 15% IRR



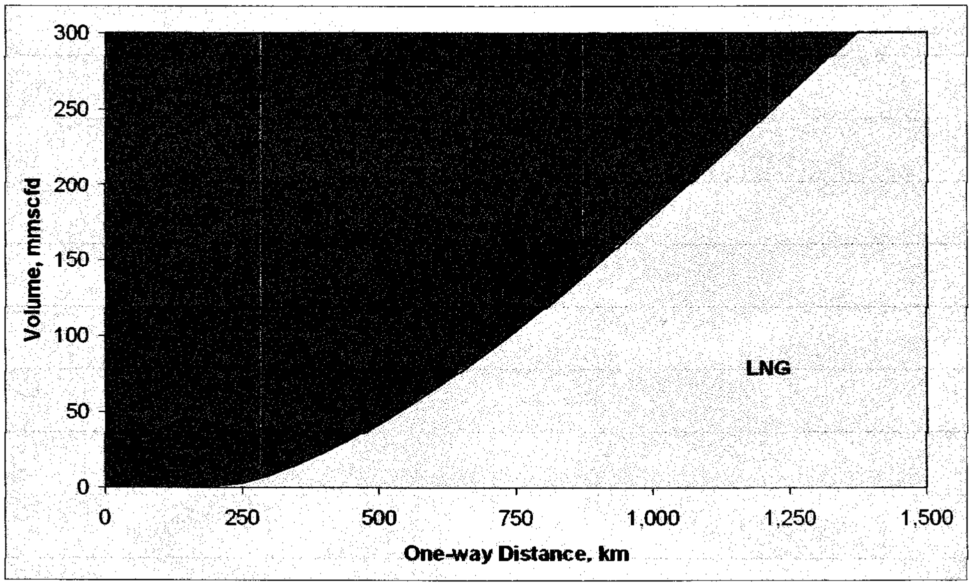
For one-way distances up to 250 km, Figure 8.26 shows CNG and pipeline transportation to be the lowest cost modes of terrestrial gas transportation at volume rates up to 2.5 mmscfd. For higher volumes and longer distances than those, LNG and pipeline transportation are the most competitive modes of transportation. This chart only addresses relative competitiveness among the three modes of terrestrial gas transportation. Actual transportation tariffs need to be calculated using the relevant tariff model.

8.4.2 Lowest Cost Marine CNG/LNG/PL Gas Delivery

Figure 8.27 below presents the results for marine gas transportation at a 15% investor's rate of return and feed gas price of $3/mscf.

Figure 8.27 shows LNG and pipeline transportation to be the least costly modes of marine gas transportation at volume rates up to 300 mmscfd and one-way distances up to about 1,300 km. Up to 250 km, pipeline transportation is the lowest cost mode of marine gas transportation. For one-way distances in excess of 250 km, LNG becomes the lowest cost mode of marine gas transportation for low volumes, say up to 50 mmscfd for a distance of about 500 km or 100 mmscfd for a distance in excess of 750 km. CNG is not competitive for any combination of volume and distance due to the low tug boat speed (8 knot vs more than 16 knots for LNG tankers) and the high cost of storage, i.e., barge-mounted GTMs. In order for CNG transportation to become competitive with the other modes of marine gas transportation for volumes up to 50 mmscfd, the tug/barge speed has to increase to 16 knots, i.e., ship-borne rather than barge-mounted GTMs, and the cost of GTM decrease by 50%.

Figure 8.27 Lowest Cost Marine CNG/LNG/PL Gas Delivery @ 15% IRR



As with Figure 8.26, this chart only addresses relative competitiveness among the three modes of marine gas transportation. Actual transportation tariffs need to be calculated using the relevant tariff model.

8.4.3 Limitations of Applicability

Figures 8.26 and 8.27 are generic charts, which assume all conditions for transportation to be identical, i.e., identical gas source, no existing compression or LNG liquefaction facilities or storage, new shipping vessels, transportation modules and receiving terminal at market destination. To the extent useful facilities already exist for one of the modes of gas transportation, the relative competitiveness changes. E.g., gas transportation cost from an existing LNG plant to remote locations are considerably lower than implied by Figure 8.26 and would favor the LNG mode of transportation over CNG and pipeline. Likewise, availability of a high pressure gas source would favor the CNG mode of transportation. Thus, Figures 8.26 and 8.27 are only useful for a generalized screening and ranking of gas transportation modes. Any specific gas supply chain may require only a subset of the links and components embedded in the generic tariff models presented in this section or in other ways alter the cost structure in favor of one or the other transportation mode, which has been taken into account in the analysis of location specific supply chains in Task 7 (Section 10).

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9.1 INTRODUCTION

This study component (Task 6) was sub-contracted to Enersea Transport LLC of the United States of America. The scope of the study was marine transportation of CNG. Two cases were commissioned for study:

- *Transportation of relatively small amounts of CNG by tug pulled barge.* Two one-way distances were evaluated, 56 km and 370 km, the latter being judged the maximum range for use of tug pulled barges by Enersea. Ships would be used beyond this distance.

  and

- Transportation of larger quantities of CNG, 100 mmscfd and 200 mmscfd, by ship over a distance of 1235 km.

A summary of the Enersea Study is attached to this report as Appendix E. The following summarizes the concepts and findings of the Enersea Study Report.

In its review of the analysis by Enersea, the Study Team concluded that some Enersea assumptions (tug fuel price, gas price, etc) were not appropriate for Indonesian conditions at the time of study. In addition, some utility and gas conditioning costs (dehydration) were listed as client costs. Pendawa has computed cost estimates for these items and summarized their impacts on the cost of service tariff determined by Enersea, expressed in US$/mmBtu shipped.

The results of a review by the Study Team of Enersea's operating costs are presented in Tables 9.3-9.5. The impact of gas dehydration is given in Table 9.6. The ensuing combined impact of all items on the cost-of-service tariff is presented in Table 9.7.

9.2 FINDINGS BY ENERSEA

9.2.1 CNG Transportation by Tug-pulled Barge

Concept a Gas quantity: 15 mmscfd
Distance: 56 km

Enersea concluded that transportation by tug-pulled barge was appropriate for this distance, sea conditions and gas quantity.

The proposed operation would require three barges each with 15 mmscfd capacity. At any point in time, one barge would be supplying gas at the delivery end, one being filled at the supply end, and one in transit. One tug would be used.

Concept b Gas quantity: 40 mmscfd
Distance: 370 km

Enersea concluded that transportation by articulated tug/barges was appropriate for this distance, sea conditions and gas quantity. In this case, four barges and two tugs would be required.

Table 9.1 below presents Enersea's Cost of Service Tariffs for both concepts.

Table 9.1 Barge Case - Cost of Service Tariffs, $/mmBtu

Concept	Distance, km	Gas Rate, mmscfd	Fleet, # Barge/Tug	Tariff, incl. Tug fuel	Tariff w/o Tug fuel
a	56	15	3/1	$2.63	$2.33
b	370	40	4/2	$2.28	$1.95

9.2.2 CNG Transportation by Ship

Concept a Gas quantity: 100 mmscfd
Distance: 1,235 km

Enersea concluded that transportation by ship was appropriate for this distance, sea conditions and gas quantity.

The proposed operation would require one ship designed to carry 630 mmscf and onshore storage of 495 mmscf.

Concept b Gas quantity: 200 mmscfd
Distance: 1,235 km

The proposed operation would require two ships each of 630 mmscf capacity and onshore storage of 395 mmscf.

Table 9.2 below provides Enersea's Cost-of-Service Tariffs in US$/mscf for both concepts.

Table 9.2 Ship Case - Cost of Service Tariffs, $/mmBtu

Concept	Distance, km	Gas Rate, mmscfd	Fleet, # Ship	Tariff, incl. Storage.
a	1,235	100	1	$2.45
b	1,235	200	2	$1.90

9.3 ADJUSTMENTS TO ENERSEA'S TARIFFS

The Study Team has independently ascertained the tariff increments associated with the items deemed "Client's Responsibility" by Enersea. The results are presented below.

9.3.1 Barge Fuel (MDO)

Enersea based barge fuel costs on US$600/ton, equivalent to US$75/bbl of crude oil and US$ 84/bbl for middle distillate oil (MDO).

At time of study Pendawa believed a more appropriate cost is US$55/bbl of crude oil equivalent to US$61.6/bbl for MDO. The effect on the cost-of-service tariffs is given in Table 9.3 below.

Table 9.3 Vessel Fuel Cost US$/mscf shipped

Mode	One-Way	mmscfd	Pendawa	Enersea
Barge	56 km	15	0.22	0.30
	370 km	40	0.24	0.33
Ship	1,235 km	100	Gas	Gas
		200		

9.3.2 Electricity

Enersea assumes that electricity costs will be born by client and therefore are not included in the cost-of-service tariffs.

The price of electricity is assumed to be $0.09/ kWh in the Barge Case and $0.067/ kWh for Ship Case reflecting different regional electricity prices in Indonesia.

Based on the quantity of gas shipped in each case the cost per mscfe is shown in Table 9.4 below.

Table 9.4 Impact of Electricity Charges, $/mscfe

Mode	mmscfd	$/mmBtu shipped
Barge	15	0.52
	40	0.43
Ship	100	0.06
	200	0.04

9.3.3 Own Use Gas

Enersea assume the cost of gas consumed during the processes to be born by Client *and, therefore, not included in the cost of service tariff.*

Based on gas at US$5/mscf and the quantity of gas shipped in each case, the cost per mmBtu is shown in Table 9.5.

Table 9.5 Own Use Gas Charges, $/mscfe

Mode	mmscfd	$/mscfe shipped
Barge	15	0.02
	40	0.02
Ship	100	0.35
	200	0.35

9.3.4 Cost of Gas Dehydration

Enersea's process requires the water content of the feed gas to be less than 6 lbs/mmscf. PGN's[1] specifications for pipeline gas allows 15 lbs/mmscf. Therefore, dehydration of the feed gas will be required to manufacture CNG. In their report, Enersea listed dehydration as a Client responsibility.

The impacts of the cost of dehydration on the cost-of-service tariffs are listed in Table 9.6 below based on Pendawa's capital cost estimates for dehydration and a 15% investor's rate of return.

Table 9.6 Impact of Dehydration Cost, $/mscfe

mmscfd	Capital Cost, $MM	$/mscfe shipped
15	2.6	0.12
40	4.7	0.09
100	8.3	0.07
200	12.5(1)	0.05

(1) Extrapolated from 15-100 mmscfd capital cost data

9.4 All-in Delivered Cost of CNG by Barge and Ship.

Table 9.7 below presents Enersea's cost-of-service tariffs and the all-in tariffs resulting from the Study Teams adjustments to Enersea's estimates to reflect "Client's Responsibilities" and local conditions at the site of service.

[1] PGN - PT Perusahaan Gas Negara.

Table 9.7 Cost-of-Service Tariff Summary, $/mscfe

Mode	Volume, mmscfd	km	Enersea Tariff	Barge Fuel	Electri-city	Own Gas	De-Hydr	Total
Barge	15	56	2.33	0.22	0.52	0.02	0.12	3.21
	40	370	1.95	0.24	0.43	0.02	0.09	2.73
Ship	100	1,235	2.45	Gas	0.06	0.35	0.07	2.93
	200	1,235	1.90	Gas	0.04	0.35	0.05	2.34

Table 9.7 shows Study Team add-ons of $0.78/mmBtu for the low volume, short-haul service and $0.44-0.48 per mmBtu for the higher volume, long-haul service.

Table 9.8 below compares the Enersea and adjusted Enersea cost-of-service tariffs with the CNG costs of supply determined by the Marine CNG Transportation Tariff Model developed in Section 8 adjusted to reflect Enersea's assumptions in respect of CNG tug/barge and carrier ship speeds (8 and 18 knots, respectively) and size.

Table 9.8 Comparison of Cost-of-Service Tariffs, $/mmBtu

Mode	Volume	Distance	Enersea		This Study, Section 8	
	mmscfd	km	Findings	Adjusted	15% IRR	20% IRR
Barge	15	56	2.33	3.21	2.58	3.19
	40	370	1.95	2.73	2.33	2.93
Ship	100	1,235	2.45	2.93	2.43	3.03
	200		1.90	2.34	1.95	2.45

Table 9.8 shows the cost-of-service tariffs for CNG deliveries by barge and by ship determined in this study at 15-20% IRR to reasonably bracket the "Enersea Adjusted" values with the latter coming closer to the model tariffs at 20% IRR. The actual IRRs expected by Enersea as a full transportation service provider are unknown to the Study Team.

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10.1 INTRODUCTION

This section presents the price competitiveness of CNG/LNG in domestic OBF markets by comparing the netback value (NBV) of gas for three oil price scenarios with the cost of supply (COS) of CNG/LNG for three levels of feed gas price. A gas NBV higher than the CNG/LNG COS implies CNG/LNG price competitiveness with OBFs, the more so the more the ratio of the two exceeds one. A gas NBV less than CNG/LNG COS suggests CNG/LNG supplies not being price competitive with alternative OBFs, and, hence, that no replacement of OBF will take place by reason of economic considerations. The domestic markets being examined are small scale power generation, industrial manufacture and transportation, i.e., those for which potential replacements of OBFs by CNG/LNG were assessed in Section 4.

10.2 APPROACH

Recall that the NBV of gas is defined as the price at which natural gas can produce a product of equal quality to that of the next best, alternative fuel yielding equivalent benefits to the manufacturer/owner, including a return on the capital investment, be it in a green-field plant or a conversion.

The approach to determining the NBV of gas therefore comprises:

i. Identifying the fuel use in the manufacturing process, where gas may be employed as an alternative;

ii. Quantifying associated investments, operating costs and fuel use efficiencies of gas as well as the alternative fuel for both green-field plants as well as conversions;

iii. For green-field plants, calculating the price of gas yielding the same net present value (NPV) to the investor/manufacturer as the alternative fuel per unit of manufactured goods using a discount rate of 10% p.a.;

iv. For conversions of existing manufacturing plants, calculating the price of gas yielding a 33% internal rate of return to the investor/manufacturer on the incremental conversion investment taking into account differences in operating costs and fuel efficiency vis-à-vis the alternative fuel.

This methodology applies irrespective of sector, i.e., electric power generation, industrial manufacturing or transportation, save for a capital charge of 12.75% replacing the rate of return criteria of items (iii) and (iv) for electric power generation.

The cost of supply (COS) of CNG/LNG is the total cost of producing CNG/LNG from natural gas, storing, transporting and receiving it at a terminal within a (prospective) end-user distribution system, but excluding distribution to end-users, including a return on associated capital investments in the supply chain. The approach to determining the COS of CNG/LNG, therefore, entails calculation of a tariff yielding a 15% after-tax investor's rate of return on the cash flows of the entire supply chain comprising:

i. Feed gas purchase;

ii. Investment in an appropriately sized compression or liquefaction and storage facility and coverage of operating costs, including fuel gas consumption;

iii. Investment in transportation equipment and coverage of associated operating costs; and

iv. Investment in receiving and send-out facilities and coverage of attendant operating costs.

Gas NBVs and CNG/LNG COSs will be calculated for three oil and feed gas price scenarios for the small electric power generation, industrial and transportation sectors.

10.3 OIL AND FEED GAS PRICE SCENARIOS

The price competitiveness of CNG/LNG in OBF markets will be determined for three oil and feed gas price scenarios selected to cover the central range of:

- Recent world market oil price variations and their "futures" projection; and
- Recent domestic Indonesian gas prices and their anticipated future upward movement in sympathy with world market oil prices.

Table 10.1 Oil and Feed Gas Price Scenarios

Energy Type	Unit	Low	Median	High
Brent Crude Oil (BCO)	$/B	40	60	80
Feed Gas	$/MMBTU	3	4	5

Using the 2003-2007 Brent-Crude-Oil-OBF-product-price correlations shown in Table 10.2 below and the Public Supply Obligation "alphas" (supply/distribution costs plus retail profit margins) approved by BPH Migas for Pertamina for 2006, the delivered costs of OBF products presented in Table 10.3 are obtained.

Table 10.2 OBF Product Correlations with Brent Crude Oil

Reference	Fuel Type	Multiplier
Brent Crude Oil	ADO	1.15
	IDO	1.11
	FO	0.83
	Gasoline	1.18

Table 10.3 Delivered Costs of OBF Products

Fuel Type	Conversions	Ex Ref. Fuel Prices, $/liter			T, D & RM*, $/liter			VAT			Delivered Cost of OBF		
		Brent Crude Oil, $/B						10%			$/mmBtu		
	Btu/liter	40	60	80	Low	Median	High	Low	Median	High	Low	Median	High
ADO	36,939	0.29	0.43	0.58	0.06	0.07	0.08	0.03	0.05	0.07	10.40	15.01	19.61
IDO	38,437	0.28	0.42	0.56	0.06	0.07	0.08	0.03	0.05	0.06	9.71	13.99	18.27
FO	39,685	0.21	0.31	0.42	0.06	0.07	0.08	0.03	0.04	0.05	7.45	10.62	13.79
Gasoline	33,196	0.30	0.45	0.59	0.06	0.07	0.08	0.04	0.05	0.07	11.82	17.07	22.32
ADO**	36,939	0.29	0.43	0.58	0.03	0.04	0.05	0.03	0.05	0.06	9.43	14.15	18.87

* Transportation, Distribution and Retail Margin **Special *T, D & RM* rate applicable to *PLN* only

The delivered costs of OBF products are used in the subsections below to calculate the NBVs of gas usage in electric power generation, industry and transportation.

10.4 GAS NETBACK VALUES

In this subsection netback values (NBVs) of gas use in small scale electric power generation, industrial manufacturing processes and transportation will be determined relative to the delivered cost of alternative oil based fuels (OBFs) based on the $40, $60 and $80 per barrel oil price scenarios defined in the preceding subsection.

10.4.1 Gas NBV in Small Scale Electric Power Generation

As discussed in Section 4 of this report, replacement of OBF in electric power generation by CNG/LNG is only considered feasible in small scale (SS) generating facilities, i.e., those with total output of be less than 50 MW. The generating technologies employed in small scale OBF fired electric power generation are diesel engines (DE) and gas turbines (labeled TTOC for "Turbine Technology Open Cycle" in this study). The relevant characteristics of these generating technologies for purpose of determining gas NBVs are presented in Tables 10.4 and 10.5 below.

Table 10.4 SS Power Generating Technology Characteristics, Conversions[1]

Item	Unit	DE	TTOC
Fuel Switch		ADO=>NG	ADO=>NG
Unit Size	MW	< 5	> 10
Capital Cost*	$/KW	+200	+20
Interest Rate	%	12	12
Construction Duration	Years	0.5	1
Capital Cost plus IDC**	$/KW	6	1
Capital Charge	%	12.75	12.75
Operating Expense*	$/KW	+10	-5
Fuel Efficiency*	%	-2	-1
Fuel Mix, ADO:NG	%	30:70	0:100

*Incremental to diesel engine generating technology
**Interest During Construction at an annual interest rate of 10%

[1] Introduction to CPH Catalog of Technologies, p.8, Year 2000

Table 10.5 SS Power Generating Technology Characteristics, New Units[1]

Item	Unit	Diesel Engine		TTOC	
Fuel		ADO	NG	ADO	NG
Unit Size	MW	5 <	5 <	> 10	> 10
Capital Cost	$/KW	600	700	370	350
Interest Rate	%	12	12	12	12
Construction Duration	Years	0.5	0.5	1	1
Capital Cost plus IDC*	$/KW	617	720	392	371
Capital Charge	%	12.75	12.75	12.75	12.75
Operating Expense	$/KW	40	35	25	20
Fuel Efficiency	%	38	36	34	33
Fuel Composition	%	100	100	100	100

*Interest During Construction at an annual interest rate of 10%

Based on the generating technology characteristics presented in Tables 10.4 and 10.5, the NBVs of gas as an alternative fuel to ADO (also sometimes called High Speed Diesel) were determined as the price of gas, which yields the same generating cost, including a capital charge, for a given technology as the ADO for a given generating unit capacity factor (defined as the percent of rated capacity actually produced over a specified period of time). The gas NBVs vis-à-vis ADO for the Low, Median and High oil price scenarios are presented as functions of generating unit capacity factor in Tables 10.6 and 10.7 below and graphically in Figures 10.1 and 10.2. Detailed calculations are contained in Appendix F.

Table 10.6 Gas NBV in Small Scale Power Generation, Conversions, $/mmBtu

Oil Price	Fuel		Alternative Fuel	Type, Size Power Plant	Capacity Factor					
$/B	Type	$/MMBTU			100%	80%	60%	40%	20%	10%
40	ADO	9.43	30% ADO/70% NG	Engine (< 5 MW)	7.43	7.27	7.04	6.55	5.07	2.13
			NG	TTOC (> 10 MW)	8.90	8.91	8.92	8.94	9.00	9.13
60	ADO	14.15	30% ADO/70% NG	Engine (< 5 MW)	11.43	11.29	11.04	10.55	9.08	6.13
			NG	TTOC (> 10 MW)	13.35	13.35	13.36	13.38	13.44	13.56
80	ADO	18.87	30% ADO/70% NG	Engine (< 5 MW)	15.45	15.29	15.05	14.56	13.08	10.15
			NG	TTOC (> 10 MW)	17.78	17.78	17.80	17.81	17.89	18.01

Table 10.7 Gas NBV in Small Scale Power Generation, New Units, $/mmBtu

Oil Price	Fuel		Alternative Fuel	Type, Size Power Plant	Capacity Factor					
$/B	Type	$/MMBTU			100%	80%	60%	40%	20%	10%
40	ADO	9.43	NG	Engine (<5 MW)	8.84	8.81	8.77	8.69	8.45	7.95
				TTOC (> 10 MW)	9.24	9.26	9.29	9.37	9.58	10.01
60	ADO	14.15	NG	Engine (<5 MW)	13.31	13.28	13.24	13.16	12.91	12.43
				TTOC (> 10 MW)	13.82	13.84	13.88	13.95	14.16	14.58
80	ADO	18.87	NG	Engine (<5 MW)	17.78	17.76	17.71	17.63	17.39	16.89
				TTOC (> 10 MW)	18.40	18.41	18.45	18.52	18.74	19.17

Tables 10.6 and 10.7 along with Figures 10.1 and 10.2 show the NBVs of gas to be lower in converted electric power generating units than in new units due to the more favorable generating characteristics of new units, such as their lower unit cost differentials, better fuel efficiencies and their use of 100% natural gas fuel (rather than the 30/70 ADO/NG mix used in converted units).

[1] Introduction to CPH Catalog of Technologies, p.8, Year 2000

Figure 10.1 Gas NBV vs Capacity Factor in SS Power Generation, Conversions

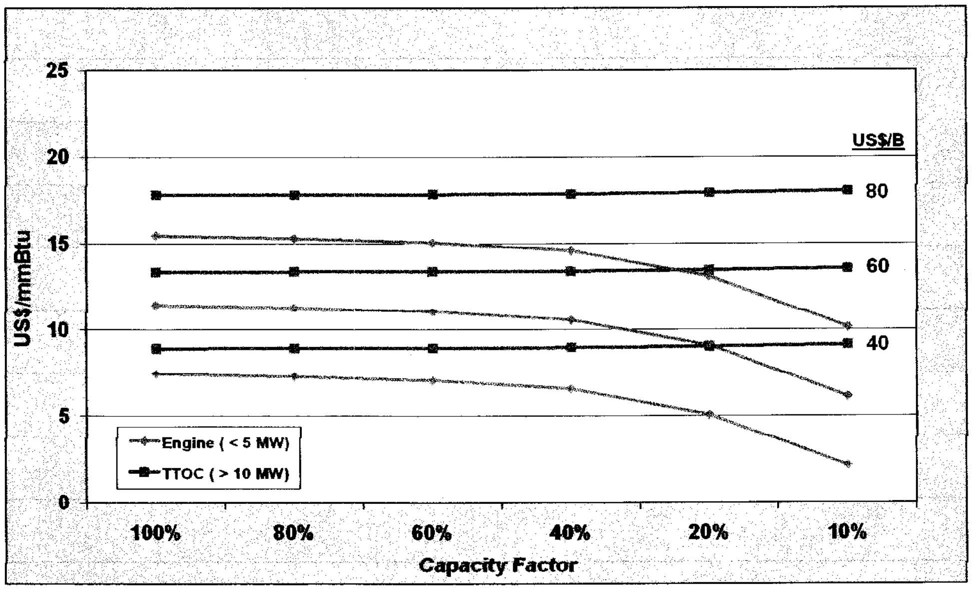
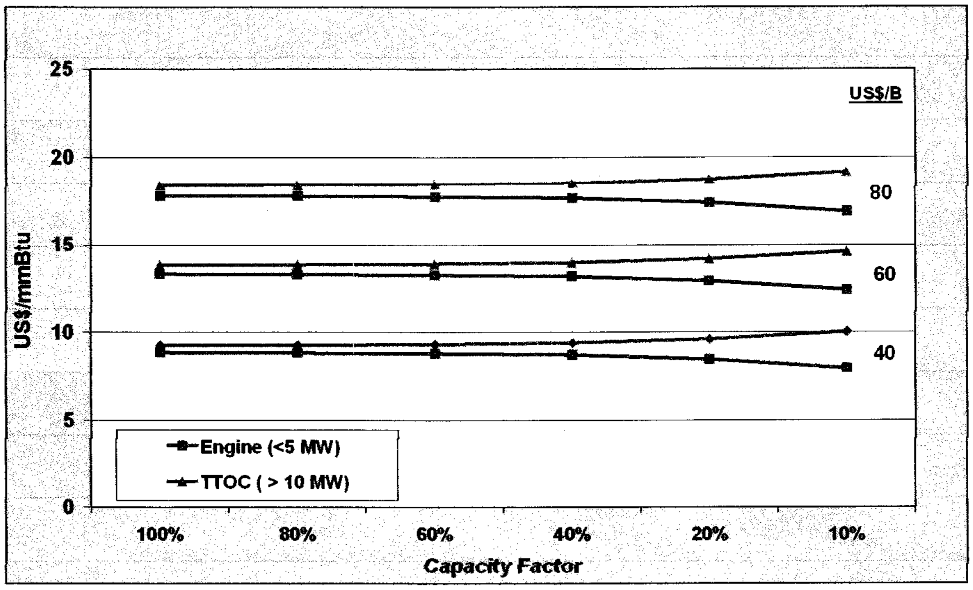


Figure 10.2 Gas NBV vs Capacity Factor in SS Power Generation, New Units



By comparison with the delivered cost of OBF products listed in Table 10.3 above, the NBVs of gas in electric power generation at capacity factors ranging from 40-50% (typical of small scale electric power generating units) equals 70-80% of the BTU equivalent cost of the alternative fuel, ADO, when used in converted diesel engines, but in excess of 94% of the BTU equivalent cost of ADO, when used in new engines or gas turbines (TTOC). The reasons for this difference are reduced operating costs and smaller fuel efficiency penalties associated with new engines and TTOC generating equipment than converted diesel engines.

10.4.2 Gas NBV in Industry

The main use of natural gas in industry is as fuel in the manufacturing sector, where it competes mainly with IDO and, in a few instances, FO. Therefore, the NBV of gas will be calculated for a large number of small scale manufacturing processes in order to assess the price competitiveness of gas within this sector.

The NBV of gas usage in 32 small manufacturing processes in replacement of IDO were analyzed for both new plants and conversions of older plants under the three oil price scenarios. The investor's rate of return on capital was assumed to be 10% for new plants (a general manufacturing sector rate of return), while the investor's rate of return on conversions was assumed to be 33% reflecting a commonly stated desire to obtain "a 3 year payback on incremental investments in manufacturing process improvements". The results of the gas NBV calculations are summarized in Table 10.8, while detailed gas NBV determinations are contained in Appendix F.

Table 10.8 Avg. Gas NBVs in Small Manufacturing Processes, $/mmBtu

Oil Price	Fuel		Alt. Fuel	Avg. NBV of Gas in 34 Manufacturing Processes, $/mmBtu	
$/B	Type	$/mmBtu		New Plants	Conversions
40	IDO	9.71	NG	12.14	9.92
60		13.99		17.27	14.47
80		18.27		22.40	19.03

The average gas NBVs are higher for new plants than for conversions, since a conversion investment of finite size is required, new gas fired boilers generally are less costly than new IDO fired boilers, and a higher return is expected on conversions than new plant investments. Average gas NBVs for both new plants and conversions are higher than the corresponding BTU equivalent costs of the alternative fuel, IDO, since gas fired boilers are less expensive to buy (investment) and operate (operating & maintenance expense) and exhibit higher fuel efficiency, so much so that the operating cost and fuel efficiency differentials more than offset the conversion investment.

10.4.3 Gas NBV in Transportation

Using a methodology analogous to that for manufacturing processes, the NBV of gas usage in transportation was evaluated. Based on the vehicle use criteria presented in Table 4.5 of this report, incremental costs to convert vehicles to CNG or LNG or purchase of Original Equipment Manufactured (OEM) natural gas vehicles, ongoing incremental operating costs, including fuel costs, and published differential fuel efficiencies, the NBV of gas in transportation was determined for the previously selected three oil price scenarios. NGV conversion costs and OEM vehicle prices, operating costs and fuel efficiencies, all incremental to those of corresponding conventional diesel or gasoline fueled vehicles, used in this analysis were obtained from public sources[1,2] and are presented in Tables 10.9 through 10.12 below.

Table 10.9 Converted CNG NGV Characteristics

Vehicle		Conversion*			
Type	Fuel	to	Cost, $	O&E, $/yr	Fuel Eff.
Large Bus	ADO	ADO/Diesel	12,000	1,000	-22%
Metromini Bus			11,000	1,000	-22%
Small Truck			9,000	1,000	-22%
Medium Truck			11,000	1,000	-22%
Large Truck			12,000	1,000	-22%
Small Truck	Gasoline	CNG	1,500	500	-10%
Taxi			1,500	500	-10%
Mikrolet			1,500	500	-10%

*Incremental to conventional diesel or gasoline vehicles

Table 10.10 OEM CNG NGV Characteristics

Vehicle		OEM*			
Type	Fuel	Fuel	Cost, $	O&E, $/yr	Fuel Eff.
Large Bus	ADO	CNG	18,000	1,000	-30%
Metromini Bus			16,000	1,000	-30%
Small Truck			13,000	1,000	-30%
Medium Truck			16,000	1,000	-30%
Large Truck			18,000	1,000	-30%
Small Truck	Gasoline		3,000	500	-7%
Taxi			3,000	500	-7%
Mikrolet			3,000	500	-7%

*Incremental to conventional diesel or gasoline vehicles

Table 10.11 Converted LNG NGV Characteristics

Vehicle		Conversion*			
Type	Fuel	Fuel	Cost, $	O&E, $/yr	Fuel Eff.
Large Bus	ADO	ADO/LNG	11,000	1,000	-22%
Metromini Bus			9,000	1,000	-22%
Small Truck			6,000	1,000	-22%
Medium Truck			9,000	1,000	-22%
Large Truck			11,000	1,000	-22%

*Incremental to conventional diesel or gasoline vehicles

1 "The Future is Now" presented by Petroleum Authority of Thailand at Natural Gas for Vehicles Conference & Exhibition in Bangkok, November 27-29, 2006

2 "Comparison of Clean Diesel Buses to CNG Buses" presented by New York City Transit, Department of Buses, at DEER Conference 2003 in Newport, RI

Table 10.12 OEM LNG NGV Characteristics

Vehicle		OEM*			
Type	Fuel	Fuel	Cost, $	O&E, $/yr	Fuel Eff.
Large Bus	ADO	LNG	18,000	1,000	-30%
Metromini Bus			*15,000*	*1,000*	-30%
Small Truck			10,000	1,000	-30%
Medium Truck			15,000	1,000	-30%
Large Truck			18,000	1,000	-30%

*Incremental to conventional diesel or gasoline vehicles

The detailed calculations of gas NBVs in CNG and LNG NGVs are contained in Appendix F and summarized in Tables 10.13 below.

Table 10.13 Gas NBVs in CNG and LNG NGVs

		Conversion (33% IRR)				OEM (10% IRR)			
Crude Oil Price, $/B			40	60	80		40	60	80
Vehicle Type	Fuel	Fuel	Gas NBV in NGV, $/mmBtu			Fuel	Gas NBV in NGV, $/mmBtu		
Large Bus	Diesel	ADO/CNG	4.06	7.63	11.20	CNG	6.01	9.56	13.10
Metromini Bus			-0.65	2.92	6.49	CNG	3.73	7.27	10.82
Small Truck			-13.08	-9.51	-5.94	CNG	-2.54	1.00	4.54
Medium Truck			-5.07	-1.60	1.97	CNG	1.52	5.06	8.60
Large Truck			4.06	7.63	11.20	CNG	6.01	9.56	13.10
Small Truck	Gasoline	CNG	5.63	10.41	15.18	CNG	6.38	11.28	16.19
Taxi			7.86	12.63	17.41	CNG	8.41	13.32	18.22
Mikrolet			*7.59*	*12.36*	*17.14*	*CNG*	*8.16*	*13.07*	*17.98*
Large Bus	Diesel	ADO/LNG	4.33	7.90	11.47	LNG	6.01	9.56	13.10
Metromini Bus			0.60	4.17	7.77	LNG	3.91	7.46	11.00
Small Truck			-7.73	-4.16	-0.59	LNG	-0.99	2.55	6.10
Medium Truck			-3.26	0.31	3.88	LNG	1.80	5.34	8.88

The NBV determinations show OEM NGVs to have higher gas NBVs than the corresponding conversions due to the faster payback required for the latter (33% vs 10% investor's rate of return for OEMs). Also, some vehicle type conversions are uneconomic, i.e., negative NBVs, even at the $80/B oil price scenario, such as small trucks, be the fuel CNG or LNG, due to the combination of their relatively high conventional fuel efficiency and short daily travel distances relative to the cost of conversion.

10.5 CNG/LNG COST OF SUPPLY

In this subsection, the cost of supply (COS) of CNG/LNG to small scale electric generating plants, selected industrial manufacturing locations and the transportation sector identified in Section 4 will be determined for the $3, $4 and $5 per mmBtu feed gas prices defined in subsection 10.3 above.

10.5.1 CNG/LNG COS in Power Generation and Nearby Industry

The costs of CNG/LNG supply to small scale electric power plants and industries located in their vicinity have been determined for three different feed gas prices using the methodology outlined in subsection 10.2 above and employing the Terrestrial and Marine CNG/LNG Tariff Models described in Section 8. The costs of CNG/LNG supply to yield a 15% after-tax rate of return to the supply chain investor were determined for all small scale OBF fired power plants identified in Section 4 as holding potential for conversion to CNG/LNG based on identified sources of feed gas supply, distances to power plant, modes of transportation and volume requirements. The detailed calculations are contained in Appendix F, while sample results have been summarized in Table 10.14 below.

Table 10.14 Sample Costs of CNG/LNG Supply to SS Power Plants & Nearby Industry

Fuel	Region	From	To	Generating Technology	Volume	One-way Distance	Transport Mode**	Cost of Supply, $/mmBtu Feed Gas Price, $/mmBtu		
				DE/TTOC*	mmscfd	km	Mar/Terr	3	4	5
LNG	Aceh	Arun	Banda Aceh	DE	7.07	245	Terr	5.33	6.41	7.49
		Arun	Meulaboh	DE	1.4	250	Terr	5.49	6.57	7.64
	Riau	Batam	P. Pinang	DE	9.93	480	Mar	7.89	9.11	10.34
		Batam	PP/Mentok	DE	0.78	480/75	Mar/Terr	8.76	9.98	11.21
	E.Java/Bali	Bontang	Gilimanuk	TTOC	37.3	198	Terr	5.74	6.85	7.97
		Bontang	Gilimanuk/ Pemaron	TTOC	7.64	198/132	Terr	6.37	7.48	8.60
	Kalimantan	Bontang	Pontianak	DE	9.51	1680	Mar	7.18	8.33	9.49
		Bontang	Singkawang	DE	2.58	1818	Mar/Terr	7.89	9.05	10.20
	Papua	Tangguh	Jayapura	DE	5.21	1620	Mar	7.83	9.00	10.17
CNG	Jambi	Duri PL	Payo Selincah	DE	5.31	60	Terr	5.38	6.40	7.41
	Lampung	Bandar L	Tarahan	DE	8.86	56	Terr	5.16	6.18	7.19

*DE=Diesel Engine; TTOC=Turbine Technology, Open Cycle ** Marine (Mar) or Terrestrial (Terr)

As pointed out in Section 8, the costs of CNG/LNG supply are strong functions of distance and, especially for marine transportation, volume due to the transportation component. However, for terrestrial CNG/LNG transportation of volumes in excess of 1 mmscfd, costs of supply are weak functions of volume, since the most capital intensive link in the supply chain, the truck/trailer requirement, merely scales up proportional to volume.

The cost of supply in some locations reflects multiple transportation modes, e.g., to deliver LNG to Singkawang and Sambas, West Kalimantan, entails marine LNG transportation from Bontang to Pontianak followed by 130-210 kilometers, respectively, of terrestrial LNG transportation to these two cities.

10.5.2 CNG/LNG COS in Industry

Only in Java are industrial OBF markets per se large and compact enough to justify CNG/LNG-based gas supply. The regency-by-regency industrial OBF market assessment presented in Section 4 identified nine markets as prime candidates for CNG/LNG-based gas supply. The detailed calculations of the cost of CNG/LNG supply to these markets are contained in Appendix F. A summary of the CNG/LNG COS findings are presented in Table 10.15 below.

Table 10.15 Cost of CNG/LNG Supply to Industrial Locations in Java

Region	From	To	Fuel	Transport Mode	Volume (mmscfd)			One-way Distance	Cost of Supply, $/mmBtu*		
									Feed Gas Price, $/mmBtu		
			CNG/LNG		Low	Med	High	km	3	4	5
W. Java	Jatibarang	Bandung	CNG	Terrestrial	1	1.5	2	135	8.34	8.92	9.73
	Jatibarang	Sukabumi						210	9.04	9.64	10.48
	Jatibarang	Majalengka						75	7.74	8.12	9.04
C. Java	Semarang	Solo						110	7.79	8.50	9.47
	Semarang	Kudus						50	7.21	8.08	8.78
	Semarang	Yogyakarta						110	7.79	8.5	9.47
E. Java	Surabaya	Malang						90	7.64	8.48	9.15
	Probolinggo	Jember						90	7.64	8.48	9.15
	Surabaya	*Blitar*						*180*	*8.68*	*9.35*	*10.15*

*Including $1/mmBtu local distribution tariff

Table 10.15 shows that the cost of CNG supply is always less than that of LNG supply for the volumes under consideration. Since the CNG mode of gas delivery is fuel efficient and supply economies of scale is reached at relatively low volumes, the variations in delivered cost of CNG-based gas supply to industrial markets under the three feed gas price scenarios mirrors primarily the feed gas price differences.

10.5.3 CNG/LNG COS in Transportation

The cost of CNG/LNG supply in transportation has three components:

- Feed gas cost;
- Cost of compression for CNG or liquefaction and transportation for LNG; and
- Cost of refueling, i.e., storage and dispensing.

These will be discussed and presented separately for CNG and LNG in the next two subsections.

10.5.3.1 CNG Cost of Supply for NGVs

Being located in and prevalent throughout major cities, CNG refueling stations are assumed to be supplied feed gas by fixed pipeline connections, compress natural gas to 3,200 psia for storage in multiple high pressure tanks for release on demand by CNG customers. Compression and storage facility costs were obtained from the Terrestrial Tariff Model described in Section 8, while refueling station costs were developed from a U.S. Department of Natural Resources paper[1]. Detailed CNG COSs for NGV were calculated for three different dispensing rates and are contained in Appendix F and summarized in Table 10.16 below. The COS of refueling is essentially independent of the price of feed gas.

Table 10.16 CNG Refueling Station Unit Cost vs Throughput

Feed Gas	Capacity		Tariff
$/mscf	mmscfd	LADOE*/hr	$/mmBtu
3.00	0.5	564	2.97
	1.0	1,128	2.60
	2.0	2,256	2.36

**Liters of Automotive Diesel Oil Equivalents*

Assuming a dispensing rate of 1 mmscfd, the ensuing costs of CNG supply in transportation are presented in Table 10.17 below showing a range of $5.60-7.60 per mmBtu for feed gas prices ranging from $3-5 per mscf.

Table 10.17 CNG Cost of Supply for NGVs

Feed Gas	Refueling Tariff	COS
$/mscf	$/mmBtu	$/mmBtu
3.00	2.60	5.60
4.00		6.60
5.00		7.60

10.5.3.2 LNG Cost of Supply for NGVs

LNG refueling stations are assumed to be supplied by LNG tanker truck from an appropriately sized LNG plant 250 km away dispensing 5 mmscfd equivalent of LNG. The liquefaction facility and trucking costs were based on similar sized facilities being built in Thailand[2] and incorporated into the Terrestrial Tariff Model described in Section 8, while the LNG refueling station costs were deemed equal to that of the CNG refueling station discussed in the previous subsection.

The costs of LNG manufacture at $3 per mscf for feed gas are presented in Table 10.18 below for three different small scale LNG plant sizes. The ensuing costs of LNG supply for the three different feed gas price scenarios are shown in Table 10.19 below.

[1] "CNG Refueling Facility Cost", Compressed Natural Gas Vehicles, Department of Natural Resources Technical Note, March 2, 2000.
[2] Private Pendawa communication, December, 2006

Table 10.18 LNG Refueling Station Unit Cost vs Throughput

Feed Gas $/mscf	Capacity mmscfd	Liquefaction $/mmBtu
3.00	2	3.90
	5	3.31
	10	2.92

Table 10.19 LNG Cost of Supply for NGVs

Feed Gas $/mscf	5 mmscfd LNG Supply Chain COS, $/mmBtu			
	Liquefaction	Transportation*	Refueling	Total
3.00	3.31	0.66	0.24	7.21
4.00	3.50	0.66	0.26	8.42
5.00	3.69	0.66	0.28	9.63

The cost of LNG supply is up to $2 per mmBtu higher than for CNG supply due to the higher cost of liquefaction and transportation of LNG to the refueling stations, which are assumed to be located an average distance of 250 km from the liquefaction facility.

10.6 GAS NET BACK VALUE vs CNG/LNG COST OF SUPPLY

This subsection identifies the combinations of oil price and feed gas price levels, which render CNG/LNG competitive with OBF products in small scale power generation, industry and transportation. Competitiveness is defined as netback values (NBV) of gas in each sector exceeding the costs of supply (COS) of CNG/LNG to that location/sector. The ratio of gas NBV to CNG/LNG COS is used in Section 11 to determine the long run degree of OBF replacement in the three markets and, thereby, the total market for CNG/LNG in Indonesia over time.

10.6.1 Competitiveness of CNG/LNG in Power Generation

As mentioned in subsection 10.5.1 above, CNG/LNG supply to small scale power plants and industry outside Java will be lumped, since the industrial fuel demand per se is too small and logistically diffuse to be met economically by CNG/LNG delivery. However, industry located in the vicinity of small scale power plants constitutes an economically viable target for replacement of OBF. Hence, all gas equivalent volumes presented in this subsection represent small scale power plant demand plus allocated industrial demand, the latter deemed equal to 15% of gas-in-power demand. The NBVs of gas in industry being higher than in small scale power generation, i.e., Table 10.6 entries exceeding Table 10.5 entries for any Capacity Factor, ensures competitiveness of CNG/LNG in industrial use, if it is competitive in small scale power plant use.

The competitiveness of CNG/LNG vis-à-vis OBFs in small scale power generation and industry was determined for all locations within Indonesia with small scale OBF fired power plants not located in the vicinity of existing or planned gas transmission and distribution infrastructure, i.e., those locations identified in Section 4 of this report. The location-by-location gas NBVs and CNG/LNG COSs are contained in Appendix F. The comparisons for a few, selected locations are presented in Table 10.20 below, namely those for which COSs were previously presented in Table 10.14 above.

The coloring scheme in Table 10.20 is designed to enable a quick appraisal of the competitiveness of CNG/LNG in replacing OBFs in small scale electric power generation. Given the three oil price scenarios of $40, $60 and $80 per barrel, the coloring scheme identifies the lowest oil price for which the cost of CNG/LNG supply at a specified feed gas price is less than the gas NBV. Thus, "yellow" areas in Table 10.20 indicate power plants, where CNG/LNG fueled electric power generation costs are lower than that of OBFs based on $40 per barrel (or higher) oil prices; "orange" areas indicate power plants, where CNG/LNG generates electric power at lower costs than OBFs at $60 per barrel of oil (or more); and "green" areas signify CNG/LNG fueled plants needing OBF prices equivalent to $80 per barrel (or more) to be competitive.

Table 10.20 Competitiveness of CNG/LNG in Power Generation in Selective Locations

Fuel	Region	From	To	Generating Technology	CF**	Volume	Gas NBV, $/mmBtu***			Cost of CNG/LNG Supply, $/mmBtu		
							Oil Price, $/B			Feed Gas Price, $/mmBtu		
				DE/TTOC*	%	mmscfd	40	60	80	3	4	5
LNG	Aceh	Arun	Banda Aceh	DE	55	7.07	7.84	12.07	16.31	5.33	6.41	7.49
		Arun	Meulaboh	DE	47	1.4	7.72	11.95	16.20	5.49	6.57	7.64
	Riau	Batam	P. Pinang	DE	59	9.93	8.07	12.32	16.55	7.89	9.11	10.34
		Batam	PP/Mentok	DE	47	0.78	7.72	11.95	16.20	8.76	9.98	11.21
	E.Java/Bali	Bontang	Gilimanuk	TTOC	11	37.3	9.54	14.04	18.56	5.74	6.85	7.97
		Bontang	Gilimanuk/ Pemaron	TTOC	21	7.64	9.28	13.79	18.30	6.37	7.48	8.60
	Kalimantan	Bontang	Pontianak	DE	50	9.51	7.77	12.00	16.24	7.18	8.33	9.49
		Bontang	Singkawang	DE	50	2.58	7.77	12.00	16.24	7.89	9.05	10.20
	Papua	Tangguh	Jayapura	DE	52	5.21	6.84	10.84	14.85	7.83	9.00	10.17
CNG	Jambi	Duri PL	Payo Selincah	DE	50	5.31	7.77	12.00	16.24	5.38	6.40	7.41
	Lampung	Bandar L	Tarahan	DE	50	8.86	7.77	12.00	16.24	5.16	6.18	7.19

* DE = Diesel Engine; TTOC = Turbine Technology Open Cycle
** Capacity Factor
*** 50/50 = Conversions/New Units

Economically viable $40/B and higher oil prices
Economically viable $60/B and higher oil prices
Economically viable $80/B and higher oil prices

At feed gas prices of $3-5 per mmBtu, Table 10.20 shows CNG/LNG to be an economically viable alternative to OBFs at an oil equivalent price of $40/B or more in about half of the locations/feed gas price combinations, i.e., those marked in "yellow" in the three rightmost columns of the table. In the rest of the location/feed gas price combinations, namely those marked in "orange", the oil price needs to exceed $60/B for CNG/LNG replacement of OBFs to be economically viable.

10.6.2 Competitiveness of CNG/LNG in Industry

The competitiveness of CNG/LNG-based gas use vis-à-vis OBFs in industry was determined for nine cities in Java. The details of the location-by-location gas NBVs and CNG/LNG COSs are contained in Appendix F. Table 10.21 below summarizes the results identifying the economic viability of replacing OBFs by CNG/LNG-based gas. Note that the gas NBVs quoted in Table 10.21 reflect the average NBVs of conversions and new units.

Table 10.21 Competitiveness of CNG/LNG in Industry

Region	To	Fuel	Volume (mmscfd)			Gas NBV, \$/mmBtu*			Cost of CNG/LNG Supply, \$/mmBtu**		
						Oil Price, \$/B			Feed Gas Price, \$/mmBtu		
		CNG/LNG	Low	Med	High	40	60	80	3	4	5
W. Java	Bandung	CNG	1	1.5	2	11.03	15.87	20.72	8.34	8.92	9.73
	Sukabumi								9.04	9.64	10.48
	Majalengka								7.74	8.12	9.04
C. Java	Solo								7.79	8.50	9.47
	Kudus								7.21	8.08	8.78
	Yogyakarta								7.79	8.5	9.47
E. Java	Malang								7.64	8.48	9.15
	Jember								7.64	8.48	9.15
	Blitar								8.68	9.35	10.15

* 50/50 = Conversions/New Units
** Including a \$1/mmBtu distribution tariff

☐ Economically viable \$40/B and higher oil prices

Table 10.21 shows replacement of OBFs in industrial plants by CNG/LNG-based gas to be economically viable throughout Java for the lowest oil price scenario, \$40/B, even with CNG/LNG feed gas priced at \$5/mmBtu.

10.6.3 Competitiveness of CNG/LNG in Transportation

Comparing the gas NBVs of CNG/LNG usage in NGVs presented in Table 10.13 and the CNG and LNG COS values contained in Tables 10.17 and 10.19, respectively, enables determination of the competitiveness of CNG/LNG in replacing OBFs in transportation. A gas NBV higher than the CNG/LNG COS indicates economically viable replacement potential, while a gas NBV below the corresponding CNG/LNG COS suggests no economic incentive to switch.

Detailed calculations and comparisons of gas NBVs and CNG/LNG COSs are contained in Appendix F. Table 10.22 below summarizes the results for conversion of conventional fuel vehicles to natural gas, while Table 10.23 tabulates the results for Original Equipment Manufacturer's NGVs. The coloring scheme is analogous to that used in Tables 10.20 and 10.21 above, here only applied to CNG/LNG use in transportation rather than in small scale power generation or industrial manufacturing processes. White elements/areas in the CNG/LNG COS portion of the tables indicate CNG/LNG not being an economically viable alternative to OBFs even in the \$80 per barrel oil price scenario.

Table 10.22 Competitiveness of CNG/LNG in Transportation, Conversions

Vehicle Type	Fuel Switch		Gas NBV, $/mmBtu Crude Oil Price, $/B			CNG/LNG COS, $/mmBtu Feed Gas Price, $/mscf		
	From	To	40	60	80	3	4	5
Large Bus	ADO	ADO/CNG	4.06	7.63	11.20	5.60	6.60	7.60
Metromini Bus			-0.65	2.92	6.49		6.60	7.60
Small Truck			-13.08	-9.51	-5.94	5.60	6.60	7.60
Medium Truck			-5.07	-1.60	1.97	5.60	6.60	7.60
Large Truck			4.06	7.63	11.20	5.60	6.60	7.60
Small Truck	Gasoline	CNG	5.63	10.41	15.18	5.60	6.60	7.60
Taxi			7.86	12.63	17.41	5.60	6.60	7.60
Mikrolet			7.59	12.36	17.14	5.60	6.60	7.60
Large Bus	ADO	ADO/LNG	4.33	7.90	11.47	7.21		
Metromini Bus			0.60	4.17	7.77		8.42	9.63
Small Truck			-7.73	-4.16	-0.59	7.21	8.42	9.63
Medium Truck			-3.26	0.31	3.88	7.21	8.42	9.63
Large Truck			4.33	7.90	11.47	7.21		

Economically viable at $40/B or higher oil prices

Economically viable at $60/B or higher oil prices

Economically viable at $80/B or higher oil prices

Table 10.23 Competitiveness of CNG/LNG in Transportation, OEMs

Vehicle Type	Fuel Switch		Gas NBV, $/mmBtu Crude Oil Price, $/B			CNG/LNG COS, $/mmBtu Feed Gas Price, $/mmBtu		
	From	To	40	60	80	3	4	5
Large Bus	ADO	CNG	6.01	9.56	13.10	5.60	6.60	7.60
Metromini Bus			3.73	7.27	10.82	5.60	6.60	
Small Truck			-2.54	1.00	4.54	5.60	6.60	7.60
Medium Truck			1.52	5.06	8.60			
Large Truck			6.01	9.56	13.10	5.60	6.60	7.60
Small Truck	Gasoline		6.38	11.28	16.19	5.60	6.60	7.60
Taxi			8.41	13.32	18.22	5.60	6.60	7.60
Mikrolet			8.16	13.07	17.98	5.60	6.60	7.60
Large Bus	ADO	LNG	6.01	9.56	13.10	7.21	8.42	
Metromini Bus			3.91	7.46	11.00	7.21		
Small Truck			-0.99	2.55	6.10	7.21	8.42	9.63
Medium Truck			1.80	5.34	8.88			9.63
Large Truck			6.01	9.56	13.10	7.21	8.42	

Economically viable at $40/B or higher oil prices

Economically viable at $60/B or higher oil prices

Economically viable at $80/B or higher oil prices

Tables 10.22 and 10.23 show most CNG fueled vehicle types, conversions as well as OEMs, requiring OBFs priced at or above the oil equivalent price of $60 per barrel to be competitive, i.e., large swaths of orange, green and white in the rightmost portions of the tables. The tables also suggest that CNG is most cost competitive for gasoline fueled vehicles, such as taxis and mikrolets, and that LNG fueled vehicles require

OBFs priced at or above the oil equivalent price of $80 per barrel to be competitive, i.e., predominantly green and white areas in the rightmost portions of the tables.

Section 11 will translate the quantified CNG/LNG competitiveness expressed in Tables 10.22 and 10.23 into probability-of-switch/market-shares and estimations of future CNG/LNG demand.

--oOo--

11.1 INTRODUCTION

This section presents estimates of ultimate nationwide replacements of OBF by CNG/LNG-based gas for three combinations of oil and feed gas prices. In each of the three markets, where CNG/LNG was determined to be potentially competitive, the degree of economic competitiveness, measured by the ratio of gas netback value (NBV) to CNG/LNG cost of supply (COS), is used to determine the ultimate market share in customer markets captured by CNG/LNG or the probability of conversion from OBF to CNG/LNG-based gas for individual customers. Using the gas NBV and CNG/LNG COS data developed in Section 10, forecasts of CNG/LNG demand in small scale power generation, industry and transportation will be presented for the three combinations of oil and CNG/LNG feed gas prices shown in Table 11.1 below.

Table 11.1 Oil and CNG/LNG Feed Gas Price Combination Scenarios

Case	Low	Median	High
Oil Price, $/B	40	60	80
CNG/LNG Feed Gas Price, $/ MMBTU	3	4	5

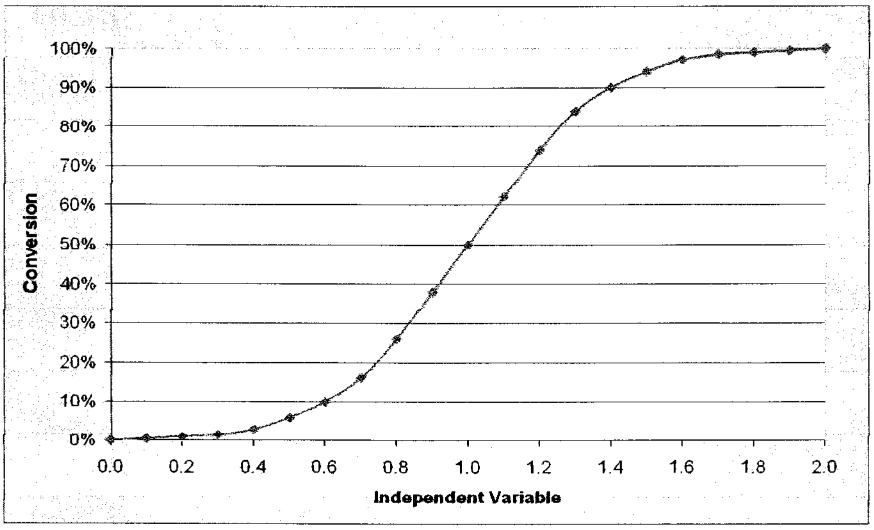
11.2 APPROACH

The approach adopted in this study to determine ultimate market share uses the S-curve of growth[1] to convert economic benefit of using one fuel over another into ultimate market share in a given market. A typical S-curve of growth is shown in Figure 11.1 below.

S-curves are frequently used to estimate or forecast the rate of adoption of a technology, the rate at which the performance of a technology improves or the market penetration of a technology or product over time. The S-curve of growth is characterized by an initial phase of slow exponential growth, followed by a phase of rapid growth and concluded by a phase of declining growth as saturation levels are reached. This growth pattern as a function of increasing benefit-to-cost ratio models well the introduction of CNG/LNG-based gas into a broad spectrum, conventional OBF market environment, i.e., initial reluctance to switch to a new and unreliable fuel supply with marginal economic benefits, gradually replaced by rapidly increasing acceptance as confidence in the economic benefits, reliability of supply and technology, and ultimately followed by decelerating rate of growth as competition for the last market decile strengthens.

[1] "S-curve Forecasting. Tools for Managers" by Stephen R. Lawrence, Boulder, Colorado reported in Wikepedia.

Figure 11.1 Typical S-curve of Growth

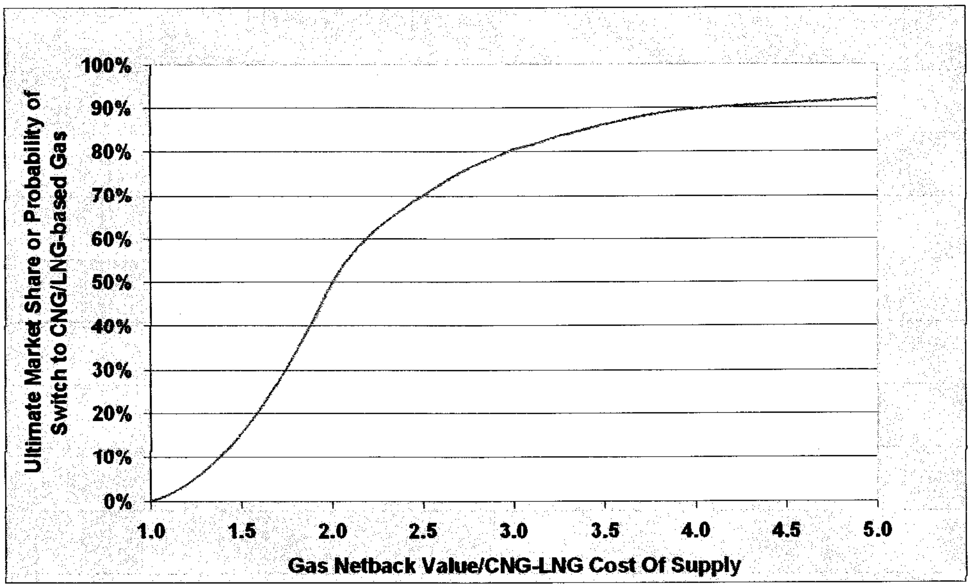


In this study we are interested in determining the ultimate degree of OBF replacement by CNG/LNG-based gas in small scale electric power generation, industrial manufacturing processes and transportation. The S-curve of growth in this study correlates the ultimate market share captured by CNG/LNG-based gas in a specific market with the ratio of the NBV of gas in that market to the CNG/LNG COS, i.e., NBV/COS. The higher the NBV/COS ratio, the higher the ultimate market share captured by CNG/LNG-based gas will be. A ratio below one precludes any market capture by CNG/LNG as there is no economic incentive to switch. As the ratio rises above one, the market share grows slowly due to inherent reluctance on the part of customers to switch to a new fuel and the initially marginal benefits derived from such a switch. As the NBV/COS ratio increases further above one, the economic benefits of switching to CNG/LNG become compelling and customers become convinced of the economic benefits of a switch leading to widespread conversion to CNG/LNG-based gas in the market place. Finally, at high NBV/COS ratios even the most intransigent of customers become convinced of the benefits of switching to the alternative fuel, but to capture the last 10% of a market becomes increasingly difficult.

For single customer markets, such as PLN-dominated SMS electric power generation, the S-curve of growth is used to determine the probability of a plant or facility switching from OBF to CNG/LNG-based gas as a function of the NBV/COS ratio. The rationale for using the S-curve to predict probability of switching is analogous to that of predicting ultimate market share in a multi-customer market.

Since no hard data are available at this time on ultimate OBF market capture by CNG/LNG-based gas, a general S-curve of growth applicable to the small scale power generation, industrial and transportation sectors will be adopted for this study based on Pendawa's perception of the strength of economic drivers and speed of implementation in Indonesia. The S-curve selected for this study is shown in Figure 11.2 below.

Figure 11.2 CNG/LNG Penetration of OBF Market



The S-curve chosen implies no switch from OBF to CNG/LNG-based gas in the absence of an economic incentive, i.e., Gas NBV/CNG-LNG COS values of 1 or less. At a NBV-COS ratio of two, the ultimate market share will be approximately 50%, while a ratio of three will bring about an ultimate market share of 80%. Thereafter, additional ultimate market share grows asymptotically toward 95% at a NBV/COS value of 7. Moreover, the "ultimate" market share is assumed to be achieved in 2018 in the small scale electric power generation and industrial sectors, i.e., 8 years after commencement of an assumed concerted drive to replace OBF with CNG/LNG in 2010. For transportation, it is assumed that the "ultimate" market share will be achieved 10 years after introduction of CNG/LNG to a city or along the North Java Highway, i.e., 2016 for the cities of Jakarta and Surabaya already enjoying CNG service, but 2018 for a city like Cirebon and 2022 for a city like Semarang.

11.3 PROJECTED CNG/LNG REPLACEMENT OF OBF IN POWER

Using the gas NBVs and CNG/LNG COSs developed in Section 10 and presented in subsection 10.6.1 to determine the ratio of NBV-to-COS and then applying that ratio to the S-curve shown in Figure 11.2 allows determination of the probability of replacing OBF by CNG/LNG in each identified power plant location for the established range of oil and feed gas prices. Table 11.2 below shows the application of this methodology to the determination of the probability of switching at each of the seven small scale electric power plants located in the province of Aceh.

Table 11.2 Gas NBV/LNG COS and Probability of LNG Use in Power Generation, Aceh

Feed Gas,	Gas NBV/LNG COS									Probability of Conversion to LNG								
$/mmBtu	3			4			5			3			4			5		
Oil, $/B	40	60	80	40	60	80	40	60	80	40	60	80	40	60	80	40	60	80
Banda Aceh	1.47	2.26	3.06	1.22	1.88	2.54	1.05	1.61	2.18	14%	62%	81%	5%	40%	71%	1%	22%	58%
Sigli	1.49	2.31	3.14	1.23	1.91	2.59	1.05	1.63	2.21	15%	64%	82%	5%	43%	73%	1%	23%	60%
Takengan	1.37	2.15	2.94	1.14	1.79	2.45	0.98	1.54	2.10	10%	57%	79%	2%	34%	68%	0%	17%	55%
Meulaboh	1.41	2.18	2.95	1.18	1.82	2.47	1.01	1.56	2.12	11%	58%	79%	3%	35%	69%	0%	19%	56%
Blang Pidie	1.33	2.06	2.79	1.12	1.73	2.35	0.97	1.50	2.03	8%	53%	77%	2%	29%	65%	0%	15%	52%
Tapak Tuan	1.32	2.04	2.77	1.11	1.72	2.34	0.96	1.49	2.02	8%	52%	76%	2%	29%	64%	0%	15%	51%
Subussalam	1.26	1.95	2.64	1.08	1.66	2.25	0.94	1.45	1.96	6%	46%	74%	1%	25%	61%	0%	13%	47%

Table 11.2 shows the probability of replacing OBF in power generation in Aceh with LNG ranging from 0 to 82 percent depending on the economic driver, i.e., the NBV/COS ratio, for the switch. The higher the NBV/COS ratio is, the higher the probability of conversion to LNG.

Applying the same computational methodology across the entire range of identified small scale electric power plants throughout Indonesia results in the expected replacement of OBF in the small scale electric power generating sector, which the Study Team assumed to be completed by year 2018. The program to replace OBF by CNG/LNG in electric power generation would commence in 2010 with conversion of one or two smaller power plants in each province and gradually expand to reach the expected conversion within the province by 2018. The resultant projections of expected CNG/LNG replacement of OBF in small scale power generation are shown numerically in Tables 11.3 through 11.5 below for the three previously selected combinations of oil and feed gas prices, namely $40/B & $3/mmBtu (Low), $60/B & $4/mmBtu (Median) and $80/B & $5/mmBtu (High), and graphically in Figure 11.3. The detailed calculations are contained in Appendix G.

Tables 11.3 through 11.5 show projected CNG/LNG replacements of OBF in small scale electric power generation to range from 13-62 mmscfd by 2010 increasing to 35-189 mmscfd by 2025. The analysis shows CNG/LNG penetration of the small scale electric power generation OBF market to be a strong function of oil prices, i.e., conversion to CNG/LNG does not become material until oil prices reach $60 per barrel, but then grows again by 65% with another $20 per barrel increase to $80 per barrel.

The declining CNG/LNG replacement in 2015 in the province of South Sulawesi is due to an assumption that pipeline gas will be supplied to areas with small scale power generation plants by then.

Table 11.3 Projected CNG/LNG-in-Power Replacement of OBF, Low Case, mmscfd

Province	2010	2015	2020	2025
NAD Aceh	1	2	3	4
N. Sumatra	1	2	2	3
W. Sumatra	1	2	2	3
Riau	0	1	1	1
Jambi	1	1	1	2
S. Sumatra	0	0	0	0
Bangka Belitung	0	0	0	0
Bengkulu	0	0	0	0
Lampung	1	2	2	3
Bali	2	8	11	14
W. Nusatenggara	1	1	2	2
E. Nusatenggara	0	0	0	0
West Kalimantan	0	0	0	0
S. & C. Kalimantan	0	0	0	0
East Kalimantan	0	0	0	0
S. & SE. Sulawesi	4	0	0	0
Central Sulawesi	0	1	1	1
North Sulawesi	0	0	0	0
Gorontalo	0	0	0	0
Maluku & N. Maluku	0	0	0	0
Papua	0	0	0	0
Total	**13**	**19**	**26**	**35**

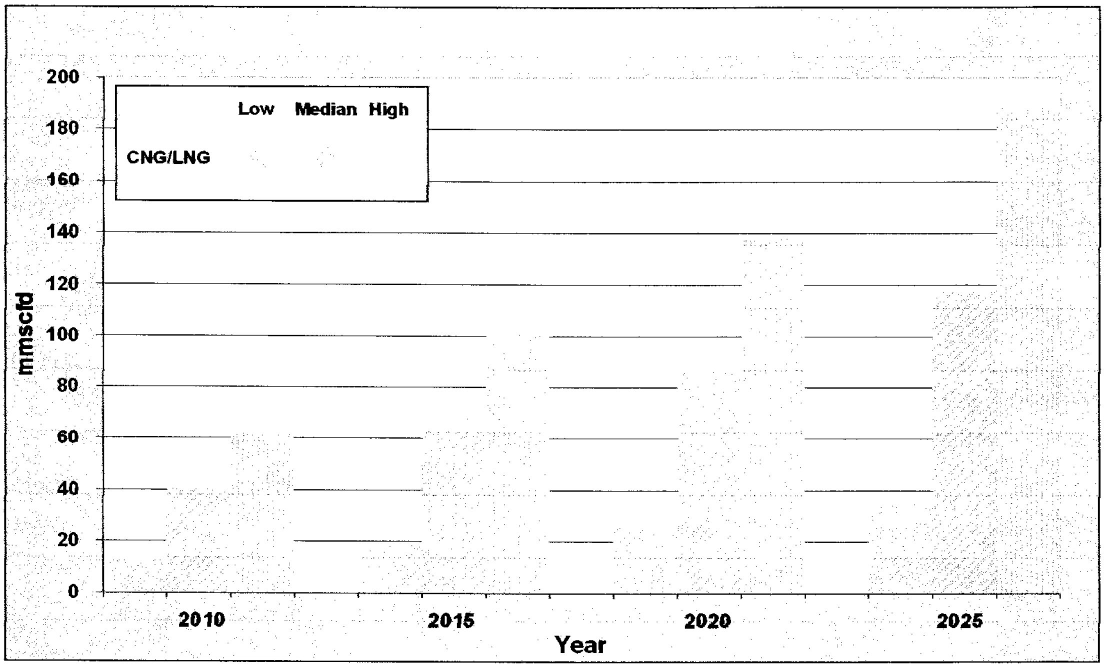
Table 11.4 Projected CNG/LNG-in-Power Replacement of OBF, Median Case, mmscfd

Province	2010	2015	2020	2025
NAD Aceh	2	6	8	11
N. Sumatra	4	5	7	10
W. Sumatra	4	5	7	9
Riau	2	3	5	7
Jambi	2	3	4	5
S. Sumatra	0	0	0	0
Bangka Belitung	0	1	1	2
Bengkulu	0	1	1	2
Lampung	4	6	8	11
Bali	4	21	28	37
W. Nusatenggara	3	3	5	7
E. Nusatenggara	0	1	1	1
West Kalimantan	1	2	3	4
S. & C. Kalimantan	2	3	5	7
East Kalimantan	0	0	0	0
S. & SE. Sulawesi	9	0	0	0
Central Sulawesi	2	2	3	4
North Sulawesi	0	0	0	0
Gorontalo	0	0	0	0
Maluku & N. Maluku	0	0	0	1
Papua	0	0	0	0
Total	**41**	**63**	**86**	**118**

Table 11.5 Projected CNG/LNG-in-Power Replacement of OBF, High Case, mmscfd

Province	2010	2015	2020	2025
NAD Aceh	3	8	12	16
N. Sumatra	6	8	11	14
W. Sumatra	6	8	11	14
Riau	3	7	9	13
Jambi	3	4	6	8
S. Sumatra	0	0	0	0
Bangka Belitung	1	2	3	4
Bengkulu	1	2	3	4
Lampung	6	9	12	16
Bali	5	29	39	53
W. Nusatenggara	4	6	8	11
E. Nusatenggara	1	1	2	2
West Kalimantan	3	5	7	9
S. & C. Kalimantan	4	6	9	12
East Kalimantan	0	0	0	0
S. & SE. Sulawesi	11	0	0	1
Central Sulawesi	3	4	5	7
North Sulawesi	0	0	0	0
Gorontalo	0	0	0	0
Maluku & N. Maluku	1	1	1	2
Papua	1	1	1	1
Total	**62**	**101**	**138**	**189**

Figure 11.3 Projected OBF Replacements by CNG/LNG in Electric Power Generation



11.4 PROJECTED OBF REPLACEMENT IN INDUSTRY

Using the gas NBVs and CNG/LNG COSs developed in Section 10 to determine the ratio of NBV-to-COS and then applying that ratio to the S-curve shown in Figure 11.2 allows determination of the ultimate share of the industrial OBF market in the vicinity of small scale power plants outside Java and the industrial OBF market in major areas of industrialization in Java for the established range of oil and feed gas prices, which CNG/LNG will capture. Table 11.6 below shows the application of this methodology to the determination of the ultimate share of the industrial OBF market captured by LNG in the province of Aceh.

Table 11.6 (Gas NBV)/(LNG COS) and Industrial Market Share Captured by LNG

Feed Gas,	Gas NBV/LNG COS									Ultimate Industrial Market Share Captured by CNG/LNG								
$/mmBtu	3			4			5			3			4			5		
Oil, $/B	40	60	80	40	60	80	40	60	80	40	60	80	40	60	80	40	60	80
Banda Aceh	2.07	2.98	3.89	1.72	2.48	3.23	1.47	2.12	2.77	53%	80%	89%	28%	69%	83%	14%	56%	76%
Sigli	2.14	3.08	4.02	1.77	2.55	3.33	1.51	2.17	2.83	57%	81%	90%	32%	71%	85%	16%	58%	78%
Takengan	2.04	2.93	3.83	1.70	2.45	3.19	1.46	2.10	2.74	52%	79%	89%	27%	68%	83%	13%	55%	76%
Meulaboh	2.01	2.89	3.77	1.68	2.42	3.15	1.44	2.08	2.71	50%	79%	89%	26%	67%	82%	13%	54%	75%
Blang Pidie	1.90	2.73	3.57	1.60	2.30	3.01	1.38	1.99	2.60	42%	76%	87%	21%	63%	80%	10%	50%	73%
Tapak Tuan	1.88	2.71	3.53	1.59	2.29	2.98	1.38	1.98	2.58	40%	75%	87%	20%	63%	80%	10%	48%	72%
Subussalam	1.80	2.58	3.37	1.53	2.20	2.87	1.33	1.91	2.50	34%	72%	85%	17%	59%	78%	8%	43%	70%

Table 11.6 shows the ultimate share of industrial OBF market capture by LNG in Aceh reaching 8-90 percent depending on the economic driver, i.e., the NBV/COS ratio, for the switch. The higher the NBV/COS ratio is, the higher the probability of conversion to LNG.

Applying the same computational methodology across the entire range of industrial markets in the vicinity of small scale electrical power plants outside Java and major industrial markets in Java not currently served or planned to be served by pipeline gas in the near future results in the ultimate, expected replacement of OBF in the industrial market, which the Study Team assumed to occur by year 2018. The program to replace OBF by CNG/LNG in industrial markets would commence in 2010 with conversion of a small number of industrial plants in each province and gradually expand to reach the expected conversion within the province by 2018. The resultant projections of OBF replacement by CNG/LNG in industrial markets are summarized numerically in Tables 11.7 through 11.9 below for the three previously selected combinations of oil and feed gas prices and graphically in Figure 11.4. Detailed calculations are contained in Appendix G.

Tables 11.7 through 11.9 show projected CNG/LNG replacement of OBF in industrial markets to range from 5-19 mmscfd by 2010 increasing to 17-120 mmscfd by 2025. While the analysis shows CNG/LNG penetration of the industrial market to be a strong function of oil prices, the over-all industrial market is quite small resulting in only modest amounts of OBF replacement even in the $80/B case.

As for CNG/LNG penetration of the small scale electric power generation market discussed in the previous subsection, the reduced rate of growth in industrial market OBF replacements in the outer years, e.g., in the provinces of West Java, Central and East Java, are due to the assumption that pipeline gas will be available to selected industrial markets by then replacing CNG/LNG supplies.

Table 11.7 Projected CNG/LNG Replacement of OBF in Industry, Low Case, mmscfd

Region	Province	2010	2015	2020	2025
Outside Java	NAD Aceh	0.5	1.0	1.4	2.0
	N. Sumatra	0.7	0.9	1.2	1.6
	W. Sumatra	0.4	0.5	0.7	0.9
	Riau	0.4	0.8	1.0	1.3
	Jambi	0.4	0.5	0.7	0.9
	S. Sumatra				
	Bangka Belitung	0.1	0.2	0.2	0.3
	Bengkulu	0.1	0.2	0.3	0.4
	Lampung	0.7	1.0	1.3	1.7
	Bali	0.4	2.1	2.8	3.8
	W. Nusatenggara	0.4	0.5	0.7	0.9
	E. Nusatenggara	0.0	0.1	0.1	0.1
	W. Kalimantan	0.3	0.4	0.5	0.7
	S. & C. Kalimantan	0.4	0.5	0.6	0.8
	E. Kalimantan				
	S. & SE. Sulawesi	1.6			
	C. Sulawesi	0.4	0.5	0.7	0.9
	N. Sulawesi				
	Gorontalo				
	Maluku & N. Maluku				
	Papua				
	Subtotal	**7**	**9**	**12**	**16**
Java	DKI Jakarta				
	West Java	1.9	6.7	7.5	8.3
	Central Java	0.9	3.2	4.9	5.6
	DI Yogyakarta	1.0	1.2	1.4	2.1
	East Java	0.9	4.7	3.4	1.0
	Subtotal	**5**	**16**	**17**	**17**
	Grand Total	**12**	**25**	**29**	**33**

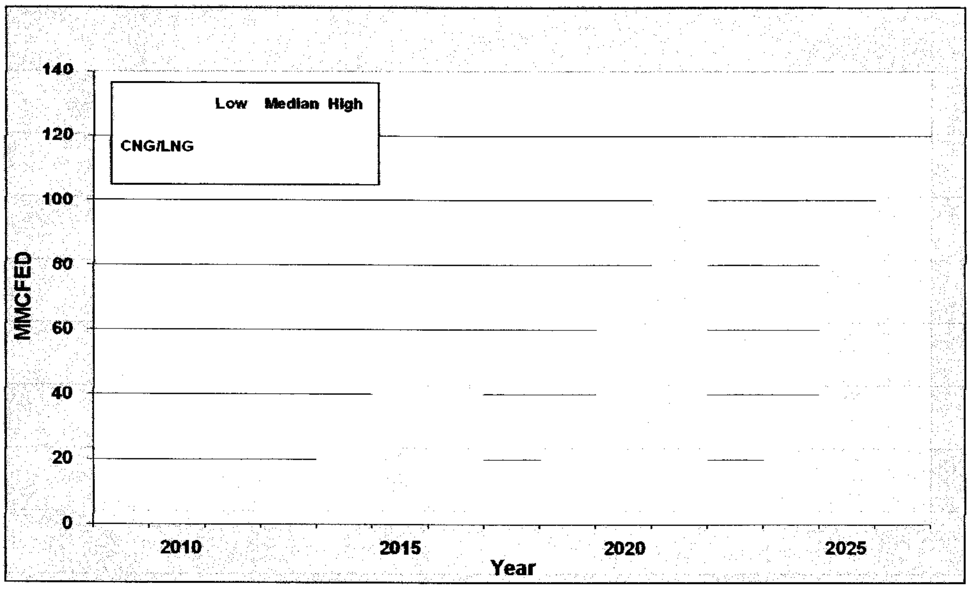
Table 11.8 Projected CNG/LNG Replacement of OBF in Industry, Median Case, mmscfd

Region	Province	2010	2015	2020	2025
Outside Java	NAD Aceh	0.7	1.3	1.9	2.6
	N. Sumatra	1.0	1.2	1.6	2.1
	W. Sumatra	0.8	1.0	1.4	1.8
	Riau	0.9	1.6	2.2	2.9
	Jambi	0.5	0.7	0.9	1.2
	S. Sumatra				
	Bangka Belitung	0.3	0.5	0.7	0.9
	Bengkulu	0.2	0.5	0.6	0.8
	Lampung	0.9	1.3	1.7	2.3
	Bali	0.6	3.7	5.0	6.7
	W. Nusatenggara	0.7	1.0	1.3	1.7
	E. Nusatenggara	0.1	0.2	0.2	0.3
	W. Kalimantan	0.7	1.2	1.5	2.0
	S. & C. Kalimantan	1.0	1.3	1.7	2.3
	E. Kalimantan				
	S. & SE. Sulawesi	2.4	0.0	0.1	0.2
	C. Sulawesi	0.6	0.7	1.0	1.3
	N. Sulawesi	0.0	0.0	0.0	0.0
	Gorontalo				
	Maluku & N. Maluku	0.3	0.4	0.5	0.7
	Papua	0.2	0.3	0.4	0.5
	Subtotal	**12**	**17**	**23**	**30**
Java	DKI Jakarta				
	West Java	1.9	12.7	22.1	24.5
	Central Java	0.9	5.3	13.3	15.4
	DI Yogyakarta	1.0	2.3	5.4	7.3
	East Java	0.9	8.4	11.4	4.6
	Subtotal	**5**	**29**	**52**	**52**
	Grand Total	**17**	**46**	**75**	**82**

Table 11.9 Projected CNG/LNG Replacement of OBF in Industry, High Case, mmscfd

Region	Province	2010	2015	2020	2025
Outside Java	NAD Aceh	0.8	1.5	2.1	2.9
	N. Sumatra	1.1	1.3	1.8	2.4
	W. Sumatra	1.0	1.3	1.7	2.2
	Riau	1.1	2.1	2.7	3.6
	Jambi	0.6	0.8	1.0	1.4
	S. Sumatra				
	Bangka Belitung	0.4	0.9	1.2	1.6
	Bengkulu	0.3	0.6	0.8	1.0
	Lampung	1.0	1.4	1.9	2.5
	Bali	0.7	4.4	5.9	7.9
	W. Nusatenggara	0.9	1.2	1.6	2.1
	E. Nusatenggara	0.2	0.3	0.4	0.6
	W. Kalimantan	1.0	1.7	2.2	2.9
	S. & C. Kalimantan	1.2	1.5	2.1	2.7
	E. Kalimantan				
	S. & SE. Sulawesi	2.8	0.0	0.1	0.3
	C. Sulawesi	0.7	0.9	1.1	1.5
	N. Sulawesi	0.1	0.2	0.3	0.3
	Gorontalo				
	Maluku & N. Maluku	0.4	0.5	0.7	0.9
	Papua	0.4	0.5	0.7	0.9
	Subtotal	**14**	**21**	**28**	**38**
Java	DKI Jakarta				
	West Java	1.9	15.8	32.7	35.9
	Central Java	0.9	6.3	23.1	26.3
	DI Yogyakarta	1.0	2.9	8.1	10.9
	East Java	0.9	10.7	19.0	8.9
	Subtotal	**5**	**36**	**83**	**82**
	Grand Total	**19**	**57**	**111**	**120**

11.4 Projected CNG/LNG Replacement of OBF in Industry



11.5 PROJECTED OBF REPLACEMENT IN TRANSPORTATION

Applying the ultimate-market-share-vs-Gas-NBV/(CNG or LNG COS) correlation presented in Figure 11.2 to the NBV-to-COS ratios calculated for each vehicle type for the three selected combinations of oil and CNG/LNG feed gas prices, the ultimate, i.e., year 2018+, market shares for each vehicle type for the specified range of oil price and feed gas prices have been determined. The detailed calculations are contained in Appendix G and summarized for "Conversions" and "OEMs" in the rightmost part of Tables 11.10 and 11.11 below, respectively. A blank element in the tables indicates zero market shares, i.e., vehicle conversion to natural gas or the purchase of an OEM NGV is not economically viable for the particular combination of oil and CNG/LNG feed gas prices.

Table 11.10 (Gas NBV)/(CNG-LNG COS) and Ultimate NGV Market Share, Conversions

Conversion		Gas NBV/CNG COS or Gas NBV/LNG COS									Ultimate Pct NGVs in Vehicle Population*								
Feed Gas, $/mmBtu		3			4			5			3			4			5		
Oil, $/B		40	60	80	40	60	80	40	60	80	40	60	80	40	60	80	40	60	80
CNG	Large Bus (D)	0.73	1.36	2.00	0.62	1.16	1.70	0.53	1.00	1.474		9%	50%		3%	27%			14%
	Metromini Bus (D)	-0.12	0.52	1.16	-0.10	0.44	0.98	-0.09	0.38	0.85			3%						
	Small Truck (D)	-2.34	-1.70	-1.06	-1.98	-1.44	-0.90	-1.72	-1.25	-0.78									
	Medium Truck (D)	-0.91	-0.29	0.35	-0.77	-0.24	0.30	-0.67	-0.21	0.26									
	Large Truck (D)	0.73	1.36	2.00	0.62	1.16	1.70	0.53	1.00	1.47		9%	50%		3%	27%			14%
	Small Truck (G)	1.01	1.86	2.71	0.85	1.58	2.30	0.74	1.37	2.00	0%	39%	75%		20%	63%		10%	50%
	Taxi (G)	1.40	2.26	3.11	1.19	1.91	2.64	1.03	1.66	2.29	11%	61%	82%	4%	43%	74%	0%	25%	63%
	Mikrolet (G)	1.36	2.21	3.06	1.15	1.87	2.60	1.00	1.63	2.26	9%	59%	81%	3%	40%	73%		22%	61%
LNG	Large Bus (D)	0.60	1.10	1.591	0.51	0.94	1.36	0.45	0.82	1.19		1%	20%			9%			4%
	Metromini Bus (D)	0.08	0.58	1.08	0.07	0.50	0.92	0.06	0.43	0.81			1%						
	Small Truck (D)	-1.07	-0.58	-0.08	-0.92	-0.49	-0.07	-0.80	-0.43	-0.06									
	Medium Truck (D)	-0.45	0.04	0.54	-0.39	0.04	0.46	-0.34	0.03	0.40									
	Large Truck (D)	0.60	1.10	1.59	0.51	0.94	1.36	0.45	0.82	1.19		1%	20%			9%			4%

* Determined by S-curve in Figure 11.2

Table 11.11 (Gas NBV)/(CNG-LNG COS) and Ultimate NGV Market Share, OEMs

OEM		Gas NBV/CNG COS or Gas NBV/LNG COS									Ultimate Pct NGVs in Vehicle Population*								
Feed Gas, $/mmBtu		3			4			5			3			4			5		
Oil, $/B		40	60	80	40	60	80	40	60	80	40	60	80	40	60	80	40	60	80
CNG	Large Bus (D)	1.073	1.707	2.339	0.91	1.45	1.98	0.79	1.26	1.72	1%	28%	65%		13%	49%		6%	29%
	Metromini Bus (D)	0.666	1.298	1.932	0.57	1.10	1.64	0.49	0.96	1.42		7%	44%		2%	23%			12%
	Small Truck (D)	-0.454	0.179	0.811	-0.38	0.15	0.69	-0.33	0.13	0.60									
	Medium Truck (D)	0.271	0.904	1.536	0.23	0.77	1.30	0.20	0.67	1.13			17%			7%			2%
	Large Truck (D)	1.073	1.707	2.339	0.91	1.45	1.98	0.79	1.26	1.72	1%	28%	65%		13%	49%		6%	29%
	Small Truck (G)	1.139	2.014	2.891	0.97	1.71	2.45	0.84	1.48	2.13	2%	51%	79%		28%	68%		15%	56%
	Taxi (G)	1.502	2.379	3.254	1.27	2.02	2.76	1.11	1.75	2.40	16%	66%	84%	6%	51%	76%	2%	31%	67%
	Mikrolet (G)	1.457	2.334	3.211	1.24	1.98	2.72	1.07	1.72	2.37	13%	64%	83%	5%	49%	76%	1%	28%	66%
LNG	Large Bus (D)	0.83	1.33	1.82	0.71	1.14	1.56	0.62	0.99	1.36		8%	35%		2%	18%			9%
	Metromini Bus (D)	0.54	1.03	1.53	0.46	0.89	1.31	0.41	0.77	1.142		0%	17%			7%			2%
	Small Truck (D)	-0.14	0.35	0.85	-0.12	0.30	0.72	-0.10	0.26	0.63									
	Medium Truck (D)	0.25	0.74	1.23	0.21	0.63	1.05	0.19	0.55	0.92			5%			1%			
	Large Truck (D)	0.83	1.33	1.82	0.71	1.14	1.56	0.62	0.99	1.36		8%	35%		2%	18%			9%

* Determined by S-curve in Figure 11.2

Tables 11.10 suggests that one-third of the oil-price-CNG-feed-gas-price combinations results in positive market shares for converted NGVs with, unsurprisingly, the preponderance of larger market shares occurring at the higher end of the oil price range. Table 11.11 suggests a larger proportion of CNG fuelled OEM NGVs being economically viable than converted NGVs for the specified ranges of oil price and CNG feed gas price and the ultimate market shares being larger than for converted NGVs. This simply reflects the higher Gas NBV of OEMs than converted NGVs.

Tables 11.10 and 11.11 show few LNG fuelled NGVs to be economically viable and mainly at the highest of oil prices, i.e., $80 per barrel. This is due to the higher COS of LNG than CNG. Again, OEM LNG NGVs are economically more viable than converted LNG NGVs.

Projections of CNG/LNG consumption in NGVs in replacement of OBFs have been made for the Low, Median and High oil and CNG/LNG feed gas price combinations defined in subsection 11.1. The detailed calculations are contained in Appendix G and summarized for CNG replacements of OBFs in Tables 11.12 through 11.14 and for LNG replacements in Table 11.15 below. Total projected CNG/LNG consumption in transportation under the three oil price and feed gas scenarios are presented in Table 11.16 and shown graphically in Figure 11.5.

Recall that the ultimate market shares listed in Tables 11.10 and 11.11 are assumed to be reached 10 years after introduction of natural gas distribution to the city, whereupon OBF replacement is assumed to grow at 6% p.a. through 2025, and that cities and areas not already providing CNG for NGVs will commence such service at the earliest in 2008. Where LNG NGVs are economically viable, the program to provide LNG distribution and refueling is assumed to commence in 2008 and reach the ultimate market share in 2018.

Table 11.12 Projected CNG Replacements of OBFs in Transportation, Low Case, mmscfd

City	2005	2008	2010	2015	2020	2025
Jakarta	0.2	2.3	2.7	9.6	16.9	20.6
Bandung				0.65	1.89	4.29
Cirebon		0.08	0.46	1.06	3.05	3.86
Semarang				0.36	1.03	2.34
Surabaya	0.02	0.07	0.18	2.36	4.92	6.00
Medan		0.08	0.49	1.12	3.24	4.10
Pekanbaru		0.04	0.21	0.49	1.41	1.78
Palembang		0.07	0.41	0.94	2.69	3.41
B. Lampung			0.14	0.45	1.59	2.05
Pontianak				0.25	0.73	1.66
Banjarmasin				0.15	0.43	0.97
Balikpapan		0.02	0.12	0.28	0.81	1.03
Samarinda			0.03	0.26	1.07	1.41
Manado				0.12	0.34	0.78
Makassar				0.32	0.93	2.12
Total	**0.2**	**3**	**5**	**18**	**41**	**56**

Table 11.13 Projected CNG Replacements of OBFs in Transportation, Median Case, mmscfed

City	2005	2008	2010	2015	2020	2025
Jakarta	0.2	3	7	44	86	106
Bandung				1	8	22
Cirebon	0	0.1	0.6	4	15	20
Semarang				0.7	4	12
Surabaya	0.02	0.1	0.3	10	25	31
Medan		0.1	0.7	4	16	21
Pekanbaru		0.04	0.3	2	7	9
Palembang		0.1	0.6	3	14	17
B. Lampung			0.1	2	8	10
Pontianak				0.5	3	8
Banjarmasin			0.0	0.3	1.7	5
Balikpapan			0.2	1.0	4	5
Samarinda				0.8	5	7
Manado				0.2	1.4	4
Makassar				0.6	4	11
Total	**0.2**	**4**	**10**	**74**	**203**	**288**

Table 11.14 Projected CNG Replacements of OBFs in Transportation, High Case, mmscfd

City	2005	2008	2010	2015	2020	2025
Jakarta	0.2	5	9	77	155	190
Bandung				2	13	39
Cirebon			1	6	28	36
Semarang				1	7	22
Surabaya	0.02	0.1	0.4	17	45	56
Medan		0.1	1	7	30	38
Pekanbaru		0.04	0.5	3	13	16
Palembang		0.1	1	6	25	31
B. Lampung			0.1	2	15	19
Pontianak				0.6	5	15
Banjarmasin				0.3	3	9
Balikpapan			0.3	2	7	9
Samarinda				1	10	13
Manado				0.3	2	7
Makassar				1	6	19
Total	**0.2**	**5**	**13**	**125**	**365**	**520**

Table 11.12 shows a very modest CNG NGV program in the Low scenario ($40/B and $3/mmBtu) due to insufficient economic incentives. However, under the Median scenario ($60/B and $4/mmBtu) CNG consumption is projected to reach 74 mmscfd

by 2015 and 288 mmscfed by 2025 and under the High scenario ($80/B for oil and $5/mmBtu) 125 and 520 mmscfd by the same points in time as the gas netback values relative to those of the Low scenario increase more than the costs of supply under these scenarios.

Table 11.15 Projected LNG Replacements of OBFs in Transportation, mmscfed

MMCFD	2005	2008	2010	2015	2020	2025
Low	0.0	0.0	0.0	0.0	0.0	0.0
Median	0.0	1	3	4	5	6
High	0.0	5	6	12	20	25

Table 11.15 shows economic viability of an LNG NGVs program, albeit an exceedingly small one, at an oil price of $60 per barrel, which quadruples at $80 per barrel. Oil prices well in excess of $100 per barrel, or substantial levies on competing fuels and/or subsidies on LNG fuels/vehicles, are required to stimulate a material LNG NGVs program.

Table 11.16 Projected CNG/LNG Replacements of OBFs in Transportation, mmscfd

MMCFD	2005	2008	2010	2015	2020	2025
Low	0.2	3	5	18	41	56
Median	0.2	5	13	78	208	294
High	0.2	10	20	138	385	545

Figure 11.5 Projected CNG/LNG Replacements of OBFs in Transportation

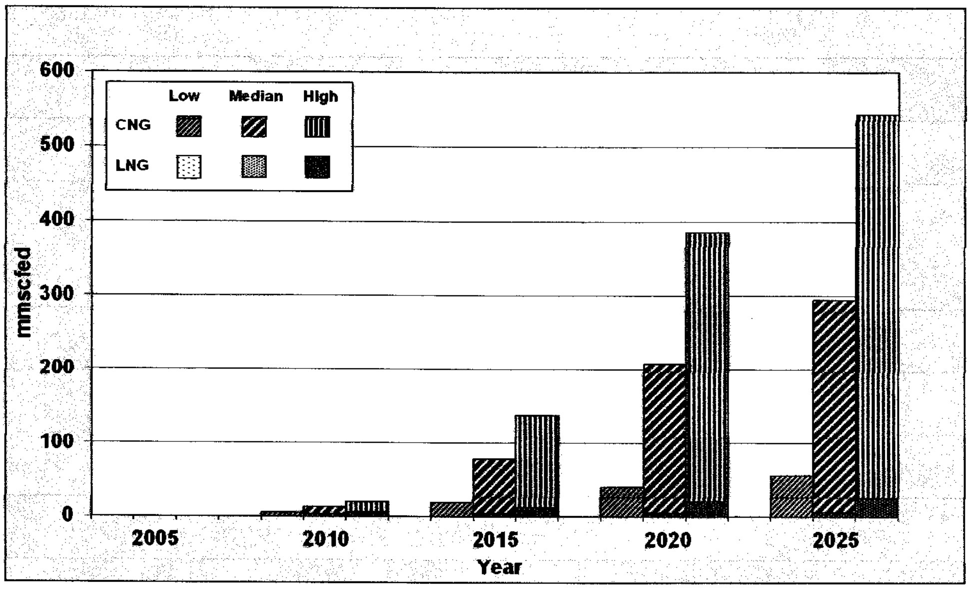


Table 11.16 and Figure 11.5 show projected CNG/LNG consumption in replacement of OBFs in transportation amounting to 5-20 mmscfd by 2010 increasing to 56-545 mmscfd by 2025, of which nearly all is in the form of CNG. In general, CNG replacement of OBFs in transportation does not become economically viable until oil prices exceed \$60/B, while LNG replacement of OBFs requires oil prices in excess of \$80/B.

11.6 PROJECTED NATIONWIDE OBF REPLACEMENT

Adding up the projected CNG/LNG consumption by sector for each of the three combinations of oil and CNG/LNG feed gas prices provides the projected CNG/LNG consumption in replacement of OBFs throughout Indonesia. Table 11.17 and Figure 11.6 summarize the results numerically and graphically, respectively.

Table 11.17 Projected Nationwide CNG/LNG Replacements of OBFs, mmscfd

Scenario	Sector	2010	2015	2020	2025
Low	Power	13	19	26	35
	Industry	12	25	29	33
	Transportation	5	18	41	56
	Total	29	62	96	125
Median	Power	41	63	86	118
	Industry	17	46	75	82
	Transportation	11	77	208	294
	Total	69	186	369	494
High	Power	62	101	138	189
	Industry	19	57	111	120
	Transportation	20	138	385	545
	Total	101	295	635	853

Figure 11.6 Projected Nationwide OBF Replacements of OBFs by Sector

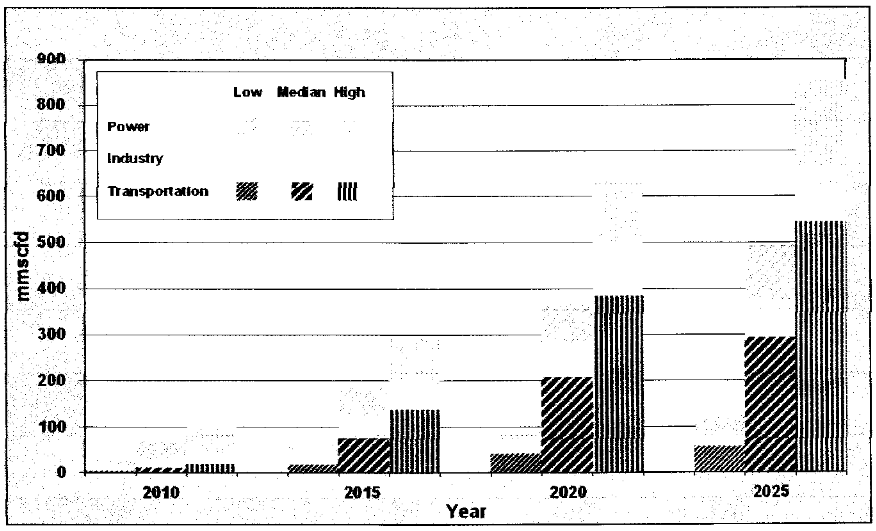


Table 11.17 and Figure 11.6 show projected CNG/LNG replacement of OBFs in Indonesia to range from 29-101 mmscfd in 2010 increasing to 125-853 mmscfd by 2025. While the small scale electric power generating sector is projected to constitute the largest CNG/LNG market in the early years, the NGV market dominates after 2015 with a projected 45-65 percent of the nationwide CNG/LNG market by 2025.

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12.1 INTRODUCTION

This section provides estimates of the timing and magnitude of capital investments required to replace OBFs with CNG/LNG-based gas in accordance with the three market capture projections presented in Section 11.

12.2 APPROACH

Capital investments are required both by the consumers switching from OBF to CNG/LNG as well as by CNG/LNG suppliers. The consumer investments accounted for in this study are either associated with conversion of existing equipment to burn gas or the incremental investment in acquiring gas burning rather than OBF fueled new equipment. The CNG/LNG supplier investments included in this study are capital outlays in the entire CNG or LNG supply chain, as the case may be.

All capital investment amounts are expressed in millions of unescalated, 2006 United States Dollars.

12.3 SWITCHING CAPITAL NEEDS IN POWER

The capital investments required to switch from OBFs to CNG/LNG in the small scale electric power generation sector are incurred by the consumers in the form of conversion of their conventional fuel fired diesel engines and gas turbines to burning CNG or LNG-based natural gas or in the purchase of new natural gas fired generating equipment. Moreover, the CNG/LNG suppliers incur capital investments in manufacturing, storing, transporting and delivering CNG/LNG-based natural gas to the consumers.

Power plant conversion costs and new power plant costs incremental to those of OBF fuelled generating units have been calculated for the Low, Median and High levels of projected CNG/LNG consumption in the small scale electric power generation market identified in Section 4. The detailed calculations are contained in Appendix H and summarized in Table 12.1 below.

Table 12.1 shows cumulative incremental capital needs of $28-137 MM by 2010 growing to $61-320 MM by 2025 primarily to convert OBF burning units to CNG/LNG and, to a much lesser extent, to construct new, small scale CNG/LNG fired power plants in accordance with the projected CNG/LNG replacements of OBFs in small scale power plants projected in Section 11. The magnitude of new, small scale CNG/LNG fired power plant additions cannot be inferred from the incremental capital investment figures cited above, since the figures reflect the off-setting effects of higher unit cost gas fuelled (diesel) engines and lower unit cost gas fuelled turbines (TTOC).

Table 12.1 Cum. Incr. CNG/LNG-in-Power Plant Switching Capital Needs, $MM

Scenario	Type	2010	2015	2020	2025
Low	Conversion	28	49	52	57
	New	0	0	2	4
	Total	**28**	**49**	**54**	**61**
Median	Conversion	87	153	165	180
	New	0	1	9	19
	Total	**87**	**154**	**173**	**199**
High	Conversion	137	243	261	286
	New	0	2	16	34
	Total	**137**	**245**	**277**	**320**

The CNG/LNG supply chain investments required to manufacture, transport and deliver CNG/LNG-based gas to small scale electric power generating units have been calculated for the Low, Median and High levels of projected CNG/LNG replacements of OBFs in small scale power plants listed in Section 11 above. The detailed calculations are contained in Appendix H and summarized in Table 12.2 below.

Table 12.2 Cum. Incr. CNG/LNG-in-Power Supply Chain Capital Needs, $MM

Scenario	2010	2015	2020	2025
Low	26	48	65	88
Median	90	155	203	266
High	155	267	353	469

Table 12.2 shows CNG/LNG-in-power supply chain capital investments of $26-155 MM by 2010 increasing to $88-469 MM by 2025 to deliver the quantities of CNG/LNG projected in Section 11.

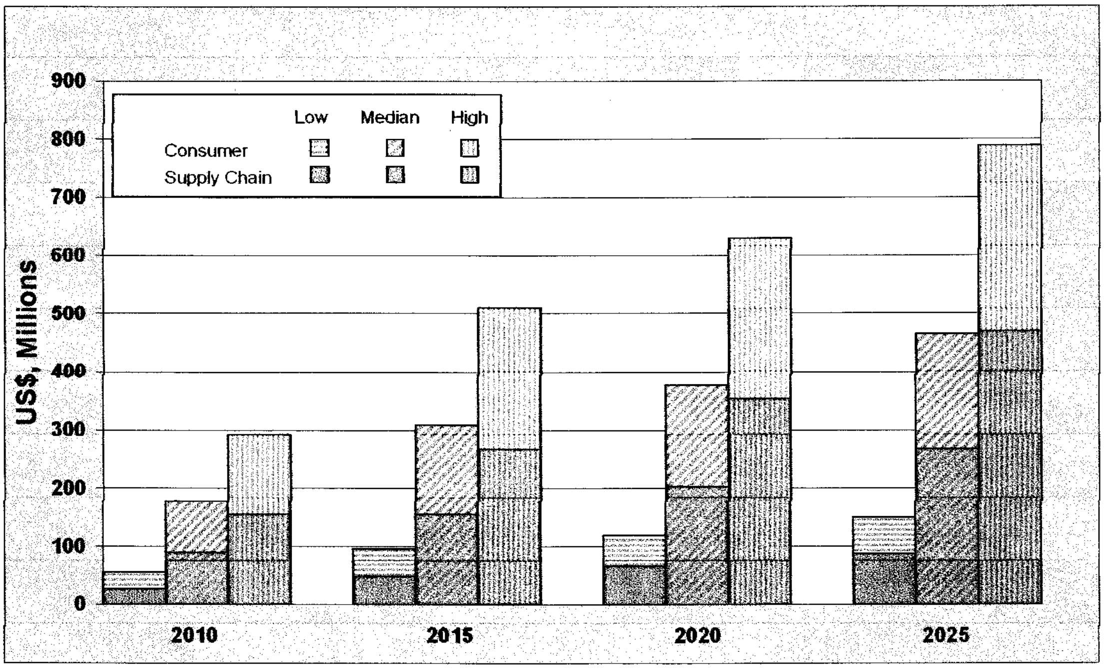
The total incremental switching capital required to effect the Low, Median and High CNG/LNG replacements of OBFs in electric power generation have been determined as the sum of incremental consumer investments and CNG/LNG supply chain investments. The detailed calculations are contained in Appendix H, while a summary is presented in Table 12.3 below. Figure 12.1 provides a graphical representation of the projected magnitude and growth in incremental electric power sector investments required to achieve the projected levels of OBF replacement.

Table 12.3 and Figure 12.1 show a requirement for incremental capital investments of $54-292 MM by 2010 rising to $150-789 MM by 2025 to achieve the levels of OBF replacement by CNG/LNG in small scale electric power generation projected in Section 11.

Table 12.3 Cum. Incr. CNG/LNG Switching Capital Needs in Power Generation, $MM

Scenario	Segment	2010	2015	2020	2025
Low	Consumers	28	49	54	61
	Supply Chain	26	48	65	88
	Total	**54**	**97**	**119**	**150**
Median	Consumers	87	154	173	199
	Supply Chain	90	155	203	266
	Total	**177**	**309**	**377**	**465**
High	Consumers	137	245	277	320
	Supply Chain	155	267	353	469
	Total	**292**	**512**	**630**	**789**

Figure 12.1 Cum. Incremental CNG/LNG Switching Capital Needs in Power Generation



12.4 SWITCHING CAPITAL NEEDS IN INDUSTRY

Consumer investments in the industrial sector accounted for in this study are either for conversion of existing boilers and heaters from burning OBFs to burning CNG/LNG-based gas or the incremental investment (or savings) from installing gas fuelled boilers and heaters in new plants rather than OBF fuelled ones. CNG/LNG supplier investments cover the entire supply chain, i.e., investments in feed gas treatment, compression/liquefaction, storage, terrestrial or marine transportation, and receiving terminal storage/(LNG) regasification/send-out.

Industrial plant conversion costs and new plant investments incremental to those of OBF fuelled generating units have been calculated for the Low, Median and High levels of projected CNG/LNG replacements of OBFs in industry identified in Section 11. The detailed calculations are contained in Appendix H and summarized in Table 12.4 below.

Table 12.4 Cum. Incr. Industrial Consumer Switching Capital Needs, $MM

Scenario	Type	2010	2015	2020	2025
Low	Conversion	8	17	18	19
	New	0	-2	-10	-17
	Total	**8**	**15**	**8**	**2**
Median	Conversion	11	29	35	38
	New	0	-5	-41	-56
	Total	**11**	**24**	**-5**	**-18**
High	Conversion	13	35	47	50
	New	0	-7	-70	-91
	Total	**13**	**28**	**-23**	**-40**

Table 12.4 shows cumulative, incremental industrial consumer capital investments of $8-13 MM by 2010 declining to $2 to minus 40 MM by 2025 to enable the levels of OBF replacement projected in Section 11. In other words, industrial consumers save a cumulative $40 MM by 2025 in capital investments under the High scenario by switching from OBFs to CNG/LNG-based gas, since new gas fueled heaters and boilers are on average less expensive than their OBF fueled counterparts and more than offset the projected cost of conversions.

The CNG/LNG supply chain investments required to manufacture, transport and deliver CNG/LNG-based gas to industry have been calculated for the Low, Median and High levels of projected OBF replacements by CNG/LNG listed in Section 11 above. The detailed calculations are contained in Appendix H and summarized in Table 12.5 below.

Table 12.5 Cum. CNG/LNG-in-Industry Supply Chain Capital Needs, $MM

Scenario	2010	2015	2020	2025
Low	27	65	92	119
Median	42	109	188	223
High	50	138	276	325

Table 12.5 shows CNG/LNG supply chain capital investments of $27-50 MM by 2010 increasing to $119-325 MM by 2025 to deliver the quantities of CNG/LNG projected to be used by industry in Section 11.

Total incremental switching capital required to effect the projected CNG/LNG replacements of OBFs in industry under the Low, Median and High scenario have been determined as the sum of incremental consumer investments and CNG/LNG supply chain investments. The detailed calculations are contained in Appendix H and summarized in Table 12.6 below. Figure 12.2 provides a graphical representation of the projected magnitude and growth in industrial sector cumulative incremental investments required to achieve the projected levels of OBF replacement.

Table 12.6 Cum. Incr. CNG/LNG Switching Capital Needs in Industry, $MM

Scenario	Segment	2010	2015	2020	2025
Low	Consumers	8	15	8	2
	Supply Chain	27	65	92	119
	Total	**34**	**80**	**100**	**122**
Median	Consumers	11	24	-5	-18
	Supply Chain	42	109	188	223
	Total	**53**	**134**	**183**	**205**
High	Consumers	13	28	-23	-40
	Supply Chain	50	138	276	325
	Total	**63**	**166**	**253**	**284**

Figure 12.2 Cum. Incr. CNG/LNG Switching Capital Needs in Industry

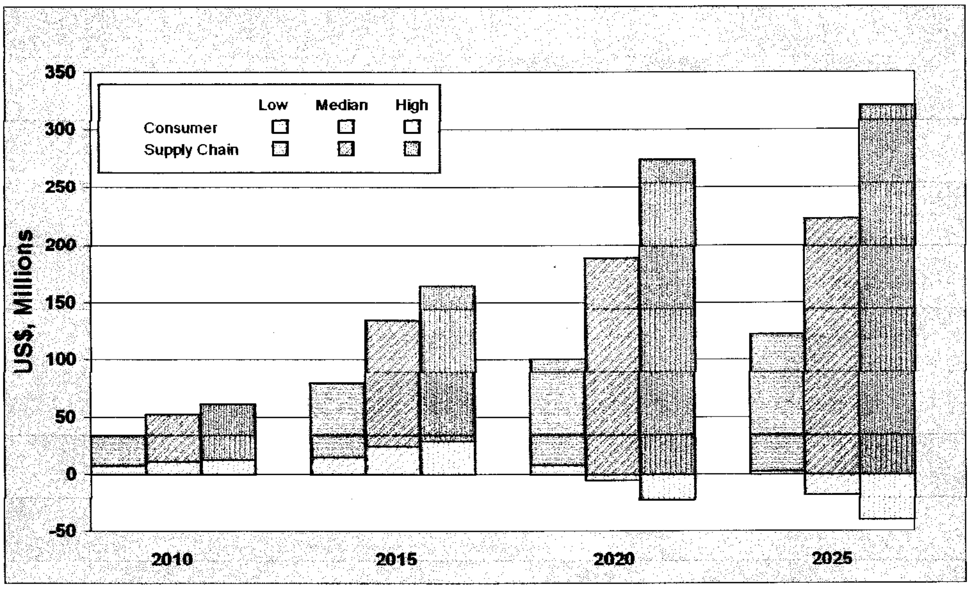


Table 12.6 and Figure 12.2 show the cumulative, incremental switching capital needed to effect the Low, Median and High levels of CNG/LNG replacements of OBFs in the industrial sector to range from $34-63 MM by 2010 growing to $122-284

MM by 2025. Projected consumer investments are less than with continued OBF use due to the lower units cost of gas fuelled industrial heaters and furnaces than their OBF fuelled counterparts, but such savings are more than offset by the required supply chain investments

12.5 SWITCHING CAPITAL NEEDS IN TRANSPORTATION

The capital investments required to switch from OBFs to CNG/LNG in the transportation sector are incurred by the consumers in the form of conversion of their conventional fuel vehicles to burning CNG or LNG based natural gas or in the purchase of Original Equipment Manufacture (OEM) new natural gas vehicles (NGVs). In addition, the CNG/LNG suppliers incur capital investments in manufacturing, delivering and dispensing CNG/LNG to NGVs.

The NGV investments incurred by consumers incremental to those of conventional diesel or gasoline vehicles have been calculated for the Low, Median and High levels of OBF replacements by CNG/LNG in the transportation sector projected in Section 11. The detailed calculations are contained in Appendix H and summarized in Table 12.7 below.

Table 12.7 Cum. Incr. NGV Consumer Switching Investments, $MM

Scenario	Fuel	2010	2015	2020	2025
Low	CNG	15	62	149	212
	LNG	0	0	0	0
	CNG/LNG	15	62	149	212
Median	CNG	30	262	822	1,230
	LNG	5	12	19	23
	CNG/LNG	36	273	841	1,253
High	CNG	54	515	1,666	2,490
	LNG	21	47	76	93
	CNG/LNG	75	561	1,743	2,583

Table 12.7 shows cumulative, incremental NGV switching capital needs ranging from $15-75 MM by 2010 growing to $212-2,583 MM by 2025, almost exclusively expended on CNG fueled NGVs used in and around cities. As pointed out in Section 11, no LNG replacement of OBF in transportation occurs under the Low price scenario and only modest market shares are projected to be captured in the large bus and truck segments of the long distance transportation sector in the Median and High price scenarios due to the high cost of LNG supply.

The CNG/LNG supply chain investments required to deliver and dispense CNG/LNG-based gas to NGVs have been calculated for the Low, Median and High levels of OBF replacements by CNG/LNG in transportation projected in Section 11.

The detailed calculations are contained in Appendix H and summarized in Table 12.8 below.

Table 12.8 Cum. CNG/LNG-in-Transportation Supply Chain Investments, $MM

Scenario	Fuel	Facility	2010	2015	2020	2025
Low	CNG	Refueling Stations	21	79	176	242
	LNG	Supply Chain	0	0	0	0
	CNG/LNG	Supply Chain	21	79	176	242
Median	CNG	Refueling Stations	42	317	869	1,236
	LNG	Supply Chain	8	15	25	31
	CNG/LNG	Supply Chain	50	332	894	1,267
High	CNG	Refueling Stations	58	538	1,566	2,231
	LNG	Supply Chain	31	61	100	122
	CNG/LNG	Supply Chain	88	599	1,666	2,353

Table 12.8 shows the need for cumulative CNG/LNG supply chain capital investments ranging from $21-88 MM by 2010 growing to $242-2,353 MM by 2025 to achieve the levels of OBF replacements projected in Section 11. Almost all investments are expended on CNG supply,

Total switching capital investments required to effect the Low, Median and High levels of OBF replacements by CNG/LNG in transportation have been determined as the sum of incremental NGV investments and CNG/LNG supply chain investments. The detailed calculations are contained in Appendix H and summarized in Table 12.9 below. Figure 12.3 provides a graphical representation of the projected magnitude and growth in cumulative, incremental transportation sector investments needed to reach the projected levels of CNG/LNG consumption.

Table 12.9 Cum. Inc. CNG/LNG-in-Transportation Switching Investments, $MM

Scenario	Segment	2010	2015	2020	2025
Low	Consumers	15	62	149	212
	Supply Chain	21	79	176	242
	Total	35	141	325	454
Median	Consumers	36	273	841	1,253
	Supply Chain	50	332	894	1,267
	Total	86	606	1,735	2,520
High	Consumers	75	561	1,743	2,583
	Supply Chain	88	599	1,666	2,353
	Total	164	1,161	3,409	4,936

Figure 12.3 Cum. Incr. CNG/LNG Switching Capital Needs in Transportation

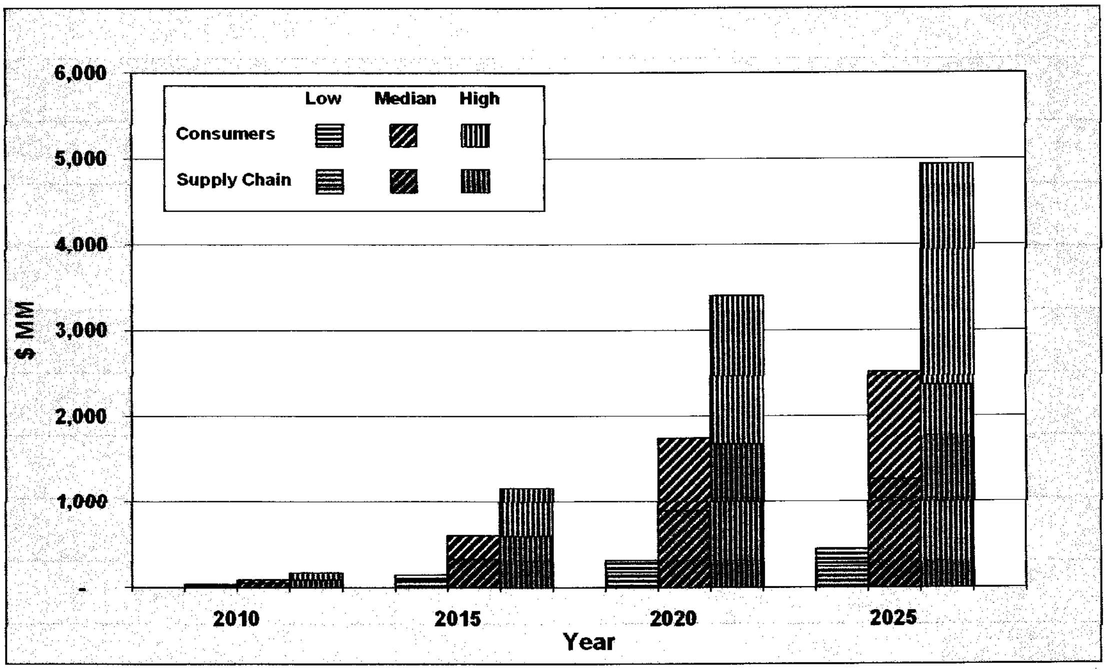


Table 12.9 and Figure 12.3 show the cumulative, incremental switching capital investments required to effect the Low, Median and High levels of OBF replacements by CNG/LNG in transportation to range from $35-164 MM by 2010 growing to $454-4,936 MM by 2025. The investments are evenly distributed between CNG/LNG consumers and suppliers. In the Low scenario, all investments are in CNG NGVs and city-based CNG supply systems and infrastructure. In the Median and High scenarios, a modest LNG NGV program is projected to evolve.

12.6 TOTAL NATIONWIDE SWITCHING CAPITAL NEEDS

Capital investments required by consumers as well as by CNG/LNG suppliers to achieve the projected levels of OBF replacements by CNG/LNG in small scale electric power generation, industry and transportation throughout Indonesia are summarized in Tables 12.10 through 12.12 and shown graphically in Figure 12.4.

Table 12.10 Cum. Incr. Nationwide Consumer Switching Capital Needs, $MM

Scenario	2010	2015	2020	2025
Low	50	126	211	275
Median	134	452	1,010	1,434
High	225	835	1,997	2,863

Table 12.11 Cum. Nationwide CNG/LNG Supply Chain Capital Needs, $MM

Scenario	2010	2015	2020	2025
Low	73	175	306	419
Median	229	642	1,300	1,800
High	399	1,133	2,373	3,291

Table 12.12 Cum. Incr. Nationwide CNG/LNG Switching Capital Needs $MM

Scenario	Sector	Segment	2010	2015	2020	2025
Low	*Power Generation*	Consumers	28	49	54	61
		Supply Chain	26	48	65	88
	Industry	Consumers	8	15	8	2
		Supply Chain	27	65	92	119
	Transport	Consumers	15	62	149	212
		Supply Chain	21	79	176	242
	All		124	317	544	725
Median	Power Generation	Consumers	87	154	173	199
		Supply Chain	90	155	203	266
	Industry	Consumers	11	24	-5	-18
		Supply Chain	*42*	*109*	*188*	223
	Transport	Consumers	36	273	841	1,253
		Supply Chain	50	332	894	1,267
	All		315	1,049	2,295	3,190
High	*Power Generation*	Consumers	137	245	277	320
		Supply Chain	155	267	353	469
	Industry	Consumers	13	28	-23	-40
		Supply Chain	50	138	276	325
	Transport	Consumers	75	561	1,743	2,583
		Supply Chain	88	599	1,666	2,353
	All	Total	519	1,839	4,292	6,009

Figure 12.4 Cum. Incr. Nationwide CNG/LNG Switching Capital Needs

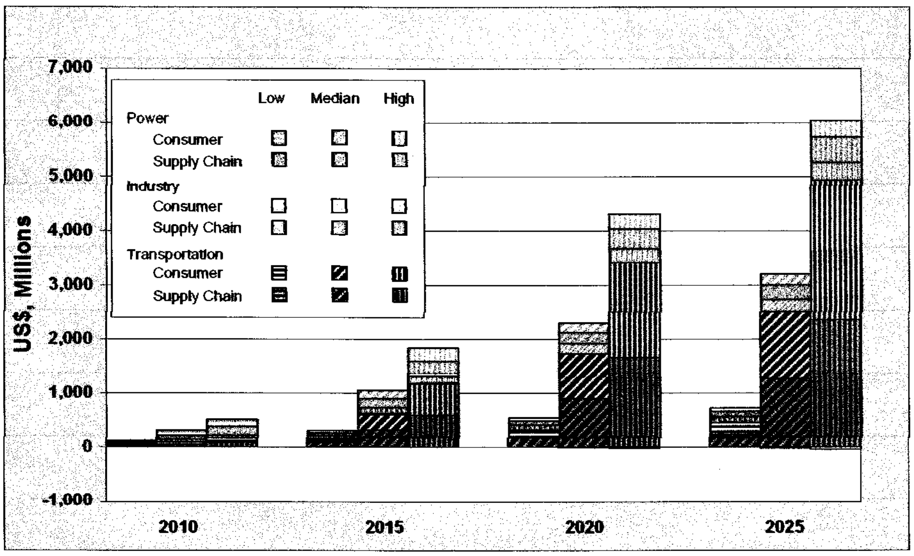


Table 12.12 and Figure 12.4 show the need for cumulative, incremental investments ranging from $124-519 MM by 2010 growing to $725-6,009 MM by 2025 to enable the levels of CNG/LNG replacements of OBFs projected in Section 11.

In the Low scenario, 63% of the investments are projected to occur in and associated with the transportation sector, while the small scale power generation sector accounts for 21%. In the High scenario, transportation sector investments grow to account for 82% of total investments, while that of the power generation sector declines to 13%, reflecting the leveraging impact of OBF prices on the economic viability of NGVs.

While consumer and supply chain investments are of approximately equal magnitude in small scale power generation and transportation, industrial consumer investments are a small fraction of the supply chain investment, occasionally even negative, e.g., by 2020 and 2025 in the Median and High scenarios, reflecting savings relative to investments in OBF fuelled user facilities.

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13.1 INTRODUCTION

Two small scale CNG/LNG distribution systems have been subjected to conceptual technical and economic assessment in order to ascertain the feasibility of their implementation. The two case studies are:

- Case 1: CNG/LNG distribution to three regional power plants involving both marine and terrestrial transportation. Two options were considered
  - Case 1a: Gas sourced from an existing LNG plant; and
  - Case 1b: Gas sourced from pipeline.
- Case 2: LNG production and marine transportation to a receiving/storage terminal for subsequent regasification and distribution by pipeline to power plant and industry.

13.2 CNG/LNG DISTRIBUTION TO REGIONAL POWER PLANTS (Case 1)

13.2.1 Background

Three power generating stations with combined available capacity of 356 MW from open cycle gas turbines and diesel engines were considered. The 2005 average load was 125 MW, equivalent to about 28 mmscfd. This volume is projected to grow at 6% p.a. to 37 mmscfd by 2010.

Table 13.1 below lists details of each power station and derives the potential gas demand at each station expressed in millions of standard cubic feet per day.

Table 13.1 Potential Gas-in-Power Demand

Power Station	Type	Capacity		Output	Capacity Factor	Plant Efficiency	Potential Demand	
		Installed	Available				2005	2010
		MW	MW	GWh	%	%	mmscfd	mmscfd
# 1	GT	145	131	176	15	31	5.3	7.1
# 2	GT	125	113	457	46	31	13.8	22.6
	DE	75	40	132	22	40	3.1	
# 3	GT	80	72	189	30	31	5.7	7.6
Total		425	356	954			28	37

No gas transmission lines currently connect the power stations nor are there plans to build any. CNG or LNG based gas supply to these power stations was considered. The proposition was to deliver either:

- Case 1a: LNG sourced at an existing liquefaction plant and shipped approximately 1,000 km to a receiving terminal adjacent to Power Plant #1 and using overland LNG tanker truck transportation to supply the remaining two power plants each located 132 km from the receiving terminal; or

- Case 1b: CNG or LNG produced from pipeline supply 198 km away from Power Plant #1 by:

    - Road delivery to a commercial vehicular ferry port and short trans-shipment to a receiving terminal adjacent to Power Plant # 1 followed by subsequent road delivery to the remaining two power plants; or

    - Marine delivery of LNG from a port adjacent to the liquefaction plant and shipment directly to a receiving terminal adjacent to Power Plant #1, a sea route distance of 250 km, followed by subsequent road delivery of LNG to the remaining two power plants.

13.2.2 Case 1a: LNG Supply from Existing Liquefaction Plant

Table 13.2 below summarizes the operational logistics of the marine/terrestrial LNG supply system, the capital investments in the supply chain and the calculated tariffs assuming a 15% investor's rate of return for delivery of LNG from the existing liquefaction plant to a receiving terminal and terrestrial delivery to the regional power plants.

Table 13.2 shows that a 37-mmscfd-LNG-delivery-system for three power plants requires an investment of only $88 MM, predominantly in the LNG tanker and the receiving port terminal. No investment in liquefaction/storage and offloading facilities at the LNG source is included, since this analysis assumes spare capacity in the LNG plant, storage and shipping facilities allowing supply to the three regional power plants to be integrated with existing LNG production in return for payment of a liquefaction/storage/offloading capital charge of $1 per mscfe and apportioned operating costs.

The weighted average cost of LNG manufacture at source, transportation to and regasification at the three power plants ranges from $3.27-3.53 per mscfe for feed gas prices of $3-5 per mscf.

Table 13.2 LNG-in-Power System Logistics, Investments and Tariffs

System Variable	Item	Source to P/P # 1	P/P #1 to P/P #2	P/P #1 to P/P #3	Total
Transportation Logistics	Mode of Transportation	Marine	Terrestrial	Terrestrial	
	Volume (mmscfd)	37.3	22.6	7.6	37.3
	Distance, one way (km)	1056	132	132	
	Tanker (m^3)/Truck (mmscf)	7,100	0.65	0.65	
	Average Velocity (km/h)	29	40	40	
	Trips/tanker or vehicle/day	0.33	2.79	2.79	
	Distance/tanker or vehicle/day	691	737	737	
	One-way travel time (hours)	37	3.3	3.3	
	Number of Tankers or Trucks	1	16	6	
Investments	Liquefaction/Storage/Offloading, $MM	-*	-	-	0
	Transportation, $MM	34	5	2	41
	Receiving Terminal, $MM	35	8	3	47
	Total, $MM	**70**	**13**	**5**	**88**
Tariff	Per Leg, $/mscf, @ $3/mscf Feed Gas	2.75*	0.62	0.68	
	Delivery, $/mscf, @ $3/mscf Feed Gas	**2.75***	**3.37**	**3.44**	**3.27**
	Per Leg, $/mscf, @ $4/mscf Feed Gas	2.87*	0.63	0.70	
	Delivery, $/mscf, @ $4/mscf Feed Gas	**2.87***	3.50	3.57	**3.39**
	Per Leg, $/mscf, @ $5/mscf Feed Gas	2.99*	0.65	0.72	
	Delivery, $/mscf, @ $5/mscf Feed Gas	**2.99***	**3.64**	**3.71**	**3.53**

*Including a liquefaction/storage/offloading capital charge of $1 per mscfe and apportioned operating costs.
P/P – Power Plant.

13.2.3 Case 1b: CNG/LNG Supply from Pipeline Source

This case assumes that gas is available from a pipeline source approximately 200 km from the proposed point of use separated by a narrow body of ocean water. The envisioned supply chains are:

- Terrestrial CNG delivery using tanker trucks and a commercial vehicular ferry to transport the truck across the body of water; and
- LNG delivery using
  - (a) An identical delivery procedure as for CNG above; or
  - (b) Marine transport from a port adjacent to the pipeline/LNG plant directly to a receiving terminal port adjacent to Power Plant #1. A sailing distance of about 250 km followed by LNG road transport to the remaining two power plants.

Each alternative will be analyzed separately in the subsections below.

13.2.3.1 Case 1ba: CNG Supply from Pipeline Gas Source

CNG supply from the gas source (pipeline) to the three regional power plants entails constructing a large compressor station at the gas off-take point, providing trailer-mounted CNG 8-tube cylinder skids for storage at the compressor station, truck/trailers for overland transportation and storage at terminals adjacent to the power plants.

Table 13.3 below summarizes the operational logistics of the terrestrial CNG supply system, the capital investments in the supply chain and the calculated tariffs assuming a 15% investor's rate of return for delivery of CNG from source to the power plants.

Table 13.3 CNG-in-Power System Logistics, Investments and Tariffs

System Variable	Item	Source to P/P # 1	P/P #1 to P/P #2	P/P #1 to P/P #3	Total
Transportation Logistics	Mode of Transportation	Terrestrial	Terrestrial	Terrestrial	
	Capacity (mmscfd)	37.3	22.6	7.6	37.3
	Distance, one way (km)	198	132	132	
	Load/truck (mmscf)	0.167	0.167	0.167	
	Average Velocity (km/h)	40	40	40	
	Trips/vehicle/day	2.42	3.64	3.64	
	Distance/vehicle/day	960	960	960	
	One-way travel time (hours)	4.95	3.3	3.3	
	Number of Truck (#)	116	47	16	179
Investments	Compression, $MM	62	-	-	62
	Transportation, $MM	30	12	4	46
	Receiving Terminal, $MM	9	4	3	16
	Total, $MM	**101**	**16**	**7**	**124**
Tariffs	Per Leg, $/mscf	3.12	1.40	1.49	
	Delivery, $/mscf	***3.12***	***4.52***	***4.61***	***4.27***

Table 13.3 shows that the 37-mmscfd-CNG-delivery-system requires an investment of $124 MM, predominantly in the compressor plant at gas source and truck/CNG-cylinder-skid-trailers. The weighted average cost of CNG manufacture at source, transportation to and storage at the three power plants is $4.27 per mscfe, which is essentially unaffected by the cost of feed gas at source.

13.2.3.2 Case 1bb: LNG Supply from Pipeline Gas Source

LNG supply from source to the three power plants entails constructing a liquefaction and storage facility at the gas off-take point and providing transportation by either:

(a) Overland trucks from the gas source/LNG plant to a commercial vehicular ferry port for ferrying to a receiving terminal port adjacent to Power Plant #1 followed by transshipment of LNG by overland trucks to storage at the remaining two power plants for regasification and send-out; or

(b) Ocean-going tanker directly from a port adjacent to gas source/LNG plant to a receiving terminal port adjacent to Power Plant # 1 and subsequent road transportation of LNG to storage at the remaining two power plants for regasification and send-out.

13.2.3.2.1 Case 1bba: Truck/Vehicular Ferry LNG Transportation

Table 13.4 below summarizes the operational logistics of the terrestrial LNG supply system, the capital investments in the supply chain and the calculated tariffs assuming a 15% investor's rate of return for delivery of LNG from gas source to the three power plants.

Table 13.4 Truck/Vehicular Ferry LNG-in-Power System Logistics, Investments and Tariffs

System Variable	Item	Source to P/P # 1	P/P #1 to P/P #2	P/P #1 to P/P #3	Total
Transportation Logistics	Mode of Transportation	Terrestrial	Terrestrial	Terrestrial	
	Capacity (mmscfd)	37.3	22.6	7.6	37.3
	Distance, one way (km)	198	132	132	
	Load/truck (mmscf)	0.65	0.65	0.65	
	Average Velocity (km/h)	40	40	40	
	Trips/vehicle/day	2.02	2.79	2.79	
	Distance/vehicle/day	799	737	737	
	One-way travel time (hours)	4.95	3.3	3.3	
	Number of Truck (#)	36	16	6	58
Investments	Liquefaction/Storage/Offloading, $MM	108	-	-	108
	Transportation, $MM	11	5	2	18
	Receiving Terminal, $MM	12	8	3	23
	Total, $MM	**130**	**13**	**5**	**148**
Tariffs	Per Leg, $/mscf, @ $3/mscf Feed Gas	3.06	0.62	0.68	
	Delivery, $/mscf, @ $3/mscf Feed Gas	**3.06**	**3.68**	**3.74**	**3.57**
	Per Leg, $/mscf, @ $4/mscf Feed Gas	3.22	0.63	0.70	
	Delivery, $/mscf, @ $4/mscf Feed Gas	**3.22**	**3.85**	**3.92**	**3.74**
	Per Leg, $/mscf, @ $5/mscf Feed Gas	3.39	0.65	0.72	
	Delivery, $/mscf, @ $5/mscf Feed Gas	**3.39**	**4.04**	**4.11**	**3.93**

Table 13.4 shows that a 37-mmscfd-truck/vehicular-ferry-LNG-delivery-system requires an investment of $148 MM, predominantly in the small scale LNG plant.

The weighted average cost of LNG manufacture at source, transportation to and storage at the three power plants and regasification ranges from $3.57-3.93 per mscfe for feed gas prices of $3-5 per mscf at source.

13.2.3.2.2 Case 1bbb: Marine/Terrestrial Transportation

Table 13.5 below summarizes the operational logistics of the combined marine (ship)/terrestrial LNG supply system, the capital investments in the supply chain and the calculated tariffs assuming a 15% investor's rate of return for delivery of LNG from gas source to the three power plants.

Table 13.5 Marine/Terrestrial LNG-in-Power System Logistics, Investments and Tariffs

System Variable	Item	Source to P/P # 1	P/P #1 to P/P #2	P/P #1 to P/P #3	Total
Transportation Logistics	Mode of Transportation	Marine	Terrestrial	Terrestrial	
	Capacity (mmscfd)	37.3	22.6	7.6	37.3
	Distance, one way (km)	250	132	132	
	Tanker (m^3)/Truck (mmscf)	2,000	0.65	0.65	
	Average Velocity (km/h)	29.0	40	40	
	Trips/tanker or vehicle/day	1.1	2.79	2.79	
	Distance/tanker or vehicle/day	537	737	737	
	One-way travel time (hours)	8.7	3.3	3.3	
	Number of Tankers or Trucks	1	16	6	
Investments	Liquefaction/Storage/Offloading, $MM	110	-	-	110
	Transportation, $MM	17	5	2	24
	Receiving Terminal, $MM	18	8	3	29
	Total, $MM	**145**	**13**	**5**	**163**
Tariffs	Per Leg, $/mscf, @ $3/mscf Feed Gas	3.07	0.62	0.68	
	Delivery, $/mscf, @ $3/mscf Feed Gas	**3.07**	**3.69**	**3.75**	**3.58**
	Per Leg, $/mscf, @ $4/mscf Feed Gas	3.25	0.63	0.70	
	Delivery, $/mscf, @ $4/mscf Feed Gas	**3.25**	**3.88**	**3.95**	**3.77**
	Per Leg, $/mscf, @ $5/mscf Feed Gas	3.43	0.65	0.72	
	Delivery, $/mscf, @ $5/mscf Feed Gas	**3.43**	**4.08**	**4.15**	**3.97**

Table 13.5 shows that a 37-mmscfd-marine/terrestrial-LNG-delivery-system requires an investment of $163 MM, predominantly in the small scale LNG plant. The weighted average cost of LNG manufacture at source, transportation to and storage at the three power plants and regasification ranges from $3.58-3.97 per mscfe for feed gas prices of $3-5 per mscf at source.

13.2.4 Cost of Gas Supply to the Three Regional Power Plants

The immediately prior subsections show LNG supply from the existing liquefaction plant (Case 1a) at $3.27-3.53 per mscfe to be lowest cost transportation of natural gas to the three regional power plants, with LNG supply from pipeline source, Truck/Vehicular Ferry (Case 1bba) and marine/terrestrial (Case 1bbb), at $3.57-3.97 per mscfe a close second. CNG transportation from pipeline source (Case 1ba) is a more distant third with a weighted average tariff of $4.27. The costs of supply of LNG to the three regional power plants are presented in Table 13.6 below.

Table 13.6 Costs of Supply of Natural Gas as LNG to Three Regional Power Plants

Feed Gas, $/mscf	Gas Source	Transportation, $/mscfe			Cost of Supply, $/mscfe			
		P/P # 1	P/P # 2	P/P # 3	P/P # 1	P/P # 2	P/P # 3	Vol Wtd. Avg.*
3	LNG Plant	2.75	3.37	3.44	5.75	6.37	6.44	6.27
	Pipeline	3.06	3.68	3.74	6.06	6.68	6.74	6.57
4	LNG Plant	2.87	3.50	3.57	6.87	7.50	7.57	7.39
	Pipeline	3.22	3.85	3.92	7.22	7.85	7.92	7.74
5	LNG Plant	2.99	3.64	3.71	7.99	8.64	8.71	8.53
	Pipeline	3.39	4.04	4.11	8.39	9.04	9.11	8.93

*Based on 7.1 mmscfd to P/P # 1, 22.6 mmscfd to P/P #2 and 7.6 mmscfd to P/P #3.

13.2.5 Competitiveness of LNG-in-Power Generation

The economic viability of LNG supply to the three regional power plants is measured by its cost of supply vis-à-vis the netback value of gas in small scale, TTOC (Turbine Technology Open Cycle, also known as gas turbine) electric power generation fuelled by automotive diesel oil (ADO).

Table 13.7 presents the NBVs of gas in small scale, electric power generation at different power plant capacity factors for three different oil prices previously calculated in Section 10 and presented in Table 10.6.

Table 13.7 Netback Values of Gas in Converted TTOC Power Generation, $/mmBtu

Oil Price	Alternative Fuel		Capacity Factor			
$/B	Type	$/mmBtu	80%	60%	40%	20%
40	ADO	9.43	8.91	8.92	8.94	9.00
60	ADO	14.15	13.35	13.36	13.38	13.44
80	ADO	18.87	17.78	17.8	17.81	17.89

With the NBVs of gas used as fuel in converted TTOC units operating at the 20-40% capacity factor applicable to the power plants exceeding the COS of LNG for all combinations of oil prices and feed gas prices, the two proposed LNG supply systems are economically viable.

13.3 Case 2: LONG DISTANCE LNG SUPPLY FOR POWER AND INDUSTRY

13.3.1 Background

This analysis assesses the technical feasibility and economical viability of supplying 50 mmscfd as LNG to a pipeline system for power and industry use 1600 km from the gas source. A crude oil price basis of $70 per barrel is assumed for the analysis.

13.3.2 LNG Supply Project Engineering Specifications

Table 13.8 sets out the boundary conditions for the feasibility study.

Table 13.8 LNG Supply Project Boundary Conditions

Feed Gas Source	Pipeline
Gas Demand at Receipt Point	50 mmscfd
Distance Source-Receipt Point	1,600 km

The envisioned LNG supply scheme consists of gas supply from an off-take on a gas pipeline to a small natural gas liquefaction plant located adjacent to a port equipped with cryogenic storage and loading facilities for ocean-going LNG tankers. An appropriately sized LNG tanker is acquired to deliver the loaded LNG to a receiving terminal 1,600 km away. Upon arrival at the receiving terminal, the LNG is pumped from the tanker to a cryogenic storage. The LNG tanker returns empty to supply source for another refill.

Entering gas demand and one-way distance from Table 13.8 into the Marine Transport Tariff Model developed in Section 8, generic project specifications are generated by the logistics portion of the model, while capital cost are estimated by its unit cost correlations. The detailed calculations are contained Appendix N and summarized in Table 13.9.

Table 13.9 LNG Supply Project Specifications and Capex

Item	LNG			LNG	LNG Receiving Terminal			Total
	Plant	Storage	Loading*	Tanker	Offloading*	Storage	Regasification	
	mmtpa	m3	m3/h	m3	m3/h	m3	mmscfd	$MM
Sizing	0.45	35,000	2,800	14,000	2,800	35,000	100	
$MM	125	38	10	51	10	38	8	280
Design Criteria	120%	3	5	120%	5	3	2	
	of mean daily demand	times minimum requirement based on tanker RT time	hours to fill tanker	of size to deliver mean daily demand; 16 knots	hours to unload full tanker	times minimum requirement based on tanker RT time	times mean daily demand	

*Loading/offloading and ancillary plant/receiving terminal facilities

The proposed 35,000 m3 LNG storage quantity is too large for free standing units and will require a site-constructed tank. Two types of LNG storage tanks are common:

- "Single containment" employing a bund-wall around the tanks to contain spill; and
- "Double or full containment" using effectively two tanks, one inside the other.

The "single containment" tank concept considered in this assessment is about 25% less costly than "full containment" tank types.

In the USA, "Exclusion Zones" are required around LNG facilities. The applicable code is NFPA 59A. Two criteria are applied in determining the exclusion zone around an LNG storage facility: (1) Vapor dispersion and (2) thermal radiation. The vapor dispersion criterion determines an area around the tank farm sufficiently wide for escaping LNG vapor to dilute below the lower flammable limit. The thermal radiation criterion delimits an area around the tank farm sufficiently broad to protect the public from heat radiation from LNG fires. An Exclusion Zone is defined as an area surrounding the LNG facilities within which the operator legally controls all activities. LNG facilities include berthed LNG carriers, loading/unloading equipment, storage, pipelines and ancillary amenities.

Additionally, a security zone surrounding berthed LNG carriers is often declared meaning that other vessels over a pre-determined size are not allowed to approach within a 500 m radius of said berthed carriers.

In Indonesia, the possible regulatory impact on the proposed project is more difficult assess than technical factors, because there appears to be no published Indonesian requirements for LNG ship movements and docking in commercial port areas. Indonesia does have "Port Liability Agreements" for the Arun and Bontang LNG export harbors, basically a contractual document between vessel owner, operator, terminal owner, LNG buyer and seller. It allocates liability to visiting LNG tankers and their owners regardless of fault and in return the terminal owner agrees to limit liability to US$150 million.

Since few LNG carriers exist in the size range required for this project, the cost for purpose-built carrier was utilized in the evaluations. The majority of LNG carriers (80%) of 10,000m3 and above now on order will be membrane containment type, 18% will be Moss spherical and 2% other. Membrane tanks fit more efficiently inside the ship hull and hence offer better economics than Moss spherical. A drawback for the former is sloshing of the LNG cargo, which renders it less suited to "milk-run"-type LNG delivery.

The LNG in receiving terminal storage is gasified in submerged combustion or shell-and-tube exchangers for send-out to customers. These types of vaporizers are proposed when land scarcity dictates minimum plant footprint. Operating costs are significant, since approximately 2% of throughput gas is consumed in the vaporization process. Other gasification methods employing (sea) water as heat source are available, but have not been assumed used here due to a lack of site specifics.

In general, however, heat absorption by LNG to achieve vaporization in a shell-and-tube heat exchanger using (sea) water as a heat source is designed to allow a (sea) water temperature decline of no more than 8°C (15°F). On this basis, vaporization of 50 mmscfd requires absorption of 42 mmBtu/hr from the (sea) water, equivalent to a throughput of 21,000 liters per minute.

13.3.3 Cost of LNG Supply

The ensuing cost-of-service tariffs at 15 and 20 percent investor's rate of return were calculated using the Marine Transport Tariff Model's cash flow component, which, added to the cost of LNG feed gas at the LNG plant busbar, yields the cost of LNG supply. The sample calculations of the costs of LNG supply for different cryogenic storage capacities at the LNG plant/receiving terminal and feed gas prices are contained in Appendix N and summarized in Table 13.10 .

Table 13.10 Case 2: Costs of LNG Supply

Storage*	Feed Gas	Tariff, $/mscf		Cost of Supply, $/mscf	
	$/mscf	@ 15% IRR	@ 20% IRR	@ 15% IRR	@ 20% IRR
3	3	4.22	5.16	7.22	8.16
	4	4.42	5.36	8.42	9.36
	5	4.63	5.57	9.63	10.57
	6	4.83	5.78	10.83	11.78
2	3	3.92	4.78	6.92	7.78
	4	4.13	4.98	8.13	8.98
	5	4.33	5.19	9.33	10.19
	6	4.54	5.39	10.54	11.39

*times minimum requirement based on tanker RT time

At a 15% investor's rate of return, Table 13.10 shows the cost of LNG supply ranging from $7-11 per mscf for LNG feed gas prices of $3-6 per mscf, while a 20% return increases costs by about $1 per mscf. Table 13.10 shows that reducing cryogenic storage at the LNG plant and the receiving station by 1/3 reduces cost of supply by $0.30-0.40 per mscf.

13.3.4 Competitiveness of LNG Imports for Power and Industry (Case 2)

To determine the competitiveness of the proposed LNG supply scheme, the costs of LNG supply contained in Table 13.10 are compared to the costs of alternative fuels, namely ADO for power generation and IDO for industry.

Table 13.11 lists delivered costs of ADO to PLN and IDO to industry for three crude oil prices covering the range of $50-90 per barrel suggested by PGN.

Table 13.11 Delivered Costs of OBF Products

Fuel Type	Conver-sions	Brent CO Multi-plier*	Ex. Ref. Fuel Prices, $/liter			T, D & RM**, $/liter			VAT			Delivered Costs of OBFs		
			Brent Crude Oil, $/B						10%			$/mmBtu		
	Btu/liter		50	70	90	Low	Median	High	Low	Median	High	Low	Median	High
ADO	36,939	1.15	0.36	0.51	0.65	0.06	0.07	0.08	0.04	0.06	0.07	12.56	17.16	21.77
IDO	38,437	1.11	0.35	0.49	0.63	0.06	0.07	0.08	0.04	0.06	0.07	11.71	15.99	20.27
FO	39,685	0.83	0.26	0.37	0.47	0.06	0.07	0.08	0.03	0.04	0.05	8.90	12.07	15.24
Gasoline	33,196	1.18	0.37	0.52	0.67	0.06	0.07	0.08	0.04	0.06	0.07	14.28	19.53	24.78
ADO***	36,939	1.15	0.36	0.51	0.65	0.03	0.05	0.06	0.04	0.06	0.07	11.79	16.51	21.23

* 2003-2006 correlation between OBF product and Brent Crude oil prices, ex. Singapore
** *Transportation, Distribution and Retail Margin granted by BPH Migas*
*** Special T, D & RM rate applicable to PLN only

As shown in Table 13.11, at a crude oil price of $70 per barrel ADO supplied to PLN is priced at $16.51/mmBtu, while the retail price of IDO to industry is $15.99/mmBtu.

Figure 13.1 contrasts graphically the costs of LNG supply to a send-out point located 1,600 km away from the gas source/LNG plant at different LNG feed gas prices and investor's rate of return with the costs of supply of ADO to PLN and IDO to industry for crude oil prices ranging from $50-90 per barrel.

Figure 13.1 Cost of LNG Supply vs. Cost of Alternative Fuels

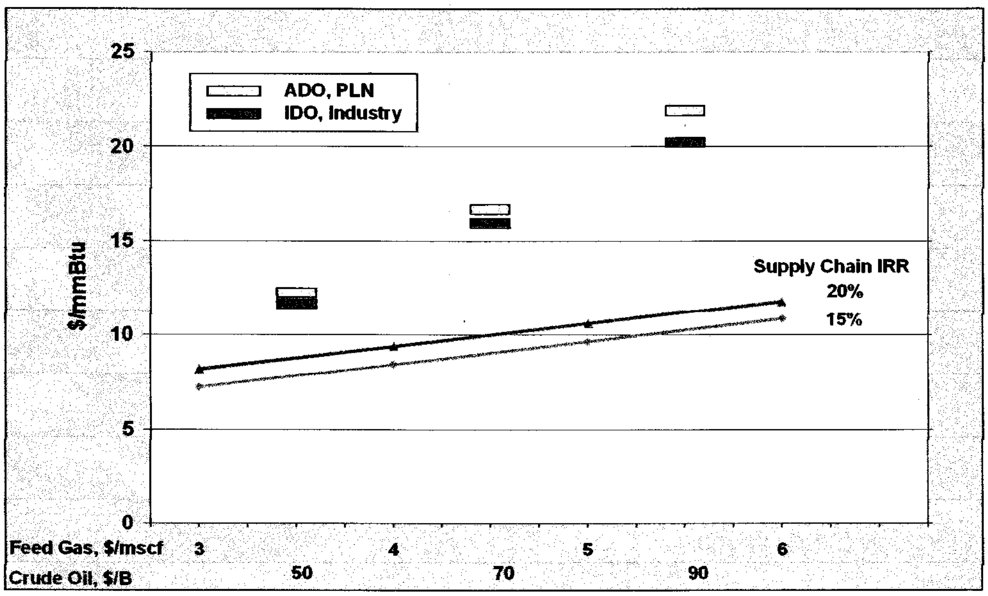

Figure 13.1 shows the costs of LNG supply to be $4-9 per mmBtu below the costs of alternative fuels. As a matter of fact, even at the highest cost of LNG supply (feed gas price of $6 per mscf and IRR of 20%), the cost of LNG supply is (marginally) lower than alternative fuel costs at the lowest crude oil price under consideration, namely $50 per barrel.

13.3.5 Conclusions

In summary, the proposed LNG supply scheme is

- Technically feasible, since it relies on proven technologies in facilities and ships. Lead times on delivery of specialty items, such a small LNG tankers and vaporization exchangers, are currently long and prices therefore inflated; and

- Economically viable showing costs of supply $4-9 per mmBtu below alternative fuels.

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14.1 INTRODUCTION

This section addresses the regulatory framework for SMS CNG/LNG manufacture, transportation, storage and distribution in Indonesia by reviewing the Indonesian laws and regulations applicable to CNG/LNG supply activities. Also, a comparison with natural gas regulatory frameworks in other countries in the world is made.

14.2 REGULATORY FRAMEWORK FOR SMS CNG/LNG SUPPLY ACTIVITIES

14.2.1 Laws

The basic premise underlying the oil and gas industry in Indonesia is the Constitution of the Republic of Indonesia of 1945. Article 33 of the Constitution states, that "all the natural wealth on land and in the waters under the jurisdiction of the State shall be used for the greatest benefit and welfare of the people." Based on this principle, the House of Representatives (DPR) promulgated Law No. 22 (2001) about oil and natural gas. The law spawned a host of implementing regulations at the executive level, i.e., governmental regulations and presidential and ministerial decrees, along with regional regulations.

The goals of Law 22/2001 are to ensure "effective implementation and control" of oil and gas activities in Indonesia. The law, among others, defines "upstream" and "downstream" activities, establishes "regulatory agencies" and their areas of responsibility, requires legal separation of upstream and downstream activities in order to achieve cost transparency ("unbundling") without imposing ownership restrictions, and prioritizes natural gas for domestic needs.

Law 21/2001 authorizes establishment of an upstream regulatory agency, BP Migas, responsible for upstream (exploration and production) oil and gas activities and a downstream regulatory agency, BPH Migas, responsible for downstream (transportation, processing, storage and distribution) oil and natural gas activities to replace state oil and gas company Pertamina, which had previously held these regulatory responsibilities in addition to its oil and gas enterprise mission. The Law does not explicitly address CNG and LNG activities.

14.2.2 SMS CNG/LNG Regulations

Government Regulations No. 34 and 35 of 2004 apply to "upstream" and "downstream" activities, respectively. No. 34/2004 does not explicitly address CNG/LNG, but categorizes "field development, processing, transportation, storage and sales of own production carried out by Contractors (under a Cooperation or

Production Sharing Contract with BP Migas) as Upstream Business Activities." Thus, CNG and LNG manufacture, transportation, storage and distribution based on "own" production and as a natural extension of conventional field processing is considered an "upstream" activity under the jurisdiction of BP Migas. However, CNG/LNG manufacture, transportation, storage and distribution based on third party feed gas, as most SMS CNG/LNG would be, are categorized as "downstream" activities.

Government Regulation No. 36/2004 and its companion ministerial decree MEMR 007/2005, address the "downstream" oil and gas (and CNG and LNG) business, specifically issuance of business license. MEMR 007/2005 states that a gas (e.g., CNG and LNG) manufacture, transportation, storage and distribution business license must be obtained from the Ministry of Energy and Mineral Resources (MEMR) by fulfilling certain technical requirements, such as:

- submission of a plan specifying the fluid type, capacity, operations area, transportation mode and technology to be used along with the quantity and quality of the product;

- submission of an Environmental Impact Assessment approved by the Ministry of the Environment;

- compliance with Ministry of Transport regulations, specifically SK. 725/AJ.302/DRJD/2004, in respect of CNG/LNG land and sea transportation;

- local site use permit from relevant agency in respect of storage facilities; and

- ownership and/or control of "trading facilities and means" in respect of trading (distribution).

MEMR Regulation 007/2005 delegates control, monitoring and administrative responsibility for SMS CNG and LNG activities to BPH Migas and MEMR.

Ministry of Transport Regulation SK.725/AJ.302/DRJD/204 prescribes prior approval by director general of land transportation for delivery of dangerous goods, such as CNG/LNG, over land, such approval to be renewed every 6 months. Also, certain facilities requirements are to be met, such as twist locks for non-permanently installed vessels (on trailers), prime mover compliance with automotive design requirements approved by directorate general, pressure vessel design and manufacture compliance with ASME Code Section VIII and recertification every 5 years.

As natural gas is categorized as a "regular commodity", the Department of Transport has adopted no specific set of regulations concerning LNG tankers, not to mention CNG barges or container ships. In respect of marine transportation of CNG and

LNG, the Ministry of Transportation has adopted International Maritime Organization guidelines and criteria for approval of gas carrier fitness.

In summary, Indonesia has a set of broad, business conducive regulations for CNG and LNG manufacturing, transportation, storage and distribution, but is short of specific, detailed regulations aimed at setting minimum technical standards and safe operation.

14.3 NATURAL GAS REGULATORY FRAMEWORKS ABROAD

Figure 14.1 below shows a comparison of the Indonesian natural gas regulatory framework with those of six other countries, where LNG is an export/import commodity, namely Australia, India, Venezuela, Japan, United States and Spain. The comparison focuses on the degree and nature of government involvement in the natural gas operations of the country.

The appendix highlights the relatively higher degree of multilayered, government involvement in the natural gas (specifically LNG) business in Indonesia and Venezuela than in the other countries.

Figure 14.1 Comparisons with Natural Gas Regulatory Frameworks Abroad

Field	Business Segment		Indonesia	Australia	India	Venezuela	Japan	USA	Spain
Oil & Gas Regulatory Body	Upstream		BP Migas & MEMR	State Government for reserves located in State coastal waters, Otherwise Commonwealth Government	Directorate general of Hydrocarbons of Ministry of Petroleum and Natural Gas	Ministry of Energy and Petroleum	Ministry of Trade and Industry	Federal Energy Regulatory Commission	The competent body of the relevant Spanish Regional Authority or Ministry of Industry
	Downstream		BPH Migas						
Cross Border Sales or Distribution of State's Share			Upstream Contractor or Third Party appointed by BP Migas	N/A	N/A		N/A	N/A	N/A
Business License	E&P		Issued by MEMR	Issued by State or Commonwealth Govememnt	Issued by Government		Given by the Minister of Trade and Industry consulting with the director of Mine Safety and Inspection and director of Bureau of economy Trade and Industry	Issued by Federal Energy Regulatory Commission and Bureau of Land Management (Federal Level)	The competent body of the relevant Spanish Regional Authority or Ministry of Industry
	General Gas Transportation				N/A		Given by the minister of METI	Issued by Federal Energy Regulatory Commission	Government
	Gas Pipeline		Special Right issued by BPH Migas						
	LNG Transportation		Ministry of Transportation						
	Construction & Operation of LNG Facilities	Local	Issued by related regional govemement						
		Foreign	Issued by related regional govemement & Capital Investment Coordination Board (BKPM)				N/A		
	Gas Trading		MEMR						N/A
Authorization concerning environment			Approved by Directorate General of Oil and Gas of MEMR	Approved by State or Commonwealth Government and Environmetal Protection Agency	Given by Ministry of Environment & Forest & Relevant State Government	Approved by Ministry of Environment and Natural Resources			Ministry of Environment or equivalent regional authority body
Authorization concerning health & safety				Approved by State or Commonwealth Government and NOPSA (National Offshore Petroleum Safety Authority) for offshore facilities	N/A	Approved by Ministry of Health & Social Welfare	Approved by the Minister of Trade and Industry consulting with the director of Mine Safety and Inspection		N/A
Land Rights	Private-owned land		Agreement with land owner	Agreement with land owner	Given by Government or State Government	Agreement with land owner. Prior authorizations from Ministry of Agriculture & Land required	Agreement with land owner	Agreement with land owner	Agreement with land owner
	State-owned land		Long term lease agreement with State	State				Lease issued by the Secretay of Interior (Federal Land)	
Third Party Access to Transportation Facilities			Determined by BPH Migas	Determined by the facility's license holder	Regulated by Government of India through GAIL	Mutual agreement, if not by MEP	Mutual agreement with facility owner	Determined by the Federal energy Regulatory Commission	Government
LNG Sales Price			Approved by the government	Current market forces & private contracts	N/A	Determined by government	N/A	N/A	N/A
Regulatory body for competition			Business Competition Supervision Commission (KPPU)	Australian Competition and Consumer Competition (ACCC)	Monopolies and Restrictive Trade Practices (MRTP) Commission	Office of the Venezuelan Pro-Competition Superitendent	Japan Fair Trade Commission	Federal Trade Commission and Department of Justice	National Energy Commission

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15.1 INTRODUCTION

This section identifies and quantifies the pollutants and greenhouse gas emission reductions, which would result from the projected replacements of OBFs by CNG or LNG. It also determines the monetary value of greenhouse gas emission reductions under the Clean Development Mechanism carbon trading system.

15.2 BACKGROUND

Greenhouse gases (GHG) are gaseous components of the atmosphere that contribute to the greenhouse effect. CO, CO_2, CH4, N2O, CF_4, C_2F_6, volatile organic compounds (VOC) and nitrogen oxides ($NO_x = NO + NO_2$) are classified as GHG. The concentrations of several greenhouse gases have increased significantly over the last decade. Some of the main sources of greenhouse gases are caused by human activities include burning of fossil fuels; deforestation; use of chlorofluorocarbons (CFCs) in refrigeration systems, and the use of CFCs and halons in fire suppression systems and manufacturing processes.

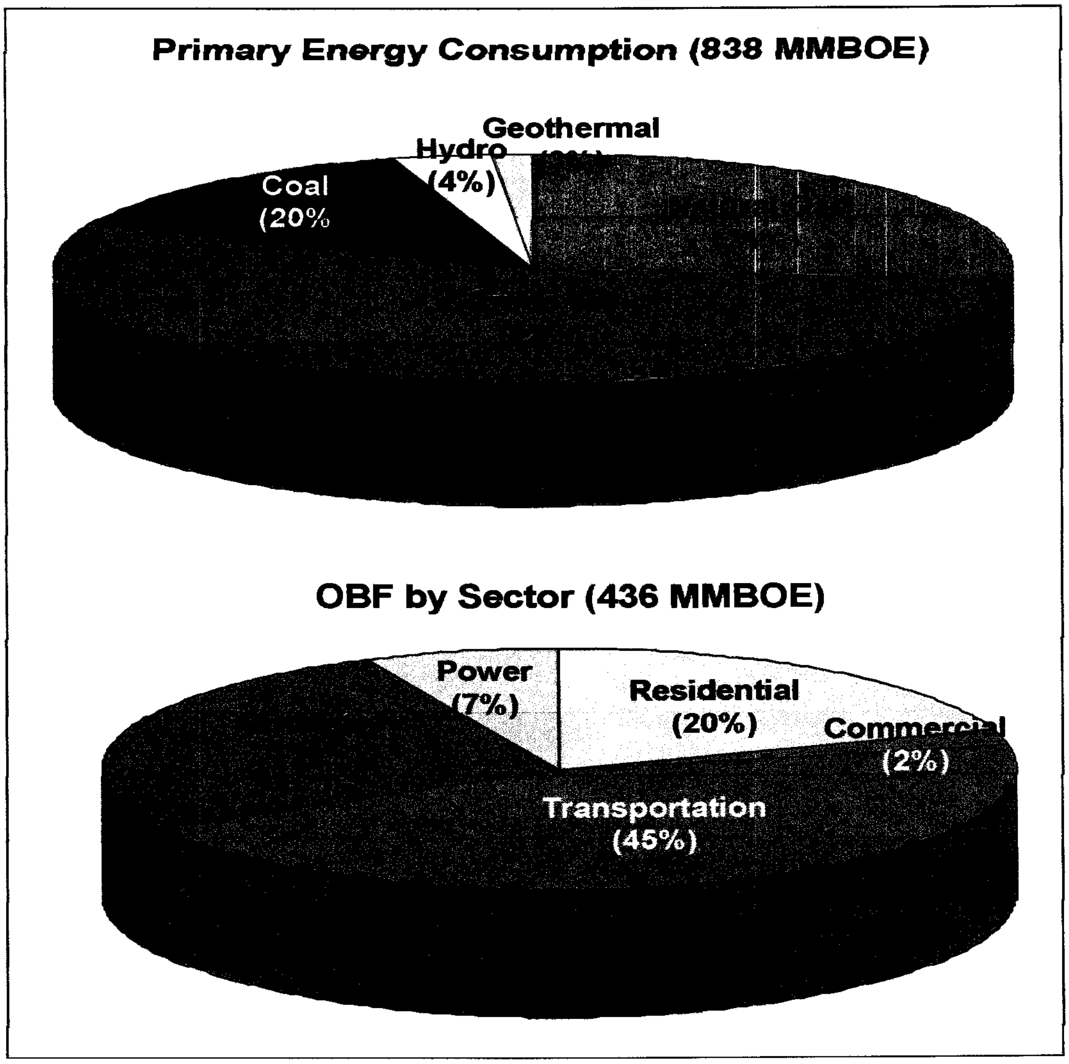
Factors that influence growth in GHG emissions are the same as those that drive increases in energy demand. Among the most significant are population growth, increased penetration of computers, electronics, appliances and office equipment, increases in commercial floor space, growth in industrial output, increases in highway, rail and air travel, and continued reliance on fossil fuels for electric power generation.

Energy systems (power stations, industrial processes, transportation and fossil fuel processing) are the primary sources of man-made greenhouse gas emissions. Therefore, significant potential for GHG emission reduction resides with the energy sector. The source of energy used for power generation considerably affects the amount of GHG emissions. Since fossil fuels represent a dominant share in primary energy supply, energy-related GHG emissions exhibit a seemingly irreversible upward trend.

As shown in Figure 15.1, OBFs accounted for more than half of total Indonesian primary energy consumption of 436 million barrels of oil equivalent in 2005 with the transportation, power generation and industrial sectors being responsible for more than three-quarters of that. Increased consumption of natural gas in these sectors would reduce GHG emissions and diminish the need for state treasury-sapping fuel subsidies.

The power generation and industrial sectors are rather inflexible in their fuel consumption due to most fuel supply systems and burner/boiler/heater facilities being fuel specific and the capital intensive nature of switching to a new fuel, such as natural gas. Also, shortage of transmission pipeline capacity and dependence on a single-source supplier have been barriers to increased natural gas based consumption. SMS CNG and LNG distribution would overcome the supply bottleneck and support any fuel switching project aimed at reducing GHG emissions.

Figure 15.1 Primary Energy and OBF Consumptions in Indonesia (2005)



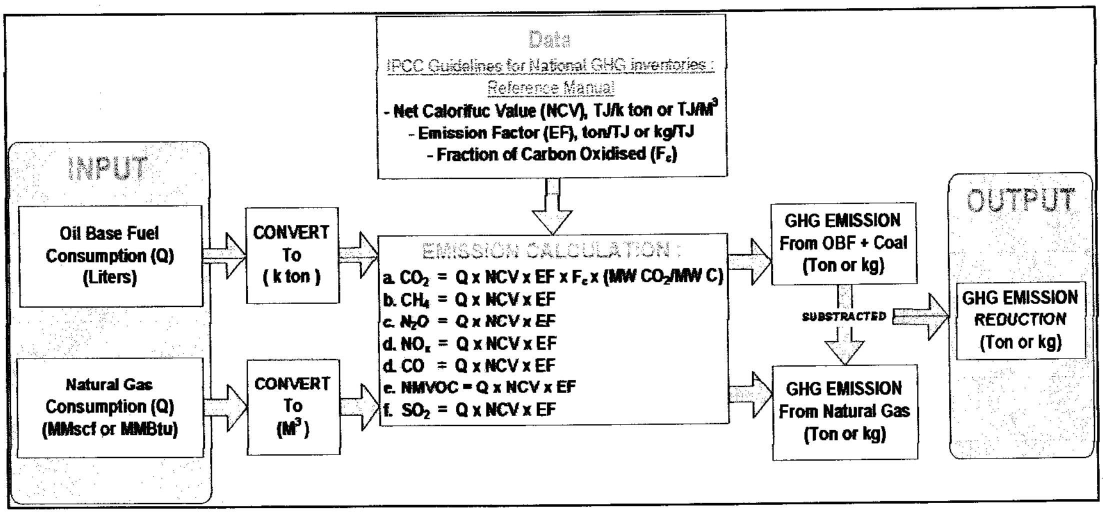
The use of natural gas in (public) transport has become increasingly popular due to its contribution to a cleaner local environment. Natural gas vehicles offer the lowest emission (90% less carbon monoxide) and pollution ratings, but vehicle owners currently find only few places to refuel their cars. On a worldwide scale there are about 3 million cars with CNG-fuelled engines (about 0.5% of the world car population). This number will likely increase once governments provide clarity about their fiscal policies, i.e. incentives for fuel switching in transportation).

15.3 GHG EMISSION REDUCTIONS

15.3.1 GHG Emissions Reduction Calculation Methodology

To quantify GHG emission reductions due to fuel switching, a method of calculation promulgated by the Intergovernmental Panel on Climate Change (IPCC)[1] will be used. This methodology calculates GHG emissions from fuel combustion only and is depicted schematically in Figure 15.2 below.

Figure 15.2 Method for Calculating GHG Emission Reductions



Using mmBtu as input uniformly throughout this study, the "emission calculation" formulae in Figure 4.2 simply to:

$$CO_2 = Q^*CF(J/Btu)^*EF^*F_c^*(MW\ CO2/MC\ C)$$
$$CH_4 = Q^*CF(J/Btu)^*EF$$
$$N_2O = Q^*CF(J/Btu)^*EF$$
etc.

where

CO_2, CH_4, N_2O = Rate of CO_2, CH_4 or N_2O emission, tons/kg per day
Q = Fuel Consumption, BBtu per day
CF(J/Btu) = Conversion factor from Btus to Joules, or 1055
EF = Emission Factor
F_c = Fraction of Carbon Oxidized

[1] Guidelines for National GHG Inventories: Reference Manual, Revision 1996 published by IPCC

MW CO2 = Molecular Weight of CO2, 44
MW C = Molecular Weight of Carbon, 12

15.3.1.1 CO_2 Emission Factors

The applicable EF and F_c values for calculation of CO_2 emissions are presented in Tables 15.1 and 15.2 below.

Table 15.1 Carbon Emission Factors, EF

Fuel Type	Carbon Emission Factor, Ton C/TJ
Gasoline	18.9
Diesel Oil	20.2
Fuel Oil	21.1
Natural Gas	15.3

Table 15.2 Fraction of Carbon Oxidized, Fc

Fuel Type	% Oxidization
Oil and Oil Products	99.0
Natural Gas	99.5

15.3.1.2 CH_4 Emission Factors

The applicable EF values for calculation of CH_4 emissions are presented in Table 15.3 below.

Table 15.3 CH_4 Emission Factors, EF, kg/TJ

Industry Type	Natural Gas	Diesel Oil	Gasoline
Power Generation	1	3	-
Manufacturing Industry	5	2	-
Road Transportation	50	5	20

15.3.1.3 N_2O Emission Factors

The applicable EF values for calculation of N_2O emissions are presented in Table 15.4 below.

Table 15.4 N_2O Emission Factors, EF, kg/TJ

Industry Type	Natural Gas	Diesel Oil	Gasoline
Power Generation	0.1	0.6	-
Manufacturing Industry	0.1	0.6	-
Road Transportation	0.1	0.6	0.6

15.3.2 Projected GHG Emission Reductions

Tables 15.5 and 15.6 below summarize projected OBF savings by fuel type and sector and projected CNG/LNG consumption in replacement of OBFs under each of the three oil and feed gas price scenarios, respectively.

Table 15.5 Projected OBF Savings by Fuel Type and Sector, BBtud

LOW	2010	2015	2020	2025
ADO, Power	12	17	24	33
Transport, CNG	2	4	5	5
Transport, LNG	0	0	0	0
Subtotal	14	21	29	38
IDO, Industry	12	23	26	27
Gasoline, Transp.	2	12	33	46
Total	28	56	88	112
MEDIAN				
ADO, Power	37	58	80	109
Transport, CNG	5	16	34	47
Transport, LNG	1	2	4	5
Subtotal	43	76	117	161
IDO, Industry	18	42	67	67
Gasoline, Transp.	3	48	142	204
Total	64	166	326	433
HIGH				
ADO, Power	56	92	128	175
Transport, CNG	6	36	89	127
Transport, LNG	5	9	16	19
Subtotal	66	138	232	321
IDO, Industry	20	52	99	93
Gasoline, Transp.	5	73	232	331
Total	92	262	563	745

Table 15.6 Projected CNG/LNG Consumption in Replacement of OBFs, BBtud

LOW	2010	2015	2020	2025
Power	13	19	26	35
Industry	12	25	29	33
Transport, CNG	5	18	41	56
Transport, LNG	0	0	0	0
Total	29	62	96	125
MEDIAN				
Power	41	63	86	118
Industry	17	46	75	82
Transport, CNG	10	74	203	288
Transport, LNG	2	3	5	6
Total	69	186	369	494
HIGH				
Power	62	101	138	189
Industry	19	57	111	120
Transport, CNG	13	125	365	520
Transport, LNG	6	12	20	25
Total	101	295	635	853

Emission reductions resulting from projected replacement of OBFs by CNG/LNG in power generation, industry and transportation under the three scenarios have been calculated in respect of CO_2, CH_4 and N_2O. The results are summarized in Tables 15.7 through 15.9 below and presented graphically in Figures 15.3 through 15.5. The detailed calculations are contained in Appendix I.

Table 15.7 Projected CO_2 Emission Reductions, Million Tonnes CO_2 per Year

Scenario	2010	2015	2020	2025
Low	0.17	0.24	0.36	0.41
Median	0.33	0.63	1.07	1.27
High	0.44	0.96	1.90	2.17

Figure 15.3 Projected CO_2 Emission Reductions

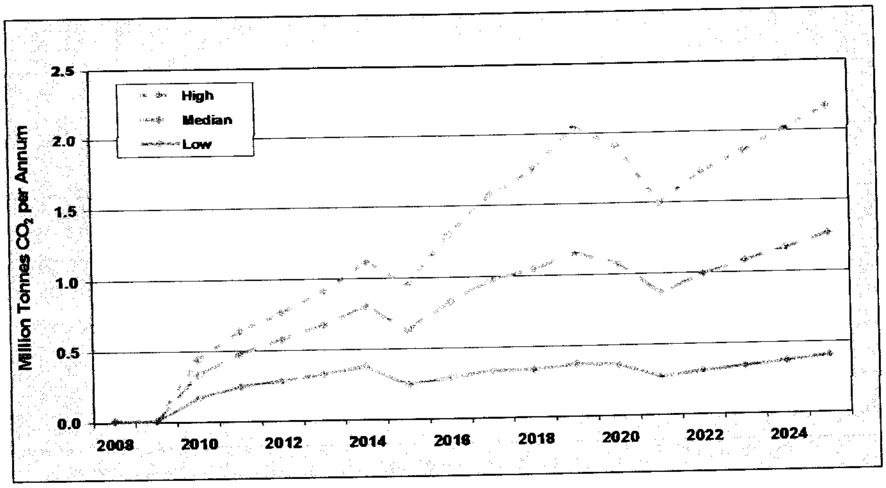


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Table 15.7 and Figure 15.3 show a series of rising CO_2 emission reductions followed by one-year declines reaching 0.4, 1.2 and 2.2 million tons of CO_2 reductions in 2025 for the Low, Median and High scenarios, respectively. The one-year emission reduction retreats are caused by projected declines in CNG/LNG usage in power generation and industry, e.g., in South Sulawesi and Java, as pipeline gas replaces CNG/LNG as a result of assumed gas infrastructure build-out.

Table 15.8 Projected CH_4 Emission Reductions, Tonnes CH_4 per Year

Scenario	2010	2015	2020	2025
Low	-79	-270	-549	-739
Median	-173	-1,091	-2,864	-4,022
High	-298	-2,006	-5,468	-7,681

Figure 15.4 Projected CH_4 Emission Reductions

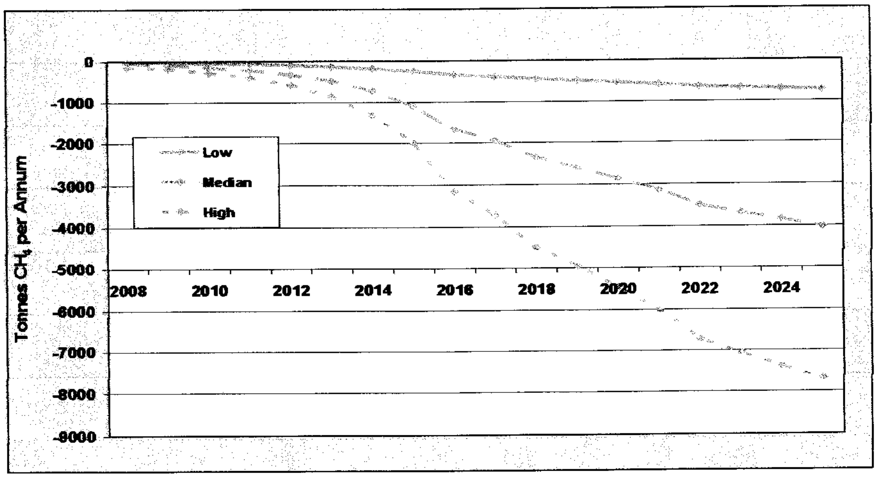


Table 15.8 and Figure 15.4 show projected CH_4 emission reductions by weight to be $1/300^{th}$ – $1/500^{th}$ of the CO_2 emission reductions and reversed, i.e., an increase rather than a reduction. The CH_4 emission *increases* are about 1, 4 and 7 thousand tones of CH_4 per year by 2025 for the Low, Median and High scenario, respectively.

Table 15.9 Projected N_2O Emission Reductions, Tonnes N_2O per Year

Scenario	2010	2015	2020	2025
Low	5	11	17	21
Median	12	31	61	81
High	17	49	106	139

Figure 15.5 Projected N_2O Emission Reductions

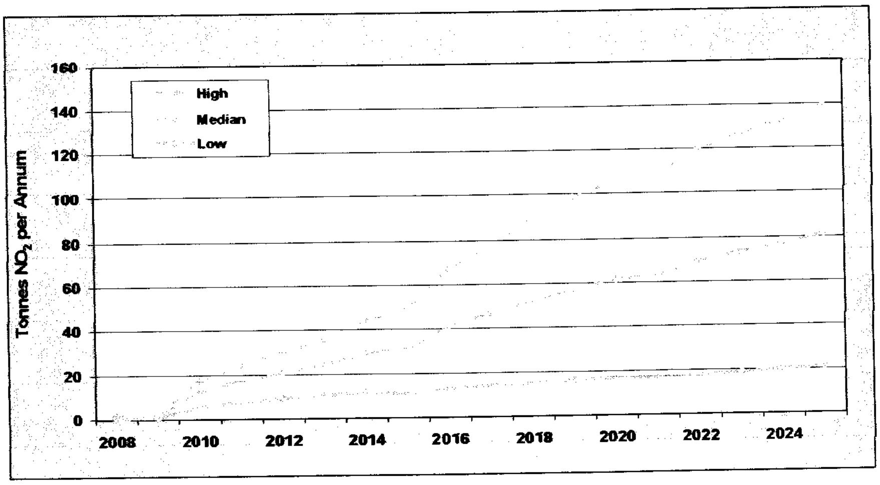


Table 15.11 and Figure 15.5 show projected N_2O emission reductions by weight to be about four orders of magnitude less than projected CO_2 emission reductions reaching 21, 81 and 139 tonnes per year by 2025 for the Low, Median and High scenario, respectively. As for CO_2 emission reductions, the flattening of the N_2O emission reduction profiles with time is due to replacement of CNG/LNG by pipeline gas as gas pipeline transmission infrastructure is built-out.

15.4 MONETARY VALUE OF GHG EMISSION REDUCTIONS

15.4.1 Background for Carbon Trading

15.3.1.3 History

In July 1992, representatives from 155 nations gathered in Rio de Janeiro for the United Nations Conference on the Environment and Development (UNCED). Recognition that climate change was a reality led to the signing of United Nations Framework Convention on Climate Change (UNFCCC), which resulted in a voluntary commitment by Annex 1 Countries (industrialized countries) to reduce their emissions to the levels of 1990 by year 2000. Imbedded in the agreement was the concept of Joint Implementation (JI) of activities to reduce GHG emissions or promote the absorption of atmospheric CO_2. Investors engaged in such projects (anywhere in the world) would be allowed to claim credits for the carbon emission reduction (or carbon sequestration) activities. These credits should be equivalent to the carbon reduction derived from the specific investment, and investors should be allowed to use them to lower GHG related liabilities in their respective home countries. The rationale of JI is that the marginal cost of emission reduction, or CO_2 sequestration, are generally lower in developing than in developed countries.

Dissatisfaction among the G77 countries over the concept of JI led to growing opposition to the JI model. Perceived problems included a feeling that this was a mechanism for industrialized countries to avoid addressing the real issues of reducing emissions at sources and that developing countries might be handing over their cheap offset opportunities to industrialized countries during the initial phase, in which developing countries had no commitment to GHG emission reductions.

In December 1997, 170 countries drafted the Kyoto Protocol. The most important aspect of the Kyoto Protocol is the adoption of binding commitments by 36 developed countries and economies in transition (collectively called the "Annex 1 Countries" and listed in Appendix I) to reduce their GHG emissions an average of 5.2% below year 1990 levels by 2008-2012. The commitments are differentiated by countries. At the same time, the Protocol approves use of three "flexibility mechanisms" for facilitating achievement of these GHG emission reduction targets, one of which is relevant to Indonesia and this project, namely the Clean Development Mechanism (CDM). The CDM refers to climate change mitigation projects undertaken between Annex 1 and non-Annex 1 countries. This new mechanism differs from JI, in that a particular project investment must contribute to sustainable development of the non-Annex 1 host country and emission reductions must be independently certified, the latter creating the term "certified emission reductions" (CER).

CDM is the only mechanism, by which developing countries, such as Indonesia, can participate in the Kyoto Protocol. The CDM allows countries with GHG emission limitation and reduction commitments, i.e., Annex 1 Countries, to engage in project-based activities in developing countries with the two-fold aim of assisting developing countries to achieve sustainable development and helping Annex 1 Countries meet their emission reduction targets. CDM projects produce GHG emission reduction units, called certified emission reductions (CERs), which must be verified and authenticated by independent certifiers. For projects to qualify as valid mitigation activities in the context of the Kyoto Protocol, they have to fulfill a series of eligibility criteria as follows:

- **Host country approval** – A GHG mitigation project has to be acceptable and approved by the host country government under its respective sustainable development criteria (social, economic, environmental) and other developmental criteria;
- **Contribution to sustainable development** – Under the CDM there is a specific objective of assisting developing countries in achieving sustainable development. While international initiatives are underway to develop common guidelines, no outputs have been produced to date. Currently, individual country definitions are used to determine eligibility;
- **Emission additionality** – Carbon credits are based on the difference in GHG emissions (or CO_2 sequestration) between projected or business-as-usual practices

(known as the baseline or reference scenario) and practices occurring due to project activities (known as the project scenario). This behavioral difference in GHG emissions is called "emission additionality". Emission additionality is a requirement of both JI and CDM projects. It was designed to ensure that carbon credit projects result in real reductions in the current rate of GHG accumulation in the atmosphere. Not all projects that might appear to have positive GHG effects are additional. For carbon credits to be acceptable under the terms of the Kyoto Protocol, no project can claim GHG emission reductions unless project proponents can reasonably demonstrate that the project's practices are "additional" to baseline scenario, or produces a "full life net GHG emission reduction"; and

- **Financial additionality** - The financing of the GHG mitigation project should not be as a result of diversion of resources from any international development funding.

15.4.1.2 Current Situation[1]

There are currently over 600 projects registered with the CDM Executive Board in Bonn, Germany, generating tradable emission credits valued at a little over $10 billion. These credits can be sold to companies in Annex 1 Countries to meet their Kyoto Protocol country emission targets. Of these projects, India leads with 226 projects followed by Brazil with 78 and China with 71. Indonesia has managed to secure only 8 projects.

There are another 1,000 projects in the pipeline with tradable carbon credits of about $20 billion until 2012.

The CER, or carbon, credits generated by CDM qualifying projects have since 2004 traded under "World Bank" type contracts for US$ 4 - 5, under "standard off-take contract" for US$ 5 - 8, under "guaranteed delivery contracts" for US$ 5-12, and under "exchange contracts" for US$ 8 -15 per ton of CO_2 equivalent emission reduction.

Demand for carbon credits from the European Union, Japan and Canada is expected to amount to three to four billion tons of carbon dioxide equivalents for the period 2008 - 2012 worth billions of dollars. Currently, the U.K. is the largest investor in carbon trading accounting for 36% of all carbon trading followed by the Netherlands with 18%, Japan with 11% and Switzerland with 8%.

[1] "Indonesia Left Behind in Global Carbon Trade" by Tony Beck reported in the Jakarta Poston May 3, 2007

The designated national authority in Indonesia responsible for identifying and communicating qualifying CDM projects to its counterparts in Annex 1 Countries is the National Commission on CDM (Komnas MPB).

15.4.2 CDM Monetary Value Calculation Methodology

CO_2, CH_4 and N_2O are the only types of GHGs, which are included in the monetary value calculations. The monetary value of GHG emission reductions can be calculated by multiplying total GHG emission reductions (expressed in tons of CO_2 equivalents) by the price of carbon (US$/ton CO_2). Because the calculation basis is in terms of CO_2, other qualifying GHG emissions have to be converted to CO_2 equivalents using their respective Global Warming Potential (GWP) factors. As shown in Figure 15.6, the GWP factors for CH_4 and N_2O are 21 and 310, respectively, meaning that CH_4 has 21 times and N_2O 310 times the destroying effect of CO_2.

Figure 15.6 GWP Conversion Factors for CH_4 and N_2O

$$ton\,CO_2 = 21\frac{CO_2}{CH_4} \times ton\,CH_4$$

$$ton\,CO_2 = 310\frac{CO_2}{N_2O} \times ton\,N_2O$$

15.4.3 Carbon Trading Value of Projected GHG Emission Reductions

Assuming combustion GHG emission reductions to equal "emission additionality", as defined by CDM, allows determination of the carbon trading values generated by the projected replacements of OBFs with CNG/LNG in power generation, industry and transportation. Applying the GWP formulae of Figure 15.6 to the projected GHG emission reductions presented in Subsection 15.3.2 above, CO_2-equivalent GHG emission reductions can be calculated. Assuming carbon trading values of \$2 to \$10 per tonne of CO_2 equivalent GHG emission reduction, the cumulative carbon trading values for different project durations can be quantified for each of the three oil/CNG/LNG feed gas price scenarios.

A summary of the results is shown in Table 15.10 and presented graphically in Figure 15.7 below, while the detailed calculations are contained in Appendix I. The carbon trading values shown in Table 15.10 represent the cumulative carbon trading values for the periods shown, while those in Figure 15.7 are for the study time frame of 2008-2025.

Table 15.10 Carbon Trading Values of Projected GHG Emission Reductions from replacing OBFs with CNG/LNG in Power Generation, Industry and Transportation

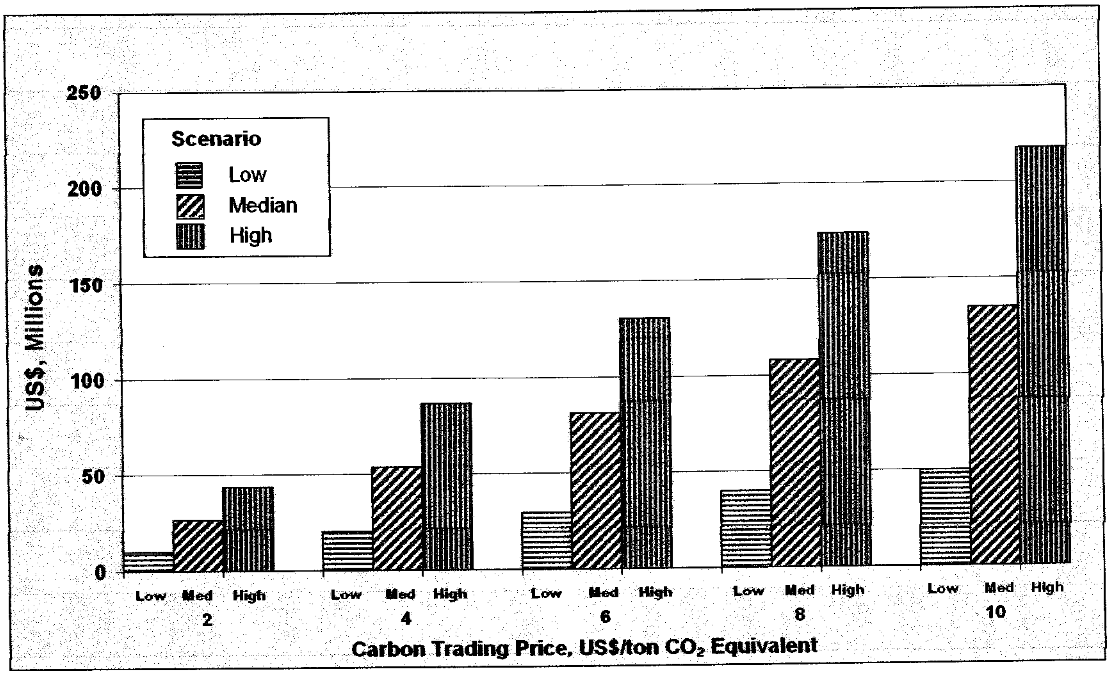
Scenario	$/t CO2E	Cum 2008-2012	Cum 2008-2015	Cum 2008-2020	Cum 2008-2025
Low	2	1	3	7	10
Median		3	7	17	27
High		4	10	26	43
Low	4	3	7	13	20
Median		6	14	34	54
High		7	19	52	87
Low	6	4	10	20	30
Median		8	21	50	81
High		11	29	78	130
Low	8	6	13	27	40
Median		11	28	67	108
High		15	38	104	174
Low	10	7	16	33	50
Median		14	35	84	135
High		19	48	130	217

Under the Low ($40/B, $3/mscf), Median ($60/B, $4/mscf) and High ($80/B, $5/mscf) oil and CNG/LNG feed gas price scenarios, the life time (2008-2025) carbon trading value ranges from $10 - 50 million, $27 – 135 million and $43 – 217 million, respectively, as the carbon trading price increases from $2 – 10 per ton CO_2 equivalent.

With estimated requirements of cumulative incremental capital expenditures of $0.7 billion (Low scenario), $3.2 billion (Median scenario) and $6.0 billion (High scenario) to implement the projected replacements of OBFs with CNG/LNG in power generation, industry and transportation over the same period (see Section 12 above), these carbon trading values represent significant amounts of money ranging from 0.7-1.4 percent at a carbon trading price of $2 to 4-7 percent at $10. Measured against the cumulative CNG/LNG consumer investments only, the carbon trading values represent 2-4 percent at $2 and 8-18 percent at $10, i.e., about doubling the CER subsidy as a fraction of consumer investment.

The likely sellers of GHG emission reductions, or CERs, are the consumers, such as PLN and CNG vehicle fleet owners, e.g., TransJakarta Busway, which have invested in cleaner burning CNG/LNG.

Figure 15.7 Cum. 2008-25 Carbon Trading Values of Projected GHG Emission Reductions



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16.1 INTRODUCTION

This section presents two measures of monetary gains from replacing OBFs with CNG/LNG, namely projected national and consumer monetary gains. The national monetary gain represents the foreign exchange savings, which accrue to Indonesia, while the consumer monetary gain equates to the total net savings by the former OBF consumers, who have switched to CNG/LNG. Both measures of monetary gains will be determined for each of the three, alternative crude oil and CNG/LNG feed gas price scenarios.

16.2 NATIONAL MONETARY GAINS

The national monetary gain, or foreign exchange savings, equals the value of reduced importation of OBFs partially offset by payments to foreign entities for CNG/LNG supply and utilization by consumers.

16.2.1 Methodology

The national monetary gain from replacing OBFs with CNG/LNG is defined as:

- the savings from reduced importation of OBFs, less
- payments to foreign entities in respect of;
    - Production and transmission of natural gas used as feed gas for CNG/LNG manufacture;
    - Manufacture/distribution of CNG/LNG; and
    - Conversion of existing and incremental cost of new-built CNG/LNG fuelled facilities by consumers.

In calculating national monetary gains according to the definition above, a number of simplifying assumptions were made:

i. All OBFs replaced by CNG/LNG is assumed imported from Singapore leading to a landed cost equal to the Singapore ex. refinery price plus tanker transportation to Jakarta. Since Indonesia imports more than 400 MBD of OBFs, assuming CNG/LNG to replace all imported OBFs in the margin is valid.

ii. All natural gas used in manufacture of CNG/LNG derives from domestic sources.

iii. Existing gas production and transmission facilities are capable of supplying the feed gas for CNG/LNG manufacture, i.e., marginal up/midstream feed gas capital expenditures are zero.

iv. No foreign ownership in the CNG/LNG supply chain and all operating and maintenance being sourced domestically, leaving foreign payments in respect of supply chain capital expenditures only.

v. No foreign ownership of CNG/LNG consumer facilities and all operating and maintenance being sourced domestically, leaving foreign payments in respect of consumer conversion and incremental, new-built CNG/LNG fuelled facilities capital expenditures only.

16.2.2 Projected National Monetary Gains

The detailed determination of projected national monetary gains is contained in Appendix J, while summaries are presented in tabular and graphical form below.

16.2.2.1 OBF Savings

The OBF, i.e., ADO, IDO and Premium Gasoline, consumption avoided in power generation, industry and transportation as a result of the projected switch to CNG/LNG is presented in Table 16.1 below for the three crude oil and CNG/LNG feed gas price scenarios.

Table 16.1 Projected OBF Avoidance by Switch to CNG/LNG, BBtud

Scenario	2010	2015	2020	2025
Low	28	56	83	112
Median	64	166	326	433
High	92	262	563	745

The applicable OBF import prices (assumed equal to the Singapore ex refinery price plus shipping) for the three oil price scenarios are listed in Table 16.2 below.

Table 16.2 OBF Import Prices C.I.F. Jakarta, $/mmBtu

Fuel Type	Brent Crude Oil Price ($/B)		
	Low (40)	Median (60)	High (80)
ADO	7.89	11.81	15.74
IDO	7.32	10.96	14.60
Gasoline	9.01	13.49	17.96

Applying the appropriate OBF import price to the avoided consumption of each OBF type for each of the three crude oil and CNG/LNG feed gas price scenarios determines the foreign exchange savings realized in replacing OBFs by CNG/LNG.

The results are summarized in Table 16.3 below. The detailed assumptions and calculations are contained in Appendix J.

Table 16.3 Cumulative OBF Foreign Exchange Savings, $MM

Scenario	2010	2015	2020	2025
Low	94	814	1,954	3,462
Median	315	3,113	9,288	18,139
High	632	6,219	20,140	40,456

Table 16.3 shows cumulative foreign exchange savings by 2025 from the projected CNG/LNG replacements of OBF in small scale power generation, industry and transportation ranging from $3-40 billion for the Low to High crude oil and CNG/LNG feed gas price scenarios.

16.2.2.2 Foreign Payments, CNG/LNG Feed Gas Production and Transmission

Annual payments to foreign entities in respect of CNG/LNG feed gas production and transmission have been determined by applying generic upstream and midstream operating (opex) unit costs, unit profits and foreign share percentages to the feed gas volumes corresponding to the projected CNG/LNG consumption in power generation, industry and transportation. The assumptions and results are presented in Tables 16.4 through 16.6 below. The detailed assumptions and calculations are contained in Appendix J.

Table 16.4 Projected CNG/LNG Replacements of OBFs, BBtud

Scenario	2010	2015	2020	2025
Low	29	62	96	125
Median	69	186	369	494
High	101	295	635	853

Table 16.5 Annual Foreign Payments, Upstream Opex and Profits, $MM

<table>
<tr><th>Scenario</th><th>Type</th><th>$/mscf</th><th>Foreign Share</th><th>2010</th><th>2015</th><th>2020</th><th>2025</th></tr>
<tr><td>Low</td><td rowspan="3">Opex</td><td rowspan="3">0.41</td><td rowspan="3">33%</td><td>1</td><td>3</td><td>5</td><td>6</td></tr>
<tr><td>Median</td><td>3</td><td>9</td><td>18</td><td>24</td></tr>
<tr><td>High</td><td>5</td><td>15</td><td>31</td><td>42</td></tr>
<tr><td>Low</td><td rowspan="3">Profits</td><td>0.65</td><td rowspan="3">85%</td><td>6</td><td>13</td><td>19</td><td>25</td></tr>
<tr><td>Median</td><td>0.97</td><td>21</td><td>56</td><td>111</td><td>149</td></tr>
<tr><td>High</td><td>1.30</td><td>41</td><td>119</td><td>256</td><td>344</td></tr>
<tr><td>Low</td><td rowspan="3">Opex + Profits</td><td rowspan="3" colspan="2"></td><td>7</td><td>16</td><td>24</td><td>31</td></tr>
<tr><td>Median</td><td>24</td><td>65</td><td>129</td><td>173</td></tr>
<tr><td>High</td><td>46</td><td>134</td><td>287</td><td>386</td></tr>
</table>

Table 16.6 Annual Foreign Payments, Midstream Opex and Profits, $MM

Scenario	Type	$/mscf	Foreign Share	2010	2015	2020	2025
Low	Opex	0.08	25%	0.2	0.5	0.7	0.9
Median				0.5	1.4	2.7	3.6
High				0.7	2.2	4.6	6.2
Low	Profits	0.13	10%	0.1	0.3	0.5	0.6
Median				0.3	0.9	1.8	2.3
High				0.5	1.4	3.0	4.0
Low	Opex + Profits			0.4	0.8	1.2	1.5
Median				0.8	2.2	4.4	6.0
High				1.2	3.6	7.6	10.3

Tables 16.5 and 16.6 show payments to foreign entities in respect of upstream CNG/LNG feed gas supply to dwarf those of midstream due to both larger unit costs and profits as well as larger foreign shares, i.e., foreign components of opex and foreign participating interests in gas producing production sharing contracts.

16.2.2.3 Foreign Payments, CNG/LNG Supply Chain

Annual payments to foreign entities in the build-out of the CNG/LNG supply chain are derived by multiplying supply chain build-out unit capex costs, foreign share percentages thereof and incremental annual feed gas supply requirements for each of the three CNG/LNG feed gas price scenarios. The assumptions and ensuing results are summarized in Table 16.7 below. The detailed assumptions and calculations are contained in Appendix J.

Table 16.7 Cum. Foreign Payments, Supply Chain Build-out, $MM

Scenario	Sector	Foreign Share	2010	2015	2020	2025
Low	Power	66%	26	48	65	88
	Industry	49%	27	65	92	119
	Transport	68%	14	54	120	165
	Total		67	166	277	372
Median	Power	66%	90	155	203	266
	Industry	49%	42	109	188	223
	Transport	68%	34	226	608	861
	Total		165	491	999	1,351
High	Power	66%	155	267	353	469
	Industry	49%	50	138	276	325
	Transport	68%	60	407	1,133	1,600
	Total		266	812	1,762	2,394

16.2.2.4 Foreign Payments, Consumer Conversions and New-built Facilities

Annual payments to foreign entities in the build-out of the CNG/LNG supply chain are derived by multiplying consumer conversion/incremental new gas fuelled facilities unit capex costs, estimated foreign share percentages thereof and incremental annual feed gas supply requirements for each of the three CNG/LNG feed gas price scenarios. The results are summarized in Table 16.8 below. The detailed assumptions and calculations are contained in Appendix J.

Table 16.8 Cum. Foreign Payments in Consumer Conversion, $MM

Scenario	Sector	Foreign Share	2010	2015	2020	2025
Low	Power	65%	18	32	35	40
	Industry	61%	5	9	5	1
	Transport	65%	10	40	97	138
	Total		32	81	137	179
Median	Power	65%	57	100	113	129
	Industry	61%	7	15	-3	-11
	Transport	65%	23	178	547	814
	Total		87	293	656	933
High	Power	65%	89	159	180	208
	Industry	61%	8	17	-14	-25
	Transport	65%	41	303	908	1,331
	Total		137	480	1,074	1,514

The negative foreign payments in respect of industry merely reflects the lower cost of new built, gas fuelled industrial heating and steam generating facilities than their OBF fuelled counterparts.

16.2.2.5 Total Foreign Payments, CNG/LNG Supply & Utilization

Total foreign payments in respect of CNG/LNG supply and utilization are the sum of payments to foreign entities in implementing and maintaining the upstream/midstream/distribution supply chain and consumer switch from OBF to CNG/LNG fuelled equipment and facilities. Total foreign payments are summarized in Table 16.9 below, while detailed data are contained in Appendix J.

Table 16.9 shows cumulative payments to foreign entities by 2025 under the Low scenario of $891 MM growing 4-fold to $3.9 billion under the Median scenario and nearly doubling again to $7.5 billion under the High scenario reflecting strong growth of CNG/LNG usage primarily in transportation as the crude oil price increases.

Table 16.9 Cum. Foreign Payments in CNG/LNG Supply & Utilization, $MM

Scenario	Sector	2010	2015	2020	2025
Low	Upstream	9	76	182	324
	Midstream	0	4	9	16
	Supply Chain	67	166	277	372
	Consumer	32	81	137	179
	Total	109	327	604	891
Median	Upstream	28	274	809	1,592
	Midstream	1	9	28	55
	Supply Chain	165	491	999	1,351
	Consumer	87	293	656	933
	Total	281	1,066	2,492	3,930
High	Upstream	56	536	1,707	3,455
	Midstream	1	14	45	92
	Supply Chain	266	812	1,762	2,394
	Consumer	137	480	1,074	1,514
	Total	460	1,842	4,589	7,454

16.2.2.6 Projected National Monetary Gains from Switching to CNG/LNG

The national monetary gains, i.e., foreign exchange savings, from replacing OBFs by CNG/LNG in power generation, industry and transportation are the savings from avoided OBF imports presented in subsection 16.2.2.1 less total payments to foreign entities in respect of CNG/LNG supply and utilization presented in Subsection 16.2.2.5. Cumulative national monetary gains have been determined for all three crude oil and CNG/LNG feed gas price scenarios and are summarized in Table 16.10 and shown graphically in Figure 16.1 below. Detailed calculations are contained in Appendix J.

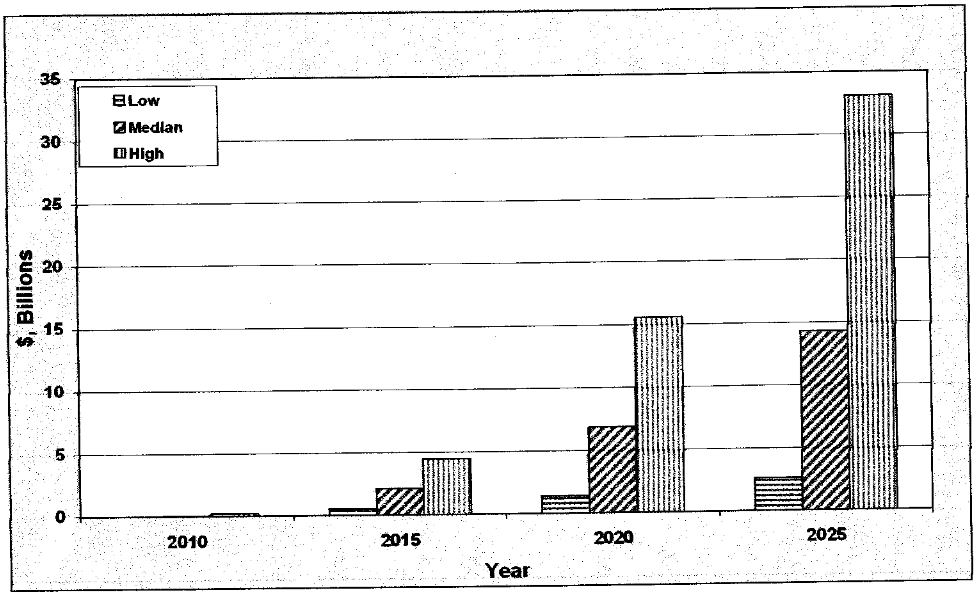
Table 16.10 Cum. National Monetary Gains from Switch to CNG/LNG, $MM

Scenario	2010	2015	2020	2025
Low	-15	487	1,350	2,572
Median	34	2,047	6,795	14,209
High	171	4,377	15,551	33,002

Table 16.10 and Figure 16.1 show cumulative foreign exchange savings from replacing OBFs with CNG/LNG in power generation, industry and transportation of -15 MM by 2010 growing to $2.5 billion by 2025 in the Low scenario. Under the Median scenario, $34 MM of foreign exchange savings are realized by 2010 increasing to $14 billion by 2025, while the corresponding savings are $171 MM and $33 billion, respectively, for the High scenario. To put these foreign exchange savings into perspective, Indonesian imports of ADO (Automotive Diesel Oil) in 2005 amounted to 248,000 barrels daily at an average price of $74 per barrel resulting in an annual ADO import bill of almost $7 billion. While the cumulative projected

foreign exchange savings by 2025 under the Median scenario equate to only two years of current ADO import bills, projected one year foreign exchange savings in 2025 equate to 20% of Indonesia's 2005 ADO import bill under the Median scenario and 65% under the High scenario.

Figure 16.1: Cum. National Monetary Gains from Switch to CNG/LNG



16.3 CONSUMER GAINS

Consumer monetary gain is defined as the total savings realized by CNG/LNG consumers from switching from OBFs to CNG/LNG. Consumer monetary gains will be determined for each of the three crude oil and CNG/LNG feed gas price scenarios.

16.3.1 Methodology

The consumer monetary gain equals savings on replacing OBFs with CNG/LNG less the cost of converting existing OBF fuelled consumer equipment to CNG/LNG and the incremental cost of new CNG/LNG fuelled equipment over the equivalent OBF fuelled equipment.

16.3.2 Consumer Monetary Gains

Each of the three components comprising consumer monetary gains will be determined separately and the results summarized below. The detailed calculations are contained in Appendix J.

16.3.2.1 Savings on Avoided OBF Purchases by Consumers

Savings on avoided OBF purchases by consumers are the avoided OBF volumes multiplied by the OBF retail prices. The retail prices for the three types of OBFs being replaced by CNG/LNG are shown for the three oil price scenarios in Table 16.11.

Table 16.11 OBF Retail Prices

Fuel Type	Brent Crude Oil Price ($/B)		
	Low (40)	Median (60)	High (80)
ADO	10.40	15.01	19.61
IDO	9.71	13.99	18.27
Gasoline	11.82	17.07	22.32

The cumulative savings on avoided OBF purchases by consumers are summarized in Table 16.12 below. Detailed calculations are contained in Appendix J.

Table 16.12 Cumulative Savings on Avoided OBF Purchases, $MM

Scenario	Sector	2010	2015	2020	2025
Low	Power	44	390	793	1,346
	Industry	44	452	911	1,345
	Transport	36	233	874	1,873
	Total	124	1,075	2,578	4,564
Median	Power	201	1,779	3,708	6,360
	Industry	91	1,057	2,580	4,118
	Transport	109	1,122	5,507	12,548
	Total	401	3,957	11,796	23,027
High	Power	399	3,593	7,621	13,172
	Industry	136	1,642	4,398	7,157
	Transport	253	2,518	13,076	30,063
	Total	788	7,754	25,095	50,392

16.3.2.2 Cost of CNG/LNG Purchases by Consumers

The cost of CNG/LNG purchases by consumers are the projected volumes of CNG/LNG replacements of OBFs multiplied by the cost of CNG/LNG supply. The weighted average costs, expressed in 2006 US$, of CNG/LNG supply in the power generation, industrial and transportation sectors in 2010 are shown in Table 16.13 for the three crude oil and CNG/LNG feed gas price scenarios. Since CNG/LNG costs of supply were determined individually for each supply chain within a province and supply chain throughputs grow at different rates, the provincial and national weighted average sector costs of supply vary over time, although not dramatically. Hence, the 2010 national weighted average sector costs of CNG/LNG supply were chosen for display in Table 16.13 for illustrative purposes only.

Table 16.13 Nationwide Weighted Average Costs of CNG/LNG Supply in 2010

Scenario	Sector	$/mmBtu
Low	Power	6.23
	Industry	7.05
	Transport	5.60
Median	Power	7.50
	Industry	7.55
	Transport	6.60
High	Power	8.75
	Industry	9.01
	Transport	7.69

The ensuing costs of projected CNG/LNG purchases by consumers are summarized in Table 16.14 below for each of the three scenarios.

Table 16.14 Cumulative Costs of CNG/LNG Purchases by Consumers, $MM

Scenario	Sector	2010	2015	2020	2025
Low	Power	29	252	510	862
	Industry	30	321	678	1,059
	Transport	22	135	478	1,003
	Total	81	708	1,667	2,924
Median	Power	111	967	2,002	3,416
	Industry	46	538	1,380	2,410
	Transport	56	539	2,540	5,750
	Total	213	2,044	5,922	11,575
High	Power	197	1,748	3,677	6,319
	Industry	63	791	2,237	4,078
	Transport	118	1,089	5,373	12,231
	Total	378	3,628	11,288	22,629

16.3.2.3 Costs to Consumers of Converting to CNG/LNG Fuelled Equipment

In addition to fuel charges, the costs to consumers of converting to CNG/LNG includes the costs of converting existing OBF fuelled equipment and facilities to burning CNG/LNG-based gas and the incremental costs of new CNG/LNG-based gas burning units over and above the costs of OBF fired units. These costs are summarized in Tables 16.15 and 16.16 below.

The negative incremental costs for new CNG/LNG fuelled equipment shown in Table 16.16 below reflect the lower unit cost of gas fired heaters and steam generators compared to their IDO burning counterparts. The large costs of new, i.e., Original Equipment Manufacture, NGVs, e.g., $2,430 MM by 2025 in the High scenario, reflect a combination of their high capital intensity as well as their high degree of vehicle market penetration.

Table 16.15 Cum. Costs of Conversions to CNG/LNG Fuelled Equipment, $MM

Scenario	Sector	2010	2015	2020	2025
Low	Power	28	49	52	57
	Industry	8	17	18	19
	Transport	3	7	11	12
	Total	39	72	81	88
Median	Power	87	153	165	180
	Industry	11	29	35	38
	Transport	11	34	57	69
	Total	109	216	258	287
High	Power	137	243	261	286
	Industry	13	35	47	50
	Transport	19	69	128	153
	Total	169	347	436	489

Table 16.16 Cum. Incremental Costs of New CNG/LNG Fuelled Equipment, $MM

Scenario	Sector	2010	2015	2020	2025
Low	Power	0	0	2	4
	Industry	0	-2	-10	-17
	Transport	11	55	138	200
	Total	11	53	130	187
Median	Power	0	1	9	19
	Industry	0	-5	-41	-56
	Transport	25	239	784	1,184
	Total	25	236	752	1,147
High	Power	0	2	16	34
	Industry	0	-7	-70	-91
	Transport	56	492	1,615	2,430
	Total	56	487	1,561	2,373

16.3.2.4 Projected Consumer Monetary Gains

The monetary gains by consumers switching from OBFs to CNG/LNG are savings on avoided OBF consumption (subsection 16.3.2.1) less the expense of CNG/LNG purchases (subsection 16.3.2.2) and costs of conversions and incremental new unit purchases (subsection 16.3.2.3). The projected consumer gains are summarized in Tables 16.17 through 16.19 for the low, median and high scenarios, respectively, and presented graphically in Figure 16.2.

Table 16.17 Cum. Consumer Savings from Switch to CNG/LNG, Low Scenario, $MM

Sector	Cost Type	2010	2015	2020	2025
Power	OBF	44	390	793	1,346
	CNG/LNG	-29	-252	-510	-862
	Conversions	-28	-49	-52	-57
	New Units	0	0	-2	-4
	Net	-13	88	228	423
Industry	OBF	44	452	911	1,345
	CNG/LNG	-30	-321	-678	-1,059
	Conversions	-8	-17	-18	-19
	New Units	0	2	10	17
	Net	6	117	224	284
Transport	OBF	36	233	874	1,873
	CNG/LNG	-22	-135	-478	-1,003
	Conversions	-3	-7	-11	-12
	New Units	-11	-55	-138	-200
	Net	-1	36	248	657
All	*Net*	-8	241	700	1,364

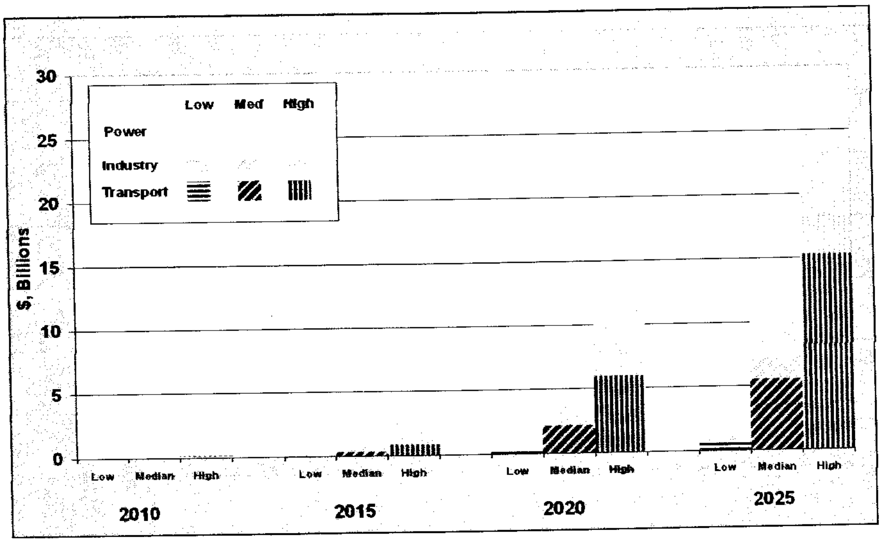
Table 16.18 Cum. Consumer Savings from Switch to CNG/LNG, Median Scenario, $MM

Sector	Cost Type	2010	2015	2020	2025
Power	OBF	201	1,779	3,708	6,360
	CNG/LNG	-111	-967	-2,002	-3,416
	Conversions	-87	-153	-165	-180
	New Units	0	-1	-9	-19
	Net	3	658	1,533	2,746
Industry	OBF	91	1,057	2,580	4,118
	CNG/LNG	-46	-538	-1,380	-2,410
	Conversions	-11	-29	-35	-38
	New Units	0	5	41	56
	Net	34	494	1,205	1,727
Transport	OBF	109	1,122	5,507	12,548
	CNG/LNG	-56	-539	-2,540	-5,750
	Conversions	-11	-34	-57	-69
	New Units	-25	-239	-784	-1,184
	Net	17	310	2,126	5,545
All	*Net*	53	1,462	4,864	10,018

Table 16.19 Cum. Consumer Savings from Switch to CNG/LNG, High Scenario, $MM

Sector	Cost Type	2010	2015	2020	2025
Power	OBF	399	3,593	7,621	13,172
	CNG/LNG	-197	-1,748	-3,677	-6,319
	Conversions	-137	-243	-261	-286
	New Units	0	-2	-16	-34
	Net	64	1,600	3,667	6,533
Industry	OBF	136	1,642	4,398	7,157
	CNG/LNG	-63	-791	-2,237	-4,078
	Conversions	-13	-35	-47	-50
	New Units	0	7	70	91
	Net	60	823	2,184	3,119
Transport	OBF	253	2,518	13,076	30,063
	CNG/LNG	-118	-1,089	-5,373	-12,231
	Conversions	-19	-69	-128	-153
	New Units	-56	-492	-1,615	-2,430
	Net	60	868	5,960	15,248
All	*Net*	185	3,291	11,811	24,901

Figure 16.2 Cum. Consumer Savings from Switch to CNG/LNG



Tables 16.17 through 16.19 and Figure 16.2 show cumulative consumer savings from the projected switch to CNG/LNG under the Low crude oil and CNG/LNG feed gas price scenario of a negative $8 MM by 2010 growing to $1.4 billion by 2025. Under the Median scenario the cumulative savings are estimated to reach $53 MM by 2010 increasing to $10 billion by 2025, while the High scenario results in projected cumulative consumer savings of $185 MM by 2010 growing to almost $25 billion by 2025. The savings in all instances lie in the difference between the price of OBFs and

CNG/LNG partially, but not materially, offset by the expense of conversions and incremental cost of gas fuelled equipment. The greatest savings are experienced by the transportation sector accounting for more than half of total projected consumer savings followed by the electric power generating sector with 25-30 percent.

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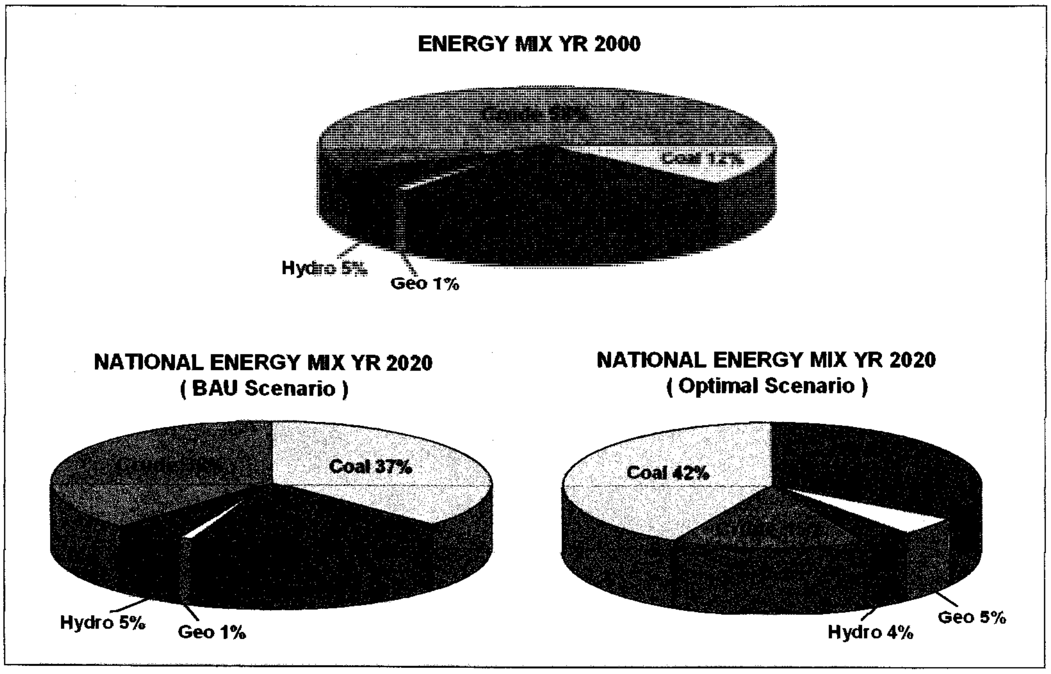
17.1 INTRODUCTION

This section presents estimates of the developmental impacts of the projected levels of OBF replacement by CNG/LNG in SMS power generation, industry and transportation. The macroeconomic measures chosen to quantify the developmental impacts of the project are GDP, Household Income and Employment, while ancillary developmental benefits, such as infrastructure build-out, market reforms, human capacity building, technology transfer, productivity improvement, resource use efficiency, demonstration effects and spin-off projects, are addressed qualitatively.

Replacement of OBFs by other forms of energy, particularly CNG/LNG, is a national Indonesian policy objective as illustrated in Figure 17.1 below. According to the "Energy Industry Development Blueprint of April, 2005"[1], the aim is to reduce crude oil (OBF) use from a current 58% of primary energy consumption to 15% by 2020 by increasing the use of, primarily, natural gas and coal.

Table 17.1 National Energy Mix Targets for 2020



17.2 METHODOLOGY

Quantitative development measures were determined using a standard economic Input-Output Model comprising 66 sectors within the Indonesian economy obtained from BPS[2]. The I/O Model uses a matrix representation of the national economy to

[1] Issued by the Department of Energy and Mineral Resources, Jakarta
[2] "2003 Edition", Central Bureau of Statistics, Jakarta

predict the effect of changes in one industry on others and the entire economy and its constituents. Thus, it specifically tracks the impact of investment in one sector on the economy as a whole. Sectors 51 (Electricity, Gas and Water Supply), 27 (Manufacture of Processed Foodstuff) and 56 (Road Transportation) were chosen to represent the three economic sectors, which are the subject of investments in the replacement of OBFs by CNG/LNG, namely SMS power generation, small industrial manufacturing processes and transportation. The economic impact is tracked in the model by macroeconomic indicators, such as output, income and employment multipliers. The output multiplier of a sector is the amount of total output in the economy resulting from a unit change in the final demand of that sector. Final demand is comprised of investments, household consumption and government expenditures. An increase in final demand of the three sectors subject to OBF replacement by CNG/LNG increases the output not only of those sectors, but also other sectors in the national economy. The increase of output in other sectors illustrates the *indirect* effects of an increase of final demand in the power generation, industrial and transportation sectors.

The output, income and employment multipliers for the three sectors subject to investment in the projected OBF replacement by CNG/LNG are listed in Table 17.1 below.

Table 17.1 BPS 66-sector I/O Model Multipliers

	SECTOR #		
	27	51	56
Output Multiplier	2.106	2.043	1.799
Income Multiplier	3.336	2.392	1.969
Employment Multiplier	0.0425	0.0087	0.0538

Output multipliers imply that a unit of incremental investment in each of the food processing industry, the electric power and transportation sectors due to fuel switching projects results in economy-wide output increases of 2.106, 2.043 and 1.799 units, respectively. The Income and Employment multipliers have similar meanings.

17.3 IMPACT ON GDP, INCOME AND EMPLOYMENT

Using the BPS 66-sector I/O model with the sector multipliers set out in Table 17.1 above, the impacts on Gross Domestic Product, Income and Employment of the capital investments required to replace projected quantities of OBFs in the power generation, industrial and transportation sectors with CNG/LNG were determined. The results are summarized below, while the detailed calculations are contained in Appendix K.

17.3.1 Impact on GDP

The impact on Gross Domestic Product (GDP) of the projected OBF-to-CNG/LNG capital investments in the SMS power generation, industrial and transportation sectors are summarized in Table 17.2 and Figures 17.2 through 17.4 below.

Table 17.2 Impact of OBF-to-CNG/LNG Investment on National GDP

Scenario	Sector	2010	2015	2020	2025
Low	Power	0.003%	0.006%	0.007%	0.009%
	Industry	0.003%	0.009%	0.017%	0.020%
	Transportation	0.002%	0.007%	0.017%	0.023%
	Total	0.008%	0.022%	0.041%	0.052%
Median	Power	0.010%	0.018%	0.022%	0.027%
	Industry	0.003%	0.008%	0.011%	0.012%
	Transportation	0.004%	0.030%	0.087%	0.126%
	Total	0.017%	0.056%	0.119%	0.166%
High	Power	0.017%	0.030%	0.037%	0.046%
	Industry	0.004%	0.010%	0.015%	0.017%
	Transportation	0.006%	0.054%	0.165%	0.242%
	Total	0.026%	0.094%	0.217%	0.305%

Figure 17.2 Impact of Low Scenario OBF-to-CNG/LNG Investment on National GDP

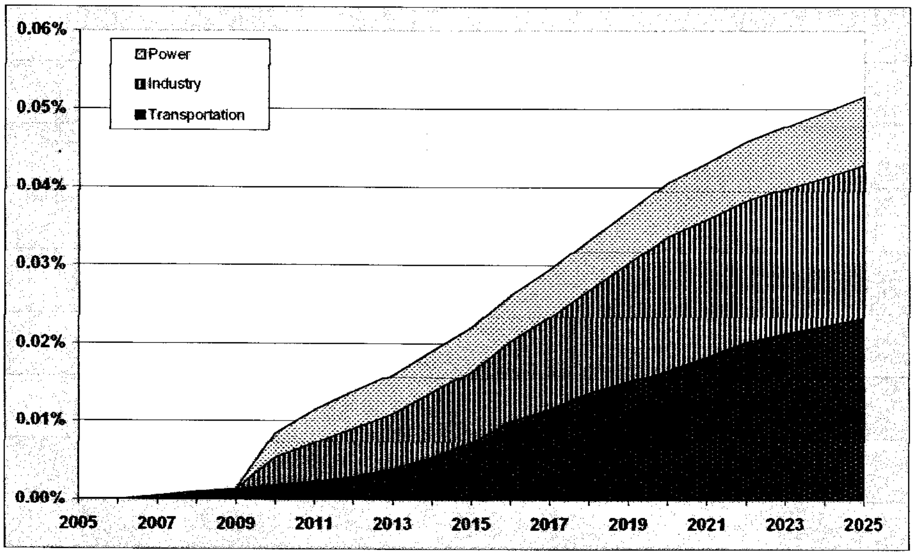


Figure 17.3 Impact of Median Scenario OBF-to-CNG/LNG Investment on National GDP

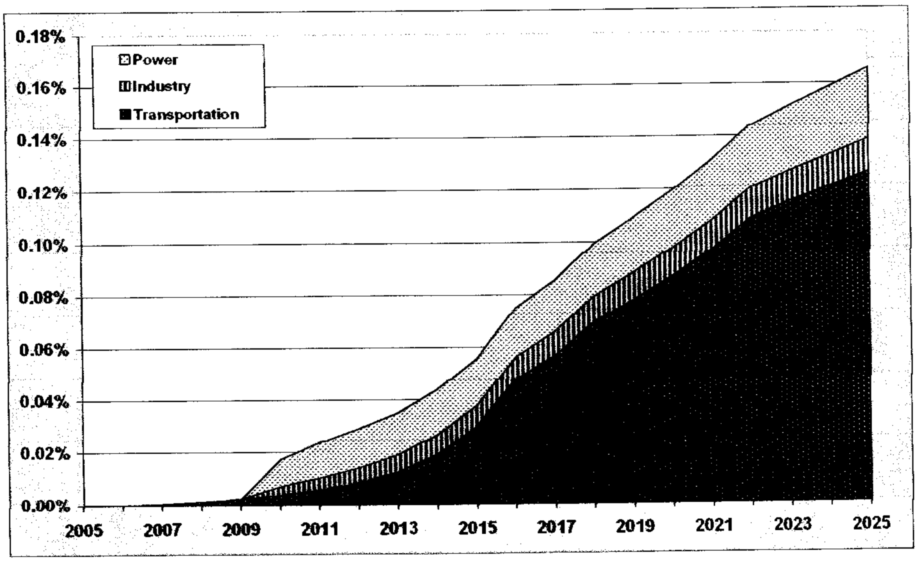


Figure 17.4 Impact of High Scenario OBF-to-CNG/LNG Investment on National GDP

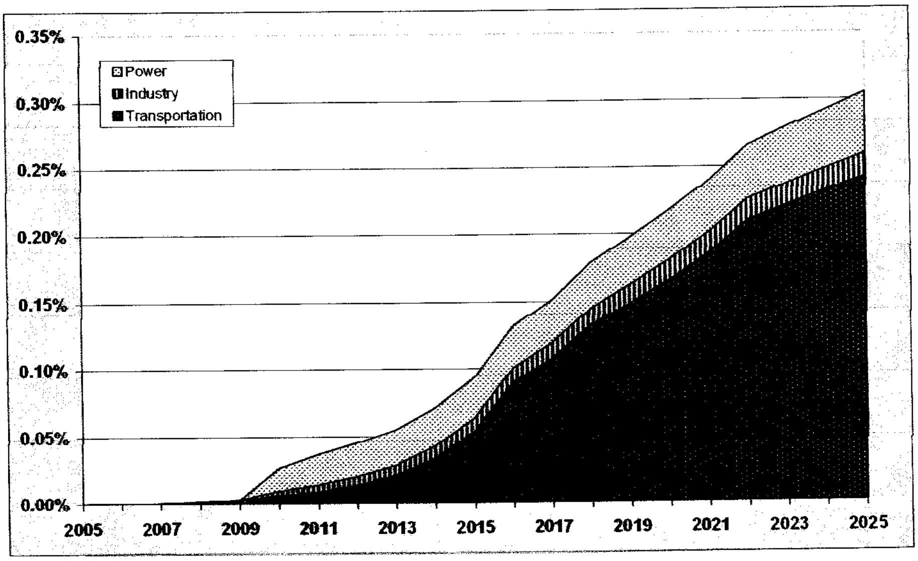


Table 17.2 and Figures 17.2 through 17.4 show estimated cumulative national GDP growths of 0.05, 0.17 and 0.31 percent by 2025 for the Low, Median and High scenarios, respectively, as a result of the projected investments required to replace OBFs by CNG/LNG in small scale power generation, industry and transportation. The corresponding GDP additions are $2, 6 and 11 billion to a $3.5 trillion economy (2006). Figures 17.2 through 17.4 highlight the increasing significance of the transportation sector as crude oil prices rise.

The inflection points on the GDP curve in 2016 and 2020-2022 reflect the confluence of assumed replacement of CNG/LNG supply to certain electric power and industrial markets by pipeline gas and the end of OBF market capture by CNG/LNG NGVs in major markets, whereupon CNG/LNG consumption only tracks sector energy market growth.

17.3.2 Impact on National Income

The impacts on national income, i.e., the salaries and wages of all households in Indonesia, of the projected OBF-to-CNG/LNG capital investments in the SMS power generation, industrial and transportation sectors are summarized in Table 17.3 and Figures 17.5 through 17.7 below.

Table 17.3 Impact of OBF-to-CNG/LNG Investment on National Income

Scenario	Sector	2010	2015	2020	2025
Low	Power	0.2%	0.4%	0.4%	0.5%
	Industry	0.3%	0.8%	1.4%	1.7%
	Transportation	0.1%	0.4%	1.0%	1.4%
	Total	0.6%	1.5%	2.8%	3.5%
Median	Power	0.6%	1.1%	1.4%	1.7%
	Industry	0.3%	0.7%	0.9%	1.0%
	Transportation	0.2%	1.7%	5.0%	7.4%
	Total	1.1%	3.5%	7.3%	10.1%
High	Power	1.1%	1.9%	2.3%	2.9%
	Industry	0.3%	0.8%	1.3%	1.4%
	Transportation	0.3%	3.1%	9.6%	14.1%
	Total	1.7%	5.8%	13.2%	18.4%

Figure 17.5 Impact of Low Scenario OBF-to-CNG/LNG Investment on National Income

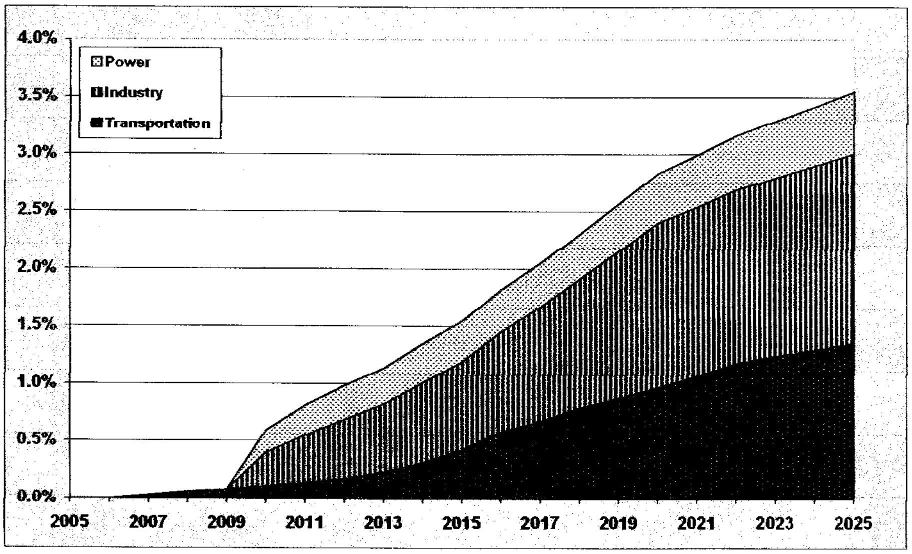


Fig. 17.6 Impact of Median Scenario OBF-to-CNG/LNG Investment on National Income

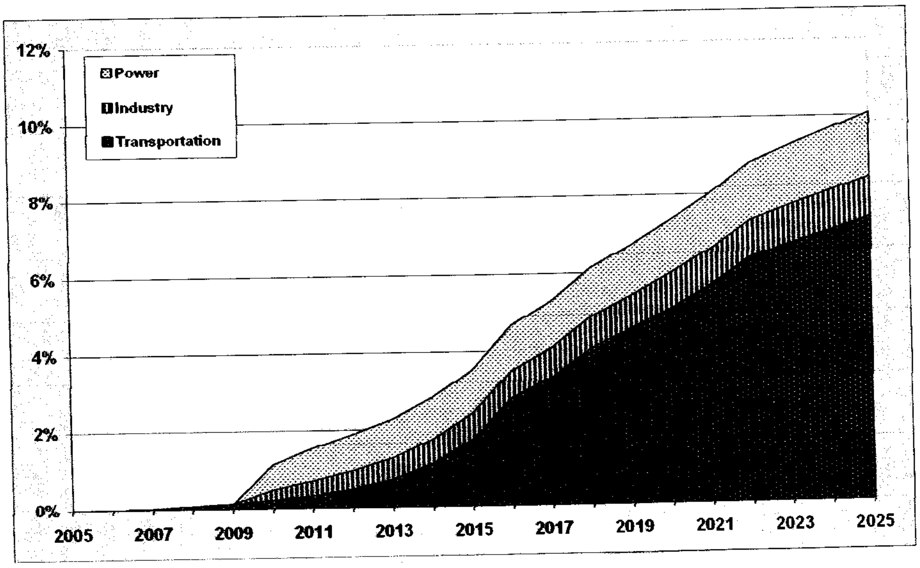


Figure 17.7 Impact of High Scenario OBF-to-CNG/LNG Investment on National Income

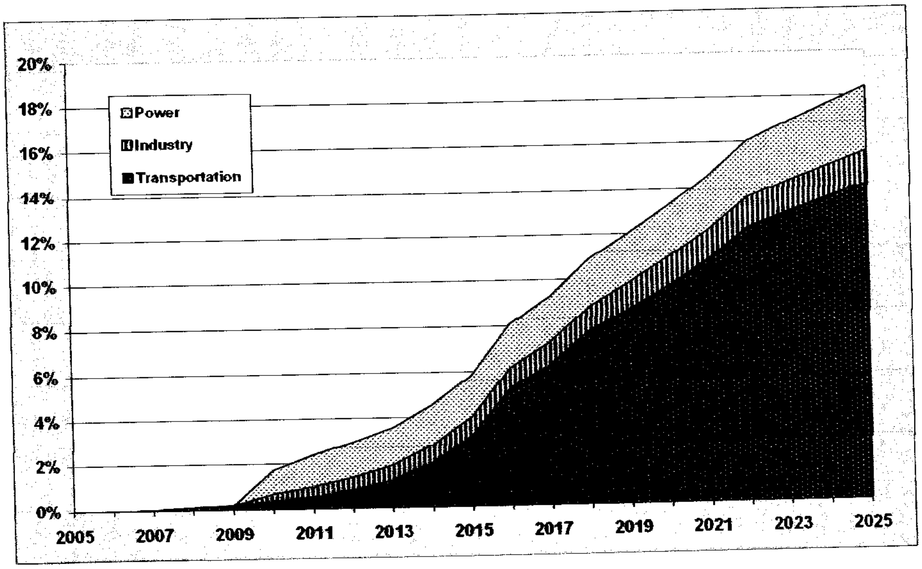


Table 17.3 and Figures 17.5 through 17.7 show estimated cumulative National Income growths of 3.5, 10.1 and 18.4 percent by 2025 for the Low, Median and High scenarios, respectively, as a result of the projected investments to replace OBFs by CNG/LNG in the small scale power generation, industrial and transportation sectors. The corresponding National Income additions are $2.3, 6.7 and 12.1 billion to a 2006 national payroll of $66 billion. Again, Figures 17.5 through 17.7 highlight the increasing significance of the transportation sector as oil prices rise.

17.3.3 Impact on National Employment

The impacts on national employment of the projected OBF-to-CNG/LNG capital investments in the SMS power generation, industrial and transportation sectors are summarized in Table 17.4 and Figures 17.8 through 17.10 below.

Table 17.4 Impact of OBF-to-CNG/LNG Investment on National Employment

Scenario	Sector	2010	2015	2020	2025
Low	Power	0.00%	0.01%	0.01%	0.01%
	Industry	0.02%	0.06%	0.11%	0.12%
	Transportation	0.02%	0.07%	0.16%	0.22%
	Total	0.04%	0.13%	0.27%	0.36%
Median	Power	0.01%	0.02%	0.03%	0.04%
	Industry	0.02%	0.05%	0.07%	0.08%
	Transportation	0.04%	0.28%	0.82%	1.19%
	Total	0.07%	0.35%	0.92%	1.31%
High	Power	0.02%	0.04%	0.05%	0.06%
	Industry	0.02%	0.06%	0.10%	0.11%
	Transportation	0.05%	0.51%	1.56%	2.28%
	Total	0.10%	0.61%	1.71%	2.45%

Fig.17.8 Impact of Low Scenario OBF-to-CNG/LNG Investment on National Employment

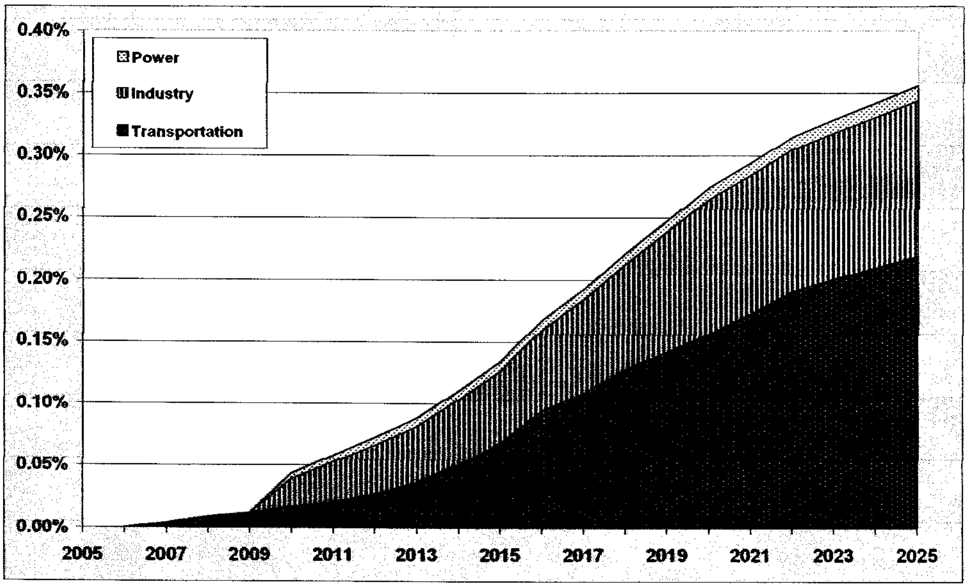


Fig. 17.9 Impact of Median Scenario OBF-to-CNG/LNG Investment on National Employment

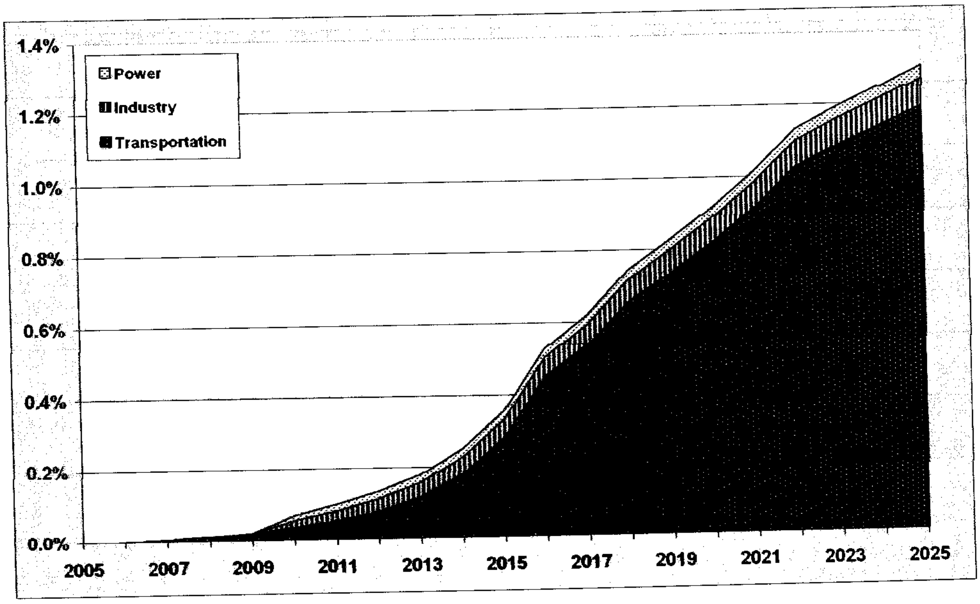


Fig. 17.10 Impact of High Scenario OBF-to-CNG/LNG Investment on National Employment

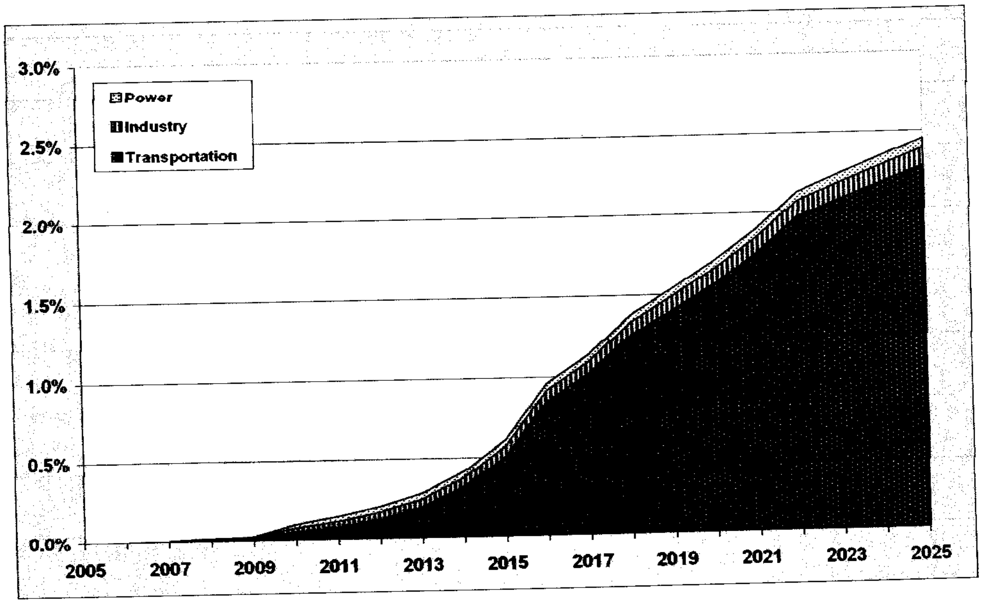


Table 17.4 and Figures 17.8 through 17.10 show estimated cumulative National Income growths of 0.36, 1.3 and 2.45 percent by 2025 for the Low, Median and High scenarios, respectively, as a result of the projected investments required to replace

OBFs by CNG/LNG in the small scale power generation, industrial and transportation sectors. The corresponding national employment additions by 2025 are 0.4, 1.2 and 2.6 million to a 2006 national workforce of 106 million. As with national GDP and Income, Figures 17.8 through 17.10 emphasize the dominance of the transportation sector as oil prices rise.

17.4 QUALITATIVE DEVELOPMENT IMPACTS

17.4.1 Infrastructure Build-out

Replacement of OBF consumption by CNG/LNG in the SMS power generation, industrial and transportation sectors in Indonesia does not in and of itself engender significant infrastructure build-out. The projected CNG/LNG-based gas consumption will stimulate gas transmission infrastructure capacity increases and additions, but given the magnitude of new CNG/LNG-based gas consumption forecasted at 0.1-0.8 bscfd by 2025 relative to current domestic gas consumption of 3+ bscfd, the impact is modest. The use of CNG/LNG-based gas in power generation, industry and transportation will, however, often be a precursor to pipeline gas delivery as consumption volumes grow in such markets to justify distribution pipeline delivery, for example in place of terrestrial CNG/LNG delivery to Bandung.

From a national economic point of view, increased use of domestically sourced fuels, such as CNG/LNG, will enhance national savings, which would likely fund additional infrastructure build-out for the benefit of society at large.

17.4.2 Market Reforms

Introduction of CNG/LNG as a credible alternative to OBFs both in terms of availability and pricing will increase fuel market competition and hasten the removal of government subsidies on automotive diesel and gasoline, which came to $9 billion in 2006. Given its beneficial effects on GHG and particulate pollutant emissions, the government may bias the market in the opposite direction by offering tax concessions to CNG/LNG users, feed gas price subsidies and/or mandate use of CNG/LNG fuel in certain vehicle types, such as taxis and bajajs, to promote CNG/LNG usage. No such measures have been promulgated yet, although the city of Jakarta has introduced CNG fuelled bus service on certain feeder routes employing currently 75 buses and having another 180 buses on order, mostly with South Korean manufacturers.

17.4.3 Human Capacity Building

Introducing CNG/LNG to consumer markets on the scale projected by this study under the Median and High scenarios will require multiplication of human technical and administrative skills. While the technical and logistics skills associated with high pressure gas manufacture and delivery are already present in Indonesia, i.e., in the compressed oxygen and nitrogen sector, the projected scales of CNG delivery under the Median and High scenarios of about 30-51 mmscfd by 2010 require a doubling of present human capacities, while projected delivery of about 400 and 700 mmscfd by 2025 suggest the need for a 30-50 fold increase in human skill capacities. Given the time frame for implementation, however, lack of relevant human skill capacity is unlikely to present a constraint on CNG usage.

LNG manufacture and storage currently takes place in Indonesia only on a large scale, i.e., at the Bontang and Arun LNG plants with capacities of 26 and 12 million tons per year. Thus, the basic technical skills exist, although they will need to proliferate and expand to also include terrestrial LNG transportation by truck-trailer and small scale transfer/storage/vaporization. However, the People's Republic of China has developed these human skill capacities over a short period of time and without an initial core of LNG-skilled personnel, as its small scale LNG usage has proliferated to more than 60 mmscfd since year 2000.

17.4.4 Technology Transfer

CNG/LNG manufacture, storage and transportation involve specialized technologies, such as gas purification, high pressure gas handling and heat transfer along with cryogenic liquids storage, piping and vaporization. As a low labor cost country with a well-developed structural steel manufacturing base, there is likely to be a strong drive to transfer those technologies to Indonesia to facilitate and expedite the projected capture of OBF markets by CNG/LNG. While such transfer was exceedingly limited in the wake of the two large-scale Indonesian LNG plants launched in the 1980's, because they were "one-of-a-kind", the small-scale CNG/LNG manufacture, storage and transportation envisioned in this study entails scaleable repeat manufacturing/construction/installation/maintenance, i.e., sustainable business development, on which a home industry can be based. That is currently happening in Thailand, whose long stagnating CNG/LNG drive took off in 2005 thanks to high OBF prices and local manufacture of major components of the supply chain and conversion kits.

17.4.5 Productivity Improvement

Lower cost CNG/LNG fuel than OBFs, generally less capital intensive equipment and facilities and lower cost maintenance will improve the productivity of investments as well as manpower. However, the productivity improvements will be of limited magnitude, initially due to the components of input in a free economy being priced at the margin of alternatives and in the longer run due to the savings on equipment and maintenance based on current technologies being in the range of 3-5% of total system costs.

17.4.6 Resource Use Efficiency

Resource use efficiency is in this study defined as the proportion of incoming resource energy delivered to the next stage of the supply chain after accounting for all "own use", losses and consumption of other energy forms in the stage. The estimated percentages in each stage of the supply chain are shown for OBF, CNG and LNG in Table 17.5 below. The OOIP/OGIP entry represents the fraction of oil or gas in place in the reservoir, which remains behind, i.e., unrecovered, at the end of field life in typical oil and gas operations. The consumer losses reflect fuel use inefficiencies in each sector.

Table 17.5 Estimated "Own Use" and Losses in each Stage of the Supply Chain

Energy Type	OOIP/ OGIP*	Production Loss	Refining/ Processing	Trans-mission	Supply Chain	Consumer		
						Power Generation	Industry	Transpor-tation
OBF	50%	1%	9%	1%	1%	60%	30%	70%
Gas, CNG	20%	2%	4%	2%	3%	69%	26%	77%
Gas, LNG	20%	2%	4%	2%	12%	69%	26%	77%

*Original Oil in Place/Original Gas In Place in the reservoir

On the basis of these individual supply/consumption stage losses, forward-looking resource use efficiencies can be calculated for each fuel end-use as a function of reference point in the supply/consumption chain. The results are shown for each consumer end-use in Tables 17.6 through 17.8.

Table 17.6 Resource Use Efficiency Tracking through the Supply/Consumption Chain, Power Generation

Energy Type	In-Place	Wellhead	Refinery/ Process Inlet	Pipeline Inlet	Storage/ Dist'n System Inlet	Power Plant Intake
OBF	18%	35%	36%	39%	40%	40%
Gas, CNG	22%	28%	28%	29%	30%	31%
Gas, LNG	20%	25%	26%	27%	27%	31%

Table 17.7 Resource Use Efficiency Tracking through the Supply/Consumption Chain, Industry

Energy Type	In-Place	Wellhead	Refinery/ Process Inlet	Pipeline Inlet	Storage/ Dist'n System Inlet	Industrial Plant Intake
OBF	31%	62%	62%	69%	69%	70%
Gas, CNG	53%	66%	67%	70%	72%	74%
Gas, LNG	48%	60%	61%	64%	65%	74%

Table 17.8 Resource Use Efficiency Tracking through the Supply/Consumption Chain, Transportation

Energy Type	In-Place	Wellhead	Refinery/ Process Inlet	Pipeline Inlet	Storage/ Dist'n System Inlet	Vehicle Fuel Tank
OBF	13%	26%	27%	29%	30%	30%
Gas, CNG	17%	21%	21%	22%	23%	23%
Gas, LNG	15%	19%	19%	20%	20%	23%

Tables 17.6 through 17.8 show CNG and LNG as more resource use efficient than OBF, when the starting point is resource in place, because a much smaller fraction of the oil in place is recovered during normal oil production operations than for natural gas.

If the basis for comparison is the "wellhead", Tables 17.6 through 17.8 show Oil/OBF to be more resource use efficient than CNG and LNG in power generation and transportation due to the lower transformation efficiency of CNG/LNG in these two sectors. However, CNG exhibits higher resource use efficiency in industry than Oil/OBF primarily due to its higher efficiency in industrial end-usages and in refining/processing. LNG has the lowest "wellhead" forward resource efficiency due to the inefficiencies of liquefaction/vaporization.

17.4.7 Demonstration Effects

Successful implementation of CNG/LNG replacement of OBFs in power generation, industry and transportation has considerable demonstration effect potential in terms of propagating the use of alternative fuels to OBFs as well as reducing atmospheric pollution. Given current high prices of OBFs and its deleterious combustion effects, a multi-pronged approach is adopted in Indonesia and other countries to introduce alternative fuels and energy sources. Aside from fundamental economics, the main barrier to success is poor commercialization, i.e., failure to create an efficient and reliable supply chain to serve a need-driven market with a high-value product of unique attributes. Its reliance on plentiful domestic gas sources and established technologies to deliver an environmentally friendly fuel to high-population density and polluted markets makes CNG/LNG-based fuel a cornerstone in the Indonesian government's "blue sky" program and an example to follow by other alternative fuels, such as biodiesel and electrification, and in city passenger transport in general. Merely observing gas-fuelled, invisible exhaust producing buses whiz by diesel fuelled buses belching out thick streams of incomplete combustion products is tell-tail enough for the public at large to demand introduction of CNG/LNG-based fuels usage.

A successful program to replace OBFs by CNG/LNG-based fuel in Indonesia would create additional support for similar programs in other Southeast Asian countries, such as Malaysia, Cambodia, Vietnam and the Philippines.

17.4.8 Spin-off Projects

The envisioned replacement of OBFs by CNG/LNG has numerous spin-off projects along its supply chain and in the consumer markets. At the outset of the supply chain, demand for CNG/LNG would stimulate development of smaller, marginal gas fields currently lying fallow because of their high cost of development for pipeline served markets. As discussed under "Technology Transfer" above, local manufacture of an increasing number of supply chain components will occur over time as Indonesian manufacturing capabilities adapt to the evolution of a sustained CNG/LNG market. Likewise, conversion kids for automobiles and, eventually, whole fuel injection systems will be manufactured locally. Also, Indonesia's size and archipelagic nature will incite development of marine transportation of CNG/LNG to remote locations currently ignored or undersupplied by OBFs, which will fuel economic development and improved living standards for currently marginalized members of Indonesian society.

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18.1 INTRODUCTION

This section reviews the projected pace of OBF replacement by CNG/LNG in small scale power generation, industry and transportation for the previously identified three crude oil and feed gas price scenarios and presents an implementation plan expressed in terms of capital spending profiles. The required capital spending to achieve the projected market captures by CNG/LNG is then recast in terms of expenditure profiles by types of facilities and equipment.

All capital investment amounts are expressed in millions of unescalated, 2006 United States Dollars.

18.2 PACE OF IMPLEMENTATION

CNG manufacture occurs in Indonesia today at 13 public NGV filling stations in Jakarta, Surabaya and Medan and at two "Transjakarta Busway" depots, while another 15 filling station are under construction. Basic small scale cryogenic gas manufacturing, storage and transportation operating skills and capabilities exist in Indonesia today applied to oxygen, nitrogen and LPG gases. However, a significant ramp up of these capabilities will be required to achieve the LNG usage projected under the Median and High scenarios.

When projecting OBF replacement by CNG/LNG in small scale power generation, industry and transportation in Section 11, the Study Team patterned commencement and pace of build-up after the Thai CNG/LNG experience and expectation tempered by Jakarta's own CNG vehicle experience in the late 1990's. Thailand commenced its CNG vehicle program in Bangkok in 1992, but real growth didn't take off until 2005, when oil prices started their meteoric rise and the economic advantage of NGVs became apparent.

To enable build-up in manufacturing and operating capabilities in support of expanded CNG/LNG usage, this study assumes that individual site CNG/LNG usage in small scale power generation and industry commences at rates of 1-2 mmscfd at the earliest in 2010 and then gradually builds up throughout the province to the estimated market share over an 8-year period. A similar approach was taken to the introduction and build-up of CNG/LNG consumption in transportation. Starting as late as 2012 with volumes as low as 0.1 MMCFD, the NGV markets in the 15 designated metropolises are assumed to grow gradually capturing the estimated ultimate market share 10 years after introduction of CNG supplies.

Implementation of the projected levels of OBF replacement by CNG/LNG requires gradual marshalling of a large, dispersed number of specialized manufacturers, equipment vendors, constructors and operators to collaborate in establishing the supply chains and undertake the necessary modifications of existing equipment or provide new gas fuelled equipment. As pointed out above, the basic elements of such specialized manufacturing and operating capabilities and skills exist in Indonesia, which, complemented by appropriate imports, can support the envisioned infrastructure build-out and consumer conversions.

18.3 IMPLEMENTATION SPENDING PLAN

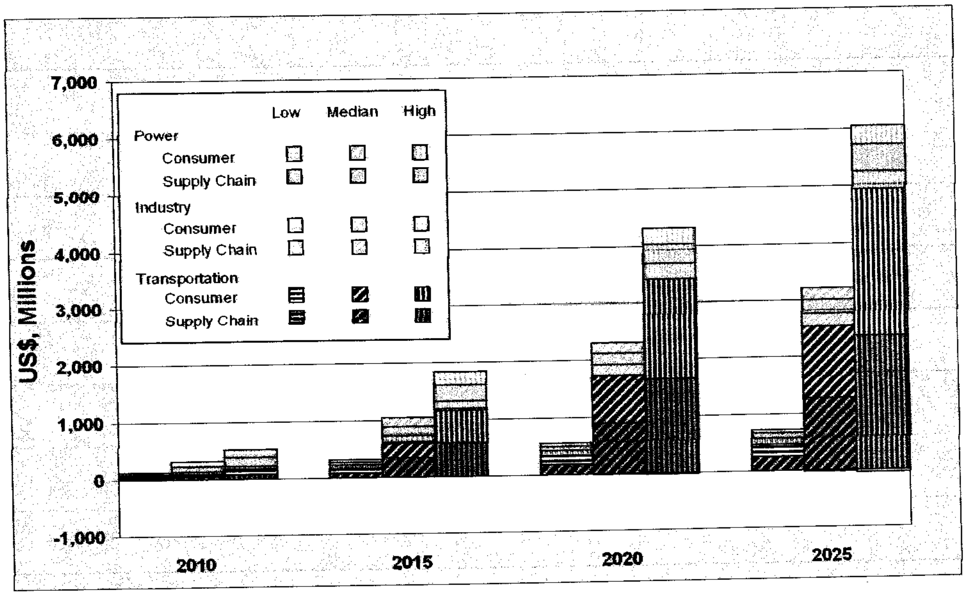
Since the project elements under the implementation plan are too numerous to enumerate, the implementation plan is expressed in terms of capital outlays over time. Section 12 presented capital spending requirements to achieve the projected levels of OBF replacement by CNG/LNG under the three alternative crude oil and feed gas price scenarios. The capital spending profiles by sector and segment under the implementation plan are reiterated in Table 18.1 and Figure 18.1 below.

Table 18.1 Implementation Plan Cumulative Capital Expenditures, $MM

Scenario	Sector	Segment	2010	2015	2020	2025
Low*	Power Generation	Consumers	28	49	54	61
		Supply Chain	26	48	65	88
	Industry	Consumers	8	15	8	2
		Supply Chain	27	65	92	119
	Transport	Consumers	15	62	149	212
		Supply Chain	21	79	176	242
	All		124	317	544	725
Median**	Power Generation	Consumers	87	154	173	199
		Supply Chain	90	155	203	266
	Industry	Consumers	11	24	-5	-18
		Supply Chain	42	109	188	223
	Transport	Consumers	36	273	841	1,253
		Supply Chain	50	332	894	1,267
	All		315	1,049	2,295	3,190
High***	Power Generation	Consumers	137	245	277	320
		Supply Chain	155	267	353	469
	Industry	Consumers	13	28	-23	-40
		Supply Chain	50	138	276	325
	Transport	Consumers	75	561	1,743	2,583
		Supply Chain	88	599	1,666	2,353
	All	Total	519	1,839	4,292	6,009

*$40/B Brent crude oil, $3/mscf feed gas
**$60/B Brent crude oil, $4/mscf feed gas
***$80/B Brent crude oil, $5/mscf feed gas

Figure 18.1 Implementation Plan Cumulative Capital Spending



Depending upon the oil and feed gas price scenario, the Implementation Plan calls for spending of $124-519 MM by 2010 growing to $0.75-6 billion by 2025.

In the Low scenario, 63% of the investments are projected to be incurred in the transportation sector with the remainder shared equally by the small scale power generation and the industrial sectors. In the High scenario, the transportation sector's share increases to 82% of total investments, while the power generation sector accounts for 13% and the industrial sector for 5%.

In the two most capital intensive sectors, the roles of consumers and supply chain are comparable, i.e., the incremental investments by consumers and supply chain entrepreneurs in the transportation and small scale power generation sectors are approximately equal, while investments in the industrial sector are entirely in the supply chain leaving consumers to actually save money relative to investments in OBF fuelled facilities.

18.4 CAPITAL EXPENDITURE CATEGORIZATION

This subsection identifies and quantities the Implementation Plan investments by equipment/facility category and time of occurrence in order to gain insight into the types of facilities, equipment and services, their dollar values and phasing required to implement the projected levels of OBF replacement by CNG/LNG in SMS power generation, industry and transportation in Indonesia.

18.4.1 Capital Expenditure Categories and Apportionment

In order to classify the Implementation Plan capital expenditures among categories of equipment and services, the components of capital outlays along the entire CNG/LNG supply and consumer chain were identified, quantified and averaged for the three levels of projected CNG/LNG replacement of OBFs. The components of expenditures were then aggregated in broad equipment categories characterized by their commonality of technology, manufacture, end-use and underlying supporting services. The derivation of the capital expenditure apportionment is presented in Appendix L along with its application to the Implementation Plan defined in Subsection 18.3 above. All capital expenditures are incurred in the supply chain to manufacture/transport/store/send-out CNG/LNG and by the consumers in switching from OBFs to CNG/LNG-fuel. As stated in Section 16, this study assumes that no capital expenditure will be incurred in the upstream (gas producing) and midstream (gas transmission) segments for the exclusive purpose of supplying feed gas for small scale CNG/LNG manufacture.

18.4.1.1 Capital Spending by Category in Power Generation

Tables 18.2 and 18.3 present the required capital spending under the Implementation Plan by small scale electric power generation sector consumers, i.e., the power station owners, and supply chain entrepreneurs, respectively, apportioned among major equipment/facility categories. Figure 18.2 presents graphically total power sector capital spending by category. The detailed calculations and supporting data are contained in Appendix L.

Table 18.2 Cum. Incr. Power Plant Capital Spending by Category, $MM

Scenario	Category	Capex Allocation	2010	2015	2020	2025
Low	Gensets	60%	17	29	33	37
	Installation	30%	8	15	16	18
	P Regs/M&M*	10%	3	5	5	6
	Total		**28**	**49**	**54**	**61**
Median	Gensets	60%	52	93	104	119
	Installation	30%	26	46	52	60
	P Regs/M&M*	10%	9	15	17	20
	Total		**87**	**154**	**173**	**199**
High	Gensets	60%	82	147	166	192
	Installation	30%	41	73	83	96
	P Regs/M&M*	10%	14	24	28	32
	Total		**137**	**245**	**277**	**320**

* Pressure Regulators, metering and monitoring systems

Table 18.2 shows investments in conversions from diesel to gas burning generator sets in existing facilities and incremental costs of gas fuelled new units accounting for more than half of the consumer investments resulting in modest outlays of $37 MM by 2025 in the Low scenario rising to a substantial $192 MM in the High scenario.

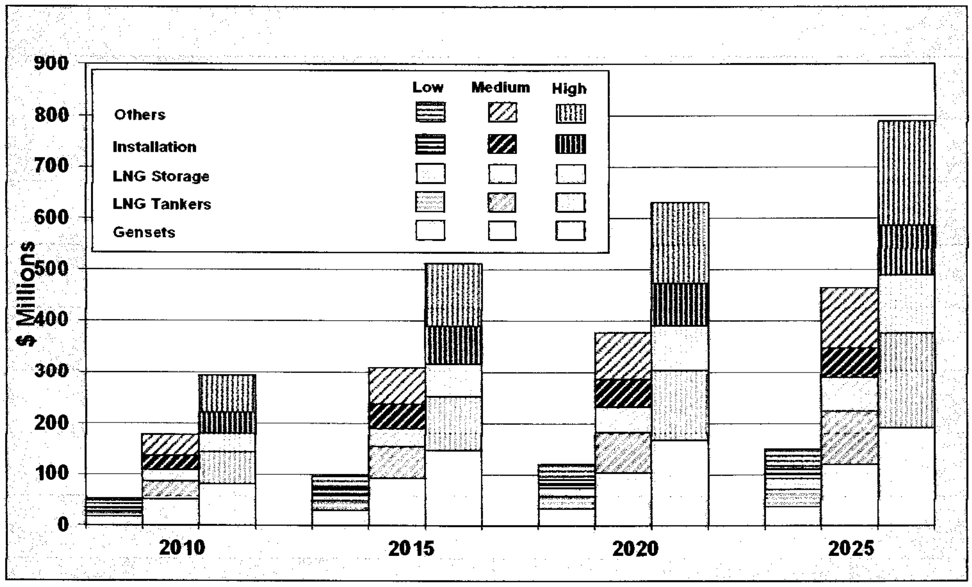
Table 18.3 Cum. CNG/LNG-in-Power Supply Chain Capital Spending by Category, $MM

Scenario	Category	2010	2015	2020	2025
Low	Prime Mover + Tanker Trailer	2	3	4	6
	LNG Tanker/Tug/Barge	10	19	25	35
	LNG Storage/Tanks	6	12	16	21
	LNG Vaporization	4	7	10	13
	Feed Gas Treatment	1	1	1	2
	Compression	2	4	6	8
	CNG Trans Mods/Manifolds/PR/M&M	1	2	3	4
	Total	**26**	**48**	**65**	**88**
Median	Prime Mover + Tanker Trailer	6	10	13	18
	LNG Tanker/Tug/Barge	35	61	80	105
	LNG Storage/Tanks	22	38	49	65
	LNG Vaporization	13	23	30	39
	Feed Gas Treatment	2	3	4	5
	Compression	8	13	17	23
	CNG Trans Mods/Manifolds/PR/M&M	4	7	10	13
	Total	**90**	**155**	**203**	**266**
High	Prime Mover + Tanker Trailer	10	18	23	31
	LNG Tanker/Tug/Barge	61	105	139	184
	LNG Storage/Tanks	38	65	86	114
	LNG Vaporization	23	39	52	69
	Feed Gas Treatment	3	5	7	9
	Compression	13	23	30	40
	CNG Trans Mods/Manifolds/PR/M&M	7	13	17	22
	Total	**155**	**267**	**353**	**469**

Table 18.3 highlights the dominance of capital expenditures on LNG-based supply chain components, such as LNG tankers, storage and vaporization facilities. Thus, expenditures on such LNG facilities are projected to reach about $69 MM by 2025 in the Low scenario increasing nearly 5-fold to $367 MM in the High scenario by the same time, while spending on Compression, the largest CNG supply chain item, is projected to reach $8 and $40 MM by 2025 in the Low and High scenarios, respectively. Recall that this study assumes no investment in "LNG plants" as part of the power sector supply chains, since all LNG supplies to the power sector are assumed to originate from existing LNG plants, i.e., Arun and Bontang. The only new LNG plants required under the Implementation Plan are small scale, i.e., 5 mmscfed LNG plants for manufacture of LNG fuel for NGV in Java.

Figure 18.2 below highlights the growth in spending on the four largest items, namely gensets, LNG tankers, LNG storage tanks and installation of generating units, which comprise about 75% of total CNG/LNG-in-power capital spending. The aggregate value of the remaining items equals that of the single largest item, gensets.

Figure 18.2 Cum. CNG/LNG-in-Power Capital Spending by Category



18.4.1.2 Capital Spending by Category in Industry

Tables 18.4 and 18.5 below present the required Implementation Plan capital spending by industrial consumers and supply chain entrepreneurs, respectively, apportioned among major equipment/facility categories. Figure 18.3 presents graphically total industrial sector capital spending by category. The detailed calculations and supporting data are contained in Appendix L.

Table 18.4 Cum. Incr. Industrial Consumer Switching Capital Spending by Category, $MM

Scenario	Category	Capex Allocation	2010	2015	2020	2025
Low	Boiler/Furnace	70%	5	10	6	2
	Heat Exchanger	20%	2	3	2	0
	P Regs/M&M*	10%	1	1	1	0
	Total	**100%**	**8**	**15**	**8**	**2**
Median	Boiler/Furnace	70%	8	17	-4	-13
	Heat Exchanger	20%	2	5	-1	-4
	P Regs/M&M*	10%	1	2	-1	-2
	Total	**100%**	**11**	**24**	**-5**	**-18**
High	Boiler/Furnace	70%	9	20	-16	-28
	Heat Exchanger	20%	3	6	-5	-8
	P Regs/M&M*	10%	1	3	-2	-4
	Total	**100%**	**13**	**28**	**-23**	**-40**

* Pressure regulators, metering and monitoring systems

Table 18.4 shows investments in "Boiler/Furnace" and "Heat Exchanger" conversions to gas and incremental costs of gas fuelled new units accounting for 90 percent of the required switching investments by industrial consumers resulting in modest incremental outlays of $2 MM by 2025 in the Low scenario reverting to a savings of $40 MM in the High scenario. Recall that the savings arise due to gas fuelled new boilers/furnaces/heat-exchangers being less costly than their IDO counterparts.

Table 18.5 Cum. CNG/LNG-in-Industry Supply Chain Capital Spending by Category, $MM

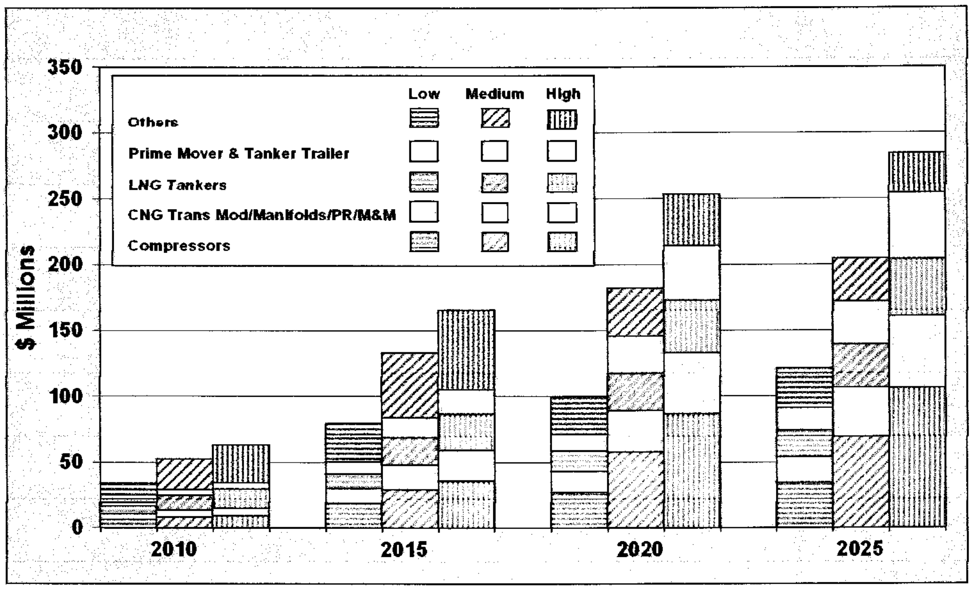
Scenario	Category	2010	2015	2020	2025
Low	Prime Mover + Tank Trailer	3	9	13	17
	LNG Tankers	6	11	15	21
	LNG Plants/Storage/Tanks	4	7	9	13
	LNG RT + Vaporization	2	4	6	8
	Feed Gas Treatment	1	4	6	8
	Compression	6	18	27	35
	CNG Trans Mods/Manifolds/PR/M&M	3	10	15	19
	Total	**27**	**65**	**92**	**119**
Median	Prime Mover + Tank Trailer	4	15	28	33
	LNG Tankers	12	22	29	33
	LNG Plants/Storage/Tanks	7	13	18	20
	LNG RT + Vaporization	4	8	11	12
	Feed Gas Treatment	2	7	13	15
	Compression	8	29	58	70
	CNG Trans Mods/Manifolds/PR/M&M	4	16	32	39
	Total	**42**	**109**	**188**	**223**
High	Prime Mover + Tank Trailer	5	18	42	50
	LNG Tankers	15	28	40	43
	LNG Plants/Storage/Tanks	9	17	25	27
	LNG RT + Vaporization	6	10	15	16
	Feed Gas Treatment	2	8	19	24
	Compression	9	36	87	106
	CNG Trans Mods/Manifolds/PR/M&M	5	20	48	59
	Total	**50**	**138**	**276**	**325**

Table 18.5 highlights the dominance of capital expenditures on CNG-based supply chain components, such as compression facilities and gas transport modules, amounting to a combined $54 MM by 2025 in the Low scenario tripling to $165 MM in the High scenario, while allocated[1] spending on LNG tankers and storage facilities, the largest LNG-based supply chain items, is projected to reach $34 MM by 2025 in the Low scenario, $70 MM in the High scenario. Recall that this study assumes no investment in "LNG plants" as part of the supply chains to industry, since all LNG supplies to the power and industrial sectors are envisioned to originate from existing LNG plants, i.e., Arun and Bontang. The only new LNG plants required under this Implementation Plan are small scale, i.e., 5 mmscfed, LNG plants for the manufacture of LNG fuel for NGV in Java.

Figure 18.3 below highlights the growth in spending on the four largest items, namely Compression, CNG Transportation Modules/Manifolds/Pressure Regulators/Metering & Monitoring Systems, LNG tankers and prime mover & tanker trailers, which comprise 60-90% of total CNG/LNG-in-industry spending.

[1] Recall that LNG supplies to industry occurs only outside Java to plants located in the vicinity of small scale power plants supplied by LNG, due to their low volumes, i.e., dis-economies of scale.

Figure 18.3 Cum. CNG/LNG-in-Industry Capital Spending by Category



18.4.1.3 Capital Spending by Category in Transportation

Tables 18.6 and 18.7 below present the required Implementation Plan capital spending by consumers to convert existing vehicles/purchase OEM NGVs (incremental to OBF vehicles) and by supply chain entrepreneurs, respectively, apportioned among major equipment/facility categories. Figure 18.4 presents graphically total transportation sector capital spending by category. The underlying detailed calculations and supporting data are contained in Appendix L.

Table 18.6 Cum. Incr. NGV/Consumer Capital Spending by Category, $MM

Scenario	Category	2010	2015	2020	2025
Low	HP Cylinder Modules	7	31	74	106
	LNG Storage/Tanks	0	0	0	0
	Vaporizer	0	0	0	0
	Compressors	0	0	0	0
	P Regs/FInj/M&M Sys*	7	31	74	106
	Total	**15**	**62**	**149**	**212**
Median	HP Cylinder Modules	15	131	411	615
	LNG Storage/Tanks	2	5	8	9
	Vaporizer	1	2	3	3
	Compressors	0	1	1	1
	P Regs/FInj/M&M Sys*	17	135	419	624
	Total	**36**	**273**	**841**	**1,253**
High	HP Cylinder Modules	27	257	833	1,245
	LNG Storage/Tanks	9	19	31	37
	Vaporizer	3	7	11	14
	Compressors	1	2	4	5
	P Regs/FInj/M&M Sys*	36	276	864	1,282
	Total	**75**	**561**	**1,743**	**2,583**

* Pressure Regulators, Fuel Injection, Metering and Monitoring systems

Table 18.6 highlights the absence, i.e., lack of economic viability, of LNG vehicles in the Low scenario, but emergence of modest LNG vehicle populations in the Median and High scenarios. Table 18.6 shows "High Pressure Cylinder Modules" and "Pressure-Regulators/Fuel-Injection/Monitoring/Metering Systems" accounting for equal parts of the investments by NGV owners of $212 MM by 2025 in the Low scenario growing dramatically to $2.5 billion in the High scenario.

Table 18.7 Cum. CNG/LNG-in-Transportation Supply Chain Capital Spending by Category, $MM

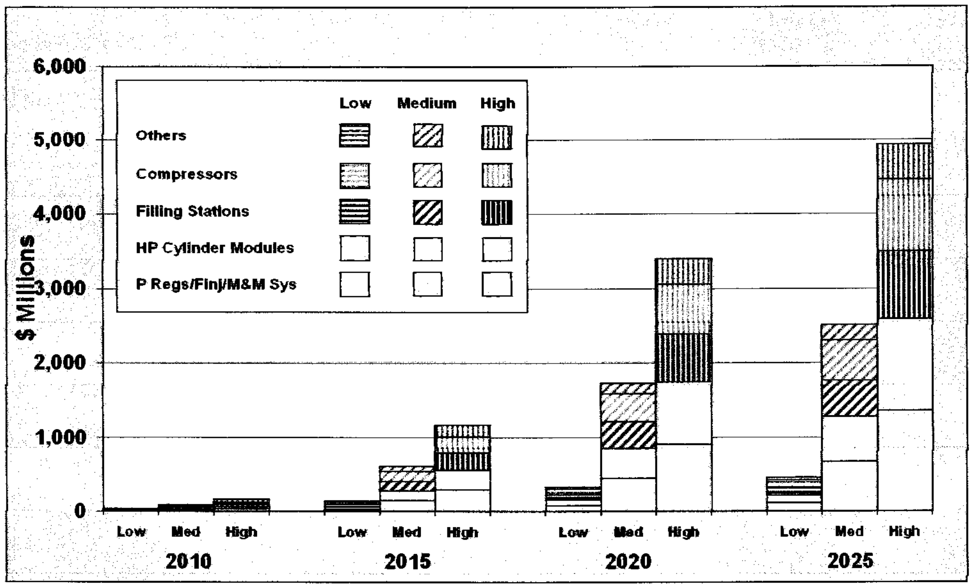
Scenario	Category	2010	2015	2020	2025
Low	LNG Plant	0	0	0	0
	Prime Mover + Trailer	0	0	0	0
	LNG Storage/Tanks	0	0	0	0
	LNG RT + Vaporization	0	0	0	0
	Gas Main/ROW	1	5	11	15
	P Regs/FInj/M&M Sys*	1	2	5	7
	Feed Gas Treatment	2	7	16	22
	Compression	9	34	75	104
	Filling Stations	8	31	68	94
	Total	**21**	**79**	**176**	**242**
Median	LNG Plant	4	8	13	15
	Prime Mover + Trailer	0	1	1	1
	LNG Storage/Tanks	1	1	2	3
	LNG RT + Vaporization	0	0	1	1
	Gas Main/ROW	3	19	53	76
	P Regs/FInj/M&M Sys*	1	10	27	38
	Feed Gas Treatment	4	29	80	113
	Compression	18	136	372	529
	Filling Stations	19	128	346	490
	Total	**50**	**332**	**894**	**1,267**
High	LNG Plant	16	31	51	62
	Prime Mover + Trailer	1	3	5	6
	LNG Storage/Tanks	3	5	9	11
	LNG RT + Vaporization	1	1	2	3
	Gas Main/ROW	4	33	96	136
	P Regs/FInj/M&M Sys*	2	16	48	68
	Feed Gas Treatment	5	49	144	205
	Compression	25	230	670	955
	Filling Stations	33	229	642	907
	Total	**88**	**599**	**1,666**	**2,353**

* Pressure Regulators, Fuel Injection, Metering and Monitoring Systems

Table 18.7 shows plan expenditures on CNG "Compression" and "Filling Stations", the two largest items, of $198 MM by 2025 in the Low scenario increasing to nearly $2 billion in the High scenario, while spending on LNG related items, including filling stations, is projected to reach upward of $100 MM by 2025 in the High scenario.

Figure 18.4 below highlights the growth in spending on the four largest items, namely Pressure Regulators/Fuel Injection/Metering & Monitoring Systems, High Pressure Cylinder Modules, Filling Stations and Compressors, which comprise 90%+ of total CNG/LNG-in-transportation capital spending.

Figure 18.4 Cum. CNG/LNG-in-Transportation Capital Spending by Category



18.4.1.4 Consumer Capital Spending by Category

Total consumer investments by equipment/facility category in all three sectors under the Implementation Plan are presented in Table 18.8 as the sum of the individual sector outlays listed above. The underlying calculations and supporting data are contained in Appendix L.

Table 18.8 shows consumer spending of $275 MM by 2025 under the Low scenario on "PR/M&M", "CNG Cylinder Modules" and "Gensets" in order of declining value increasing to nearly $2.9 billion under the High scenario, of which more than $2.6 billion is expended on "PR/M&M" and "CNG Cylinder Modules" in CNG vehicles and $288 MM on "Gensets" and "Genset Installation" in small scale electric power generation.

Table 18.8 Cum. Incr. Consumer Switching Capital Spending by Category, $MM

Scenario	Category	2010	2015	2020	2025
Low	Gensets	17	29	33	37
	Genset Accs & Instal'ns	8	15	16	18
	PR/M&M*	11	37	80	112
	Boilers/Furnaces	5	10	6	2
	Heat Exchangers	2	3	2	0
	CNG Cyl Modules	7	31	74	106
	LNG Storage/Tanks	0	0	0	0
	Vaporizers/Comp.	0	0	0	0
	Total	**50**	**126**	**211**	**275**
Median	Gensets	52	93	104	119
	Genset Accs & Instal'ns	26	46	52	60
	PR/M&M*	27	153	436	642
	Boilers/Furnaces	8	17	-4	-13
	Heat Exchangers	2	5	-1	-4
	CNG Cyl Modules	15	131	411	615
	LNG Storage/Tanks	2	5	8	9
	Vaporizers/Comp.	1	2	4	5
	Total	**134**	**452**	**1,010**	**1,434**
High	Gensets	82	147	166	192
	Genset Accs & Instal'ns	41	73	83	96
	PR/M&M*	51	303	889	1,310
	Boilers/Furnaces	9	20	-16	-28
	Heat Exchangers	3	6	-5	-8
	CNG Cyl Modules	27	257	833	1,245
	LNG Storage/Tanks	9	19	31	37
	Vaporizers/Comp.	4	9	15	19
	Total	**225**	**835**	**1,997**	**2,863**

*Pressure Regulator, Monitoring and Metering Systems

18.4.1.5 Supply Chain Capital Spending by Category

Total supply chain investments by equipment/facility category in all three sectors under the Implementation Plan are presented in Table 18.9 as the sum of the individual sector supply chain outlays listed above. The underlying calculations and supporting data are contained in Appendix L.

Table 18.9 shows cumulative supply chain capital spending of $450 MM by 2025 under the Low scenario on "Compressors", "Filling Stations", "LNG Tankers" and "LNG Storage/Tanks" in order of declining value. In the High scenario, the total supply chain investment amounts to nearly $3.1 billion by 2025, of which more than $2.2 billion is projected spent on "Compressors", "Filling Stations" and "Feed Gas Treatment" in order of declining value. In both the Low and the High scenario, LNG supply chain investments by 2025 constitute less than 15% of total supply chain outlays underscoring the lesser competitiveness of LNG than CNG in replacement of OBFs in the transportation sector.

Table 18.9 Cum. Incr. Supply Chain Capital Spending by Category, $MM

Scenario	Category	2010	2015	2020	2025
Low	Prime Movers + Trailers	5	12	18	23
	LNG Tankers	17	30	41	55
	LNG Storage/Tanks	10	19	25	34
	RT & Vaporizers	6	11	15	21
	Feed Gas Treatment	4	12	23	32
	Compressors	17	56	108	146
	CNG TM/Manifolds/Regs	5	15	24	31
	LNG Plants	0	0	0	0
	Gas Mains/ROWs	1	5	11	15
	Filling Stations	8	31	68	94
	Total	**73**	**192**	**333**	**450**
Median	Prime Movers + Trailers	11	25	42	52
	LNG Tankers	47	82	109	138
	LNG Storage/Tanks	30	52	69	88
	RT & Vaporizers	18	31	41	52
	Feed Gas Treatment	7	39	96	134
	Compressors	34	178	447	622
	CNG TM/Manifolds/Regs	10	33	68	89
	LNG Plants	4	8	13	15
	Gas Mains/ROWs	3	19	53	76
	Filling Stations	19	128	346	490
	Total	**181**	**597**	**1,285**	**1,756**
High	Prime Movers + Trailers	17	39	70	87
	LNG Tankers	76	132	179	227
	LNG Storage/Tanks	50	87	120	151
	RT & Vaporizers	29	51	69	88
	Feed Gas Treatment	10	62	170	237
	Compressors	47	289	788	1,101
	CNG TM/Manifolds/Regs	14	49	113	149
	LNG Plants	16	31	51	62
	Gas Mains/ROWs	4	33	96	136
	Filling Stations	33	229	642	907
	Total	**294**	**1,004**	**2,296**	**3,147**

18.4.1.6 Total Capital Spending by Category

Total investments by equipment/facility category in all three sectors under the Implementation Plan are presented in Table 18.10 below as the sum of the consumer and supply chain investments presented in the previous two subsections. Figure 18.5 presents graphically total capital spending by category. The underlying calculations and supporting data are contained in Appendix L.

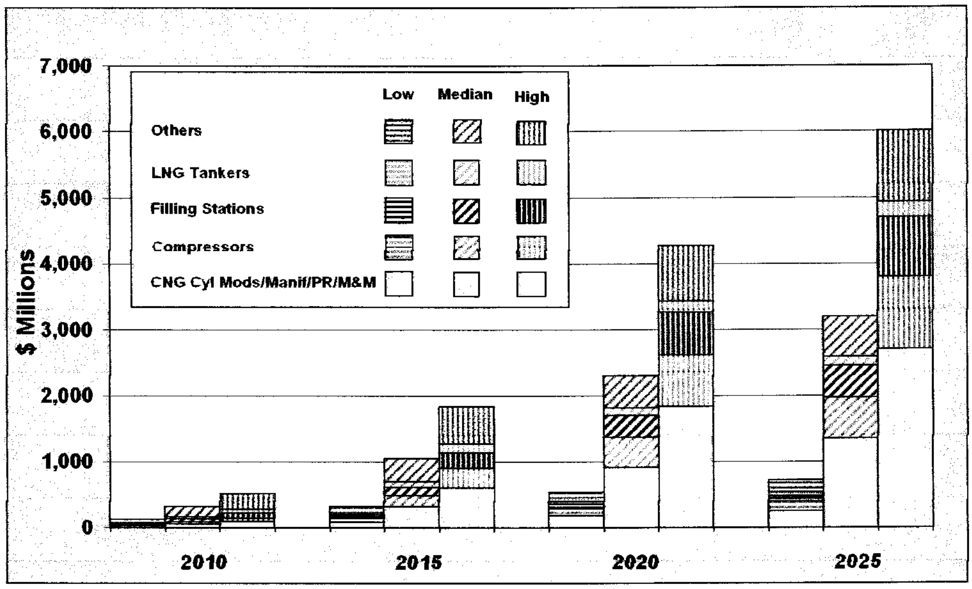
Table 18.10 shows total capital spending of $725 MM by 2025 under the Low scenario, primarily on "CNG Cylinder Modules/Manifolds/Regulators/Monitoring and Metering Systems", "Compressors", "Filling Stations" and "LNG Tankers" in order of declining value. In the High scenario, the total investment amounts to $6 billion by 2025, of which 45% is projected spent on "CNG Cylinder Modules/Manifolds/Regulators/Monitoring and Metering Systems", 18% on "Compressors" and 15% on "Filling Stations". Of the $6 billion total investment by consumers and supply chain entrepreneurs, almost 85% is projected spent on CNG systems reflecting its superior competitiveness to LNG in replacing OBFs.

Table 18.10 Cum. Incr. Capital Spending by Equipment/Facility Category, $MM

Scenario	Segment	Sector	Category	2010	2015	2020	2025
Low	Consumer	Power Gen	Gensets	17	29	33	37
			Genset Acc & Inst'n	8	15	16	18
		Industry	Boilers/Furnaces/Heat Exchangers	7	13	7	2
	Consumer/ Supply Chain	All	CNG Cyl Mods/Manif/PR/M&M	24	83	178	249
			LNG Storage/Tanks	10	19	25	34
			LNG Vaporizers	6	11	15	21
	Supply Chain		Prime Movers + Trailers	5	12	18	23
		Power/Industry	LNG Tankers	17	30	41	55
		All	Feed Gas Treatment	4	12	23	32
			Compressors	17	56	108	146
		Transport	LNG Plants	0	0	0	0
			Gas Mains/ROWs	1	5	11	15
			Filling Stations	8	31	68	94
			Total	**124**	**317**	**544**	**725**
Median	Consumer	Power Gen	Gensets	52	93	104	119
			Genset Acc & Inst'n	26	46	52	60
		Industry	Boilers/Furnaces/Heat Exchangers	10	22	-5	-16
	Consumer/ Supply Chain	All	CNG Cyl Mods/Manif/PR/M&M	52	318	915	1,346
			LNG Storage/Tanks	32	57	77	97
			LNG Vaporizers	19	34	45	57
	Supply Chain		Prime Movers + Trailers	11	25	42	52
		Power/Industry	LNG Tankers	47	82	109	138
		All	Feed Gas Treatment	7	39	96	134
			Compressors	34	178	447	622
		Transport	LNG Plants	4	8	13	15
			Gas Mains/ROWs	3	19	53	76
			Filling Stations	19	128	346	490
			Total	**315**	**1,049**	**2,295**	**3,190**
High	Consumer	Power Gen	Gensets	82	147	166	192
			Genset Acc & Inst'n	41	73	83	96
		Industry	Boilers/Furnaces/Heat Exchangers	11	26	-21	-36
	Consumer/ Supply Chain	All	CNG Cyl Mods/Manif/PR/M&M	92	610	1,835	2,705
			LNG Storage/Tanks	58	106	150	189
			LNG Vaporizers	33	60	85	106
	Supply Chain		Prime Movers + Trailers	17	39	70	87
		Power/Industry	LNG Tankers	76	132	179	227
		All	Feed Gas Treatment	10	62	170	237
			Compressors	47	289	788	1,101
		Transport	LNG Plants	16	31	51	62
			Gas Mains/ROWs	4	33	96	136
			Filling Stations	33	229	642	907
			Total	**519**	**1,839**	**4,292**	**6,009**

Figure 18.5 below highlights the growth in spending on the four largest items, namely "CNG Cylinder Modules/Pressure Regulators/Fuel Injection/Metering & Monitoring Systems", "Compressors", "Filling Stations" and "LNG Tankers", which by 2025 constitute 75-80% of total capital spending required to achieve the projected levels of OBF replacement by CNG/LNG in small scale electric power generation, industry and transportation.

Figure 18.5 Cum. Incr. Capital Spending by Equipment/Facility Category



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19.1 INTRODUCTION

This section characterizes the investments required by consumers and suppliers to enable the projected levels of OBF replacement by CNG/LNG in small scale power generation, industry and transportation and identifies potential funding options.

19.2 INVESTMENT REQUIREMENTS AND FUNDING SOURCES

19.2.1 Investment Requirements

The cumulative incremental investments required over time to achieve the replacements of OBFs by CNG/LNG projected in Section 11 were determined in Section 12 and are repeated in Table 19.1 below.

Table 19.1 Cum. Incr. CNG/LNG Switching Capital Needs, Indonesia, $MM

Scenario	Sector	Segment	2010	2015	2020	2025
Low	Power Generation	Consumers	28	49	54	61
		Supply Chain	26	48	65	88
	Industry	Consumers	8	15	8	2
		Supply Chain	27	65	92	119
	Transport	Consumers	15	62	149	212
		Supply Chain	21	79	176	242
	All		124	317	544	725
Median	Power Generation	Consumers	87	154	173	199
		Supply Chain	90	155	203	266
	Industry	Consumers	11	24	-5	-18
		Supply Chain	42	109	188	223
	Transport	Consumers	36	273	841	1,253
		Supply Chain	50	332	894	1,267
	All		315	1,049	2,295	3,190
High	Power Generation	Consumers	137	245	277	320
		Supply Chain	155	267	353	469
	Industry	Consumers	13	28	-23	-40
		Supply Chain	50	138	276	325
	Transport	Consumers	75	561	1,743	2,583
		Supply Chain	88	599	1,666	2,353
	All	Total	519	1,839	4,292	6,009

The switching investments by both consumers and suppliers are dominated by the transportation sector accounting for about 80% of total investments.

19.2.2 Consumer Investments and Funding Sources

The incremental investments by consumers, such as PLN in the small scale power generation sector, small manufacturing corporations and private firms in the industrial sector and vehicle owners in the transportation sector, to enable CNG and LNG usage in place of OBFs result from a large number of small, independent, economically grounded investment decisions by individuals and enterprises with the amounts by and large constituting a small fraction of their on-going operating budgets. CNG/LNG conversion/new unit purchases by many disparate consumer entities do not lend themselves to project packaging and financing in the capital markets. While PLN and major industrial plants may access capital markets specifically to secure funding of CNG/LNG conversion projects, it is likely to be a small part of their overall capital market funding needs. Another source of funding could be Carbon Trading funds, as was discussed in Section 15, which in individual cases could contribute as much as 20% of the required capital investment.

To the extent that project, rather than corporate balance sheet based, funding is obtainable for CNG/LNG conversions or new unit purchases, the analyses in this study suggest loan repayment to be backed by robust economics reflecting fast project payouts. Only a few consumer situations lend themselves to project financing, such as CNG bus fleet acquisition, where capital markets and export/vendor financing may constitute viable funding options. However, in general corporate asset-backed loans are likely to prevail as conversions and new CNG/LNG fueled units are just another component of ongoing consumer capital investment programs.

19.2.3 Supply Chain Investments and Funding Sources

While the total investments required are massive in the Median and High scenarios, the magnitude and nature of investments in individual CNG/LNG supply chain project investments are modest as illustrated in the tables below for both marine and terrestrial CNG/LNG supply chains representative of the underlying sector analyses presented in Section 11.

Table 19.2 Typical Marine LNG-in-Power Supply Chain Investments, $MM

Volume	Distance*	Capex, $MM			
mmscfd	km	LNG Plant & Storage**	Transport	Refueling Station	Total
3.5	720	-	7	5	12
8	1,020	-	14	11	24
20	1,680	-	31	29	59

*One way ** LNG supply from existing LNG plants

Table 19.3 Typical Terrestrial LNG-in-Power Supply Chain Investments, $MM

Volume	Distance*	Capex, $MM			
mmscfd	km	LNG Plant & Storage**	Transport	Receiving Terminal	Total
2	300	-	0.9	1.2	2.2
5		-	2.2	2.4	4.6

*One way ** LNG supply from existing LNG plants

Table 19.4 Typical Terrestrial CNG-in-Power Supply Chain Investments, $MM

Volume	Distance*	Capex, $MM			
mmscfd	km	Compression & Storage	Transport	Receiving Terminal	Total
1	150	3.6	0.8	1.1	5.5
2		6.2	1.3	1.3	8.8
3		8.7	2.1	1.5	12.3

*One way

Table 19.5 Typical Terrestrial CNG-in-Transportation Supply Chain Investment, $MM

Volume	Capex, $MM			
mmscfd	Compression	Storage	Refueling Station	Total
1	3.0	0.9	0.4	4.3

Table 19.6 Typical Terrestrial LNG-in-Transportation Supply Chain Investments, $MM

Volume	Distance*	Capex, $MM			
mmscfd	km	LNG Plant & Storage**	Transport	Refueling Station	Total
1	250	4.6	0.6	0.7	6.0
2		9.1	0.9	1.2	11.2

*One way ** 5 mmscfd liquefaction plant shared by several refueling stations

As for consumer investments, individual supply chain investments are a modest fraction of on-going operating capital budgets for the type of companies interested in the CNG/LNG supply chain business and will be financed by corporate funds (loans and retained earnings).

The interchangeability and transient nature of most of these facilities as lower cost gas pipeline service over time replaces CNG/LNG delivery make project packaging and project financing difficult.

Only marine transportation, i.e., LNG service, since CNG vessels are still in the conceptual stage and at least 3-4 years away from realization, offers the scope of segregation into special purpose vehicles with multiple funding options. A wide range of financing possibilities on favorable terms is typically available for ship construction, including lease-back options.

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20.1 INTRODUCTION

This section reiterates the Implementation Plan capital investment profiles by expenditure category, identifies the extent to which U.S. companies have historically been competitive in delivering goods and services in each category, determines the magnitude and timing of such "U.S. export targets" and presents a list of U.S. vendors/suppliers by category of product/service supply and their export targets in respect of this project.

20.2 MAGNITUDE AND PHASING OF INVESTMENTS BY CATEGORY

Table 20.1 presents the Implementation Plan investment profiles by equipment category to achieve the levels of OBF replacement by CNG/LNG in small scale power generation, industry and transportation projected in Section 11 for the three alternative crude oil and feed gas price scenarios.

Table 20.1 Implementation Plan Capital Expenditures by Equipment Category, $MM

Sector	Category	2010	2015	2020	2025
Power Gen	Gensets	17	29	33	37
	Genset Acc & Inst'n	8	15	16	18
Industry	Boilers/Furnaces/Heat Exchangers	7	13	7	2
All	CNG Cyl Mods/Manif/PR/M&M	24	83	178	249
	LNG Storage/Tanks	10	19	25	34
	LNG Rec. Terminal & Vaporizers	6	11	15	21
	Prime Movers + Trailers	5	12	18	23
Power/Industry	LNG Tankers	17	30	41	55
All	Feed Gas Treatment	4	12	23	32
	Compressors	17	56	108	146
Transport	LNG Plants	0	0	0	0
	Gas Mains/ROWs	1	5	11	15
	Filling Stations	8	31	68	94
	Total	**124**	**317**	**544**	**725**
Power Gen	Gensets	52	93	104	119
	Genset Acc & Inst'n	26	46	52	60
Industry	Boilers/Furnaces/Heat Exchangers	10	22	-5	-16
All	CNG Cyl Mods/Manif/PR/M&M	52	318	915	1,346
	LNG Storage/Tanks	32	57	77	97
	LNG Rec. Terminal & Vaporizers	19	34	45	57
	Prime Movers + Trailers	11	25	42	52
Power/Industry	LNG Tankers	47	82	109	138
All	Feed Gas Treatment	7	39	96	134
	Compressors	34	178	447	622
Transport	LNG Plants	4	8	13	15
	Gas Mains/ROWs	3	19	53	76
	Filling Stations	19	128	346	490
	Total	**315**	**1,049**	**2,295**	**3,190**
Power Gen	Gensets	82	147	166	192
	Genset Acc & Inst'n	41	73	83	96
Industry	Boilers/Furnaces/Heat Exchangers	11	26	-21	-36
All	CNG Cyl Mods/Manif/PR/M&M	92	610	1,835	2,705
	LNG Storage/Tanks	58	106	150	189
	LNG Rec. Terminal & Vaporizers	33	60	85	106
	Prime Movers + Trailers	17	39	70	87
Power/Industry	LNG Tankers	76	132	179	227
All	Feed Gas Treatment	10	62	170	237
	Compressors	47	289	788	1,101
Transport	LNG Plants	16	31	51	62
	Gas Mains/ROWs	4	33	96	136
	Filling Stations	33	229	642	907
	Total	**519**	**1,839**	**4,292**	**6,009**

20.1 INTRODUCTION

This section reiterates the Implementation Plan capital investment profiles by expenditure category, identifies the extent to which U.S. companies have historically been competitive in delivering goods and services in each category, determines the magnitude and timing of such "U.S. export targets" and presents a list of U.S. vendors/suppliers by category of product/service supply and their export targets in respect of this project.

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All	CNG Cyl Mods/Manif/PR/M&M	24	83	178	249
	LNG Storage/Tanks	10	19	25	34
	LNG Rec. Terminal & Vaporizers	6	11	15	21
	Prime Movers + Trailers	5	12	18	23
Power/Industry	LNG Tankers	17	30	41	55
All	Feed Gas Treatment	4	12	23	32
	Compressors	17	56	108	146
Transport	LNG Plants	0	0	0	0
	Gas Mains/ROWs	1	5	11	15
	Filling Stations	8	31	68	94
	Total	**124**	**317**	**544**	**725**
Power Gen	Gensets	52	93	104	119
	Genset Acc & Inst'n	26	46	52	60
Industry	Boilers/Furnaces/Heat Exchangers	10	22	-5	-16
All	CNG Cyl Mods/Manif/PR/M&M	52	318	915	1,346
	LNG Storage/Tanks	32	57	77	97
	LNG Rec. Terminal & Vaporizers	19	34	45	57
	Prime Movers + Trailers	11	25	42	52
Power/Industry	LNG Tankers	47	82	109	138
All	Feed Gas Treatment	7	39	96	134
	Compressors	34	178	447	622
Transport	LNG Plants	4	8	13	15
	Gas Mains/ROWs	3	19	53	76
	Filling Stations	19	128	346	490
	Total	**315**	**1,049**	**2,295**	**3,190**
Power Gen	Gensets	82	147	166	192
	Genset Acc & Inst'n	41	73	83	96
Industry	Boilers/Furnaces/Heat Exchangers	11	26	-21	-36
All	CNG Cyl Mods/Manif/PR/M&M	92	610	1,835	2,705
	LNG Storage/Tanks	58	106	150	189
	LNG Rec. Terminal & Vaporizers	33	60	85	106
	Prime Movers + Trailers	17	39	70	87
Power/Industry	LNG Tankers	76	132	179	227
All	Feed Gas Treatment	10	62	170	237
	Compressors	47	289	788	1,101
Transport	LNG Plants	16	31	51	62
	Gas Mains/ROWs	4	33	96	136
	Filling Stations	33	229	642	907
	Total	**519**	**1,839**	**4,292**	**6,009**

20.3 U.S. EXPORT TARGETS

A large number of U.S. companies are active in the supply of CNG/LNG delivery and consumer systems, i.e., in engineering, procurement, construction and commissioning of individual components of the CNG/LNG production, storage and transportation supply chain or complete turn-key packages as well as manufacture and assembly of consumer conversions kits and new CNG/LNG fuelled equipment. Based on historical competitiveness in overseas markets, the U.S. export potential in each of the equipment/service categories comprising the Implementation Plan has been gauged and the resultant U.S. export targets determined. The numerical results are presented in Tables 20.2 through 20.4, while Figure 20.1 highlights the dominant equipment/service categories of the U.S. export potential.

Table 20.2 U.S. Export Potential, Low Scenario

Segment	Item	U.S. Export Potential, Pct of Requirement	Cum. U.S. Export Targets, $MM			
			2010	2015	2020	2025
Upstream Opex	Well Workovers	100%	0	3	7	13
	Processing Equipment, Maintenance/Repairs	90%	0	4	10	17
	Engineering Services	5%	0	0	0	0
	Subtotal		**1**	**7**	**17**	**30**
Midstream Opex	Compressor Maintenance/Repairs	50%	0	1	1	2
	Subtotal		**0**	**1**	**1**	**2**
Supply Chain + Consumer Capex	Gensets	100%	17	29	33	37
	Genset Accessories & Installation	0%	0	0	0	0
	Boilers/Furnaces/Heat Exchangers	60%	4	8	4	1
	CNG Cylinders Mods/Manif/PR/M&M	65%	15	54	116	162
	LNG Storage/Tanks	75%	8	14	19	26
	LNG Rec. Terminal & Vaporizers	100%	6	11	15	21
	Prime Movers + Trailers	0%	0	0	0	0
	LNG Tankers	0%	0	0	0	0
	Feed Gas Treatment	100%	4	12	23	32
	Compressors	100%	17	56	108	146
	LNG Plants	100%	0	0	0	0
	Gas Mains/ROWs	0%	0	0	0	0
	Filling Stations	20%	2	6	14	19
	Subtotal		**73**	**192**	**332**	**442**
Grand Total			**74**	**199**	**351**	**475**

The U.S. export potential identified in Tables 20.2 through 20.4 is potentially very large reflecting long standing U.S. technological and commercial leadership in cryogenic and compressed gas usage and aided currently by the devaluation of the U.S. Dollar vis-à-vis most major currencies. The estimated U.S. export potential ranges from $74-308 MM by 2010 growing to $0.5-4 billion by 2025, equivalent to approximately 65% of total project value.

The U.S. export targets highlighted in Figure 20.1 mirror the allocation of projected OBF-to-CNG/LNG capital spending among the different types of supporting equipment/services identified in the Implementation Plan, except that "Feed Gas Treatment" and "Gensets" have replaced "Filling Stations" and "LNG Tankers" as major items, since U.S. companies are largely non-competitive in the latter two categories. The four major export targets, CNG Cylinder Modules and Accessories, Compressors, CNG/LNG Feed Gas Treatment facilities and Gensets, comprise about 80% of the estimated total U.S. export potential, with CNG Cylinder Modules accounting for nearly half by year 2020.

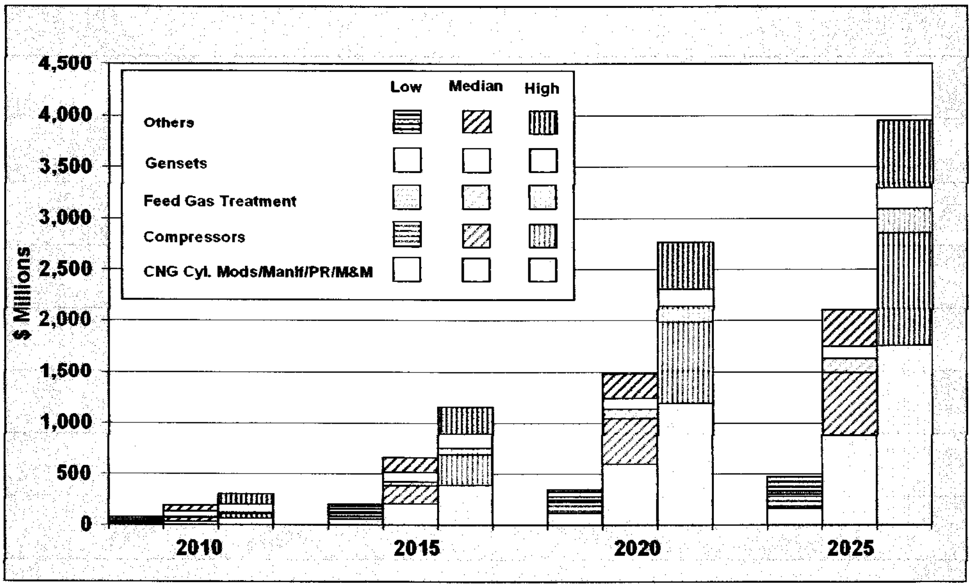
Table 20.3 U.S. Export Potential, Median Scenario

Segment	Item	U.S. Export Potential, Pct of Requirement	Cum. U.S. Export Targets, $MM			
			2010	2015	2020	2025
Upstream Opex	Well Workovers	100%	1	8	23	45
	Processing Equipment, Maintenance/Repairs	90%	1	10	31	61
	Engineering Services	5%	0	0	1	1
	Subtotal		**2**	**18**	**54**	**107**
Midstream Opex	Compressor Maintenance/Repairs	50%	0	1	4	8
	Subtotal		**0**	**1**	**4**	**8**
Supply Chain + Consumer Capex	Gensets	100%	52	93	104	119
	Genset Accessories & Installation	0%	0	0	0	0
	Boilers/Furnaces/Heat Exchangers	60%	6	13	-3	-10
	CNG Cylinders Mods/Manif/PR/M&M	65%	34	206	595	875
	LNG Storage/Tanks	75%	24	43	58	73
	LNGRec. Terminal & Vaporizers	100%	19	34	45	57
	Prime Movers + Trailers	0%	0	0	0	0
	LNG Tankers	0%	0	0	0	0
	Feed Gas Treatment	100%	7	39	96	134
	Compressors	100%	34	178	447	622
	LNG Plants	100%	4	8	13	15
	Gas Mains/ROWs	0%	0	0	0	0
	Filling Stations	20%	4	26	69	98
	Subtotal		**183**	**638**	**1,424**	**1,983**
Grand Total			**185**	**658**	**1,483**	**2,098**

Table 20.4 U.S. Export Potential, High Scenario

Segment	Item	U.S. Export Potential, Pct of Requirement	Cum. U.S. Export Targets, $MM			
			2010	2015	2020	2025
Upstream Opex	Well Workovers	100%	1	12	37	75
	Processing Equipment, Maintenance/Repairs	90%	2	16	50	102
	Engineering Services	5%	0	0	1	2
	Subtotal		**3**	**28**	**88**	**179**
Midstream Opex	Compressor Maintenance/Repairs	50%	0	2	7	14
	Subtotal		**0**	**2**	**7**	**14**
Supply Chain + Consumer Capex	Gensets	100%	82	147	166	192
	Genset Accessories & Installation	0%	0	0	0	0
	Boilers/Furnaces/Heat Exchangers	60%	7	15	-12	-22
	CNG Cylinders Mods/Manif/PR/M&M	65%	60	397	1,193	1,758
	LNG Storage/Tanks	75%	44	80	113	141
	LNG Rec. Terminal & Vaporizers	100%	33	60	85	106
	Prime Movers + Trailers	0%	0	0	0	0
	LNG Tankers	0%	0	0	0	0
	Feed Gas Treatment	100%	10	62	170	237
	Compressors	100%	47	289	788	1,101
	LNG Plants	100%	16	31	51	62
	Gas Mains/ROWs	0%	0	0	0	0
	Filling Stations	20%	7	46	128	181
	Subtotal		**305**	**1,128**	**2,680**	**3,758**
Grand Total			**308**	**1,157**	**2,776**	**3,951**

Figure 20.1 U.S. Export Targets by Equipment/Service Category



20.4 POTENTIAL U.S. VENDORS/SUPPLIERS

Table 20.4 lists the names of U.S. vendors and suppliers capable of providing the identified categories of equipment and services required for implementation of the projected OBF-to-CNG/LNG switch in Indonesia along with their respective export targets. Their addresses and contact numbers are contained in Appendix M.

Table 20.4 U.S. Vendor/Supplier Candidates, Small Scale CNG/LNG Usage

Business	Value by 2025, $MM			Name
	Low	Med	High	
Well Work	**13**	**45**	**75**	1. Dowell 2. Halliburton 3. Santa Fe Global
				4. BASF Corporation 5. BE&K Construction - Houston 6. Bowden Construction Co., Ltd. 7. Clough Limited 8. Global Engineering, Inc.

Gas Processing Equipment, Maintenance/ Repairs, and Engineering Services	**17**	**61**	**102**	9. Gulf Coast 10. Gulsby Engineering, Inc. 11. IPSI LLC 12. Jacobs Engineering 13. Laser Midstream Company, L.L.C. 14. Mustang Engineering 15. Paragon Field Services Inc. 16. Pearl Development Company 17. S-Con, Inc. 18. Thomas Russell Co. 19. Universal Compression 20. Vanson Engineering Co. 21. Worley Parsons Resources & Energy
Genset, Accessories and Installation	**37**	**119**	**192**	22. Arrow Engine Company 23. Caterpillar, Inc. - Global Petroleum Group 24. Cummins Diesel 25. Gulf Coast Dismantling 26. Hawkins Filtration Products Inc. 27. J-W Power Company 28. Kams, Inc. 29. Solar Turbines, Incorporated 30. T. F. Hudgins, Inc. 31. The Hanover Company 32. Wartsila North America 33. Waukesha Engine
Boilers/Furnaces/ Heat Exchangers	**1**	**-10**	**-22**	34. Bartlet Equipment Company, Inc 35. Frames Process Systems 36. Global Process Systems Sdn Bhd 37. Gulf Coast Dismantling 38. Knight Hawk Engineering 39. Natco Group Inc.

				40. Optimized Process Furnaces 41. South-Tex Treaters, Inc. 42. Toromont Process Systems, Inc.
High Pressure Cylinders Modules/Manifold/ Pressure Regulator/M&M	**162**	**875**	**1,758**	43. ABB Automation 44. Apogee Scientific, Inc. 45. Cameron Iron Works 46. Chandler Engineering Company, LLC 47. Control Works, Inc. 48. Crane 49. Damascus Steel 50. Daniel Measurement and Control 51. DCG Partnership, Ltd. 52. Detector Electronics Corporation 53. Drake Controls, LLC 54. Dynalco 55. Elliott Turbomachinery Co. Inc. 56. Fisher Rosemount Controls International, Inc. 57. F. W. Murphy 58. Garzo Incorporated 59. Graves Analytical Services LLC 60. H & S Valve Inc. 61. Hoke 62. Honeywell 63. Ignition Systems & Controls, LP 64. Invensys Foxboro 65. Jamesbury 66. Kimray, Inc. 67. Miratech Corp. 68. Modicon Triconex 69. Moore Control Systems, Inc.

				70. Myers-Aubrey Co. 71. Opto 22 72. Orbit 73. Parker Hanifin Corporation 74. U.S. Steel 75. Vinson Process Controls 76. Walker Engineering Co.
LNG Storage/Tanks	**26**	**73**	**141**	77. ANGI International 78. Applied LNG Technologies 79. Black & Veatch Pritchard, Inc. 80. CB&I Howe-Baker Process & Technology 81. CHART Industries 82. Clean Energy 83. Dickson & Tryer Engineering Co., Ltd. 84. Domain Engineering Inc. 85. DRV Energy 86. Eaton Metal Products Company 87. Energy & Fueling Systems West 88. ForeRunner Corporation 89. Fuel Solutions 90. MEI, LLC 91. NATCO Group Inc. 92. National Petroleum & Energy Services, Inc. 93. Prometheus Energy Company 94. Rouly, Inc. 95. Saulsbury Industries, Inc 96. Surface Equipment Corp. 97. Trinity Containers, LLC 98. Washington Group International, Inc

LNG Rec. Terminals & Vaporizers	**21**	**57**	**106**	99. Air Products and Chemicals, Inc. 100. BCCK Engineering, Inc. 101. Expander Process Training 102. HPT Inc. 103. Mafi-Trench Corporation 104. Ortloff Engineers, Ltd. 105. Dickson & Tryer Engineering Co., Ltd. 106. JGC Corporation 107. NATCO Group Inc. 108. The Hanover Company
Feed Gas Treatment	**32**	**134**	**237**	109. ASK Industries, Inc. 110. CCR Technologies, Inc. 111. ElectroSep, Inc. 112. Goar, Allison & Associates, Inc. 113. Johnson Matthey Catalysts (formerly Synetix) 114. MPR Services, Inc. 115. NALCO Chemical Global Engineering, Inc. 116. S & B Engineers and Constructors, Ltd. 117. UNICAT Catalyst Technologies, Inc. 118. Zephyr Gas Services, LP
				119. Afton Pumps, Inc. 120. Ariel Corporation 121. Aurora 122. Bexar Energy Holdings, Inc 123. Brice Equipment Company 124. Compressor System, Inc. 125. Dresser-Rand Company 126. Duriron

Compressors, Maintenance/ Repairs (CMR)	**146**	**622**	**1,101**	127. Energy Dynamics, Ltd. 128. Gas Packagers, Inc. 129. General Electric 130. Gould 131. Hy-Bon Engineering Co. 132. Ingersoll Rand 133. Rino-K&K Compression, Ltd. 134. Rotor-Tech, Inc. 135. SCFM Compression Systems Co. 136. Solar 137. Sullair 138. Sundyne Compressors 139. Vanco Engineering Co. 140. Waukesha-Pearce Industries, Inc.

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