NEAR EAST UNIVERSITY

THE FACULTY OF MARITIME STUDIES

GRADUATION PROJECT

LNG CARRIAGE ON THE WORLD

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Introduction

The purpose of the IMO model coursesis to assist maritime training institutes and their teaching staff in organising and introducing new training courses, or in enhancing, updating or supplementing existing training material where the quality and effectiveness of the training courses may thereby be improved.

It is not the intention of the model course programme to present instructors with a rigid 'teaching package' which they are expected to 'follow blindly' .Nor, is the intention to substitute audio-visual or 'programmed' material for the instructor's presence .As in all training endeavours, the knowledge, skills and detication of the instructor are the key components in the transfer of knowledge and skills to those being trained through IMO model course material.

Because educational systems and the cultural backgrounds of trainees in maritime subjects vary considerably from country , the model course material has been designed to identify the basic entry requirements and trainee target group for each course in universally applicable terms , and to specify clearly the technical content and levels of knowledge and skill necessary to meet the technical intent of IMO conventions and related recommendations .

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1. EXACUTIVE SUMMARY

1.1 Main Conclusions

* Just another commodity scenario?

The surplus of LNG from the development of new liquefaction plants coupled with the increasing deregulation of power production could help create the conditions where LNG can be traded much like and other bulk commodity.

Traditionally LNG has been supplied through a very rigid chain of LNG plant, export terminal and port, shipping (usually purpose-built vessels dedicated to the specific contract), receiving port and terminal, regasification unit, storage and distribution infrastructure to deliver regasified LNG to the end-user. Although the owners/operators of each component link may be different, ultimately all the investments are directed to the delivery of gas to the end-customer and each link has little value outside the context of the chain.

But, why should this model continue to dominate when there is a surplus of supply and plenty of potential demand? If the LNG chain can be broken up with each component part remaining confident that it can source or sell (or both) LNG the benefits for future trade prospects could be enormous.

In many respects the industry is in a 'chicken and egg' situation in that a 'just another commodity trade situation cannot develop until there is a sufficient independent supply, demand and transport; but until there is a 'just another commodity' trade situation sufficient independent supply, demand and transport can not be developed.

Eventually LNG could be traded on the same basis as oil or more likely LPG; with the shipping element covered by a combination of long-term period charters, shorter term period charters, COAs and spot single voyage spot fixtures.

* Shipping capacity constraints market growth

During the 1990s LNG trade grew in volume terms by an average of 6.22% per annum to reach 124.2 bcm in 1999.If this same rate of growth is extrapolated to 2010,global LNG trade will almost double to 241.3 bcm. Given the same level of operating efficiency and no change in average haul lengths this would require an additional 40x138,000 cum vessels to the 25 LNG carriers already on order to enter service by 2010.

The LNG carrier fleet, in terms of cubic capacity, grew almost exactly the same annual average rate as trade during the 1990s at 6.15%.If fleet growth is to continue at the same rate, an additional 44x138,000 cum vessels, on top of the current order book, will need to enter service by 2010.

That the average rate of growth of the LNG fleet and the average rate of growth in LNG trade match each other in the 1990s hides the fact that the utilization of the fleet improved considerably over the decade. Given that the LNG fleet is now almost fully employed, perhaps the rates of growth of cubic meter mile demand will provide a better pointer to the future requirement for LNG carriers. During the 1990s cubic meter mile demand grew at an annual average of 7.84%.If this is assumed to continue to 2010 and the LNG fleet matched this rate on growth, an additional 71x138,000 cum carriers to the 25 vessels currently on order will need to enter service by then.

An alternative way to look at the forecast vessel requirement would be to look at how many vessels would be required as a bare minimum to deliver the forecast additional trade over the predicted average haul length, assuming a perfect operating environment and maximum efficiency. Under this scenario a further 28x138,000 cum vessels will be required in addition to the current order book to be in service by 2010.

The major unknown in the future trade growth is the amount of spot trade and principally the level of imports into the USA. To a large extent this will probably depend on the availability of vessels to facilitate such trade. In the summer of 2000 when vessels were available and LNG prices competitive, a lot of spot LNG moved to the USA.

More so than in most other bulk commodity trades the growth of LNG trade will be constrained by shipping capacity. In most other bulk trades, shipping capacity restraints tend to be very short-lived as the markets quickly encourage new building and extend vessel life by discouraging scrapping. In LNG however, the high costs and barriers to entry plus the long life of vessels mean that the market does not necessarily act quickly to resolve the situation. Much of the problem comes down to finance for these highly expensive sophisticated ships. Bankers have long memories and are understandably reluctant to advance huge sums of money to a sector that saw many vessels delivered in the 1930s straight into lay-up. They will also be reluctant to lend on the basis that these vessels can trade in a spot or short-term market when there is little precedent that this can be successfully done.

If the industry is to grow significantly beyond the traditional rigid long-term contracts and evolve into something close to a more normal bulk commodity market it will take some bold and visionary decisions by present or future industry players and a certain degree of bravery from potential financiers.

*** LNG new orders in 2000**

As of 1 September 2000,t5 (plus options) orders have been placed for new LNG vessels and a significant proportion of these were placed without any firm employment contracts. These speculative orders have been placed on some pretty sound fundamentals. There is, and will be in the near future, plenty of supply of LNG with several major new plants and expansions having come on-stream in recent years. There is also a reasonable amount of spare capacity at receiving terminals and, given the high crude oil prices of 2000,LNG has became significantly more competitively priced. The bottleneck in the supply chain between ample supply and strong demand is the transport element. There are not enough LNG vessels around to meet the potential demand and the situation is deteriorating as more projects come on-stream mopping up any remaining vessels that have been laid up or operating in the spot/short-term market in recent years.

So if the vessels were there they would be used, but that of course does not in itself mean that it it a profitable business to take part in. However, the steep fall in new building prices in the last few years has made the economics of owning and operating LNG vessels increasingly more attractive.

Many of the speculative new orders will have been placed in the knowledge that there looks to be a good chance the vessels will be able to pick up long-term employment contracts of the traditional kind. Some, however, see an altogether mote exciting future for LNG shipping.

1.2 Natural gas demand trends

* Natural gas is the third largest source of primary energy in the world, after coal and oil.
Natural gas is responsible for 24.2% of world energy consumption. This compares with oil (40.6%), coal (25%),and nuclear (7,6%)
* Rapid demand growth in the 1970s and 80s.
Natural gas enjoyed a period of remarkable growth in the 1970s with consumption more than doubling. During the 1930s,consumption expanded by a less spectacular 33%,but this was also remarkable considering that over the same period crude oil consumption increased by only a very small amount.
* Demand growth slow-down in the 1990s.
During the 1990s gas consumption growth started to weaken dramatically with the marked reduction in demand by the Former Soviet Union. World consumption growth was further undermined by the impact of the economic turmoil in the Asia Pacific region, which was partly responsible for a 0,7% contraction in gas consumption in 1997.However, LNG consumption recovered in 1998 with a growth of 1.3%, followed by a 2.4% expansion in 1999. This pushed total demand growth during the 1990s to 16,5%

1.3 Natural gas reserves

* Plentiful reserves.
Worldwide reserves of gas are now recognized to be very large (146.43 trillion cum in 1999),much larger than was thought twenty five years ago when, for example, the EEC limited gas use to so-called priority sectors. The reason for this apparent increase in reserves is largely that greater interest in the use of gas has spurred exploration in previously written-off areas.
Gas is now estimated to have reserves worldwide which are as great as oil, although both are much smaller than coal reserves. The reserve/production ratio for gas is rather larger than that for oil at 51.9 years as against 41 years. The R/P ratio for coal is 230 years.
* Reserves typically located away from gas markets
Although gas reserves are relatively plentiful viewed from a global basis, the market suffers from an uneven distribution of these reserves, which means that most of the gas consuming regions will gradually become more and more dependent on imported gas.
The major gas reserves are concentrated in the Former Soviet Union (mainly Russia) with 39%
of reserves (56.7 trillion cum) and the Middle East with 34% of reserves (49.5 trillion cum).The next largest gas location is Africa with 8% of reserves.

1.4 Historical Development of Natural Gas Carriage

By the 1950s the liquefaction process and LNG storage in stationery tanks had been developed, but nothing had been done regarding ocean transportation. Although Godfrey Cabot patented his river barge concept in 1915, forty years later little progress had been made. William Morrison began development in the USA in 1952, Dr. Oivind Lorentzen designed a ship with spherical tanks in Norway in 1954, and by 1955 Shell and Gaz de France were both working on the shipping process following a huge gas discovery in Algeria.
By 1959 the Constock Group had successfully carried the first cargo of methane from lake Charles to Canvey Island in the U.K. on the Methane Pioneer. With the success of the Methane Pioneer, events started to move at a quicker pace, especially when the U.K. decided to import gas from Algeria. Work began on the construction of two LNG carriers with aluminum tanks of the conch design. (Constock was renamed Conch Methane Ltd. in 1959).They delivered in 1964 at a cost of about 4.8 million pound each. Called the Methane Progress and Methane Princess, they each had a cargo capacity of about 27,400 cum. The demands of British Gas determined the size and speed-about 17 knots-required for weekly round trips.

France also needed Algerian gas and after tank design and insulation trials on The Beauvais (a converted liberty ship), the first French built ship, The Jukes Verne, was launched in September 1964. It used a design of self supporting tanks constructed self-supporting tanks constructed of 9% nickel steel which had low carbon content. It had seven tanks with a total capacity of 25.840 cum. A membrane design was also being built for Philips Marathon to carry LNG from Alaska to Japan. By now the size was up to 71,651 cu.m for the Polar Alaska and Artic Tokyo, both built at the Kockums yard in Sweden. While ships were being built for specific projects, in 1969 Gazocean ordered 50.000 cu-m vessels using, the Technigaz membrane technique without any transport contact. Named the Descartes, it was the world first LNG ship on speculation. Gazocean idea was that the ships could be used as back-up for various projects or, if no LNG work was forthcoming, it could carry LPG. It was initially used for LPG but soon picked up a contact for deliveries from Algeria to Cabot LNG in Boston and then to Gaz de France.

Brunie, the first Asian LNG producer, began deliveries to Japan in 1972 on the 75,000 cu-m Gadinia which was the first of a seven-ship class (in size). The vessel is also being operated by Brunie State Shipping Company.

By 1970 Kvaerner Moss had designed a large ship of 88,000-cu-m capacity using spheres and in 1973 the first ships were delivered, the Norman Lady and Pollenger. Such was the design of these ships that their size soon increased. In 1977 Abu Dhabi began shipments to Japan using four ships of 125,000-cu-m size provided by Gotaas Larsen. With entry of Indonesia as an LNG producer, American yards started building Moss ships. By 1979 23 ships were built or on order, mainly to carry LNG from Indonesia to Japan, first from Botang in August 1977, then from Arun in October 1978. The Japanese yards entered the LNG shipbuilding arena in 1982 when Kawasaki built the Golar Spiirt for Gataas Larsen fro Indonesia to Japan Business.

The Binyulu plant in Malaysia made its first delivery to Japan in 1983. This project saw the construction of five more 130,000-cu-m ships the membrane containment system.

Australia entered the LNG shipping in 1987 with the North West Shelf project. It put in place a total project fleet of eight 127,000-cu-m vessels operating between Dampier and various Japanese ports.

The next wave of LNG construction arrived in the early nineties with the plant expansion in Bintulu (Malaysia LNG Dua) in 1995, which required five vessels. The Abu Dhabi contract extension required replacement vessels: four were built in Japan for a subsequent plant expansion. The Qatargas project will require a total of ten ships. In 1997 the first of two non project dedicated ships was delivered SNAM (Eni - Italian): the 65,000 cu-m LNG Portovenere, followed in 1998 by the LNG Lerici.

2. THE NATURAL GAS MARKET

2.1 What is Natural Gas and LNG?

At the outset some brief definitions of properties and uses are worthwhile, especially as it is necessary to make a distinction between natural gas and LNG.

2.1.1 Natural gas

Natural gas is predominantly methane (typically 90%), but also present in varying proportions are smaller amounts of ethane, propane and butane. Small quantities of nitrogen, oxygen, carbon dioxide, sulfur compounds, and water may also be found in "pipeline" natural gas.
Gas obtained in solution from oil reservoirs is termed "associated gas" and normally contains a larger quantity of butane and heavier hydrocarbons. Sometimes this is referred to as Vet gas. Conversely, gas produced from unassociated reservoirs is usually known as "dry gas". The composition of some commercial natural gasses and the hydrocarbon content in typical
"Wet" and dry" gasses are summarized in table 2.1. natural gas is transported via pipeline/ however it is extremely bulky ; for example a high pressure gas line can transport only about one fifth the amount of energy a day that can be conveyed through an oil pipeline .

2.1.2 Liquefied natural gas {LNG}

The inefficiency of natural gas pipelines coupled with technical and economic problems of running pipelines over long distances directly contributed to the creation of the international LNG business. If gas is cooled to minus 160.5c {-260f}, it becomes liquid and more compact occupying only 1/600" of its gaseous volumes. During liquefaction most of the heavier hydrocarbons are removed what is transported by sea in bulk is predominantly methane - over B0 % - a colorless, transparent liquid, which is non-toxic, and non-

corrosive. LNG is however, a very volatile cargo and only specialist operators are involved in transportation.
Some of the main physical properties of methane are set out in table 2.1. Other terms relating to the natural gas and LNG industries can be fount in the glossary.

2.1.3. Applications

Natural gas meets many of the requirements for fuel in a modern day industrial society. It is efficient, pollution - friendly and has flexibility of control. Key uses are:

Table 2.1
Composition and properties of natural gas
Composition {percentages by volume}

	Netherlands Gromngen	Brunei	Algeria
Methane	81.7	88.0	86.5
Ethane	2.7	5.1	9.4
Propane	0.4	4.8	2.6
Butane	0.1	1.8	1.1
Pentane	1.1	0.2	0.1
Nitrogen	14.0	0.1	0.3

Hydrocarbon content in wet and dry gasses	Percent Wet Gas	Dry Gas
Methane	84.6	96.00
Ethane	6.4	2.00
Propane	5.3	0.60
Iso - butane	1.2	0.18
N-butane	1.4	0.12
isopentane	0.4	0.14
b- Pentane	0.3	0.06
Hexane	0.4	0.10

Physical properties of methane {LNG}
Symbol: CH_4
Carriage temperature: -165 c
Cargo pressure: 1.04 kg/sq.cm
Specific gravity {typical}: 0.475
Flash point: -175c

-Public and commercial - space and water heating and cooking
-Industrial - as an under boiler fuel for steam raising and healing applications

- electricity generation by -fuel for base load and combined cycle/ co generation power plants
- alternative motor fuel to diesel -with only one carbon and four hydrogen atoms Per molecule , natural gas is cleanest burning fossil fuel petrochemicals - a variety of chemical products e.g. methanol can be derived from natural gas
- 2.1.4. the natural gas industry

Where there are pipelines, natural gas is typically moved as a gas through the pipeline system. However , when natural gas needs to be stored or moved by ship , it is converted to LNG .Because of the existence of a pipeline system , LNG plays only a small role in the natural gas market in the united pipelines are lacking .

LNG storage

Cove point gas storage facility in Maryland, USA g/ is describe here in order to provide an example of a typical LNG storage terminal.
Cove point was built in the 1970s and includes an offshore terminal for receiving shipments of LNG and onshore shore storage. The two parts of the site are over a mile apart and are connected by a pipeline for transporting people. The offshore terminal only received

The natural gas industry

LNG shipments between 1978 and 1980, and has been shut down ever since. The terminal is due to re - open for LNG imports in 2002. meanwhile the facility has been operating as a natural gas storage site since 1995 when it added a process to convert natural gas into LNG about 30 people now work at site compared to 126 employees who worked there when the offshore terminal was open .the cove point storage site receives natural gas from a pipeline, converts it to LNG, and stores in tanks. When natural gas demand is al its highest the LNG is converted back into natural gas and returned to the pipeline. It lakes much longer to convert natural gas to LNG than is does to convert the LNG bask into natural gas. It takes about 90 days to fill one off the four storage tanks at cove point, while it only lakes a day and a hall to empty a tank.

2.1.5 Natural gas and the environment

Natural gas produces significantly less of the emissions addressed in the US 1990 clean Air Act amendments. Those emissions specifically being particulate matter {pm} carbon monoxide {co}, nitrogen compounds {nox} and non - methane hydrocarbons {NMHC}
us perspective from the Kyoto report {EIA} natural gas is a dean ,economical ,widely available fuel used in more than 58 million homes and more than 60 percent of the manufacturing plants in the United States .
Almost one - quarter oil the energy consumed in the United States comes from natural gas in 1996 the combustion of natural gas produced 318 million metric tons of carbon emissions in the United States ,about one -fifth of the U.S total . The industrial sector was

responsible for the biggest share of those emissions, about 45 percent, followed by residential, commercial, and electricity generation in order of magnitude. Twelve years from now, if no carbon reduction measures are put in place, emissions from natural gas combustion are expected to be about the protected emissions are higher in 2010, the natural gas share of total emissions increases only slightly from 1996

2.2. World primary energy consumption

World energy consumption during the 1990s is table 2.2 this reveals that world energy demand grew by 8.6% between 1990-99. If the former soviet union is excluded this figure rises to 13.1% demand growth in the early 1990s was flat due to recession in the GECD economies and more importantly the decline in eastern European demand following the collapse of the soviet bloc. Rapid economic development in south east Asia and Latin America offset declining demand elsewhere to keep demand relatively constant the mid - 1990s saw demand growth pick up again to a more healthy 2.1% in 1995 and 3.4% in 1996 modest energy demand growth returned to the ODECD economies as they recovered from recession ; the rate of decline in FSU consumption began to bottom out and demand growth in South East Asia and Latin America picked up even more strength .however ,by the end of the decade ,energy demand from ODECD economies and the start of a Merced slow - down in South East Asian demand growth as the region entered an era of economic turmoil between 1980 and 1990 natural gas market share gradually increased from 19% to 23% thereafter its market share has remained stable within a narrow band 23% -24% the other fuel types have roughly maintained their respective market share during the last ten years , although coal market share , which fell significantly during the 1980s has continued to weaken slightly .

Table 2.2
World primary energy consumption, 1990-99
By region

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
North America	2.234	2.232	2.230	2.274	2.320	2.379	2.407	2.483	2.501	2.515	2.557
Latin America	268	270	277	285	294	307	322	339	356	368	371
Europe	1.770	1.741	1.731	1.709	1.707	1.695	1.733	1.796	1.790	1.806	1.801
FSU	1.373	1.398	1.349	1.253	1.137	1.025	970	936	899	895	908
Middle east	250	254	259	273	286	303	321	344	358	369	380
Africa	206	212	212	213	220	228	239	348	252	257	261
Asia/Australia	1.682	1.748	1.802	1.881	1.957	2.075	2.188	2.314	2.348	2.308	2.255
Total world	**7.782**	**7.856**	**7.861**	**7.887**	**7.920**	**8.011**	**8.178**	**8.459**	**8.504**	**8.517**	**8.534**

%growth

North America	-0.1%	-0.1%	1.9%	2.0%	2.6%	1.1%	3.2%	0.7%	0.6%	1.7%
Latin America	0.8%	2.5%	2.7%	3.2%	4.5%	4.9%	5.2%	5.2%	3.3%	0.9%
Europe	-1.6%	-0.6%	-1.3%	-0.1%	-0.7%	2.3%	3.7%	-0.4%	0.9%	-0.9%
FSU	1.9%	-3.5%	-7.1%	-9.3%	-9.9%	-5.4%	-3.5%	-4.0%	-0.4%	1.5%
Middle East	1.6%	2.1%	5.4%	4.5%	6.0%	6.0%	7.0%	4.3%	2.8%	3.2%
Africa	2.8%	0.4%	0.5%	3.1%	3.7%	4.6%	3.8%	1.7%	1.8%	1.8%
Asia/Australia	4.0%	3.1%	4.4%	4.0%	6.1%	5.4%	5.8%	1.5%	-1.7%	-2.3%
Total World	**0.9%**	**0.1%**	**0.3%**	**0.4%**	**1.2%**	**2.1%**	**3.4%**	**0.5%**	**0.1%**	**0.1%**

By fuel type

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Oil	3.087	3.114	3.133	3.164	3.135	3.193	3.235	3.316	3.390	3.407	3.462
Gas	1.738	1.772	1.804	1.806	1.846	1.853	1.909	2.004	1.989	2.015	2.064
Coal	2.272	2.244	2.189	2.179	2.171	2.186	2.218	2.298	2.285	2.243	2.130
Nuclear	502	517	541	546	565	575	600	621	617	627	651
Hydro	182	189	194	193	203	205	216	219	222	225	227
Total World	**7.782**	**7.856**	**7.861**	**7.887**	**7.920**	**8.011**	**8.178**	**8.459**	**8.504**	**8.517**	**8.534**

% of total

Oil	39.9%	39.9%	40.1%	39.6%	39.9%	39.6%	39.2%	39.9%	40.0%	40.6%
Gas	22.6%	22.9%	22.9%	23.3%	23.1%	23.3%	23.7%	23.4%	23.7%	24.2%
Coal	28.6%	27.9%	27.6%	27.4%	27.3%	27.1%	27.2%	26.9%	26.3%	25.0%
Nuclear	6.6%	6.9%	6.9%	7.1%	7.2%	7.3%	7.3%	7 3%	7.4%	7.6%
Hydro	2.4%	2.5%	2.4%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.7%

Table 2.3
Natural gas consumption as percentage of total energy consumption by region
(Million tones oil equivalent)

		1998			**1999**	
	Natural Gas	**Total Energy**	**% Gas**	**Natural Gas**	**Total Energy**	**% Gas**
USA	552.4	2169.5	25%	555.3	2204.9	25%
Canada	63.3	221.9	29%	64.3	227.8	28%
Mexico	31.9	123.8	26%	31.9	124.6	26%
North America	647.6	2515.2	26%	651.5	2557.3	25%
Argentina	27.5	55.6	49%	30.1	57.9	52%
Brazil	5.6	126.0	4%	6.4	127.4	5%
Venezuela	29.1	56.1	52%	28.8	56.0	51%
Latin America	80.6	367.9	22%	83.8	371.2	23%

Belgium & Luxembourg	12.4	64.1	19%	13.3	65.1	20%
France	33.3	249.2	13%	33.9	252.4	13%
Germany	71.7	336.6	21%	72.1	330.9	22%
Italy	51.5	161.9	32%	55.5	165.8	33%
Holland	34.9	84.6	41%	34.1	83.7	41%
Poland	9.5	93.5	10%	9.3	92.6	10%
Spain	11.8	114.5	10%	13.5	119.1	11%
Turkey	8.9	73.2	12%	10.8	76.2	14%
United Kingdom	77.9	225.3	35%	82.5	22.4	37%
Europe	385.4	1806.3	21%	399.6	1800.8	22%
Russia Federation	328.3	595.2	55%	327.3	607.8	54%
Ukraine	61.9	133.8	46%	65.7	137.0	48%
Uzbekistan	42.3	51.7	82%	44.3	53.8	82%
FSU	476.7	894.9	53%	482.6	908.1	53%
Iran	46.6	106.2	44%	50.1	111.2	45%
Saudi Arabia	42.1	101.0	42%	41.6	104.1	40%
United Arab Emirates	27.3	45.2	60%	28.3	46.0	62%
Middle East	153.6	368.5	42%	157.8	380.3	41%
Algeria	19.4	28.0	69%	20.3	29.2	70%
Africa	43.7	265.5	17%	46.9	261.2	18%
Australia	18.3	102.6	18%	17.8	102.8	17%
Bangladesh	7.0	9.8	71%	7.1	10.0	71%
China	17.4	842.6	2%	19.3	752.6	3%
India	20.9	271.3	8%	21.4	276.4	8%
Indonesia	24.4	77.1	32%	24.5	79.6	31%
Japan	62.5	499.3	13%	67.1	507.4	13%
Malaysia	17.4	38.1	46%	18.9	38.0	50%
Pakistan	14.6	36.4	40%	16.1	37.2	43%
South Korea	13.8	166.5	8%	16.9	182.0	9%
Thailand	14.3	57.4	25%	14.8	59.3	25%
Asia /Australia	227.8	2307.5	10%	241.7	2254.7	11%
Total World	2015.4	8516.8	24%	2063.9	8533.6	24%

Table 2.3 shows natural gas market share by region {plus the more important markets} the Former Soviet Union {53%} and the Middle East {41%} is the region most reliant on natural Gas Asia/pacific {11%} is the least dependent region most reliant on natural gas however the Absence of significant pipeline infrastructure means that it is the most important market for LNG. The figures for regional reliance on oil hide some substantial national differences for instance in Asia/Pacific natural gas meets 50% of Malaysia's needs but only 3% of china's energy needs; Whilst Europe natural gas is responsible for only 2% of Sweden's energy requirements but Accounts for 37% of the United Kingdom's requirements.

2.3 Natural Gas Consumption Trends

Natural gas use on any on any wide scale is comparatively recent compared with coal or oil products. Except in the US and the USSR natural gas consumption was very small until W.W.II and even in the 1950s consumption in Europe was confined to areas around gas finds In southern France and Po valley in Italy .most gas supply in Europe at that time was based on Coal or oil due to house heating. In Asia gas use was virtually unknown. A number of Factors from the 1960s onwards combined to accelerate the use of natural gas these included the discovery in Western Europe in the 1960s of very large and cheap gas fields in the Netherlands And the southern North Sea and were followed by the Natural gas consumption

Table 2.4

{Billion cubic meters}

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
N. America	630	640	658	680	696	721	737	737	720	724
Latin America	59	61	61	65	68	74	79	84	89	93
Europe	331	339	336	354	355	381	423	416	429	444
FSU	663	666	628	609	567	547	553	518	530	536
Middle East	95	95	106	115	126	137	151	163	171	175
Africa	34	35	37	40	42	45	47	46	49	52
Asia/Australia	158	169	179	188	206	218	236	247	253	268
Total	1.969	2.004	2.007	2.051	2.059	2.122	2.227	2.211	2.240	2.293
Total exc. FSU	1.306	1.339	1.378	1.442	1.492	1.575	1.674	1.693	1.710	1.756
N America	-0.6%	1.6%	2.9%	3.3%	2.4%	3.6%	2.2%	0.1%	-2.4%	0.6%
Latin America	3.5%	3.4%	0.7%	5.9%	4.2%	8.7%	7.9%	5.8%	6.6%	4.1%
Europe	1.1%	2.7%	-0.9%	5.2%	0.2%	7.4%	11.0%	-1.7%	3.1%	3.6%
FSU	1.5%	0.5%	-5.6%	-3.1%	-6.9%	-3.5%	1.1%	-6.4%	2.3%	1.2%
Middle East	-4.7%	0.3%	12.2%	8.0%	9.3%	8.8%	10.8%	7.6%	4.8%	2.6%
Africa	3.7%	3.8%	6.2%	6.7%	5.0%	6.9%	5.4%	-2.1%	5.0%	7.2%
Asia / Australia	7.0%	6.7%	5.9%	5.4%	9.2%	5.8%	8.6%	4.5%	2.5%	6.0%
Total	1.9%	1.8%	0.1%	2.2%	0.4%	3.1%	5.0%	-0.7%	1.3%	2.7%
Total exc. FSU	0.7%	2.5%	3.0%	4.6%	3.5%	5.6%	6.3%	1.1%	1.0%	2.7%

Huge escalation in oil prices of the 1970s. Natural gas became much cheaper both in real terms and relative to its major competing fuel oil in the search for alternatives to OPEC oil which from 1975-1985 was a policy obsession in OECD countries natural gas was seen as a very desirable fuel it was available locally at least in western Europe and it was environmentally friendly compared with the other fossil fuel alternatives such as oil coal thus from the mid-1960 onwards the consumption of natural gas moved upwards sharply as shown in table 2.4and figure 2.1 in Europe and Asia though in NORTH America it passed

through a consumption decline for some years before increasing .This divergence between Europe and Asia and North America is indicative of the quite different historical development patterns between the continents. The expansion of natural gas in Europe and Asia was even more noteworthy as it occurred when overall fuel consumption was undergoing a period of stagnation or even decline.
The rapid increase in gas consumption in Europe and Asia was accompanied by a previously unknown aspect the international trading of gas which until the development of the Dutch Groningen field in the mid 1960s was virtually
Unknown apart from some Canadian sales to the US.
One of most important factors behind the growth in natural gas consumption in the 1980s was the introduction of combined cycle gas turbine generation {CCGT} power stations. These allowed for much higher efficiencies in gas fired plant compared with the coal fired units which had been regarded until then as the most cost effective fossil fuel in the power sector. Although gas was used in power generation in both the US and Japan {the latter providing the impetus for all Asia and Middle East LGN projects} the main reason for this had been environmental. However the higher efficiency CCGT stations and the continuing low price of gas linked as it usually was to oil prices meant that gas gained a genuine cost advantage. During the 1990s gas consumption growth started to weaken dramatically with the marked reduction demand by the former Soviet Union. World consumption growth was further undermined by the impact of economic turmoil in the Asia Pacific region in 1997 there was a contraction in natural gas consumption albeit by less than 1%. There was a corresponding slow down in the growth of international gas trade in 1997 trade was up by just 2.1 % on 1996 levels compared to 9.2% growth between and 1996 the downturn in natural gas consumption proved short lived with demand recovering by 1.3 % in 1998 compared to 1997 levels and 2.4% in 1999 while the international gas trade expanded by 2.6% in 1998 arid 9.1% in 1999.

Forecast natural gas consumption

{'000 billion btu}

1997	**2005**	**2010**	**2015**	**2020**	**Avg annual %change 1997-2020**
83.9	107.7	127.7	145.3	173.3	3.2%

Source: Energy Information Agency {EIA}

2.4 Natural Gas Production Trends

The dominant natural gas producing regions are North America (31.8% market share in 1999) and Former Soviet Union (21.8%). Europe (12.1%) and Asia/Pacific (11.0%) are the next largest producers, followed by the Middle East (8.0%).
Of these leading producers, the Former Soviet Union is the only region to have seen its production fall over the last ten years, with output down by around 12%. The fastest growing region during the last ten years has been the Middle East (+83%), followed by

Asia/Pacific (+82%), Africa (77%), Latin America (67%), Europe (+29%) and North America (+19%). The expansion of Middle Eastern and Asia/Pacific production has been crucial to the growth of LNG seaborne trade as much of the production from these regions is destined for export while the limited pipeline infrastructure in these regions has created opportunities for seaborne transportation. Worldwide production increased by an annual average rate of 1.6% in the 1990s (3.5% if FSU excluded) to 2.330 bcm (see Table 2.5 and Figure 2.2)

2.5 International Natural Gas Reserves

Worldwide reserves of gas are now recognized to be very large (146.43 tcm at the end of 1999) much larger than was thought twenty five years ago when for example the EEC limited gas use to so-called priority sectors. The reason for this apparent increase in reserves is largely that greater interest in the use of gas has spurred exploration in previously written off areas.

Gas is now estimated to have reserves worldwide which are as great as oil though both are much smaller than coal reserves. Figure 2.3 shows the reserve/production (R/P) ratios for the three fuels. This reveals that the R/P ratio gas is rather than that for oil at 61.9 years as against 41.0 years.

Table 2.5- Natural gas production
(Billion cubic meters)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
N. America	640	644	658	674	706	711	727	733	733	740
Latin America	59	61	61	65	68	74	80	84	89	95
Europe	217	226	227	238	240	248	280	276	275	282
FSU	760	756	729	710	671	660	669	627	645	656
Middle East	98	101	110	119	130	144	159	173	181	187
Africa	67	72	75	79	75	82	88	98	104	114
Asia/Australia	150	164	175	184	200	212	230	239	243	255
Total	**1.991**	**2.024**	**2.036**	**2.069**	**2.090**	**2.131**	**2.232**	**2.231**	**2.274**	**2.330**
Total exc.	1.231	1.268	1.307	1.359	1.419	1.471	1.563	1.604	1.629	1.673
% growth										
N. America	2.8%	0.5%	2.3%	2.3%	4.9%	0.7%	2.2%	0.8%	0.6%	0.4%
Latin America	3.2%	3.9%	0.5%	5.9%	4.5%	8.6%	8.0%	5.4%	6.6%	6.7%
Europe	-0.6%	4.3%	0.4%	5.0%	0.8%	3.1%	13.0%	-1.3%	-0.3%	2.5%
FSU	2.4%	-0.5%	-3.7%	-2.5%	-5.5%	-1.7%	1.4%	-6.3%	2.8%	1.8%
Middle East	-4.0%	3.1%	8.5%	8.2%	9.2%	11.0%	10.1%	9.3%	4.3%	3.5%
Africa	4.0%	7.9%	4.4%	4.5%	-5.2%	10.0%	7.5%	11.3%	5.6%	9.4%
Asia/Australia	7.0%	9.3%	7.0%	5.2%	8.7%	5.9%	8.3%	4.0%	1.5%	5.1%
Total	**2.3%**	**1.7%**	**0.6%**	**1.6%**	**1.0%**	**1.9%**	**4.8%**	**-0.1%**	**1.9%**	**2.5%**

Total exc. FSU	2.2%	3.0%	3.1%	4.0%	4.4%	3.6%	6.3%	2.6%	1.6%	2.7%
% total										
N. America	32.2%	31.8%	32.3%	32.6%	33.8%	33.4%	32.6%	32.9%	32.4%	31.8%
Latin America	2.9%	3.0%	3.0%	3.1%	3.2%	3.5%	3.6%	3.8%	3.9%	4.1%
Europe	10.9%	11.2%	11.2%	11.5%	11.5%	11.6%	12.5%	12.4%	12.1%	12.1%
FSU	38.2%	37.4%	35.8%	34.3%	32.1%	31.0%	30.0%	28.1%	28.4%	28.2%
Middle East	4.9%	5.0%	5.4%	5.7%	6.2%	6.8%	7.1%	7.8%	8.0%	8.0%
Africa	3.4%	3.6%	3.7%	3.8%	3.6%	3.9%	4.0%	4.4%	4.6%	4.9%
Asia/Australia	7.5%	8.1%	8.6%	8.9%	9.6%	10.0%	10.3%	10.7%	10.7%	10.9%

These gases R/P estimates must still be treated with caution as they probably still underestimate the level of gas reserves. The BP review of world gas notes that over a ten year period world gas reserves have increased annually at the rate of almost 4%. However, although gas reserves are relatively plentiful viewed from a global basis, the market suffers from an uneven distribution of these reserves which means that most of the gas consuming regions will gradually become more and more dependent on imported gas.

This identifies the major gas locations as concentrated in the former Soviet Union (mainly Russia) with 39% of reserves (56, 70 tcm) and the Middle East with 34% of reserves (49, 52 tcm). The next largest gas location is Africa with 8% of reserves (11, 16 tcm).

2.6 The International Natural Gas Trade

Table 2.6 shows the growth in world natural gas trade since 1970 relative to world natural gas production. It also breaks down international natural gas trade into pipeline and LNG movements.

Since 1970 the world natural gas trade has expanded more than ten-fold from 46bcm to 485 bcm in 1999, which is equivalent to a growth rate of 8, 5% per annum. This spectacular rate of growth slowed in 1997 and 1998, in part due to the Asian economic crisis and in part to the collapse of oil prices. In 1998, the world natural gas trade expanded by 2, 6%, which was slightly up on 1997 (2, 1%) but lower than 1996(9, 2%). It was shown in section 2.4 that, despite the slow down in the growth of seaborne trade, it was still expanding more rapidly than natural gas consumption. Rapid growth returned in 1999 with trade increasing by 9, 1%.

The international natural gas trade has increased sharply as proportion of an expanding market, but it's still a relatively minor part of the total. In 1970 international trade was equivalent to less than 5% of world natural gas production. By 1980 this figure had risen to over 13% and by 1999 international trade was equivalent to 20, 8% of production. Although the internationally traded natural gas market is relatively small, it is important in some regions, especially Asia and Europe.

International Trade in Natural Gas 1970, 1999

	World Total		World Pipeline Total		World LNG Total		LNG
	Bcm	% of Production	Bcm	% of Production	Bcm	%of Production	Share % of Trade
1970	46	4, 4%	43	4, 1%	3	0, 3%	6, 5%
1975	125	9, 9%	112	8, 9%	13	1, 0%	10, 4%
1980	201	13, 2%	169	11, 1%	32	2, 1%	15, 9%
1985	229	13, 1%	178	10, 2%	51	2, 9%	22, 3%
1990	308	15, 5%	236	11, 9%	72	3, 6%	23, 4%
1995	388	18, 2%	296	13, 9%	93	4, 3%	23, 8%
1996	424	19, 0%	322	14, 4%	102	4, 6%	24, 1%
1997	433	19, 4%	322	14, 4%	111	5, 0%	25, 7%
1998	444	19, 5%	331	14, 6%	113	5, 0%	25, 4%
1999	485	20, 8%	361	15, 5%	124	5, 3%	25, 6%

In contrast to natural gas, crude oil is relatively widely traded being equivalent to 55% of crude oil production. This disparity between natural gas and crude oil reflects the relative high cost as well as relative technical difficulties associated with the transportation of natural gas and means that gas is more likely to be consumed close to the site of production than crude oil.

Distribution of Natural Gas Trade between Pipeline and LNG

Pipeline natural gas accounted for 93% of world gas movements in 1970 and it remains the primary method of transporting gas. However, gas shipped in LNG from now accounts for over 25% of total trade.

Despite this dramatic loss of market share, near pipeline gas projects continue to be added to the global network (see recent pipeline developments). During the early 1990's the increase in pipeline capacity was sufficient to slow LNG inroads into global trade with LNG market share rising by just 2,6% from 23,4% in 1990 to 25,6% in 1999.

The world natural gas trade is dominated by eight large movements- of which only three were in LNG:

Top 8 gas trades in 1999

- Russia to Europe – 125,5 bcm
- Canada to US – 94,7 bcm
- Norway to other Europe – 45,5 bcm
- Netherlands to other Europe – 35 bcm
- Indonesia to other Asia – 33,8 bcm
- Algeria to Europe (pipeline) – 32,7 bcm
- Algeria to Europe – 23,6 bcm
- Malaysia to other Asia – 20,5 bcm

A complete breakdown of the international gas trade by pipeline is contained in seaborne LNG trades are discussed in greater detail in sections 3.4 and 6.

Recent Pipeline Developments

One of the most recent pipeline inter regional developments occurred in March 2000, when Enron , the US energy group and Total Final ELF , the Franco – Belgian oil Giant , signed a milestone agreement with the United Arab Emirates offsets group (UOG) to construct an 8 billion dollar – 10 billion dollar middle eastern gas network. The agreement signals the beginning of closer interdependence between the six states of the Gulf Co-Operation Council (GCC) and is expected to enhance political stability in the region. The first face of the initiative, known as Dolphin, will deliver up to 3 bcf a day o gas through a pipeline starting in Qatar and running through Abu Dhabi, Dubai and onto Oman.
Another potential pipeline project is the transcaspian gas line (TCGP) project from Turkmenistan to Turkey via Azerbaijan and Georgia. However, this scheme is under threat from a new BP Amoco project launched in early 2000 to pipe AzeriGas to Turkey. Results from the second well on the offshore Shah Deniz field show sufficient gas to proceed with the refurbishment of an existing gas line in Azerbaijan and the laying of new pipe in Georgia to the Turkish border. Early estimates put costs below 1 billion, less than half the projected 2- 2, 5 billion for TCGP. The volumes and timetables of both projects are the same: Kicking off with 5 bcm /yr in the winter of 2002/2003, rising to a potential 16 bcm/yr.

3. DESCRIPTION OF TRADE

In new LNG Projects, the required LNG ships generally represent 20-40 % of project cost; in the typical & 4-5 billion project, the shipping is $ 1-2 billion of needed investment.

3.1 Traditional LNG Trade

From the outset, LNG was transferred from purpose-built LNG export facilities to purpose-built import facilities by newly-built dedicated LNG carriers.
As the size of LNG production facilities and ships increased to benefit from economies of scale, LNG suppliers were assured of rectums on their investment long-term, relatively inflexible take-or-pay LNG sales contracts, which assured the full utilization of capital-intensive LNG export facilities. Buyers were financially strong companies with guarantied markets and in general, the cost of LNG shipping is passed onto the end customers. Reliability of supply was paramount and buyers could accept such inflexible, long-term LNG supply contracts.

Hire rates: latest figure is between Indian Government and Mitsui – SCI which is \$ 68,900 a day. Voyage is about 20 day. It is also speculated daily hire rate for LNG contracts are between \$115,000 a day and \$85,000 a day.

3.2 Short Term LNG Trade

In recent years, there have been changes in the nature of LNG trade, one of the main ones being the growth in short term trade, which has sales contracts with duration's of up to a few years. Increasingly, this short term trade has included the sale of single cargoes; these have been carried by one shipper to a specified destination and a price determined in advance, and is not like the true "spot" trade in oil, where cargoes can change ownership and destination while in transit. However, they are increasingly referred to as spot cargoes. The growth in short term LNG trade has been due to three factors.

1- The availability of "surplus" LNG from liquefaction plants, i.e. more LNG than has been committed to long-term LNG sales. This surplus may be due to the as-built plant capacity or through the plant being debottlenecked, i.e. its capacity increased through process modifications. Surplus LNG of this type can be sold either on short modifications. Surplus LNG of this type can be sold either on short-term or long-term sales contracts. Other forms of surplus LNG can only be sold on short-term contracts. These include surplus LNG available during the period while sales to a long-term buyer build up o the level specified in the contract and any surplus available if the buyer excises his right for the year ahead to take the minimum allowed under his contract.
2- The existences of uncommitted LNG carriers, which have been available for charter hire. In the past, there has been a reluctance to use carriers which support long-term supply contracts on temporary short-term trade, in case an accident or a delay could interfere with their use to supply the regular long-term customers.
3- Various supply-demand situations that have favored new short-term trade at the expense of buyers' commitments to a new long-term trade. In the USA, after the collapse of the long-term sales agreements with Algeria in the early 1980's the nature of the more flexible smaller-scale contracts which followed and the surplus LNG reception capacity paved the way for short-term trade to increase when market gas prices made it economic to import more LNG.

It is expected that the amount of short-term LNG trade will grow, although it could be constrained in the next five years or so by the maximum capacity of US import terminals and available LNG shipping capacity. Short-term LNG sales will come not only from conventional sources (liquefaction plant over-capacity, debottlenecking and surplus available during the build up period of long-term contracts), but some will also come from a proportion of new plant capacity, particular plant expansions.

Brownfield: Involves construction of a new LNG trains but which utilize existing infrastructure such as pipelines and receiving terminals, etc, Greenfield: New projects requiring the construction of new LNG trains, pipelines, etc.

According to SMI LNG Report 2001, short-term trade could constitute about 15-25 %(29.25-48.75 million tons) of the total world LNG trade by 2010. It is expected that the risks involved in short-term LNG trade will mean that lenders to new LNG projects will still require the depts. to be repaid through revenue from long-term, however, if deregulation worldwide leads to even greater opportunities for growth in short-term trade, more LNG project developer may be willing to invest equity in LNG facilities dedicated to such trade.

SUMMARY OF SHORT-TERM TRADE, 1997-9, MILLION TONS

Importers

	1997	1998	1999
Japan		0, 1	0, 1
Korea	4, 8	3, 8	4, 3
Taiwan		0, 2	0, 7
France			0, 05
Spain	1, 0	1, 1	1, 3
Italy		0, 1	0, 4
Turkey		0, 4	0, 2
USA	0, 2	0, 4	0, 9
Total	**6, 0**	**6, 1**	**8, 0**

Exporters

	1997	1998	1999
Indonesia	2, 5	2, 8	3, 8
Malaysia	2, 3	1, 3	1, 3
Australia	0, 2	0, 3	0, 3
Abu Dhabi	0, 9	0, 7	0, 5
Qatar	0, 1	0, 7	1, 2
Algeria		0, 3	0, 9
Total	**6, 0**	**6, 1**	**8, 0**

Source: International LNG Importers Group (GIIGNL)

SHORT-TERM LNG TRADE IN 1999 – SELLERS & BUYERS

Trade	Seller	Buyer	Million Tone/Year	No. of Cargoes
Indonesia-Japan	Pertamina	Toho Gas	0, 11	2
Indonesia-Korea	Pertamina	Kogas	1, 71	30
Indonesia-Korea	Pertamina	Kogas	1, 13	20
Indonesia-Korea	Pertamina	Kogas	0, 17	3
Indonesia-Taiwan	Pertamina	CPC	0, 73	16
Malaysia-Korea	Malaysia LNG	Kogas	1, 28	22
Malaysia-USA	Malaysia LNG	Coral Energy	0, 05	1
Australia-USA	Woodside	CMS Energy	0, 21	4
Australia-USA	Woodside	Duke Energy	0, 05	1
Abu Dhabi-Korea	Adgas	Kogas	0, 06	1
Abu Dhabi-Spain	Adgas	Enagas	0, 22	6
Total			**5, 72**	**106**

Source: LNG Trade – 2001 SMI Publishing

3.3 Stranded Gas

Economic studies revealed that it is more cost-effective to deliver LNG to smaller communities by sea directly from supplier country than by extending pipelines or operating coastal LNG carriers from the major import terminals. This mode of transportation is proposed for between small communities in Japan-Malaysia trade. The mini LNG carriers could offer ship owners similar opportunities to open up the market for "stranded gas". Stranded gas is a field too small to support development of infrastructure on a scale needed to make the gas competitive with other suppliers to major markets. A self-contained, niche-market oriented, lower cost of entry LNG carrier could be what independent ship owners require as the way to test their opportunities in the high stakes LNG shipping market.

Calgary based Coselle CNG technology provides an alternate gas transportation system that economically fits between pipelines and LNG.
Coselle CNG serves the gas transportation markets in the following circumstances:

1- Marine distances less than 2000 miles.
2- Long of difficult pipeline routes.
3- Projects where the economics benefit from the scalability and flexibility of Coselle CNG enabling the transport system to grow incrementally with demand or be redeployed to new reserves or markets.
4- Projects that requiring an offshore gas loading or offloading system.

A typical coselle consists of several miles of mall diameter pipe coiled into a carousel (hence the word "Coselle").

Market Analysis

Essentially there are two main trades for Coselle CNG:

1- The shipping of gas from a producing region to consumers separated by sea , and
2- The shipping of associated gas from offshore platforms to nearby infrastructure that can either use the gas or deliver it to other markets.

The majority of the first trade, international gas shipping can be grouped into geographical areas,

The Mediterranean Sea
The Black Sea
The Caribbean Sea
The Arabian Sea
Sakhalin Island
Canada's East Coast

3.4 Background of LNG

LNG will also support the growing use of combined cycle gas turbines (CCGT) for power generation. (CCGT) are considered relatively more efficient and less hazardous to the environment than may other power generation alternatives. The option of importing LNG in combination with the increasing popularity of CCGT expanded to potential for meeting electrification goals in the developing world, particularly in Asia. The last point is particularly significant given that the demand for power in developing Asia is expected to triple by the year 2020, even in light of the current economic crisis.
Traditionally, LNG imports have been more expensive than alternative resources, including piped natural gas. LNG is generally more costly than other energy resources due to the substantial amount of processing and expense associated with transporting LNG to the consumer. LNG must be converted from gaseous to liquid form before shipping, transported in specially designed refrigerated ships, and delivered to ports equipped with special receiving facilities. It then must be regasified and distributed to customers through pipelines, just as natural gas is usually distributed. LNG producers have aimed to reduce production costs associated with the construction of LNG plants or "trains". According to Shell International, current real costs of liquefaction are about 30% lower than in the 1960s. Typically, the cost of these trains has accounted for almost half of the total investment needed in a LNG project. Cost-cutting efforts have made some advances. According to the *Petroleum Economist* Nigeria's planned two-train facility, with a capacity of 5.2 million metric tons of LNG per year (252 billion cubic feet [bcf] Per year), is expected to cost \$3.8ft billion; a project of similar size would have been twice as expensive had it been built in the early 1980's. Trinidad and Tobago's Atlantic LNG project, due to start in 2000, is planned as a single-train unit with a capacity of 3 million metric tons per year (146.1 bcf).

This smaller facility will expand LNG opportunities for countries with smaller gas reserves. Projects while these are noteworthy, it is important to recognize that they are not representative of standard size and cost of LNG projects. They may, however, signal the start of a new trend toward more economic projects.

Since LNG is a capital and time insensitive business. LNG producers have generally opted for 25-year "take or pay" agreements. "Take or pay" agreements mean that the purchaser must pay for a minimum volume of gas for a specified period whether or not the purchaser accepts the delivery. LNG producers aim to minimize their financial risk with these types of contracts. However, these contracts have increasingly faced competitive pressures from suppliers of alternative resources who can provide more flexible contractual conditions. As a result, a new phenomenon in the LNG business is the development of spot and short-term trade. Although spot sales (transactions lasting less than one year) dropped by 30% to 57.8bcf in 1997 from around 81.1 bcf in 1996, transactions lasting between one and three years are increasing. This development is largely an outcome of an increasing demand for flexibility among LNG purchasers.

LNG export facilities exist in Asia, Africa, the Middle East, and North America. Between 1990 and 1997, worldwide LNG trade expanded by 45%, with Asian countries (specifically Japan, South Korea, and Taiwan) importing approximately 75% (2.9 trillion cubic feet) of all LNG exports. Other importers of LNG include Belgium, France, Turkey, Italy, Spain and the United States. In 1997, Indonesia was the largest exporter of LNG, accounting for 33% of the world total. This LNG went to Japan, South Korea and Taiwan. Algeria was the second largest exporter of LNG in 1997, exporting 22% of the world's total LNG to Western Europe and the United States. Other suppliers of LNG in 1997 included Australia, Brunei, Libya, Qatar, Malaysia, the United Arab Emirates and the United States. Emerging LNG suppliers include Oman, Nigeria and Trinidad and Tobago.

3.5 The Impact of the Asian Economic Crisis on LNG Importers

Until recently, growth in the world LNG market generally has been an outcome of economic growth in Asia. Consequently, the impact of the Asian economic crisis that began in 1997 has had negative repercussions for several major countries in the LNG industry. According to the *Petroleum Economist* established Asian LNG customers are cutting their imports by %40. Numerous project delays and cancellations of LNG contracts haw occurred. In the short-term, these developments will likely cause an oversupply of LNG on the market, which will further drive down LNG prices and have a negative impact on producers' profitability. Longer-term , however the Asian economic crisis could make LG more competitive other fuels, as efforts to cut LNG cost and provide more flexible LNG contracts have been intensified. In addition weaker demand in several key Asian countries has intensified an ongoing search by LNG producers (particularly from the Middle East) for new markets (i.e. in India and China). Also it is important to note that several key LNG liquefaction projects outside the Asian market are moving forward. New market entrants may become dominant LNG producers if their efforts are successful.

Japan

The world's largest LNG importer is Japan. With only minimal indigenous energy resources to speak of, Japan is almost totally reliant on energy imports. In 1997, world's total LNG supply about 476 million metric tons (2.3 Tcf). Japan imports 57% of its LNG from Indonesia and Malaysia. Japan is fearful of a potential disruption in supply from Indonesia and Malaysia, given these countries political and economic uncertainties. As a result, in August 1998, Osaka Gas announced plans to lower its imports of Indonesian LNG. In its effort to diversity its resource base, Osaka Gas plans to import 0, 35 million metric tons (17 Bct) of LNG from Qatar annually (Japan's Chubu Electric Company already imports almost all of Qatar gas' LNG output). Osaka Gas also plans to sign a contract with Oman this October to import 0, 66 million metric tons of LNG (32, 1 Bct) a year. In addition, the Japanese are considering LNG imports from Alaska's North Slope. The Asian economic crisis therefore is in a sense resulting in greater opportunities for new market producers.

In the long-term, however Japan's future demand growth for LNG is unclear. Japan's economy has grown slowly in recent years, with real GDP increasing only 1, 5% on average from 1991 to 1995. In 1996, real GDP grew a faster, 4, 1% rate, but 1997 GDP growth slowed to 0, 8% and 1998, is witnessing negative growth. As a result, although Japanese LNG imports increased in the first half of 1998, rising by more than 3%, this growth rate is far less than the average growth rate of 12% between 1975 and 1995. The potential for a deepening recession has made LNG exporters uneasy. Additionally, Japan has considered building a gas pipeline to import natural gas from Sakhalin Island and or Eastern Siberia; such developments would directly compete with LNG imports.

South Korea

With Japan's future as the main LNG growth market increasingly uncertain, many LNG producers had started focusing on South Korea as a potential source of growth. South Korea was viewed as the key country for expanded LNG consumption given the country's large economy and strong economic performance in recent years. South Korea's real GDP growth rate averaged 7.4% between 1990 and 1996. In 1997, South Korea was the second largest customer of LNG worldwide, importing 11, 3 million metric tons of LNG (550 Bct), South Korea's annual LNG imports increased by 140% between 1993 and 1997. In 1997, South Korea accounted for 18% of regional LNG imports and nearly 14% of global LNG imports. State-owned Korea Gas Corporation (Kogas) was predicting LNG imports of more than 16.5 million metric tons by the year 2000 (803 Bct).

Despite its previously positive economic situation, the Asian economic crisis has hurt South Korea, the 11.th largest economy in the world, and has had negative repercussions for short term LNG prospects. Since December 1997, South Korea has experienced a major depreciation of its currency and a sharp decline in its stock market, as well as numerous corporate bankruptcies. The GDP growth rate for 1998 is expected to be –6.0%. Meanwhile, LNG imports this year nearly collapsed in the first quarter of 1998. Kogas has cancelled or delayed planned purchases of 770 million metric tons of LNG since the beginning of 1998.

The demand slowdown in South Korea is particularly worrisome to LNG producers since South Korea (as stated above) has been viewed as a key growth market and an alternative to Japan. Furthermore, the potential construction of a gas pipeline from Sakhalin Island and/or Eastern Siberia serving Japan, China and South Korea also will undermine South Korean LNG demand. However, it is not known at this time whether these projects will be constructed.

Taiwan

Taiwan was the third largest importer of LNG in the Asian region in 1997 and the sixth largest worldwide. Taiwan has been relatively unaffected by the Asian currency crisis, with only a slight decline in economic growth and LNG demand.
Taiwan has seen only minimal cutbacks in LNG imports. For instance, Chinese petroleum Corporation (CPC) of Taiwan has cancelled two cargoes totaling 0, 11 million metric tons (5.3 Bfc) of Malaysian LNG. This development may not have been a response to economics but rather to a disagreement between the sale oil and gas company CPC, which aims to expand LNG imports, and Taipower, the state electricity company, which would rather use nuclear generation, despite growing opposition from consumers.

Thailand

In November 1997, Thailand postponed its first LNG purchase agreement with Oman. The agreement had cancelled for 1 million metric tons (48.7 bcf) to be delivered in 2001, rising to 1.7 million metric tons (82.8 bcf) per year in 2003, and 2.2 million metric tons (107.1 bcf) per year in 2004. Thailand delayed any imports of LNG due to its economic crisis and resulting decrease in energy demand. Thailand's economic crisis began in early July 1997 after the Thai government floated its currency (the bath), resulting in an immediate decline in its value. Between July 1997 and February 1998 the bath lost more than 50% of its value against US dollar. Thailand's real GDP growth rate for 1997 was –0.5%, down from 6.0% in 1996 and 8.7% in 1995. Negative growth (-6.8%) is projected to continue in 1998 before rebounding in 1999 to 0.9%.
Despite several loan packages from the International Monetary Fund and implementation of economic reforms, the negative impact of the Asian economic crisis on Thailand's demand for energy in general and LNG imports specifically is unlikely to turn around in the near future.

3.6 Impact of the Asian Economic Crisis on LNG Exporters

Exporters of LNG to Asia and elsewhere have been adversely impacted by declining LNG prices due to weak demand. Asian LNG producers like Indonesia and Malaysia have been "twice hurt", so to speak , versus those LNG producers form their regions, as they are suffering not only from softening customer demand in Asia, but also from their own economic woes. Indonesia has been the world's largest exporter of LNG, exporting 26 million metric tons (1.3 Tct) of LNG in 1997. The economic crisis in Indonesia, as well as the currency crisis impact on many of its customers, has hurt Indonesia's LNG business. For instance, Japan's Osaka Gas Company has started that it will reduce the level of its

LNG imports from Indonesia (from which it imports 40% of its supply) in order to reduce its dependency on the country given its recent economic and political turmoil. In addition, other companies are postponing their Indonesian LNG projects. The 6.0 million metric tons per year (292 bcf Per year) Tangguh LNG proposal, based on Arco natural gas discoveries in the far Eastern province of Iran Jaya, has been formally delayed to 2004.

Indonesia

Plans for expansion of existing facilities have run into financial and other hurdles. The expansion of the Bontang complex in Kalimantan has slowed after completion of the G train. (LNG plants are usually called "trains" and several are usually built at one site to benefit from economies of scale). Commissioning of the H train was due for mid-1998 but was delayed due to the political and economic crises facing the country. Although it is believed that H train will be completed and functioning by sometime in 1999, a proposed I train is less certain. Meanwhile, the future of the Arun LNG project is uncertain. Located at the northern tip of Sumata, Arun is experiencing diminishing proven gas reserves and Mobil, the main producer, does not know how much longer the complex can operate at full capacity.

Malaysia

Malaysia accounted for approximately 19% of total world LNG exports in 1997. After many years of strong economic growth, Malaysia is currently feeling the effects of the economic crisis that befell Southeast Asia starting in mid-1997, with a -4.1% GDP growth rate expected in 1998, (and positive0.9% in 1999). Japan's importance as Malaysia's main LNG customer has increased because several other established Asian customers of Malaysian LNG are cutting imports. South Korea already has cancelled three LNG cargoes totaling 0.17 million metric tons (8.3 bcf), while Taiwan has cancelled two LNG cargoes totaling 0.11 million metric tons (5.4 bcf)

Australia

While Australia's domestic economic situation has been relatively untouched by the Asian currency crisis, as a major exporter of LNG to the region, its key markets have been adversely affected. Shell and Mobil have had difficulty securing long-term contractual buyers for the Gorgon LNG project, thus slowing project engineering work. Furthermore, the prospects of LNG development from large gas reserves offshore Western Australia and in the Timor Gap have diminished. Many producers are simply skeptical of the current market according to the Petroleum Economist squabbles between partners BHP and Phillips also have halted planning for the proposed Bayu-Undan project and a Woodside. Shell initiative for basing and LNG project on Timor Gap reserves is still in the exploration stage.

3.7 Middle Eastern LNG Suppliers

The Middle East is becoming a new source of LNG supply, both with projects commissioned and coming online, and with add-on liquefaction capacity starting to appear. The emergence of Middle Eastern LNG supply is competing with the traditional suppliers for the Asia Pacific such as Indonesia, Malaysia, Brunei, and Australia. Asia's economic crisis has intensified this competition, as well as pushed Middle Eastern suppliers to find alternative markets.

Qatar

The main LNG companies in Qatar Liquefied Gas Company (Qatargas), and the Ras Laftan LNG Company (Ras Gas). Qatargas's main supply contracts are with Japan, Spain, and Turkey. Ras Gas's main customer is Korea Gas Corporation (KOGAS), which has agreed to import 0,6 million metric tons (29,2 bcf) of gas per year starting in 1999. This volume is supposed to increase to 4,8 million metric tons (233,8 bcf) per year by 2003. Given South Korea's current economic situation, it is not known whether KOGAS will be able to meet Ras Gas contractual obligations. As a result Moody's has downgraded Ras Gas debt rating and Standard and Poor's has placed the project on its watch list.

Oman

The main current Oman LNG project is a two-train plant being constructed near Sur at a cost of $2 billion. Oman LNG is planning to sell 4, 1 million metric tons (200 bcf) per year to KOGAS and 0, 7 million metric tons (34 Bet) to Osaka Gas Company of Japan in 2000. Oman LNG also plans to sell 1, 2 million metric tons (58, 4 bcf) a year to MetGas, subsidiary of Enron, for its Dabhol power plant project in India over the course of 25 years. The Indian supply agreement was largely the outcome of Oman seeking alternative markets after a proposed supply agreement with Thailand tell through.

3.8 New LNG Market, New LNG Projects

Given current pressures facing the global LNG market, LNG producers have been seeking new opportunities more aggressively, and also have been aiming to expand existing, smaller markets. India and China are new potential LNG markets. European countries and the United States are markets that could expand in the near future.

India

LNG imports into India appear closer to becoming a reality. In 1996, India's state-owned Gas Authority of India, Ltd. (GAIL) made an international call for LNG supplies as part of a $10 billion projects to diversity its energy sources. The Indian government had planned to set up two regasification plants, one at Ennore, near Madras on India's southern coast, and one at Mangalore on the western coast. Despite the fact that in August 1998 bids for the Mangalore LNG terminal were cancelled, (it was reported that the ministry of Petroleum

Nigeria is also aiming to export LNG to markets in Europe and the United States. A major LNG project called Bonny LNG is expected to come online in October 1999. Project participants include Nigerian National Petroleum Corporation, Shell Gas BV, Cleag Bermuda (ELF) and Agip International BV with Shell as a technical partner.
Originally planned as two-train, 5, 7 million metric tons (277, 5 bcf) per year capacity project, Nigeria LNG announced in June 1998 plans to add a third train. This addition will increase capacity to 8, 7 million metric tons (423, 7 bcf) per year.
The major share of production volume (49%) from Nigeria LNG has been contracted to ENEL, the Italian state electricity company, while the remaining volume has been sold to the following gas companies: Enagas of Spain (22, 4%), Gaz de France (7%) and Turkey's BOTAŞ (13%) leaving about 9% of uncommitted volume. Nigeria LNG is seeking contracts for this uncommitted volume. Potential markets include other European countries and potentially the United States.

Existing LNG Liquefaction Plants

EXISTING	PLANT OPERATOR	TRAINS	CAPACITY	STARTUP
AFRICA				
Algeria:				
ArzewGLIZ	Sonalrach	6	8, 8 (429) bcf	1978
ArzewGL2Z	Sonalrach	6	8, 8 (428, 6) bcf	1981
ArzewGL4Z	Sonalrach	1	1, 1(54) bcf	1964
SkikdaGLIK Phase1	Sonalrach	3	2, 8(141, 2) bcf	1972
SkikdaGLIK Phase2	Sonalrach	3	3, 0(146) bcf	1981
Libya:				
Marsa el Brega	NOC	4	2, 6(126, 7) bcf	1970
Total			**27, 1(1320) bcf**	
ASIA PACIFIC				
Australia:				
Northwest Shelf	NWS joint venture	3	7, 5(365, 2) bcf	1989-1992
Brunei: Lumut	Brunei LNG	5	6, 5 (316, 6) bcf	1972

Indonesia:

Amu Phase 1	PTArunNGL	3	4, 5(219, 2) bcf	1978
Arun Phase 2	PTArunNGL	2	3, 0(146, 1) bcf	1984
Arun Phase 3				1986
Bontang A/B	PT badak NGL	2	1, 5(73) bcf	1986
Bontang C/D	PT badak NGL	2	3, 2(156) bcf	1977
Bontang E	PT badak NGL	1	2, 3(112) bcf	1989
Bontang F	PT badak NGL	1	2, 3(112) bcf	1993
Bontang G	PT badak NGL	1	2, 7(131, 5) bcf	1998

Malaysia:

Bintulu MLNG 1	MLNG1	3	8, 1(394, 5) bcf	1983
Bintulu MLNG2	MLNG2	1	7, 8(379) bcf	1995
Total			**49, 4(2405, 8) bcf**	

MIDDLE EAST

Abu Dhabi:

Das Island 1	ADGAS	2	5, 3(258, 11) bcf	1977
Das Island 2	ADGAS	1	2, 3(112) bcf	1994

Qatar:

QATAR	QatarGas	2	4, 7(228, 9) bcf	1996
Total			**12, 3(599) bcf**	

UNITED STATES

Kenai	Phillips	1	1, 3(63, 3) bcf	1969
Total			**1, 3(63, 3) bcf**	

WORLD TOTAL			**90, 3(4398) bcf**	

UNDER CONSTRUCTION	PLANT OPERATOR	TRAINS	CAPACITY	STARTUP
AFRICA				
Nigeria:				
Bonny Island	Nigeria LNG	3	8, 7(423, 7) bcf	1999
Total			**8, 7(423, 7) bcf**	
ASIA PACIFIC				
Indonesia:				
Bontang H	PT badak NGL	1	2, 7(131, 5) bcf	2000
Total			**2, 7(131, 5) bcf**	
LATIN AMERICA				
Trindad and Tobago:				
Trinidad and Tobago	Atlantic LNG	1	3, 0(146, 1) bcf	1999
Total			**3, 0(146, 1) bcf**	
MIDDLE EAST				
Oman:				
Oman LNG	Oman LNG	2	6, 6(321, 4) bcf	2000
Qatar	Ragas	2	5, 0(243, 5) bcf	1999
Total			**11, 6(564, 9) bcf**	

4. LNG CONTRACTS AND TRADE ROUTES

This chapter examines in detail the individual traditional style LNG contracts . In 1999 , the eleven exporters and nine importers combined to form 25 LNG trade routes . The emergency of Oman as an exporter for the first time in 2000 will boost the number of trades as will the appearance of India as an importer in the early 2000s . However , it is expected that LNG contracts will gradually become less than rigid in the future as more abundant LNG supplies lead to greater competition which in turn encourages more spot shipments and other non traditional types of LNG contract such as cargo swapping and cross trading .

4.1 Exiting LNG contracts

There are currently eleven LNG exporters in the world supplying just nine countries on a regular basis . The links between LNG exporters and importers is shown in the following table . This table shows the 25 trades governed by long-term contracts that were active as of January 2000 .

Exporter	**Importer**
Abu Dhabi	-Japan
Algeria	-Belgium
	-France
	-Italy
	-Spain
	-Turkey
	-USA
Australia	-Japan
Brunei	-Japan
	-South Korea
Indonesia	-Japan
	-South Korea
	-Taiwan
Libya	-Spain
Malaysia	-Japan
	-South Korea
	-Taiwan
Nigeria	-France
	-Spain
	-Turkey
Qatar	-Japan
	-South Korea
Trinidad & Tobago	-Spain
	-USA
USA (Alaska)	-Japan

A listing of LNG contracts in operation as of January 2000 together with further more detailed information is provided in table 4.1 Oman became the 12n LNG exporter when

It commenced exports from mid-2000 . The following section provides commentary on the history and current status of all the long-term LNG contracts.
It should be noted that the data about contract volumes can be in cubic meters or in metric tons. The conversion factors are as follows:
1 ton LNG (with specific gravity = 0.425) is equivalent to 2.353 cubic meters of LNG 1 ton LNG (with specific gravity = 0.475) is equivalent to 2.105 cubic meters of LNG
The range of conversion factors means that it is difficult to standard units. However, in order to allow the reader to compare projects, it was decided to convert all volumes measured in cubic meters to tons based on the conversion ratio 2.105. Both metric tons and cubic meters are used in other parts of the report.

4.1.1 Abu Dhabi - Japan

Located at Abu Dhabi's Das Island, the first, and until recently the only, Middle East LNG export terminal commenced operations in 1997 under a 20 year contract to supply gas to Tokyo Electric Power Company (TEPCO) .
The exporter of the LNG is the Abu Gas Liquefaction Company limited (ADGAS) which comprises Abu Dhabi National Oil Company (ADNOC) with a 70% share holding (up from 51%) , Mitsui 15% , (down from 25%) , BPAmoco 10% (16%) and TotalFina 5% (8%)
The original contracted volume was 2.06 mta but this had crept up to 2.3 mta ,following a project to increase the capacity of the two liquefaction trains on Das Island in the early 1990s . In 1990 ADGAS and TEPCO agreed not only to extend the time scale of the existing contract , from 1997 to 2019 at 2.3 mta , but also to expand it with an additional 2.0 mta of LNG , the expansion to run from 1994 to 2019 .
To provide the additional volume , a third train of 2.3 mta capacity was constructed (increasing total capacity to 4.6 mta) and four 137,500 m³ with the existing contract extended a further 22 years , ADNOC also decided to replace the five existing LNG carriers serving the trade (Norman Lady , Hitti , Gitni , Golar Freeze , Khannur) and ordered four new 137,500 m3 LNG carriers from Findlands Kvaerner Masa Yard in April 1993 (Ai Hamra , Mraweh , Mubaraz , Umm at Ashtan) . The final ship in the series was delivered in April 1997 .
In November 1997 , South Korea cancelled a 0.8 mta contract with the Adgas venture . As a result any extra LNG volumes generated by the Das Island facility were placed on the spot market . In 1999 , the spot export trade reached around 0.5 million tons .
In 1998 difficulties with its LNG customers as well as problems in the crude oil sector caused by surplus oil and collapsing prices led ADNOC to lease finance its LNG fleet (operated by Natural Gas Shipping Co : eight vessels , and Adnatco : ten vessels) through Abu Dhabi-based Oasis International Leasing Co (a joint venture between British AerospaceAsset Management and instutional and individual LJAE investors). This sale , which fitted into a wider policy of increased privatisation , provided extra funds for ADNOC to allow it to undertake expansion programmes at its oil fields , refineries and petrochemical plants . there are also plans for a future international bond issue .

4.1.2 Algeria – Belgium

The first agreement between Sonatrach and Distrigas of Belgium was signed in 1975 . the financial terms of the contracts where subsequently revised in 1981 before deliveries began in 1982 . Contract volumes were orginally fixed at 1.2 mta (2.5 bcm/year) rising to 2.4 mta (5 bcm/year) from 1986 onwards .
The basis of the pricing formula meant, however, that the LNG went from 4.80 million dolar btu in January 1981 to $5.28 million btu in April 1981 . This price rise was unacceptable to Distrigas , and in 1983 Algeria agreed to reduce contract liftings to 0.71-0.76 mta (1.5 , 1.6 bcm/year)
In 1985 Distrigas signed a stopgap agreement which had a retroactive effect , modifiying the pricing agreement in the gas supply contract to April 1937 . Deliveries from May 1936 were reduced to 1.4 mta (3 bcm/year) instead of the agreed 2.4 mta , while the selling price was realigned with sonatrach sales to Gas De France and Enagas. Even so, deliveries were slower than anticipated, which led to further disagreement between both parties over pricing and quantities . In June 1989 they signed an agreement canceling thearbitration agreement started in 1937 . Price terms are now based on the average price of a basket of crude.
In 1990 Distrigas imported 2.9 million tons of LNG from Algeria. In February of the same year the Belgian government retained a 50% holding in Distrigas when the Public treasury decided to relinguish 12% of its stake to Societe Nationaled Investment.
Following the various conract revisions, Distrigas of Belgium purchases LNG from Algeria under a FOB contract that calls for the delivery of 3.3 mta until 2006. Whether or not Belgium will need to renew this contract beyond 2005 is a moot point as Zeebrugge has become a key interface point for the increasingly sophisticated North Sea pipeline grid through which gas from the U.K, Norway and the Netherlands passes.
In recent years Algeria has not supplied the full volume of contracted gas to Belgium due to temporary liquefaction plant shutdowns that needed to be made as part of projects to revamp Algerian LNG export capability. Distrigas has purchased several shiploads of LNG from Abu Dhabi to make up the difference.

4.1.3 Algeria – France

Gaz de France imports LNG from Algeria under fob purchase agreements with Sonatrach (the Algerian state oil and gas company). LNG is shipped the two French receving terminals , at Montoir near Si Nazaire and at Fos near Marseilles .Fos is unable to accept gas carriers in excess of 50,000 m3 while Montoir can accommodate 130,000 m3 carriers .
The original 1962 contract involving 0.37 mta of LNG to Fos , has been extended to 2002 . The second , 1972 contract stipulates the transport of 2.60 mta to Fos and has been extended to 2013 . The third , 1982 contract requires the movement of 3.8 mta of LNG to Montoir and has also been extended to 2013 . The final agreement is a short-term arrangement which involves the shipment of 0.80 mta from the Bethouia loading terminal, half to Montoir and half to Fos , over the period 1991-2002 .
Plant modernising programmes have meant that Algeria has not always been able to supply full contract volumes. Therefore, like Distrigas in Belgium , Gaz de France has purchased several shiploads of LNG from Abu Dhabi to make up the shortfall .

History: Gaz de France originally had three contracts with Sonatrach and was committed to lifting over 7 mta of LNG each year. However, in 1984 Gaz de France reguested , and was granted , a 10% margin of flexibility on liftings over an eight –year period . A temporary agreement was concluded in 1986 and negotiations then continued throughout 1987 and 1988. Essentially the French were seeking greater flexibility in the rate of liftings and pricing formulas. In January 1989 an agreement was settled which set a base price of $2.28 – $2.29 /billion tons for LNG delivered in France . The four-year agreement was applicable retroactively from the beginning of 1987, so the base price formula was used to calculate the arrears owed by Gaz de France on imports delivered in 1987 and 1988. During 1990 Sonatrach, Gaz de France and Sonelgaz created a joint engineering company SAFIR for the renovation of an Arzew liquefaction plant .

4.1.4 Algeria – Italy

Snam of Italy has a 20-year, fob contract to supply 1.3 – 1.5 mta of LNG from Algeria starting in 1997 (finishing 2007) . The trade started with the company's existing pair of 40,000 m3 ships but these were substituted soon after start – up by the 65,000 m^3 new building Snam Portovenere . A 65,000 LNG m^3 carrier has been chosen as this is the largest size ship capable of serving all the Mediterranean LNG terminals. The gas is being delivered to be existing Panigaglia LNG terminal near La Spezia which, with two 50,000 m3 storage tanks, has the capacity to handle 2.3 mta of LNG. Sonatrach had been selling Snam spot cargoes of Algerian LNG since 1990.

4.1.5 Algeria – Spain

The original LNG contract between Sonatrach and Enagas , the Spanish utility , was signed in 1975 . Under this agreement LNG is shipped from Skikda and Bethouia in Algeria to receiving terminals at Barcelona, Cartagena and Huelva.
The trade has been beset with protracted disputes over pricing and quantities. Between 1979 and 1984h spain lifted only 3.5 million tons (7.3 bcm) of LNG , whereas the contract stipulation was 8.8 million tons (18.5 bcm) .
However, the relationship was placed on a more even keel following a revised agreement in 1985.
Under the new agreement, Spain undertook to pay Algeria $300 million, which represented the backdated price increase of gas already delivered and $200 million to cover Sonatrach's cost for the construction of a liquefaction plant. In addition, Enagas undertook to step up deliveries to a level of 1.8 mta (3.8 bcm/year) by the end of the contract , which was extended by six years to 2004 .

4.1.6 Algeria – Turkey

In 1994 Sonatrach began exporting LNG to Turkey under a cif contract with BOTAS, the Turkish gas utility. The agreement is scheduled to run until 2014 and by 1998 deliveries will have built up from 1.5 mta to the full contract level of 3.0 mta . The BOTAS LNG reception terminal, located at Marmara Ereglisi on the north coast of the Marmara Sea, has three 85,000 m^3 LNG carriers.

4.1.7 Algeria – United States

Algeria – Boston (Distrigas Agreement)

This trade had its origins in the 1970sh however, the structure of the current trade is the result of an agreement in February 1980 between Sonatrading Amsterdam (a wholly owned subsidiary of Sonatrach) and Distrigas which stipulated the delivery of roughly 1.4 mta of LNG over a 15-year period .
A second agreement in December 1988 between Distrigas and Sonatrach and covering the delivery of 48 cargoes, each of 125,000 cum over a five-year period , has now expired . This particular agreement was dubbed the "Boeing deal " because it was a counter-trade arrangement , involving three Boeing 767-300 aircraft .
Due to the revamping of liquefaction plants, and the preference of Sonatrach to sell the available cargoes to Europe where prices were higher. In 1996h the number of cargoes increased to eleven or 585,000 tons. It is estimated that around 20 cargoes were delivered in 1999.

Algeria – Lake Charles (Panhandle Agreement)

In April 1987, Sonatrach signed a contract with Panhandle Eastern providing for the supply of 3.0 mta of LNG to the Lake Charles terminal over a 20-year period (1989 – 2009). Deliveries had previously been made between 1981 and 1983, but were suspended because of disagreement over pricing and quantity. The 1987 agreement, unlike the earlier contract, contained the flexible clauses relating to price and quantities . No minimum volumes were stipulated and there was no take or pay clause. In mid-December Sonatrach's ship, Mostefa Ben Boufaid , delivered its first shipment of LNG to the Lake Charles facility under the 1987 20-year contract . As was the case with the Distrigas project above , the revamping of Algeria's liquefaction plants has meant that Sonatrach has not been able to fulfil contractual obligations with Panhandle over recent years . For example, just two cargoes were delivered in 1995. However, trade has been running a delivery rate of one shipload per month since 1997 with around 10 cargoes delivered in 1999 .

4.1.8 Australia – Japan

The first shipment from the North West Shelf project (Loading Dampier) to Japan was made in July 1989. The initial delivery volumes were 2.8 mta but this was gradually increased to 5.34 mta by 1994-95. There were further contract extensions in 1995 and 1996 with exports rising to 7.33 mta (9% of total world production). The 20-year contract with the Japanesebuyers is set to expire in 2009. The current North West Shelf project employs eight 125,000 m3 LNG carriers.
The contract extensions were made possible following the addition of extra capacity from the debottlenecking of the three trains at Australian liquefaction facility at Karratha in North – Western Australia in 1995 .Before the Japanese customers took up

these additional volumes , Australia sold several cargoes of LNG , on both a spot and short – term basis , to Turkey , Spain and Korea .
The North West Shelf project manager is Woodside Petroleum, BMP Petroleum, BP development Australia Ltd , California Asiatic Oil Company , Shell Development (Australia) and Japan Auatralia LNG , a joint Mitsubishi/Mitsui venture . The operation works on the basis of a singlelong - term contract with five Japanese electric utilities and three Japanese gas companies, the amounts of LNG purchased varying amongst the companies. Despite the slowdown in LNG demand growth following the Asian economic crisis, the North West Shelf partners continue to investigate possible expansion obtions.

4.1.9 Brunei – Japan

This trade started in 1972 and is one of the oldest LNG contracts . The initial 20-year contract to supply 5.14 mta of LNG was extended in 1990 for a further 20 years until 2012 at slightly higher volumes of 5.54 mta .
The gas is sold the three companies (Tokyo Electric , Tokyo Gas , and Osaka Gas) using a pricing formula based on actual crude oil prices . The contract is serviced by seven 75,000 m^3 LNG carriers .
The Brunei liquefaction plant at Lumut was refurbished to enable ships of 125,000 m3 lo load in a convential manner via midship manifolds. Prior to this, the 75,000 m3 ships could only be loaded by means of their special stern manifolds at a long jetty facility that had been built lo accommodate the shallow waters near the terminal.
Brunei appeared to be less affected than other Pacific exporters by the Asian economic crisis. While Australia, Malaysia and South Korea all postponed LNG carrier new building programs, Brunei announced in July 1998 that it would go ahead with a replacement order for one 135,000 m3 LNG carrier worth $2.20 million

4.1.10 Brunei – South Korea

The Brunei liquefaction plant at Lumut has five trains with a total capacity of 7.2 mta of LNG . The facility has the ability to produce up to 1 mta of LNG more than that contracted for by its Japanese customers, and between 1994-96 an additional 0.7 mta was sold to Korea Gas. In January 1997 Brunei signed a five-year contract with Korea Gas for the supply of 0.7 mta . The LNG Port Hafcourt was initially used to service this trade until the start-up of Nigeria LNG for which the ship had been booked .
In April 1999 the first non-shell-operated field in offshore Brunei waters , Maharaje Lela , will come on – stream . Gas from this field will be processed at Lumut and will provide enough for 22 LNG shipments per annum for the first three years and 15 shipments per year thereafter . Gas sale agreements were finalized for this gas in Spring 1997 . Partners in the Maharaja Lela block are Elf (37.5%) , Fletcher Challenge Energy (35%) , Jasra (22.5%) and private Brunei interests (5%) .

4.1.11 Indonesia – Japan

Indonesia began exporting LNG to Japan in 1977 and the relationship between the two countries has blossomed to the extend that today Pertamina , Indonesia's oil and gas company , has contracts for the sale of a total of 17.7 mta of LNG to various Japanese

gas and electric companies –equivalent to approximately half of Japan's LNG requirements .
All the Indonesian LNG exported to Japan, as well as that shipped to Taiwan and Korea, is produced at two liquefaction complexes , one at Bontang Bay in East Kalimantan and the second at Arun .
The LNG trade between Indonesia and Japan is regulated by several contracts of varying duration. These contracts have been revised and extended over the years. For example in April 1990, Pertamina and Japanese buyers agreed to a revision of their 1973 contracts and 1981 expansion contracts. The alterations included changes to the lake or pay clause and abolition of the currency adjustment clause. Buyers agreed to lake additional LNG amounting to 21.7 million tons over the remaining life of their contracts with Pertamina .
History: In October 1990 , Pertamina signed an additional contract to supply 2 mta LNG for a period of 20 years to three Japanese companies – Tokyo Gas , Osaka Gas and Toho Gas . The gas was provided from a sixth liquefaction (rain built at Bontang Bay in 1994 and serviced by two new ships .A seventh trail (H train) was completed at Botang at the end of 1997 to service a farther 2.6 mta extension to existing contracts . An eighth Bontang LNG train (G train) , to service new Korean and Taiwan purchase contracts , was completed in 1999 .
Bontang's eighth trains have the capability to liquefy 21 mta of LNG, making it the largest such facility in the world . A ninth train is scheduled for commissioning in 2001 but as yet this capacity is uncommitted. A further train is being mooted for early in the next decade, but increasing difficulty in proving additional gas reserves may hamper further expansion. Indonesian LNG expansion plans are discussed more fully in later sections.
A total of 20 ships are utilized to service Indonesia –Japan LNG trades. Most of the LNG carriers are in the 125,000 – 135,000 m3 size range although the fleet does include the 1996-built , 19,100 m3 Surya Aki which is used to carry cargoes , on behalf of Hiroshima Gas and Nihon Gas , to small regional LNG terminals at Hatsuikaichi and Kagoshima , respectively . (Hiroshima Gas purchases 200,000 tpa and Nihon Gas 70,000 tpa under a contract that expires 2020).
Quantities are due to double in the year 2000, by which time a second ship of same size may be required)

4.1.12 Indonesia – South Korea

Deliveries to South Korea began in late 1986 under an original contract due to run to 2006. However, the initial contract volumes proved to be insufficient and, in 1990 , 14 additional cargoes of LNG were shipped . In April 1991h two contracts between Pertamina and KGC were signed covering LNG deliveries between 1992 and 2014. The first of these contracts extended the existing agreement. It stipulated deliveries of 1.9 mta (estimated) for the period 1992-95 and deliveries of 2.3 mta 1996 – 2007The second contract was done on a fob basis , and caters for a build – up in volumes to 2 mta between 1996 and 2013 falling to 1 mta in 2014 . The last year of the contract.
South Korea was one of the primary victims of the financial crisis impacting on Asia from the middle of 1997. The resulting economic slow-down led to the cancellation of up to 35 cargoes during 1998 including 15 from Indonesia, as well as seven from Malaysia and 13 spot cargoes from Abu Dhabi .

4.1.13 Indonesia – Taiwan

The contract between Pertamina and the Chinese Petroleum Corporation was signed in 1987 and the first cargo was delivered in April 1990 to Taiwan's reception terminal at Yung – An. This contract covers the supply of 1.5 mta for 20-year period (until 2010) with an obtional five-year extension period. CPC also has an option to enlarge the agreed consignment from 1.5 to 2.25m tpa .
In 1994 CPC agreed to buy an additional 900,000 tons of Indonesian LNG for delivery in the 1998 – 99 period. Links between CPC and Pertamina were further cemented in 1995 when the two parties signed a $6bn deal which calls for the delivery of an additional 1.9 mta of LNG for 20 years , beginning in January 1998 (until 2018) . An eighth liquefaction train (G train) was completed in 1999 at Bontang Bay in Indonesia partly to supply this Taiwanese contract.

4.1.14 Libya – Spain

The contract between Enagas (Spain) and Sirte Oil Co. (Libya) was to start in 1969 , but did not actually commence until 1971 . Deliveries were made to the Enagas LNG terminal in Barcelona. The agreement was suspended in 1980 due to the differences in opinion in the pricing formula. No further deliveries were made until 1984 when a new contract was agreed. This stipulated that Sirte Oil Co. should purchase 750m cum of LNG a year. Deliveries did, in fad, begin in 1984 , but never reached the contractual quantity and ceased in 1986 . Towards the end of 1988 a short-term contract was concluded which specified the delivery of 17 LNG cargoes in 1983 and 1989 . However, some of the last cargoes were in fact delivered fro Algeria.
The original 20-year contract was due to expire in 1991 but in 1990 Enagas an extension of its supply agreement with Sirte Oil Co. This started in July 1990 for a period of 18.5 years. The initial annual volumes were 1 million tones in 1991/1992 and 1.5 million tons in 1993 before rising to 1.8 mta from 1994 onwards.
Libya had trouble meeting its contractual obligations in 1996 delivering only 0.8 million tons. Whether the Libyan agreement will be extended beyond 2008 depends on a number of factors, not least is the diversity of supply sources . Spain began receiving Algerian gas via the TransMaghreb pipeline, which runs under the Straits of Gibraltar , in 1996 and in 1999 it took delivery of its first imports from Trinidad & Tobago and Nigeria . Spain's demand for gas is forecast to increase from 16.5 bcm in 2000 to 19 bcm in 2010 .
In 1999h Spain completed an upgrade of its Cartagena terminal to enable the handling of 130,000 m3 ships . A large –ship LNG terminal in Northern Spain, at El Ferrol , has been under consideration for several years . The development of a diverse gas supplier base will be a key factor in the decision on whether or not to proceed with El Ferrol,

4.1.15 Malaysia – Japan

Malaysia is the third largest exporter of LNG after Indonesia and Algeria. Bintulu's two liquefaction plants (1 & 2) have a total capacity of 15.8 mta of LNG.
Malaysian LNG is sold to Japan fewer than three main agreements. the first involves LNG bought by two companies ,Tokyo Electric and Tokyo Gas , regulated by two separate contracts . The first contract runs from 1983 to 2003 and is based on volumes of 6 mta . A second contract covering 1.5 mta will run from 1991 to 2003, to take into account the additional supplies of LNG which are now available following the debottlenecking of the Bintulu plant in 1990.
The second agreement was initiated in 1990 when Malaysia LNG signed a contract with Saibu Gas of Japan covering the purchase of 20-year period beginning 1993. Start-up volumes were 0.15 mta and built up to full contract volumes of 0.36 mta .
LNG for the first two schemes is provided by the three train liquefaction plant at Bintulu (Bintulu 1) on the island of Sarawak. The start-up capacity of the plant was 7.4 mta and this was increased the 8 mta in 1990, following debottlenecking. The exporter of the shipments from Bintulu 1 is Malaysia LNG Sdn Bhd 1 (MLNG1) , a consortium comprising Petronas , the Malaysian national oil company (with 50% of the shares) , Shell (17.5%) , Mitsubishi (17.5%) and the state of Sarawak (5%)
The third agreement to sell Malaysian LNG to Japan started up in 1995 with the completion of the second three –train liquefaction plant at Bintulu , (Bintulu 2) . Some 2.6 mta , of Bintulu H's 7.8 mta rated output , was sold to five major Japanese gas and electric utilities under two separate contracts , both of which expire in 2015 . These contracts have been negotiated on a cif bases and the LNG is carried in ships owned by Petronas . The operator of this plant , MLNG 2 , is a consortium comprising Petronas (with 70% of the shares) , Shell (15%) and Mitsubishi (15%) . The state of Sarawak has an option to acquire up to 10% in MLNG 2.
Bintulu 2 also supports LNG sales to two smaller Japanese gas utilities. The first, Shizuoka Gas Company is supplied LNG under a 20-year contract 1997 – 2017 at 0.16 mta rising to 0.50 mta by 2001. The second , Sendai City Gas Bureau (SCGB) is supplied LNG under a 20-year contract 1997 – 2017 at 0.15 mta rising to 0.36 mta at maturity .
There are over 100 small gas companies in Japan which do not have access to natural gas and provide their customers either with LPG or manufactured town gas. Several of these – including Saibu Gas and Sendai City Gas Bureau – have decided to take up the LNG option but their requirements are such that there is no need for deliveries in full-size 125,000 m3 LNG carriers. In any case, depth restrictions in most local ports preclude the entrance of such ships.
Saibu Gas received its first LNG cargo, at a purpose – built reception terminal at Fukuoka on the island of Kyushu, in 1993. The 18,800 m3 Aman Bintulu is utilised to service the trade but a second, similar – sized ship is under construction to enable the delivery rate for the 20-year trade to be increased from 0.15 to 0.36 mta . The new ship is scheduled for commissioning in September 1998. Deliveries to SCGB began in May 1997 on a cif basing utilizing the 18,800 m3 LNG carrier Aman Sendai. A second ship could be required after 2000 if it is decided to double deliveries to 0.27 mta .
The owner of the two Saibu ships and the Sendai vessel is Asia LNG Transport, a joint venture between NYK and Perbadanan National Shipping Line Sdn Bhd (PNSL) . PNSL is a private Malaysian shipping company.

The Shizuoka Gas agreement did not follow this vessel downsizing trend. It utilizes a 130,000 m3 LNG carrier to deliver small – volume, part cargoes to the terminal Shimizu where a 83,000 m3 storage tank is in place. the first shipment on this new trade was delivered in June 1997 aboard Putri Nilam . For the first four years, the ship will discharge part cargoes at Shimizu and in Tokyo Bay for Tokyo Gas. From 2001 onwards, the Shimizu terminal will be able to accept full cargoes from large LNG tankers .

4.1.16 Malaysia – South Korea

Korea Gas Corporation (Kogas) began importing Malaysian LNG on a spot basis in 1991. In 1993 the relationship with the exporter, Malaysia LNG Sdn Bhd 2, was established on a more sound footing when a long – term fob contract, which called for deliverers of 2 mta of LNG for 20 years through 2015 , was agreed . Deliveries under this contract began in 1995 from the Bintulu 2 complex and attained plateau levels in 1997. Two Korean – built ships deliver the gas to the Pyong Taek terminal.
In a separate short – term agreement concluded in November 1994 , Kogas agreed to purchase 93 cargoes of Malaysian LNG , totaling 5.25 mta , over a five – year period up to 2000 (equivalent to 1.05 mta) .
South Korea's requirement to cancel LNG cargoes as a result of the economic fall out from the Asian economic crisis extended to this trade. It is estimated that seven cargoes from Malaysia to South Korea were cancelled / deferred in 1998.

4.1.17 Malaysia – Taiwan

Malaysia LNG Sdn Bhd exports 2.25 mta of LNG from its Bintulu 2 complex to the Yung – A reception terminal under a contract finalized with Chinese Petroleum Corporation in 1995. Deliveries commenced in May 1995 and are in the process of building up to plateau levels. In 1996, total deliveries were just 1.1 million tons. Shipments are scheduled to continue until 2015.

4.1.18 Nigeria – France

The Nigerian LNG (NLNG) project finally got off the mark after 30 years of procrastination and a number of false starts with the lifting of the first ever LNG cargo from Bonny Island liquefaction terminal on the LNG Lagos (122,000 cum , built 1976) on 5 October 1999 . LNG shipments , which are delivered to an existing reception facility in Montoir , are governed by a 22.5 years cif contract (1999 – 2002) signed with the Gas de France for the delivery of 0.40 mta , which is equivalent to 7% of the total output from Nigeria's first two LNG trains .

4.1.19 Nigeria – Spain

The first LNG cargo shipped on this trade was lifted on the LNG Finisna built 1984 on 13 October 1999 with delivery at an existing reception facility at Huelva , Spain . LNG shipments are governed by a 22.5 years cif contract (1999- 2022) signed with EnEiqas of Spain for the delivery of 1.26 mta , which is equivalent to 22% of the total a separate agreement , Enagas agreed to a 21-year contract to purchase over 70% of the output (

equivalent to a further 1.26 mta) from NLNG's planned third LNG train , which is expected to be completed during the fourth quarter of 2002 .

4.1.20 Nigeria – Turkey

The first LNG cargo shipped on this trade was lifted on the LNG Lagos (122,000 cum, built 1976) on 3 November 1999 with delivery at an existing reception facility at Eregli, Turkey . LNG shipments are governed by a 22.5 years cif contract(1999 – 2022) signed with Botas in Turkey for the delivery of 1 mta , which is equivalent to 17% of the total output from Nigeria's first two LNG trains .

4.1.21 Qatar – Japan

At Zubarah , the first in a series of ten 135,000 m3 LNG carriers , initiated the new Qatargas project in January 1997 when she lifted the first cargo of Qatar LNG . With this shipment , Qatar became the world's ninth exporter of LNG and only the second from the Middle East after Abu Dhabi .
The Qatargas project is a co-operative venture between Qatar General Petroleum Corp (QGPC) and partners TotalFina (operation) , Mobil , Marubeni and Mitsui . The capital markets made their debut in the LNG sector in Qatar's Ras Laffan project.
The Qatargas project calls for the delivery of 6 mta of LNG from a three – train liquefaction complex at Ras Laffan over a period of 25 years (until 2022). After deboltlenecking it is expected that capacity will be lifted to 8 mta . Four 85,000 m3 tanks have been built at Ras Laffan to store the LNG prior to export. Qatars offshore North Field is the world's largest single reservoir of natural gas with the estimated reserves of 7.1 trillion m3, making Qatar third largest gas power after Russia and Iran .
The Qatargas LNG has been purchased by a group comprising five major Japanese electric power companies (Tokyo , Chubu , Tohoku , Kansai and Chugoku Electric) and three gas utilities (Tokyo , Osaka and Toho Gas). Of these 3 companies Chubu Electric Co. is by far the largest customer taking an estimated 4 mta. LNG sales are linked to average published LNG prices rather than to a fixed rate.
Ten tankers will eventually be required to service the Qatargas project. These vessels will be jointly owned by a consortium comprising five Japanese shipping companies (Mitsui QSK, NYK, K Line, Showa Line and Lino Kaiun). Four vessels in service by the end of 1997.
In addition to its long – term contract with Japan (and while these contracts have yet to build to full volumes e.g. . Chubu Electric Co. to take 3 million tons in 1998 equivalent to 75% of final volumes) , Qatar has taken a proactive approach to selling its surplus LNG on the spot market .
In 1997 , it signed a short – term contract with Enagas of Spain (which was faced with disrupted Libyan contract supplies) based on a 13-month term to ship 0.42 million tons using the Norman Lady (the 37,600 m3 vessel previously employed on Abu Dhabi – Japan trade , and lately earmarked for Atlantic LNG from 1999) .
Qatar's involvement with the spot market was consolidated in 1993 with an extension to its Enagas agreement and the negotiation of an additional spot contract with Turkey for 0.4 million tons. In 1999, it is calculated that Qatar completed six spot voyages to Spain, five spot voyages to the USA and one each to France and Italy .

4.1.22 Qatar – South Korea

The first of 1990 shipments was lifted on 22 September 1999 by the SK Summit (130,000 cum, built 1999) . Qatar – South Korea was the only one of the six new trades entering service in 1999 to involve an existing exporter (Nigeria (3) and Trinidad & Tobago (2) were responsible for the other new trades). It was the only one of these trades to begin operations with a new building; there will be eight in total. It was also the only one of these trades in the Pacific, and started update a time when there was a shift in emphasis to the Atlantic market. Cargo for this trade was generated by Qatar's second LNG export project at Ras Laffan . Like Qatargas , this project called Ras Laffan LNG (RasGasf) utilises the vast gas reserves of Qatar's North Field .
Phase 1 of the Ras Laffan project was completed on schedule in August 1999 and consists of a two-train liquefaction complex (each with a capacity of 3.3 mta, which was built close to the Qatargas facility at Ras Laffan on Qatar's North-Eastern coast. The RasGas terminal has two 140,000 m3 storage tanks ; these are the largest concrete LNG tanks yet built . Shipments are governed by a 25-year contract (1999 – 2024) signed between Ras Laffan LNG and Korea Gas Corporation (KGC) for the sale of 2.4 mta of LNG on an fob basis. The contract includes an option under which KGC can purchase an additional 2.4 – 3 mta from the year 2000. In September 1997, the partners initialed agreement with Itochu and Nissho Iwai under which the Japanese corporations will take 4% and 3% stakes, respectively, in RasGas . Both Mobil and QGPC will reduce their shareholdings to accommodate the new participants who, in turn, will help market the gas in Japan. RasGas with the assistance of Itochu and Nissho Iwai, is in negotiation with several Japanese utilities over the purchase of the remainder of the gas which would be available under RasGas Phase 1 should KGC decide not to exercise its option . The RasGas project has been extensively funded from world financial markets obtaining.

The following financing facilities:

- A loan of $450 million from a bank syndicate led by Japan Industrial Bank and Credit Suisse.
- A loan of $465 million by the US Export – Import Bank
- Credit facilities for $250 and $110 million guaranteed by British ECGD and Italy's Sace respectively
- Two bond issues totaling $1.2 billion by Goldman Sachs and CS First Boston

Looking further ahead, RasGas has Phase 2 of the project, involving another two trains and extra 5 mta of LNG sales, under review . Letters of intent have been signed with companies in Taiwan, Turkey, Thailand, China and India, although no firm timetables have been discussed.

4.1.23 Triniad & Tobago – Spain

The first shipment was lifted on 19 June 1999 by the Methane Arctic (71,500 cum, built 1969) from Point Fortin for delivery at an existing reception terminal in Barcelona. The first voyage was some months ahead of the scheduled November 1999 start up. There were an estimated 11 voyages completed in 1999.
Amoco Triniad supply Atlantic LNG with the 450 m ft3 / day needed to meet contract obligations over the 20-year (1999-2019) life of the project. Enagas of Spain lake %40 (1.2 mta) of the LNG output from Point Fortin under an old fashioned take or fob

contract. The transportation requirements for this project and also the trade to the US have been meet by chartering-in four existing LNG carriers.
The addition, second and third liquefaction trains at Point Fortin are already under study and, as with the first train, buyers in niche markets are being targeted. Spain maybe an important market for the second phase capacity. As part of the development phase of building the new trains, Enagas of Spain has conducted a drawn out tendering process for up to six new buildings.

4.1.24 Trinidad & Tobago-USA

Trinidad becomes the 10th LNG exporter when the Matthew (126,540cum, built 1979) lifted the first cargo from Point Fortin on 1 May 1999 for delivery at the Everett terminal in Boston. The project has a 20 year life (1999-2019) with Cabot LNG taking %60 (1.8mta) of the LNG output from Point Fortin under an old fashioned take or pay, fob contract. There were an estimated 21 voyages completed in 1999. The transportation requirement for this project and also the trade to Spain has been meeting by chartering in four existing LNG carriers.

4.1.25 USA (Alaska)-Japan

This trade started in 1969 and involves LNG shipment from Kenai in Alaska to Negishi in Tokyo Bay. The contract was originally due to expire in 1984, but in 1982 was extended for a further five years and then in 1988 the two producers, Philips and Marathon reached agreement with Tokyo Electric and Tokyo Gas for a 15-year extension to 2004, with the option for a further five years to 2009. There is an option in the contract to allow flexibility in the lifting's of +16% to –10%. The contract quantity in 1990 amounted to 1.06 million tons of LNG.
In 1994 import levels were boasted from 0.96 to 1.24 mta to reflect the greater cubic capacity of two new vessels which were introduced into the trade to replace the 71,600 cum LNG carriers which had served the trade since its inception. The new ships, Polar Eagle and Arctic Sun are owned by Philips and Marathon on a 70/30 basis and each has a capacity of 89,000 m3.

4.2 Planned new LNG trades

The following projects are in the advanced stages of development and are expected to reach fruition in 2000/2001. However, while these projects are at an advanced stage of development, the complexity of the "LNG chain" (comprising upstream gas development projects down to IPPs, power generation utilities or retail distribution networks), coupled with changing economic conditions means start-up dates are liable to slippage.

4.2.1 Abu Dhabi – India

Abu Dhabi has signed a contract to supply Dabhol Power Company, via its Dabhof reception terminal on the Indian West Coast, with 0.5 mta starting in late 2001.

4.2.2 Algeria – Greece

In 1988 the Public Gas Corporation of Greece (DEPA) agreed to purchase 9 mtons (equivalent to 0.6 mta) of Algerian LNG from Sonatrach during the period 1999-2012. According to tracking data no voyages were completed in 1999.
The LNG will be loaded at Skikda shipped to a new terminal under construction on the island of Revithoussa near Piraeus. The Greek reception facility will feature two 72,000 m3 storage tanks which are being built with a special support system to protect against the risk of earthquake damage.

DEPA will be responsible for the shipping aspect of the LNG project and is seeking to charter an existing LNG carrier in the 25-40,000 m3 size. Due to port restrictions DEPA is looking for ships no bigger than 205 meters in length and 30 meters in breadth. In addition, the draft cannot be greater than 9 meters.
The LNG will supplement pipeline gas deliveries from Gazprom of Russia which started up September 1996. DEPA has agreed to buy up to 1.2 billion m3/year from mid 1997 and 2.4 billion tons 2007 The Russian gas will be supplied initially to a power station and three local distribution firms.

4.2.3 Nigeria – Italy

This is the last of the four start-up trades from phase 1 of the Nigeria LNG project . According to tracking data no shipments were made in 1999 . The trade is governed by a 22.5 years cif contract (1999-2022) signed with ENEL of Italy for 2.8 mta , which is equivalent to 49% of the total output from the first two Nigerian LNG trains .
A major obstacle to the success of the project was resolved in September 1997 following a deal that allowed ENEL to honors its purchasing commitments. Strong environmental opposition in Italy to potential new reception terminals for Nigerian LNG proved intractable and a new agreement was necessary whereby ENEL's LNG volumes would be shipped to Montoir in France , and for Gaz de France to pipe the same quantity to Italy under a swap agreement.

4.2.5 Oman – Japan

In October 1997, the second customer was secured when Osaka Gas of Japan signed a memorandum of understanding for 0.7 mta for 25 years commencing in November 2000.This agreement was confirmed in October 1998.

4.2.6 Oman – India

This route is set to become the fist ever LNG project involving India. It had its origins in August 1998 when Oman LNG signed a memorandum of understanding with Metgas of India (a subsidiary of Enron) to supply 1.2 mta to the Dabhol power plant under construction 240 km south of Mumbai over 25 years commencing 2001 . The agreement was confirmed in October 1999 with cargo volumes increased to 1.6 mta. Enron is looking at both second hand and new building tonnage to service the Oman contract In February 1999, it was announced that Enron had secured the LNG Aries to operate on this trade from June 2002.

4.3 Potential LNG export projects

The following projects, which are mostly at the feasibility or design stage, are driven by export countries.

4.3.1 Alaska – Asia Pacific (design – 2005-2007)

The Trans – Alaska Gas system (TAGS) is one of the most ambitious LNG projects under consideration. Project manager Yukon Pacific Corporations seeking to mount a scheme on the back of the vast gas resources of Alaska's North Slope . The gas would be treated at Prudhoe Bay and piped 1.350 km to Valdes for liquefaction and transport by LNG tanker to buyers in the Far East. Large volumes would have to be processed to ensure the projects viability and proposals have been laid down for peak delivery quantities of 14 mta utilizing a fleet of 15 LNG tankers of 125,000 m3 in size . The cost of mounting this project has been put at $15bnh 40% of which would be due to the construction of a Trans-Alaska gas pipeline.
In March 1997 two memoranda of understanding were signed in an effort to reinvigorate the project. One was signed by Yukon Pacific, a company majority-owned by CSX Corporation, and the other by the owners of the North Slope's three major gas fields, i.e. Arco , BP and Exxon . Under the agreements, the parties will work to cut the projects $15bn development costs and seek a chance in the Alaskan fiscal system to make the venture more competitive. The project was given a boost in August 1997 when Philips, which has been operating the nearby Kenai LNG export plant for 30 years , was enlisted as a partner . However, it is not thought that this project will come to fruition until after 2005 .

4.3.2 Australia – Asia Pacific

Australia (NWS Phase 2) – Japan (design / construction – 2003-2005)
The existing partners in the North Weal Shelf – Japan LNG project – five leading Japanese Electric utilities (Tokyo , Chubu , Kansai , Chtigoku , and Kyushu Electric) and three city gas suppliers (Tokyo , Osaka , and Toho Gas) have expressed a readiness to increase imports of LNG from Western Australia . These companies currently import 7.33 mta of LNG under the 20-year North West Shelf contract which began in August 1989 and will run to March 2009. The companies slated that they would like to extend the current the current agreement and start another 7.33 mta contract , beginning in 2003-2005 with total exports to Japan rising to 14.7 mta .
Another two trains (fourth and fifht) would be required to service this NWS phase 2 project .The NWS partners have submitted a formal proposal to the Japanese buyers for the $2.9bn expension of the existing project . Engineering work is currently underway on a second offshore tunkline to serve the NWS project as the first line is operating at full capacity . The new line will enable increased volumes of natural gas to be delivered to the domestic market and , in the future , handle the product flows of the NWS phase 2 project .The year 2000 has been set as the target date for the comletion of this line . There is also a possibility that a further scheme , utilising gas from the nearby Gorgon field , might go ahead on the basis of sharing berthing and related facilities with NWS at Karratha .
The economic slow-down in Asia impacted negatively on the new schemes . Woodside Petroleum operators of NWS slated in October 1998 that they are unlikely to go ahead

with the purposed fifth train while start-up of the fourth train has been pushed back from early 2003 to late 2003/4 . Hovewer, planning continuous with customer targetting shifted away from the Japanese market and towards Taiwan , South Korea , China and India . The Chinese market is seen as the best prospect when it starts imports in 2005 . The confidence of the NWS partners that they will find new markets for their gas is such that in July 1999 it asked ten yards to tender for up to four newbuildings to be delivered in 2003 .By September , the number of yards had been shortlisted to four with a decision expected in early2001 .

Australia (Gorgon) – Asia Pacific (feasibility-2005)

Western Australia Petroleum (Wapet) , owners of the Gorgon field in north western Australia , favor a co-operative venture with the existing North West Shelf (NWS) LNG project as the optimum route for developing the field's mammoth gas reserves .
In the proposal being drawn up by the Gorgon partners, i.e. Chevron (with a 26.6% share holding), Texaco (26.6%), Shell (28.6%) and Mobil (14.3%), gas would be piped from the field to the NWS export terminal at Karratha for liquefaction. The field, with estimated usable reserves of 20-22 trillion ft3, would provide gas for two additional LNG processing trains at Karratha generating a potential 6-8 mta LNG exports. Cost of the two new trains is estimated at a $6 billion.
In the final analysis, because the Gorgon partners would have to defer to the NWS 2 project If Karratha was to be the loading port, they may need to develop their own export facility . Due to the Asian economic slow – down from 1997, project participants calculated that the LNG demand window had shifted backwords from 2003 to 2005 and therefore start-up plans have been revised to 2005.

Australia (Darwin) – Asia Pacific (drilling / feasibility – 2005)

In spring 1997 Shell Development (Australia) and Woodside Petroleum agreed to investigate the feasibility of a $10 billion project involving the construction of an LNG export facility and domestic gas supply plant at Darwin . The two-train LNG plant, which would come on – stream in 2005 , would be able to 7.5 mta to overseas buyers for 20 years. Potential buyers of this gas are China, Japan, Thailand, India and the Philippines and a fleet of five 135,000 m3 LNG carriers would be required the service the trade . The project is conditional on a number of factors, not least lining up sufficient reserves. The offshore Sunrise, Troubadour, Loxton Shoals and Evans Shoals fields hold and estimated 5 trillion ft3 but a further 5 trillion ft3 would be needed to make the project viable. There are a range of developments in the nearby Gulf of Bonaparte and Timor Sea which are likely to field the quantities of gas needed. The feasibility study for these projects expected to be completed by end 1993.
Santos Ltd has proposed a 2-4 mta LNG export facility in Darwin on the back of gas reserves in the offshore Petret and Tern fields, in which it has a controlling interest, in the Bonaparte Gulf of Northern Australia. Two to four 125,000 m3 LNG carriers would be needed to carry the gas to market and a start-up date of 2002 has been mooted. If this project comes to pass, the likely destination for the gas is Japan, due to participation by Osaka Gas, Sumitomo and Teikoku in the appraisal work.

Australia / Indonesia (Timor Sea)-Asia Pacific (feasibility-2002-2010)

BMP Petroleum has been selected as field operator of a project to utilize the hydrocarbons of the Bayu-Undan gas condensate discovery in an area of the Timor Sea jointly administered by Australia and Indonesia. Scheme development calls for the production of the condensate and LPG, utilizing a floating production vessel and shuttle tankers, beginning in 2001. In Phase 2 of the project LNG would be produced, either onshore or offshore, starting some time between 2002-2010. An offshore, gravity – based LNG plant is BHP's favored approach. This unit would utilize BHP's proprietary technology and would be the first of its kind in the world Bavu-Undan straddles two license blocks. Lead partner in the second block is Philips, a company which favors piping the gas 450 km to an onshore plant to be situated near Darwin. This two-train plant would be built utilizing Phillip's Optimized Cascade Process technology. The final selection remains subject to the approval of the Timor Gap Joint Authority which is expected in late 1997. Target markets for Bayu-Undan LNG are Taiwan, Japan and Korea. Estimated production is in the range 3-6mta.

4.3.3 Canada – South Korea (design 2004)

In April 1997 an international consortium led by Phillips Petroleum Canada signed a memorandum of participation to establish a 3.5 mta LNG export facility near Kitimat in British Columbia. The gas, which would be piped from Alberta to Pacific Coast terminal for liquefaction, would be purchased by Korea Gas Corporation, the Korean state gas company . Kitimat would be the third gas liquefaction facility to employ Phillips proprietary, optimized cascade LNG technology, the other two being at Kenai (Alaska) and the Point Fortin plant currently under construction in Trinidad.
However, the financial crisis that hit Asia in the second half of 1997 caused the cancellation of regular spot LNG cargoes to South Korea and led to a sharp downward assessment of South Korean future energy requirements .Consequently the initial 1999 start-up date was detailed .the project was dealt a further blow in November 1997 when Phillips Petroleum pulled out .
Despite these setbacks the remaining partners-Daewoo Corporation, PacRim LNG of Calgary, and Bechtel Enterprises-have continued the design phase. However, despite the prospect of Korea Gas Corporation joining the partnership, it is not thought that this project will come to fruition until after 2004 at the earliest.

4.3.4 Egypt – Turkey (feasibility – stalled)

In November 1996 Turkey signed an agreement in principle with Egypt , in association with Arnoco and Agip , for the delivery of 10bn m3/year (equivalent to 7.2 mta LNG) Egyptian gas to Turkey from 2001 .Delivery options include a full-scale LNG project or a $2bn sub sea pipeline from Port Said to Iskenderun in Turkey (also overland option).
The LNG project would require a 3 mta plant to be built near Port Said and a new import terminal at Izmir . Potentially, a market for the gas will created by four new power plants just announced by the Turkish government.
However, the project faces competition from plans to supply pipeline gas from Turkmenistan and Iran.

4.3.5 Indonesia – Asia Pacific

The huge offshore Natuna gas field has been identified by the Indonesia as the vehicle by which it will maintain its status as the world's leading LNG exporter. However , technical problems and geopolitical issues concerning disputed sovereignty with China and Vietnam have slowed the project's impetus as has problems of securing customers in the face of Asian economic malaise .
Exxon has a 50% stake in Natuna while other shareholders include Mobil, with 26% .Pertamina 11% and a Japanese consortium 13%.
Natuna has recoverable reserves of 46 trillion ft3 but the gas is rich in carbon dioxide and development plans have to take into account the removal of this substance from from the gas stream in an environment – friendly manner. Natuna is also handicapped by a remote location 1000 km north of Jakarta and 600 km north-east of Singapore, in waters reaching a depth of 145 meters .
In order to overcome the technical problems associated with the Natuna project , it is envisaged that large offshore platforms will be required in order to mount sophisticated cryogenic separation equipment . About %60 of the development costs are related to the field's high CO_2 content.
Various options have been put forward for exploiting these reserves, including a six – train grassroots LNG production facility on Natuna island (potentially Indonesia's third LNG facility) .The initial scheduling of this project anticipates that full production of 15 mta would not be achieved before 2010 with a start-up capacity of 5 mta by 2005 .Pertamina is also considering LNG backhaul, SWAPS and floating LNG production schemes as options to develop the Natuna field. However, many observers consider the project too costly with estimates as high as $43 billion.
Notwithstanding these LNG feasibility studies , one of the most likely initial Natuna projects was thought to be the delivery of gas by long-distance sub sea pipeline to Thailand . In May 1997 Thailand and Indonesia signed a memorandum of understanding, but this was subsequently cancelled, reinforcing the latest contention that Natuna is a project for some way in the future .

Indonesia (Tangguh) – Asia Pacific (drilling/feasibility 2003)

The Tangguh field off the coast of Irian Jaya has recently emerged as a contender to Natuna for the position of Indonesia's third LNG export facility. The development is composed of the Wiriager Deep , Berau and Muturi blocks and has officially been named Tangguh (meaning reliability and strength) supposedly in recognition of its size and economic importance to the country .Confirmed reserves (as at September 1998)in the three blocks are 1.0 , 10.3 , and 3.1 trillion ft3 respectively . Total confirmed reserves are 14.4 trillion ft3 , with probable reserves estimated at 18.3 trillion ft3 . It is estimated that this massive field could support output of 9-10.5 mta for 25 years.
The original partners in the field are Arco, with 45% of the shares, Occidental 22% Nippon Oil 18% and Kanematsu 12%.Arco is considering a fast-track development of the field in which a two-train LNG plant could be producing 6 mta for export by 2003 .Both Japan and South Korea have been targeted as baseload buyers of this potential new LNG source. However , the ongoing fragility of the political and economic situation in Indonesia , coupled with difficulty in securing long-term contracts , means that it is uncertain when Indonesia can commit itself to a new LNG project –whether it be Natuna or Tangguh .

4.3.6 Libya – Italy (construction – no contracts)

Libya's contracted deliveries of LNG to the Panigaglia terminal near La Spezia in Italy were suspended in 1980. There have been a few shipments between the two countries during the 1990s but these have been fitful at best . The Panigaglia terminal has recently been refurbished to receive normal grade gas (Libyan gas is rich in LPGs) and capacity has been expanded to 2.9 mta .
Work is being carried out on the Marsa El Brega liquefaction plant in Libya to provide LNG of a comparable grade to that marketed by other countries.
Although no contracts have been finalized, ENI of Italy has talked positively about the role that Libya should play in developing the Mediterranean gas market , as an exporter of both pipeline gas and LNG .

4.3.7 Malaysia (MLNG 3) – Asia Pacific (design 2001)

The decision to build a third LNG plant at Bintulu , Bintulu 3 (also known as Tiga) , was taken in December 1995 . Bintulu 3 will be owned and managed by Malaysia LNG Sdn Bhd 3 (MLNG 3) . MLNG 3 is a consortium comprising Petronas , the Malaysian national oil company (with 60% of the shares) and Shell , Nippon Oil , Occidental and the state of Sarawak (each with a 10% stake).The project is considered by slate-owned Petronas to be a grassroots facility , bill in reality it shares extensive facilities with the existing Bintulu projects .
The new plant will consist of two trains with a combined capacity of 6.3 mta .There are plans for a third train to be added if necessary. Likely markets for the output of Bintulu 3 will be the three existing destinations for Malaysia LNG: Japan, Korea, and Taiwan. However, new prospects in India, China and Thailand, amongst other countries, will also be targeted. Taiwan's Chinese Petroleum Corporation (CPC) has signed a memorandum of understanding with MLNG 3 for the purchase of 2 mta of LNG from Bintulu 3 on a cif basis beginning in 2001 .A similar deal has been signed with the Korea Gas Corporation. The latest agreement signed in 1999 is to supply Metropolis Gas at the Dabhol reception terminal in India with 2.6 mta starting from mid 2002.
Although there has been speculation that Bintulu 3 be put on hold because of the lack of guaranteed LNG sales, a contract for the construction of the plant is expected to be placed in 2000. The intention to push forward with the project is illustrated by what has been described as the first speculative LNG new building contract , When Petronas ordered to option two135,000 cum LNG carriers (split between Mitsubishi HI and Mitsui).
If Bintulu 3 is commissioned , Bintulu's total production will exceed that of Bontang in Indonesia , the world's current leading LNG export site . However, should a ninth train be added at Bontang . Bintulu's top ranking will be short-lived.

4.3.8 Nigeria –Portugal (feasibility-no timetable)

Until recently, Portugal was the only European country not consuming natural gas. This changed early in 1997 when Algerian gas reached Portugal with a new Maghreb Europe Gasline (MEG) . Further work is necessary on Portugal's natural gas network before it becomes fully operational but , by 2000 , delivery volumes are expected to be at plateau levels of 2.5bn m3/year under a 25-year contract with Sonatrach of Algeria . By means of new compressor stations , it will be possible to increase the flow of MEG gas to Portugal to 4.5bn m3/year , by 2000 natural gas is expected with account for 8%-10% of the countries primary consumption . Portugal , like Spain , is seeking to diversify its energy sources and Transgas , the Portuguese natural gas operator due to be privatized in 1997 , has been in discussions with Nigeria LNG Lth about a possible LNG sales contract . Volumes discussed are in the order of 0.35 mta initially .The country is anxious to reduce its heavy dependence on imported oil.

4.3.9 Norway – Europe & USA (feasibility 2003)

Stat oil is looking to develop the Snohvit , Albatross and Askeladden gas fields in the Norwegian sector of the Barents Sea . This offshore sector is located in a remote , inhospitable region with the Arctic Circleand it has been difficult to put a case together that would confirm the commercial viability of the venture . One option is to pump the gas along a multiphase sub sea pipeline to Melkoya Island near Hammerfest where a 3.5 mta liquefaction plant would be built . The use of existing LNG tonnage has also been mooted. The prefect is seeking approval in 2000 with a proposed start-up date of 2003.

4.3.10 Oman – Thailand (contract-suspended)

An agreement between Oman LNG and the Petroleum Authority of Thailand for the shipment of 2 mta from 2003 was signed in September 1996. Subsequently approved by both boards in January 1997, it was awating approval by the Thai government. However, the combination of an energy review in Thailand and the Asian economic collapse from mid-1997 led to the suspension of the deal until 2007. It is possible that *the arrangement may be re-engaged.*

4.3.11 Papua New Guinea – Asia Pacific (feasibility 2005)

Papua New Guinea has speculatively floated a proposal for LNG exports in recent years. Gas from the Hides field , which is controlled by BP , Exxon and Oil Search , would be utilized and piped to an LNG liquefaction plant on the northern coast of the country at Wewak Hides gas reserves would support a two-train export project of up to 7 mta . Markets would have to be found and a start-up before 2005 is unlikely.

4.3.12 Qatar – Mediterranean & Asia Pacific

Qatar – India (multiple projects , design –2003)

Qatar has been developing relationships with numerous potential import partners as a means to achieve its goal of exporting 30 mta of LNG by 2003-2008 , and thereby become the world's biggest exporter of LNG .
It achieved a major breakthrough in September 1998 when Ras Laffan LNG (RasGas) won the contract (beating off six competitors) to supply 7.5 mta to Petronet LNG India for 20-25 years commencing 2003. The agreement is split into two parts with 5 mta destined for the port of Dahej in the state of Gujaral and 2.5 mta to the city of Cochin in the state of Kerala .

This project represents the third Qatar LNG export project and the second undertaken by RasGas . When the agreement is ratified the project will be reclassified as a "planned new trade" . It is only the second contract signed with India to supply LNG following the contract signed with Oman in October 1999 to provide 1.6 mta to MetGas . Qatar is also negotiating with Tamil Nadu Industrial Development to supply 2.6 mta for the Ennore import terminal. This scheme has a planned start-up date of July 2003.

Qatar – Taiwan, Thailand, China, Lebanon, Jordan (design 2001)

Chinese Petroleum Corporation's (CPC) letter of intend with Ras Laffan LNG (RasGas) for the purchase of 2 mta of LNG over 25 years has now lapsed due to difficulties experienced by Taiwanese power company operator in gaining sitting and environmental permits for new gas-fired power plants . Meanwhile, the planned import volume has been reduced to 1.5 mta and the start-up date has been set for 2001.
Qatar and Thailand have agreed a memorandum of understanding covering the shipment of 2 mta for 25 years. The project is unlikely to get underway before 2003 the anticipated completion date for that LNG import terminal. Thailand has made an effort to organize pipeline imports, particularly from Burma and Indonesia's Natuna field. This will ease pressure on the need to secure LNG imports.
Ras Laffan LNG and the Wing Group , now owned by US-based Western Resources , have signed a letter of intent covering the shipment of 2.5 mta of LNG to China , with an option for a further 2.5 mta . The Wing Group is seeking to build gas-fired power plants near Shanghai and in Jiangsu Province. A 2400 MW power plant and LNG import terminal have been approved in principle by Shanghai's electric utility agency.
At the end of 1997, it was announced that the Ras Laffan LNG company had signed a memorandum of understanding with the Elf Aqurtaine group of France for the supply of LNG to Lebanon. No volumes have so far been revealed.
There are plans for Qatar to export LNG to Jordan and from there by pipeline to neighboring countries. Initial plans are for 0.5 mta of LNG from 2001. However, Jordan is also studying plans from UAE and Egypt.

Qatar – Turkey (design 2000)

Ras Laffan LNG (RasGas) has secured a contract to supply 0.7 mta of LNG to the Marmara Ereglisi terminal for onward distribution by pipeline to a power plant to be built near Istanbul by Mobil.
Marmara Ereglisi already had contracts to receive Algerian and Nigerian LNG and Qatar was lefted with tilling up the available capacity. However, there is potential for further expansion in LNG to Turkey with import terminals at Izmir and Iskenderun under consideration. In addition, Qatargas initiated a 0.4 million tons spot trade with Turkey from February 1998, although this was not sustained into 1999 .
Despite the prospect of a new LNG projects , it is thought that Turkey is mainly focusing on pipeline deals to secure future gas supplies . In April 1997 , Turkey signed a $13.5 billion , 25-years agreement with Gasprom , the Russian natural gas company , for the import of pipeline gas to help meet its growing demand for energy . Turkey currently imports 6bn m3/year of gas from Gasprom (equivalent to 4.35 mta LNG) but

under the new arrangement additional pipeline imports will begin this year with an additional 500 m3, gradually building up to a total of 30bn m3/year by 2010.
To achieve these levels the existing Russia-Turkey pipeline will have to be expanded and a second line will have to be built. Turkey's energy consumption is currently growing by 10% per annum and great effort is being made to switch from lignite coal, as the current primary domestic central heating fuel, to natural gas .
Despite the major deal with Russia , double remain about the project .Russian deliveries have not always achieved full contract volumes in the past and there are doubts about financing for the two alternative pipeline routes for the new Russia-Turkey link . Consequently, Turkey is anxious to diversify its sources of supply through further pipelines and also LNG shipments.
The Iran agreement, which would require a pipeline to be built to enable the movement of up to 10bn m3 of natural gas annually between the two countries by 2002, has aroused opposition from the US on political grounds .

4.3.13 Sakhalin island (Russia) – Asia Pacific (feasibility 2005)

Over the last 20 years, several large oil and gas deposits have been discovered of the north-eastern shore of Sakkalin Island. Sakhalin is a long narrow island situated of Russian's Pacific coast; its southern tip is only 43 km from Japan's northern most island , Hokkaido. Two of these offshore fields, Lunksoye and Piltun Astokhskoye , are being developed as the Sakhalin 2 project under a production sharing contarct with the Russian Federation by Sakhalin Energy Investment Company (SEIC) . The share holders in SEIC are Marathon Oil Company (with a 37.5% stake) , Mitsui (25%) , Shell (25%) and Mitsubishi Corporation (12.5%). The gas reserves in the two fields total 14 trillion ft3, with 80% of the local in the Lunskoye field . This is enough to support a 6 mta LNG export project over a period of 20 years.
The inhospitable environment around the two fields poses challenges for SEIC. As the sea in the area is frozen six months of the year, it is proposed to bring the gas ashore from the two fields via subsea pipeline to a common onshore processing facility. After processing, the oil and gas would be directed through to separate 625 km long pipelines to an LNG plant and oil export facility in the ice-free port of Karsako at the southern tip of the island .Detailed appraisal work is now underway but SEIG realistically hopes to begin LNG exports in 2005, the earliest at which the main regional markets of Japan, Korea and Taiwan could be expected to experience a supply shortfall . Potential buyers of Sakhalin 2 LNG will need to be reassured that federal legislation on the ownership of continental shelf resources will not be used to justify expropriation of the project. An LNG phase of another regional energy project , Sakhalin 1 , is running about three years behind that of Sakhalin 2 .

4.3.14 Venezuela – USA (construction –2003)

Venezuela's long-mooted Cristobal Colon LNG export project may be revitalized by the involvement of Enron , whose track record includes participation in the Oman-India trade which was the first ever Indian LNG import scheme. In November 1999, Enron announced a tendering process for two existing LNG carriers to service a 2.1 mta trade between Venezuela and USA. The project start-up is set for 2003 and involves reactivation of the Elbe Island LNG reception terminal to handle imports.

The Enron scheme appears to have displaced an earlier project , calling for the export of 6 mta of LNG from a terminal near the Paria peninsula in north eastern Venezuela to Europe. The partners in the Sucre Gas consortium which promoted the earlier project were Lagoven (with 33% of the shares) , Shell (30%) , Exxon (29%) .

4.3.15 Yemen – Turkey & Asia Pacific (construction-2002)

In March 1997 Yemen's energy ministry approved the Yemen LNG Company's proposed $5 billion gas export project which calls for shipments of 5 mta of LNG for 25 years, beginning at the earliest in 2003. Yemen LNg comprises TotalFina with a 36% share, Exxon and Hunt Oil jointly 30%, the Yemen government 26% and South Korea's Yukong 8%. The project was originally mooted in 1992, but a civil war in early1994 delayed proceedings .The country has since been reunited under the North Yemen .
The Yemen LNG project calls for a two-train LNG liquefaction plant (capacity 6 mta) to be built at Bal Haf on the Gulf of Aden, 330 km east of Aden. It will be supplied by pipeline from natural gas reserves in the Marib region. Two storage tanks of 125,000 m3 each are to be provided along with a single berth able to accommodate 140,000 m3 ships.
The Yemen LNG Company initially targeted the European market . It pointed out that, geographically, it is best placed of all the Middle East LNG projects to supply the European market, and in 1995 Botas , the Turkish state gas company , signed a letter of intent for the purchase of 2.6 mta of Yemen LNG over 25 years .
However, having completed the design stage at the start of 1998, Yemen construction was put on hold until sales are assured.

4.4 Potential LNG import projects

The following projects are driven by import countries

4.4.1 China (tender 2005)

Mounting energy requirements mean that there is good potential for the use of LNG in China .Environmental concerns also underpin the case for clean-burning LNG with a 1998 report by the Washington-based World Resources Institute indicating that nine of ten most polluted cities in the world were in China – a result of an almost 80% dependence on coal as the source of energy.
The scramble to supply China with LNG is set to intensify with the announcement in early 2000 that the government has approved the construction of a $500 million import terminal at Depeng Bay near Shenzhen , a city neighboring Hong , and a 2,600 mile pipeline . An invitation to tender for the construction of the project is expected from the China National Offshore Oil Corp (CNOOC) during 2000. Among those expected to bid for the contract are BP Amoco , Shell , Exxon – Mobil and Enron .The proposed start-up date is 2005 .
However, the long-term prize is the expected 20-year, In the guise of the ALNG marketing group will be a key contender, along with Malaysia , Indonesia and Qatar. The Chinese move opens the way for the development of gas power plants in Guangdong province. A second phase could raise Chinese LNG imports to 5 mta .
In June 1999, the Chinese transport giants China Merchants Transportation Holdings and China Ocean Shipping Company combined in an attempt to secure the shipping

portion of China's first LNG import project ; although , with no LNG shipping experience , they have concerned the need for foreign participation .
The Chinese development of LNG import projects should be viewed against a background of its four –pronged energy policy:

1) Build LNG receiving terminal
2) Develop domestic natural gas reserves
3) Develop coal-based methane resources
4) Import Russian natural gas

It should be noted that the potential for China to become the next big purchaser of LNG remains clouded by the unfavorable conditions with regard to securing international financing for potential projects . Stephen Craen (Chase Manhattan , London) tenders have to know there is a real market there to underpin the take or pay commitments of even the most credit worthy buyers . In the past, buyers have generally held a monopoly , like Korea Gas Corporation (Kogas) , or have operated in a highly controlled market , such as that in Japan .
Some observers believe China does not have in place a commercial structure defining the buyer and seller and establishing the contracts, regulations and fiscal environment that govern this relationship. China needs to develop a clear regulatory structure to mitigate commercial risks. It must also provide government support and involvement, particularly in the early stages of project development.

India (LNG import projects)

The emergence of Indian as a viable destination for LNG exports is the most exciting development in the LNG market in recent years. It is set to become the world's third largest importer by 2005. The importance of this new market was brought into even sharper relief by the Asian financial crisis, which caused South Korea and Taiwan to defer cargoes under existing contracts and cast doubt over new projects in the Asia Pacific region.
India's potential in the LNG market has started to be realized with the signing of the first two import agreements:

1) Oman – MetGas (subsidiary of Enron) , confirmed October 1999 (1.6 mta for 25 years commencing 2001 for the Dabhol power plant near Mumbai) .
2) Qatar – Petronet LNG signed September 1998 (7.5 mta for 20-25 years Commencing 2003, split 5.0 mta Dahej in the state of Gujarat and 2.5 mta Cochin in the state of Kerala) .

In addition to the above agreements, there are around 20 other projects involving LNG receiving terminals that have gained a government stamp of approval. However, it is expected that less than half of these will ultimately survive. It is estimated that India will be importing at least 10 mta of LNG by 2010 – the equivalent of four import terminal. Most of the purposed terminals are on the west and North West coasts of India in areas remote from coal deposits. The ten most advanced projects are listed in Table 4.2 .Final gas purchase agreements have been concluded for seven projects (as at October 1999). The total transportation requirement for these projects is estimated at around 12 LNG carriers.

Enron which signed the first Indian LNG import agreement with Oman is the front runner in establishing a fully completed LNG chain. Having secured LNG supplies from Oman other elements of the chain have started to come into place.

1) Construction of a receiving terminal at Dabhol onthe Indian west coast.
2) Construction of a high pressure transmission pipeline from the terminal through Bombay and onto Hazira , through to
3) the provision of base load demand via its large Dabhol power plant , now under construction with the first phase comleted at the end of 1998 . Initially it will use Naphtha or distillate gas, However, Enron expects to be ready to switch to LNG by 2001 when the second phase is completed.

BG is also well down the road towards completing its own LNG chain . Like Enron , BG's project is located on the Indian west coast . The project gained momentum in July 1997 when BG acquired a 44.31% controlling interest in Gujarat Gas Company Ltd (GGCL) , India's largest gas distribution company . Gujaral has 1,000 km of gas pipeline in Surat , Ankleshwar and Bharuch . BG is planning to build a gas-fired power station at Pipavav in Gujarat state which will be serviced by an LNG import terminal also at Pipavav . In the first phase to be completed by 2003, the terminal would have an initial capacity of 2.5 mta . Under phase 2 the facility would be expanded to 5 mta . The total projected cost of the terminal is $900 million.

Table 4.2
Proposed Indian LNG import projects (October 1999)

Purchaser	Volume (mta)	Import terminal	Start-up	Supplier
Dabhol Power Co	1.8	Dabhol	Late 2001	Oman LNG
Dabhol Power Co	0.5	Dabhol	Late 2001	Abu Dhabi Gas
Metropolis Gas	2.6	Dabhol	Mid 2002	Malaysia LNG
Indian Natural Gas	3.0	Trombay	2003	TotalFina SA
Petronet LNG	7.5	Dahej/Kochi	July 2003	RasLaffan LNG
Tamil Nadu Ind Dev.	2.6	Ennore	July 2003	RasLaffan LNG
BG/Sea King	2.6-5.3	Pipavav	2003	MDU&Yemen
Unacol/NATELCO	2.0	Maroli	2003	Negotiating
Shell/Essar or Ell/Reliance?		Hazira	2003	Negotiating
GAIL	5.0	under review	2005	Iran

The project is well placed to receive LNG from the Middle East and BG's director of LNG , Martin Houstan believes that the Pipavav LNG project will be one of the successful ones , because we have the port , we have an excellent local partner in GPPL, we have the market in that we own Gujarat Gas , we have got the foundations of the business .

A major factor impeding the development of LNG imports projects is that India lacks an efficient regulatory framework to govern the plethora of LNG projects .However, there are plans to set up a new Gas Regulatory Authority as part of a proposed new Gas Act ,

which is also intended to contain provisions to shift control of gas pricing away from the government and into the hands of participants in the LNG chain .
An important issue in the development of LNG in India is the policy of "Swedish" or economic nationalism. The necessity for rapid development has meant that 100% direct foreign investment has been permitted in the building of land-bases infrastructure. However, the powerful Indian shipping lobby has consistently demanded a role in LNG transportation.

4.4.3 Netherlands (LNG import project)

In 1995, a group of companies consisting of Fathom Fuels, an American LNG development company, Kemira, a Finnish chemical company operating in Rotterdam and Eneco , a regional energy distributor , formed a project called Gaiga Gas to develop an LNG import terminal in Rotterdam .
Two or three 200,000 cubic meter LNG storage tanks would be built with a throughput capacity of 6 bcm of natural gas per year. The project group is currently investigating possible sources of LNG and developing market is in the Rotterdam area.

4.4.4 Philippines (LNG import project)

Despite economic slow-down following the Asian economic crisis in the late 1990s, it is envisaged that the Philippines will require imports of LNG at some stage in the future to cope with the rising demand for energy. However, substantial domestic gas reserves have recently been proven and the government is keen to utilise this resource to save on purchases of imported oil and coal. As a result, the island nation's first and second gas-fired power stations are set to utilize local fuel. In June 1997, Shell and Occidental agreed to supply gas to First Gas Holdings Corporation, a joint venture between British Gas and First Philippines Holdings , for use in a new power plant to be built at Batangas. The gas will come from offshore Malampaya-Camago gas field in western Philippines. The power station will supply electricity to Manila , beginning in 1999 . As the gas will not begin flowing from Malampaya until 2002 , the 1500 MW plant will run on condensate during the interm period . Once the gas is on-stream , it will continue for 20 years according to the terms of the contract .
Shell and Oxy have signed a separate memorandum of understanding with the Philippines National Power Corporation (NPC) which covers the supply of gas , also from the Malampaya-Camago field , for 20 years to fuel a 1200 MW power station , also at Batangas . The two deals are being considered together as part of integrated gas development project which has been coasted at $4 billion . Final approval of the contracts was expected in November 1997. Malampaya presents significant technological challenges for the field's developers as water depths in the area are in the order of 1,000 meters.
Shell and Oxy contend that their locally produced gas will support the government's stated intention of reducing the power sector's dependency on foreign oil by placing more emphasis on indigenous power sources such as geothermal and natural gas. The companies believe that Malapaya will supply more than enough gas to meet domestic needs but the Philippines government predicts (albeit prior to economic reversals suffered in 1997) that the demand for gas will reach the equivalent of 4800 MW by

2002, well in excess of the offshore gas field's capabilities, it is estimated that Malapaya gas will enable the country to boost its energy self-sufficiency by about 30%. In addition, there are indications that the Philippines gas resources are not limited to Malapaya . The Fuga Island natural gas prospect in northern Philippines waters has potential gas reserves six times greater than those of Malampaya .

4.4.5 Krk Island (LNG import project)

The proposed Adria LNG project , led by OMV of Austria , calls for a 4 mta capacity LNG receiving plant to be built on Krk island , 100 km south of Trieste . This could be expanded to 8.5 mta at a later date. However, plans to build a gas pipeline from the Hungarian border across Slovenia to Italy to streamline the flow of Russian gas to the Italian market and the decision to divert planned Italian imports of Nigerian LNG to France could compromise the overall economics of the Krk Island project.

4.4.6 Porto Rico (LNG import project)

Enron and Kenetech Energy Systems are building, on a 50/50 basis, a combined LNG import terminal , gas-fired power station and desalination plant on the Punta Guayanilla peninsula , 15 km west of Ponce in the US territory of Puerto Rico . The 500MW combined cycle gas turbine power station is being built both to replace ageing power plant capacity and to cope with the island's expanding energy requirements. LNG has been chosen as the fuel because of its clean-burning properties and the need to diversify away from Puerto Rico's over whelming dependence on imported fuel oil . The LNG terminal will feature two 160,000 m3 storage tanks and a jetty capable of receiving 135,000 m3 ships .The participants have opted for the innovative use of stone columns and earth surcharge to mitigate against possible soil liquefaction at the terminal site . This will eliminate the need for costly and risky pile foundations for the storage tanks . The venture has been termed the EcoElectrica project and Enron is currently negotiating possible gas sales contracts. However, because the power plant will be completed before the LNG terminal, LPG will be used as the feedstock in the initial phase. Enron operates the nearby ProCaribe LPG terminal and this facility will be expanded to cope with increased product flows. When the fuel switch-over is made , the power plant will require 0.5 mta of LNG . Both the US Federal Energy Regulatory Commission and the Puerto Rican Planning Board have approved the project .

4.4.7 Thailand (LNG import projects)

The Asian economic slow-down severally affected Thailand's plans to import both LNG and pipeline gas. A deal between the Petroleum Authority of Thailand (PTT) and Oman LNG for LNG imports of 2 mta from 2003 has been pushed back to 2007, while a memorandum of understanding with Indonesia on the sale of gas from the Natuna field for delivery to Thailand by sub sea pipeline, commencing in 2005 is also in jeopardy-as is an initialed gas sales contract with the partners in Burma's offshore Yetagun field situated in the Andaman Sea. In addition, PTT's plans to build a 2.5 to 10 mta LNG import terminal south of Bangkok for completion in 2003 may also be pushed back.

5. SHIPPING SECTORS REPORTS

5.1 Liquefied Natural Gas

LNG is one of the fastest growing energy sectors. This sector is seeing some dramatic developments, with owners having embarked on a bullish ordering spree in 2000 and 2001. Growth in contract and spot demand low new building quotations and the growing attraction of a relatively clean fuel are combining to provide attractive opportunities for investors. As a result , there are 47 LNG carriers on the order book which , over the next four years , will add a mighty 6.5 million cbm to the fleet 46% of the current fleet . The vast majority of natural gas is consumed in the country of production 78% or exported by pipeline 16%. Whilst just 6% (137 billion cbm in 2000) is transported by sea in liquid form . Natural gas liquefies at –160C degree at atmospheric pressure and so transportation occurs in insulated tanks making LNG carriers among the most sophisticated (and expensive) vessels in the cargo carrying fleet .

The major part of the LNG market still consists of trade tied into contracts , with 73 of these these in place in 2000 up from 68 in 1999 . These cover the major LNG projects in Indonesia , Malaysia , Algeria , NW Australia , Qatar , Brunei , UAE , the US and (more recently) Nigeria and Trinidad&Tobago . Spot and short term sales volumes diminished overall in 2000 with the expiry of several intra-Asian short-term contracts. Nonetheless the USA bought a significant number of spot cargoes during the year.

Fleet ownership mainly reflects the geographical spread of the major projects. In terms of cubic capacity, Pctronas (Malaysian International Shipping) is the largest owner with 10 active vessels, and another 5 on order, totaling 1,99m cbm . Marginally smaller is the STASCO (Shell) fleet with 7 small vessels , 6 larger ships and 7 large vessels on order , 1,98m cbm in all Qatar Liquefied Gas is the third biggest owner , with a modern fleet of 10 "most-type" vessels amounting to 1.35m cbm.

Summary				
	End '00	Sep '01	+/- this year	-
Tonnage Supply m3 Fleet Order book	14.21 TM 3.43m	14.20m 6.60m	- 0.1% 92.3%	
Asset Values NB Price	$1 72.5m	$1 70.0m	- 1.4%	
Fleet Developments - Deliveries - Demolition - Contraction - Second hand sales	 12 1 19 0	 0 0 24 0	 -100% -100% 89%	-

2001 % +/- based on annualized figures

The LNG market has strengthened rapidly over the past year , resulting in unprecedented levels of shipyard activity . Vessel investment has hit all-time highs , with the ordering in 2000 of almost 1.5 million cbm and biggest orderbook since the mid 1970s . On the demand-side of the equation trade has continued to grow –in 2000 worldwide LNG trade amounted to 137.0 billion cbm-an increase of 10.3% over the previous year . On a longer time-scale total demand for LNG increased by nearly 8% per annum between 1980 and 2000 .

5.2 Asia continues to dominate imports

The world's largest LNG importer remains Japan , with 72.5bn cbm in 2000 (53% of the total and 5% higher than in 1999). With imports by Korea (19bn cbm in 2000) and Taiwan (5.9 bn cbm in 2000) . Asia accounts for almost three quarters of global imports. These are primarily supplied from S.E. Asia and Arabian Gulf.
Europe imported 32.68bn cbm in 2000 (43% of total trade, and 6% more than in 1999) Mostly from North Africa, but with significant quantities now coming from Nigeria. France and Spain are the biggest importers (11.23bn and 8.47bn cbm respectively in 2000) . The US, while only importing 6.24bn cbm in 2000 is by far the fastest growing market with a 37% increase year on year, and with most of this demand supplied by Trinidad , Algeria and Qatar .

5.3 Static fleet with growth to come

On the demand side, the trade in LNG until recently LNG ships were always ordered against specific project requirements .However , the combination of rapidly accelerating demand for energy , especially in the US , and relatively low new building costs , has led a number of owners to order vessels before fixing them on long-term charter . These have been either oil majors , with sufficient LNG interests to guarantee employment for the new vessels (Shell and BP) , or entrepreneurial owners , some of whose new orders remain un-fixed (Exmar , Bergesen , Golar LNG , AP Moller , Tanker Pacific)
While it is expected that these vessels will ultimately he utilized with in projects, owner will have the flexibility to profitably operate them spot or short-term before commencement of long-term employment New demand should come from Asia , particularly India , China and Japan , and also from the developed world where LNG is gaining popularity due to its relatively environment-friendly credentials and as a result of power industry de-regulation . Spot opportunities are no longer as prevalent as they were in 1999, when 8.8% of LNG was traded spot in 2000.
Bearing this in mind , it is worth considering whether the huge boom in contracting , and the lack of very old vessels is going to lead to a situation of oversupply in the next few years , with the fleet overtaking even the current strong demand growth .

5.5 Joint Ownership

Shared owner ship is a feature of the Australian North West Shelf project. BP, BHP, Chevron, Shell Woodside and a combination of Mitsubishi and Mitsui of Japan are involved. Each of the participants has a one-sixth share in five of the vessels in the fleet. These are chartered under a bareboat arrangement to the shipping firm set up to serve the project –International Gas Transportation Company (IGTC).The six companies also own equal shares in IGTC and the North West Shelf Shipping Service Company (NWSSSC – ALNG) , which has established to provide operational and technical expertise .

Joint Ownership – including the emergence of non – traditional owners:

The practice of shared ownership seems to be spreading in part because of a more flexible approach to the transportation component of LNG projects. In Japan, LNG carriers used to be built under loans from the Japanese Development Bank. However, gas companies are now more willing to be involved in the financing of LNG ships and even act as co-owners. For example, Tokyo Gas has 10% and 35% stakes respectively in the LNG Flora and the LNG Vesta, while Japanese trading houses have also expanded their involvement with LNG ownership.

The other factors such as the Asian economic crisis have also contributed to the rise of shared ownership. This latter phenomenon influenced the creation of a new co-ownership structure involving Japanese and South Korean owners. This entity was formed at the end of 1999 , when the three major Japanese Shipping Lines (Mitsui OSK, K line and NYK) each acquired 6% equity in a SK Shipping LNG carrier chartered to KOGAS (the remaining equity is split between SK Shipping 70% and Itochu Corp 12%)

LNG Fleet Ownership Summary (May 2000)

Owner	No vsls.	AVG	MIN	MAX	AVG	MIN	MAX
Petronas	10	1988	1980	1997	130,203	130,000	130,405
Qatar Liqufied Gas	9	1998	1996	1999	135,301	135,000	137,354
EnergyTransportation	8	1978	1977	1979	126,338	126,300	126,400
NationalGasShipping	8	1995	1994	1997	136,294	135,000	137,756
Shell Group	7	1974	1972	1975	75,807	75,000	77,731
Australia LNG Ship.	6	1992	1989	1994	127,555	127,452	127,747
Osprey Mar.	6	1981	1975	2000	118,120	125,858	135,000
SNTM Hyproc	6	1977	1971	1981	112,984	40,850	129,767
Hyundai Merchant	5	1998	1994	2000	131,073	125,182	135,000
NipponYusen Kaisha	5	1986	1983	1993	126,321	125,199	127,705
AGIP	4	1983	1969	1998	54,925	41,000	72,000
Mitsui O.S.K Lines	4	1988	1984	1994	126,314	125,000	127,708
Nigeria LNG Ltd.	4	1980	1976	1984	127,500	122,000	133,000
SK.Shipping Co.Ltd.	4	1998	1994	2000	133,250	125,000	138,000
Asia LNG Transport	3	1996	1993	1998	18,842	18,800	18,927
Chemikalien Seetrans	3	1972	1965	1975	332,167	25,500	35,500
Hanjin Shipping Co.	3	1998	1995	2000	134,600	130,600	138,200
Leif Hoegh & Co.	3	1975	1973	1977	100,340	87,600	125,820
P.T. Humpuss Trans	3	1993	1990	1996	94,295	19,100	136,400
Argent Marine Ops.	2	1978	1978	1978	126,540	126,540	126,540
BG International	2	1969	1969	1969	71,500	71,500	71,500
Kawasaki Kisen	2	1984	1983	1984	125,000	125,000	125,000
Lachmar Partner ship	2	1980	1980	1980	126,530	126,530	126,530
Marathon Oil	2	1993	1993	1993	89,880	89,880	89,880
Auxiliar Maritima	1	1970	1970	1970	40,000	40,000	40,000
Cabot LNG shipping	1	1979	1979	1979	126,540	126,540	126,540
Cie Generale Mar.	1	1973	1973	1973	40,081	40,081	40,081
Exmar N.V.	1	1978	1978	1978	131,260	131,260	131,260
Gazocean	1	1971	1971	1971	50,000	50,000	50,000
Korea line	1	1999	1999	1999	138,000	138,000	138,000
Louis Dreyfus	1	1977	1977	1977	129,299	129,999	129,299

TOTAL : 116 1982.5

Min/Max/Avg = Cubic meters

Vessel commercial Operator

Commercial Operator	No. Of vessels	Commercial Operator	No. Of Vessels
ALNG	8	Petronas	13
Century DA	1	British Gas	1
ADGAS	8	Brunei LNG	8
ENAGAS	8	Snam	2
Nigeria LNG Ltd.	7	Sonatrach	6
Distrigas	2	Colar Energy	1
Gas De France	4		
Kogas	18	TOTAL :	120
Pertamina	12		
BadakLNG	3	Source: LNG shipping	
Arun LNG	4	industry Review year	
Qatar Gas	10	2000 by B.Rogliano	
Philips	2	Ins. of Gas Tech.	

LNG FLEET OWNERSHIP SUMMARY
IN TERMS OF TECHNICAL MANAGEMENT

Technical Manager	No of Vessels
Alsoc	3
Bergesen	1
BP shipping	5
Chemikalin Seetrans	3
Denholm	2
Exmar	1
Gaz Ocean Armement	2
Hanjin	4
Hyundai Merchant M.	6
Humolco	3
K Line	4
Leif Hoeg	3
Louis Dreyfus	1
Marathon	2
Maritima Del Norte	1
MOL	8
NYK	11
Osprey	13
Pronav	8
Malaysia ping	11
SK Shipping	5
SNAM	4
SNTM-HYPROC	6
Stasco	14
TOTAL	121

Source: LNG Shipping Industry Review , year 2000
By B.Rogliano/Inst.Of Gas Tech.

5.6 Speculative Newly-Built Ships

There is growing number of a new LNG projects being studied and in particular, an increasing amount of short-term LNG trade. There seems to be shortage available existing carriers to use on new trade. The risk of failing to find employment for a speculatively built carrier is low. For instance, BP, Shell, and Tokyo Gas were each to order new LNG carriers, with no firm requirement for particular project . In all cases according to Drewry Consultant the order book for new buildings contains 28 LNG vessels. Some of which are shown below;

LNG Ship Orders Placed in 2000

Ship Owner	Quantity Ordered	Capacity Shipyard	In date of ordered
Bergesen	2	138,000 Daewoo	2003:2003
BP	2	138,000 Samsung	2002:2003
Exmar	3	138,000 Daewoo	2003
Malaysia LNG	2	137,100 Mitsubishi	2003:2004
Naviera	3	140,000 Daewoo	2003
Tapias	1	137,300 Hyundai	2002:2003
Nigeria	2	135,000 Mitsubishi	2002:2003
Shell	1	135,000 Mitsubishi	2003
TEPCO	2	138,000 Mitsubishi	2003:2005
Tokyo Gas	2	138,000 Kawasaki	2003:2005
Knutsen	1	138,000 AsEsponola	2003
Elcano	1	138,000 AsEspanola	2003
TOTAL	20	2,478,50	

5.7 Risk , Opportunity Analysis , Evaluation & Recommendations

Economical & Financial Risks
LNG shipping may offer limited opportunities for following reasons

1) Natural Gas investments are very capital intensive, for instance, requires \$150-\$180 billion investment on infrastructure to build distribution system .
2) Some Natural Gas fields have legal challenges, i.e. Land claims, environmental concerns, that have significant impact on execution of planning .
3) LNG vessels are very expensive to build and independent owners get involved only after confirmation of contracts.
4) Technology is still not available to widely use Natural Gas so that volume can grow.
5) Some countries which have Natural Gas resource are still struggling to establish export route, i.e. Russia, Central Asian countries.
6) Price of Gas is linked to oil prices.
7) Buyers are locked in for log term contracts 20-25 years that gives less flexibility to secure more contracts.
8) It is risky to establish an LNG Ship Owner prior securing a contract.
9) In case declaration of "force majored" , LNG vessel is released from the contract that will incur significant losses to owner .

LNG shipping industry is also viewed as "floating pipeline" . Therefore fluctuations in the market have so far been viewed unfeasible. However, growing market will bring more of spot fixtures (short term contract) . Risks associated with an LNG shipping investment whether to proceed with short-term contracts or to seek for long-term contract. This will require in-depth market analysis prior to making a decision.

Opportunities with LNG Shipping

1) Entering in "high class" & "futuristic" shipping segment.
2) Moving onto next generation of the company.

Commercial and Operational Risks

LNG expertise is essential part of the operation. The company would have to have expertise staff at sea as well as ashore.

Following are scenarios:

1) To train existing officers in oil side for LNG vessels

pro: philosophy established
cons: would crate shortage in oil side
Senior officers would not be ready immediately-because no experience
Training may be costly .

2) Cooperation with another source

Training LPG background officers for LNG vessels-Bergesen recently laid off deck officers –however not engineers

- Manning company – may be quality issue
- Joint venture with Hoegh
- Using Australian Crew true possible BHP deal
- Potential union problems

Commercial Risks

The companies at present do not have expertise on LNG . Following are possible scenarios to obtain "commercial know-how"

- Joint venture with Hoegh
- Hire an expert from outside and do it in – house
- Consultant services from a broker "Poten"
- Joint venture with another LNG company "ETG" (at least at initial stage)
- Combination of some of above

For above reasons the company would have to allocate time to make strategic decisions.

Partners

Following companies have tentative or firm LNG shipment contracts at present .

1) ALSOC – North West Shelf project
2) BP-China & Trinidad & Tobago projects
3) Philips –USWC project
4) Chevron-their USWC & Ghana projects
5) BG Gas for Egypt project

Management and Organizational Risks

The companies are oil industry oriented and seem to be much occupied with expansions and various projects. For these reasons, the senior management in the company may have been suffering from not being able to focus.
To move from "oil industry" to "gas industry" would need following actions; Senior management would need be trained for dynamics of the industry.

PRINCIPLES OF GAS CARRIER DESIGN, CONSTRUCTION AND CARGO INSTRUMENTS

1) DEFINITION OF LNG AND PROPERTIES

1.1 Natural gas

The weight of this colorless, transparent liquid is about one half of water with the same volume.

1) Composition of LNG similarly to natural gas, of which methane is the main LNG, consists of several hydrocarbons component and other hydrocarbons component. Other hydrocarbons making up this plus solved in to LNG. nitrogen such as HZ O , HZ S compound which liquid chi is however , CO2 , heavy hydrocarbons , are ethane , propane , butane , and pentane , ten found in natural gas is also other useless components in natural gas hydrocarbons , etc are removed in the often ethane , propane , butane , found in natural etc , and the greater its calorific value , as a difference between LNG and natural gas , it can be mentioned that the components of LNG change while in storage in a tank . This change methane heavier is coursed by the evaporation and nitrogen, which tanks of light components such as place earlier than that of hydrocarbons. Thus, the concentration of heavier hydrocarbons increases while in a prolonged storage.

Characteristics of LNG

The followings are enumerated as main properties of LNG. Characteristics in storage and transportation.

1) Cryogenic temperature of about –160C degree LNG will require use of suitable materials for cyrogenic temperature , consideration toward expansion and contraction due to the change in temperatures , structural design with due regard to thermal stress , effective heat insulation system , precaution against damage caused by low temperature
2) Volumetric reduction to about one six hundredth normal temperature due to liqufaction of gas at the tank.
3) A liquid in between gas the and fall of pressure, state of boiling point . When equilibrum liquid is destroyed by rise of temperature or the liquid will immediately start boiling. Liquid is rise of temperature or.
4) Density is about half , that of water
5) Inflammable, but combustion range of its vapor is narrow if 5-14 volumetric percent LNG is present in air, it fits forms an explosive mixed gas . In consideration are given with air by for example , order prevent such a formation, to avoidig keeping the heigher than the atmospheric LNG coming into tank pressure contact slightly Other physical and chemical characteristic
6) Colorless and odorless liquid.
7) Large latent heat of evaporation.
8) High volatility.
9) Low viscosity and forms white.
10) It can easily be charged even by static electricity.

10) No causticity and no toxicity.
11) Almost no solubility in water.
12) Small surface tension.

Moleculer formula Hydrocarbon The most common compound in oil and natural gas is the hydrocarbon hydrojen. There is a compound many kinds carbon the form of gases , liquids pressurre or solids at normal temperature and under normal molecule of the hydrocarbon is made up of carbon atoms bonded to one another as a around the nucleus . Nucleus and hydrojen atoms combined together the carbon can be classifed as fallows and according to the bonding state of atoms hydrocarbons .

Chain type
(Fatty group)
1) Saturated – methane series
(Paraffin series, alkane) Methane, Ethane, Propane, Ethylene series, Alkane, Olefin ethylene, propylene, Butylene
2) Unsaturated-Diene series (Diolefin series) Propadiene, Butadiene Acetylene series (Alkyne) Acetylene
Ring type
1) Saturated-Alicyclic type (Naphthene series) Cyclo-propane
2) Unsaturated-Aromatic group (qenzens series) Benzene, Toluene, Napthalene.

The hydrocarbon is fist classified into chaın type hydrocarbon ring type hydrocarbon.
Molecules of carbon are arranged and combined together the inshape of branched chain and atoms are chain series bonded molecules of ring type hydrocarbon carbon atoms combined in this shape of ring .Hydrocarbon is also classified into "saturated" "unsaturated".Ona carbon atom can be bonded to up to four of othr atoms . And when all carbon valance bonding hands are bonded to other atoms, it is called "saturated"with in the molecule, it is called "unsaturated"compound which has double or triple bonds. On the other atom hand,
Methane series (Parafin series, general formula $C_n H_2$ n-2 atom can alkane 2)

Methane CH_4
Ethane C_2H_6
Propane C_3H_8
Butane C_4H_{10}
Pentane C_5H_{12}
Hexane C_6H_{14}
Heptane C_7H_{16}
Oktane C_8H_{18}
Nonene C_9H_{20}
Dekane $C_{10}H_{12}$

What is characteristic of methane series hydrocarbon is its great stability stability. Own hydrocarbons falling under this series are similar chemical properties, and their physical similar chemical properties and show relatively regular changes carbon atoms consisting molecules their with (increase in molecular weight). Physical increase properties in the number also of in the atmospheric pressure), are solids C,-C, are condition (normal temperature gases, C_s-C_1 s liquids and C6 in isomer. This C4 H_1 o in the number is the first of carbons, molecule the formed isomers cumulated, two isomers exist in We Hı o)-5 isomers in 6 carbons and 60,523 octadecane (C, s H, 8).And normal above forming number an of further specific gravities in this series, 1 rise with boiling points, melting increase in the number sometimes increasing the stability of hydrocarbons.

2) PROPERTİES OF LNG

2.1 Density and specific gravity

Density of gas carbons isomers in the density: volume. This is expressed by the mass of substance per unit of units and numerical values of density differ depending on the way of defining the units of volume and mass .The density of gas differs depending on the temperature pressure, etc. If the gas of the same substance. As the unit for engineering (kg/m) is principally used, while (q/p) pressure, for principally used, while as the units and (gr/cm) may also be used. He gases are normally expressed by density under one atmospheric. Specific gravity of gas is normally expressed by the specific weight of gas to air, or the ratio of the mass of gas to the mass of air having the same value pressure (the standart state). At the under one atmospheric from the all gases contain the same number of molecules (6.024 x 10) in the same volme when their temperatures and pressures are the same.

Ratio of weight of one molecule:
Ratio of molecular weight Composation of air; Main components are Oxygen (O... other components such as Argon, and Nitrojen N...) carbonic gas, while there are Neon and Helium, Weight ratio. Therefore ıf the volumetric ratio of NZ specified to be 4:1. Average molecular weight of air 4N ...O_2 actual molecular weight of air is 28.96, in the air further, since at the gram molecule of 0C degree and under atmospheric pressure 760 mm Hg. Density of air at the standart state is 28.96 g / 22 .4p = 1.293 g/Q = 1.293 kg/m=0.001 293 g/ cm Molecular weight of Methane (CH) =12-(1x4) =16, Therefore Specific gravity of Methane to air = 16/28.96=0.55.
Then the temperature of Methane is the same as that of air the specific 0.555 gravity since the Methane gas temperature to of air gas (air=1at immediately 1 atm)is after the degree to express the specific gravity of the petroleum group (API degree 141.5/specific gravity)
Vapour pressure: Vapour pressure means a pressure indicated by the vapour in astate of equilibrum with the liquid of a substance at aspecific temperature. The vapour pressure is related to the kind of substances and the varies with the temperature rises. The value of the vapour pressure is not affected by other gases which are present close to the liquid surface.

In general total pressure = Vapour pressure + Air pressure an open vessel
Atmospheric pressure = Total pressure, threfore
Atmospheric pressure = Vapour pressure + Air pressure

When pressure of a liquid rises, the vapour pressure increases and air is replaced by the vapour, reducing the air pressure. However, there is no change in the total pressure.
In aclose vessel:
Tank pressure: Total pressure or a function of the vapour pressure alone. Since the cargo tank of agas carrier can be considered as the closed vessel, the total pressure inside the cargo tank can be regarded as afunctıon of vapour pressure.

Therefore; Tank pressure = Vapour pressure
Now, assuming a completely adiabatic closed vessel without increase or decrease of heat, and ıf the vessel is filled about half full with a boiling liquid, this liquid evaporates until the pressure becomes equal to the vapour pressure of this liquid . Then, the boiling stops, and the state at this point is called equilibrum.

3) DESİGN AND CONSTRUCTION

The overall layout of agas carrier similar to that of the conventional oil tanker which it invoved. The cargo containtment and iits incorpation in to the hull of the gas carrier however is very due to the need to carry its cargo under pressure, or refrigated under a combination of pressure and refrigerated under a combination of pressure and refrigeration. To examine the design of these ships in greater detail it is convenient to consult the IMO Codes and the rules of the major ship classification societies which latter have have in recent years been rewritten to incorporate all the requirements of the IMO Codes.

The IMO Codes for the construction and equipments of ships carrying liquefied gases in bulk , covers ships contracted on or after October 31 .1976 ; the IMO code for existing ships carrying liqufied gases in bulk covers ships built before the application date of the new ship code . Together, these codesare known as the IMO gas codes. A further code, the international code for the construction and equipment of ships carrying liqufied gases in bulk, with the short title of the international gas carrier IGC code, applies to ships contracted on or after July .1 .1986 with its revised and clarified wording this IGC code includes all the updated requirements of the previous gas codes for the new ships. The IGC codes has been incorporated into the 1974 safety of life at sea SOLAS convention and in 1986 will become mendatory for flags whose governments are signatories to the solas convention .
Some of the factors to be taken into consideration which affect the design of gas ships are for example;

- Types of cargo to be taken
- Conditions of carrige
- Type of trade which in turn determines the degree of cargo handling flexibility required by the ship
- Terminal facilities available when loading or discharging the vessel

Perhaps more than any other single ship type the gas tanker encompasses many different design philosophies.
General:
Ships are to survive the normal effect of flooding fallowing assumed hull damaged caused by some external force. In addition to safeguard the ship and the environment, the cargo tanks are to be protected from penetration in the case of minor damage in the case of collision or stranding by locating them at specified minimum distances inboard from the ship's shell plating. Both the damage to be assumed and the proximity of the tanks to the ship's shell are too depended upon the degree of hazard present by the prodact to be carried.

3.1 Ship Types :
Ships are to be designed to one of the fallowing standarts:

1) A type ship is a gas carrier intended to transport products which require maximum preventive measure to preclude the escape of such cargo.
2) A type 2G ship is a gas carrier intended to transport products which required significant prevent measures to prelude the escape of such cargo.
3) A type 2PG ship is a gas carrier of 150 m in length or less intended to transport products which required significant preventive measurement preclude escape of such cargo, and where the products are carried in independent type C tanks designed the maximum allowable relief valve setting of cargo tank of at least 0.7 mpa gauge and a cargo containtment system designed temperature of –55 or above. Note that aship of this description but over 150 m length is to be considered a type 2G ship.
4) A type 3G ship is a gas carrier intended to carry to products which require moderate preventive measure to preclude the escape of such cargo. Thus , A type 1G ship is a gas carrier intended for the transportation of products considered to present the greatest overall hazard and types 2G/2PG and type 3G for products progressively lesser hazards . Accordingly, type 1G ship is to be designed to survive the most severe standard of damage and its cargo tanks are to be located at the maximum prescribed distance inboard from shell plating.
LNG ethylene and full refrigated LPG ships have to comply with type 2G requirements.

List of cargoes suitable for transport in a liqufied gas tanker as listed in IMO Gas Carrier Codes:

Cargo	**Ship type**
Acetaldehyde	2G/2PG
Ammonia, Anhydrous	2G/2PG
Butadiene	2G/2PG
Butane	2G/2PG
Butane / Propane mixtures	2G/2PG
Butylenes	2G/2PG
Chlorine	1G
Diethyl ether	2G/2PG
Dimethylamine	2G/2PG
Ethane	2G
Ethyl chloride	2G/2PG
Ethylene	2G
Ethylene oxide	1G
Ethylene oxide / propylene oxide mixture with ethylene oxide content less than 30% by weight	2G/2PG
Isoprene	2G/2PG
Isopropylamine	2G/2PG
Methane	2G
Methylacetylene / propadıene mixture	2G/2PG

Methyl bromide	1G
Methyl chloride	2G/2PG
Monoethylamine	2G/2PG
Nitrojen	3G
Propane	2G/2PG
Propylene	2G/2PG
Propylene oxide	2G/2PG
Refrigerant gases	3G
Sulphur dioxide	1G
Vinyl chloride	2G/2PG
Vinyl ethyl ether	2G/2PG
Vinyldene chloride	2G/2PG

3.2 Cargo Containentment System

This section deals with the design of cargo containentment systems on liqufied gas tankers.
The purpose of this lecture is to describe generally the different cargo containentment systems on liqufied gas tankers and the cargoes normally carried in these tanks. It is essential to call attention to the fallowing points:

- tank design and location
- tank support
- tank material

The IMO code identifies five different types of cargo containment system :

a) Independent tanks
b) Membrane tanks
c) Semi membrane tanks
d) Integral tanks
e) Internal insulation tanks

The independent and membrane types of containment system are of most Significance, and the majority of liqufied gas carriers built to date utilize one or Other these two types.

a) Independent tanks types :

These types of tanks are completely self supporting and do not form part of the ship's hull and do not contribute to the hull strength. Depending mainly on the design pressure, there are three different types of independent tanks for gas carriers, types A, B and C.

- Type A tanks :

Type an independent tanks are constructed primarily of plane surfaces. The Maximum allowable tank design vapour space pressure in this type of system is By the code 0.7 bar, this means cargoes must be carried in afully refrigerated

Condition at or near atmospheric pressure.

- Type B tanks :

Type B tanks can be either be constructed of plane surface or of pressure vessel type. this type of containment system is subjected to a much more accurate type of stress analyses compared to the type A system . Such analysis must include fatigue life and crack propagation analysis . Spherical tanks are well known type B tanks. Becouse of these design factors, a type B tank requires only a partial secondary barrier and and this usually consists of a drip tray and a splash barrier. The hold space in this design is normally filled with a dry air but may be dry inert gas. A protective steel dome covers the primarry barrier above deck level, and insulation is applied to the outside of the primary barrier surface. The type B spherical tanks are almost exclusively applied to the LNG ships.

- Type C tanks :

Type C is normallyspherical or cylindrical pressure vessels with design vapour pressure higher than 2 bars.
Vessel may be vertically or horizontally mounted. This type of containment system is always used in semi refrigerated and fully pressurized liquid gas carriers. It is also commonly used for fully refrigerated transport provided appropriate low temperature stress is used in the tank construction. Type C tanks are designed and built to conventional pressure vessel codes and, as a result, can be subjected to accurate stress analysis.
Furthermore, design stress are kept reasonably low so, where this type of system is used, no secondary barrier is required and the hold space can be filled with either inert gas or air. With such an arrangement there is comperatively poor utilization of the hull volume; however, this can be improved by using intersecting pressure vessels or lobe type tanks which also taper at the forward end of the vessel.
This is common arrangement in semi pressurized fuuly refrigerated ships.

b) Membrane tank types:

The concept of the membrane system of cargo containment is based on very thin primary barriers, or membrane which is supported through the insulaton by the hull of the ship. They are not self supporting like the independent tanks outline in the section above in that the inner hull forms the load bearing structure . Membrane containment systems must be provided with a complete secondary barrier to ensure the cargo containment system's overall integrity in the event of primary barrier leakage. The membrane is designed in such a way that undue stressing of the membrane itself. There are two principal types of membrane system in common use both named after the companies who developed them and both designed primarily for the carrige of LNG

- Gas transport membrane system:

The original gas transport system comprised a 0.5mm thick inner barrier attached to the inner called surface of 200 mm thick perlite filled plywood boxes used as the primary insulation these are attached as the inner layer of an identical 0.5mm thick invar secondary barrier. Invar is chosen for the membrane because of its very low of thermal expansion joints or corrugation in the barriers unnecessary.

- Technigas TGZ Membrane system:

The techigas system, feature a primary barrier of 1.2 mm thick stainless stell with the raised corrugation or waffles to allow for expansion and contraction. The insulation that support the primary membrane consists of laminated balse wood panels between two plywood layers, the inner cald plywood layers forms the secondary barrier.

c) Semi membrane tanks:

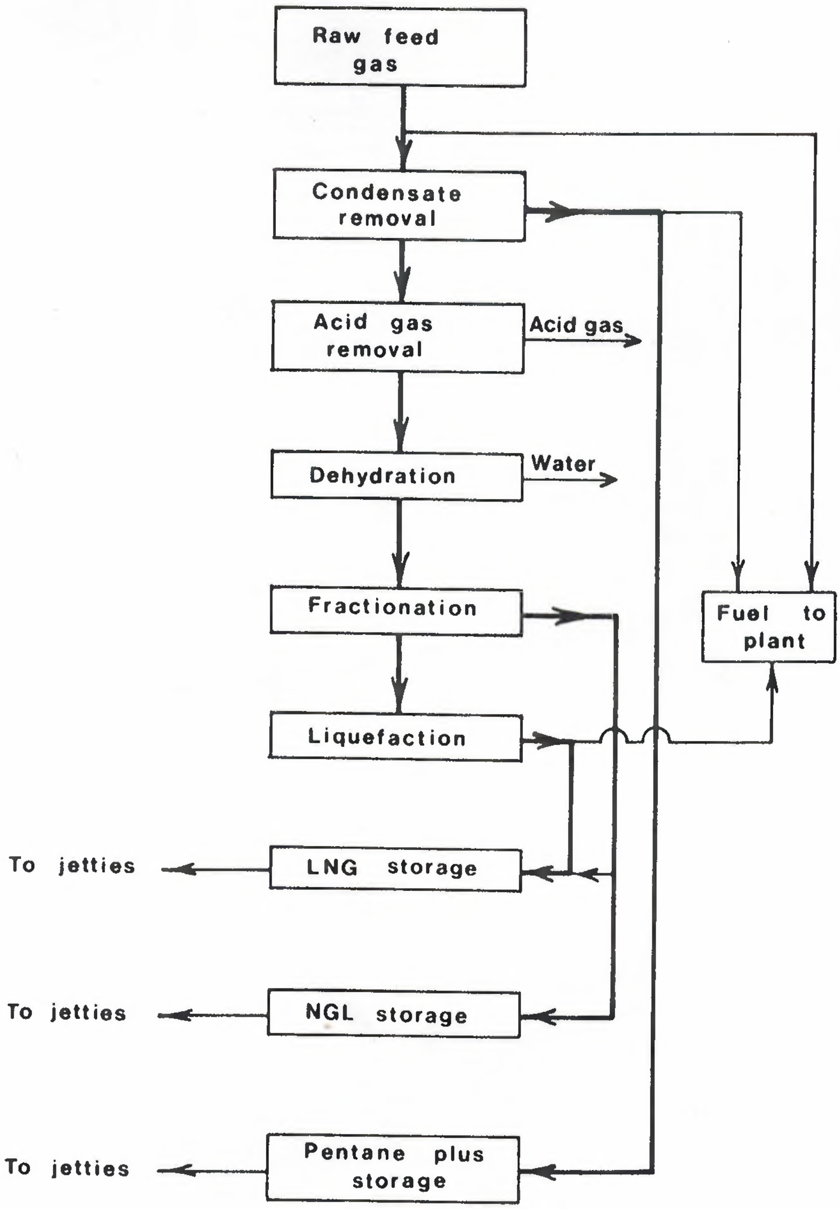
The semi membrane concept is a variation of the membrane tank system .The primary barrier is much thicker than that in the membrane system. Having flat sides and large radiused corners. The tanks are self-supporting when empty but nonself supporting in the loaded in that the liquid and vapour pressures. Acting on the primary barrier is transmitted through the insulation to the inner hull as is the case with the membrane system. The corners and edges are so designed as to accommodate expansion and contraction.

d) Integrated tanks:

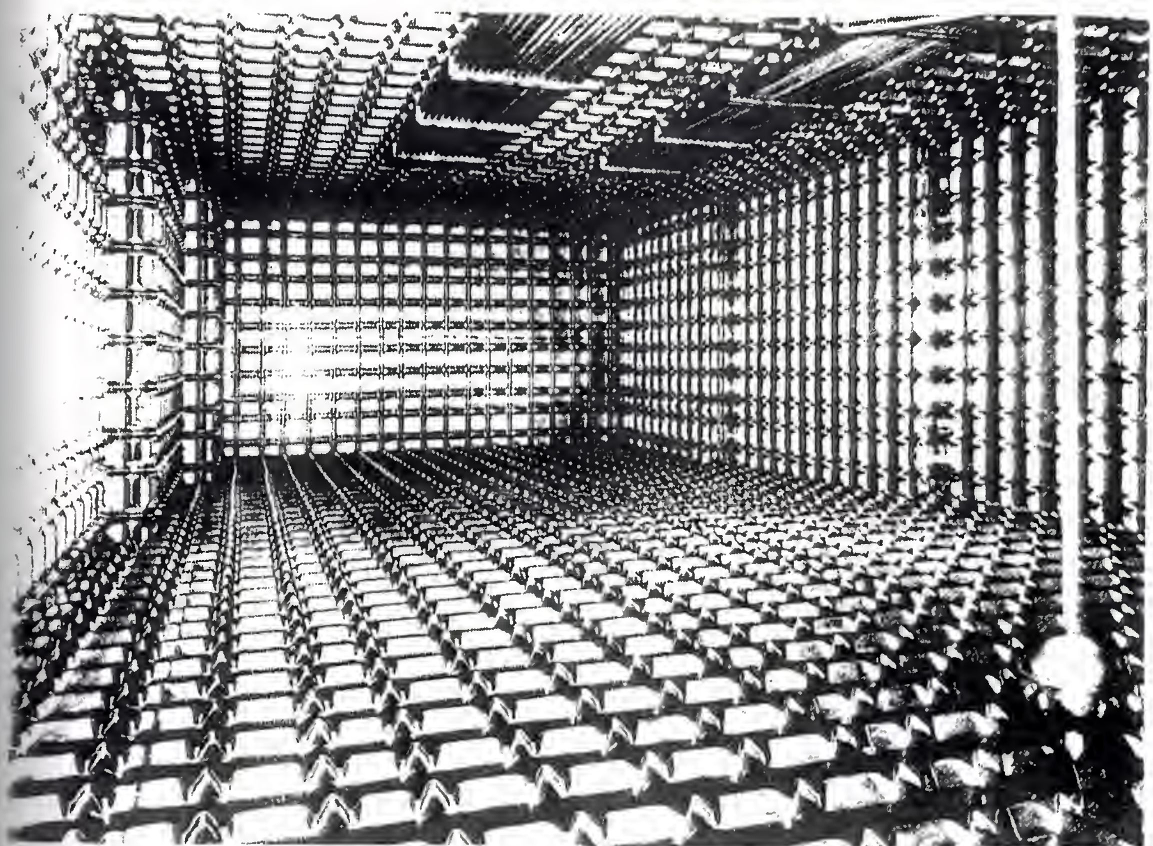
The IMO codes state that integrated tanks form a structural part of the ship's hull and are influenced in the same manner and by the same loads which stress the hull structure. They further state integral tanks are not normally allowed if the cargo temperature is below –10C degrees.

e) International insulation tanks:

Sometimes called integral tanks, internally insulated tanks are effectively an integral tanks system which utilizes insulation materials fixed to the ship's inner hull plating or an independent load bearing surface to contain and insulate the cargo.

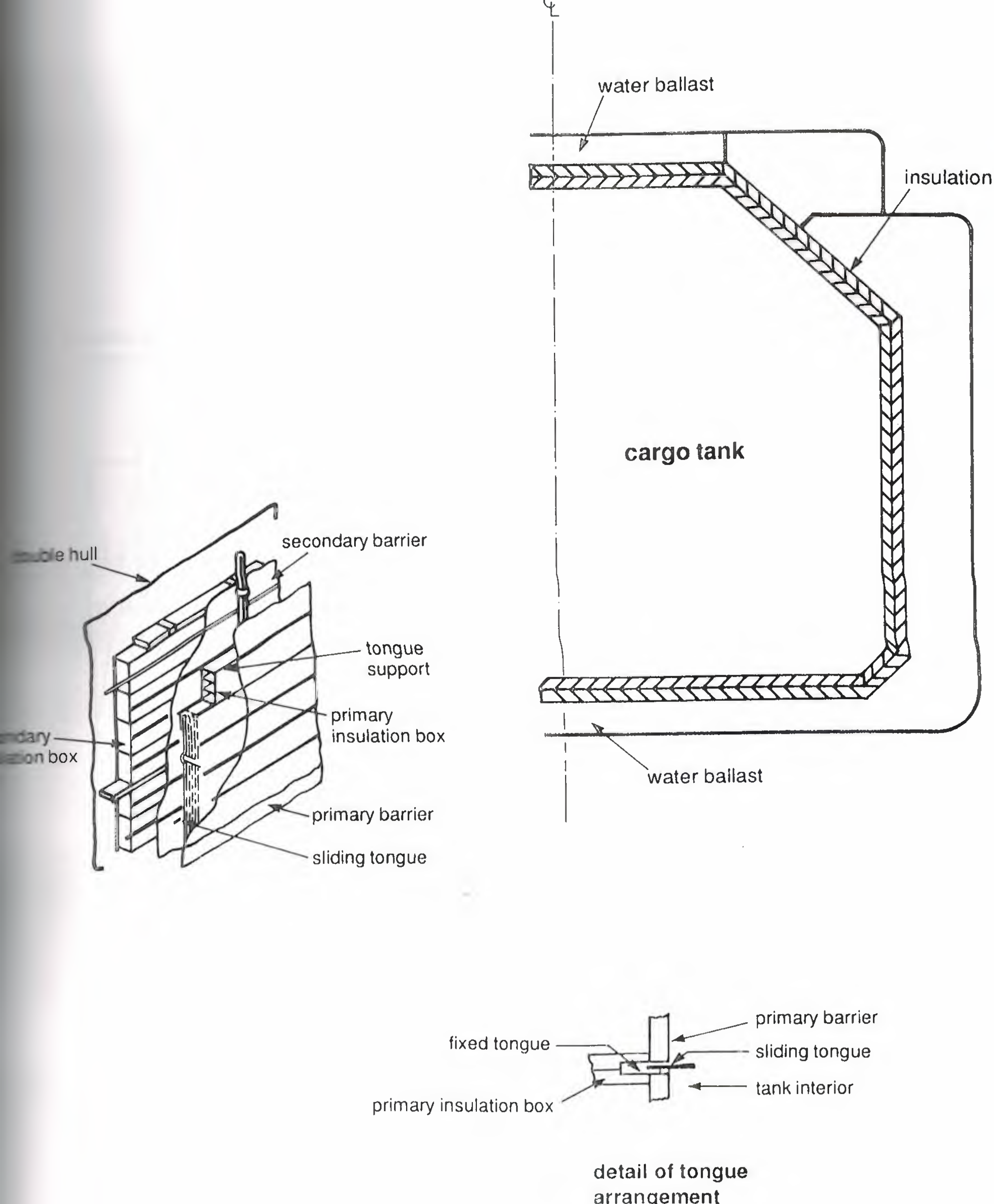


Production of LNG from Natural gas reservoirs

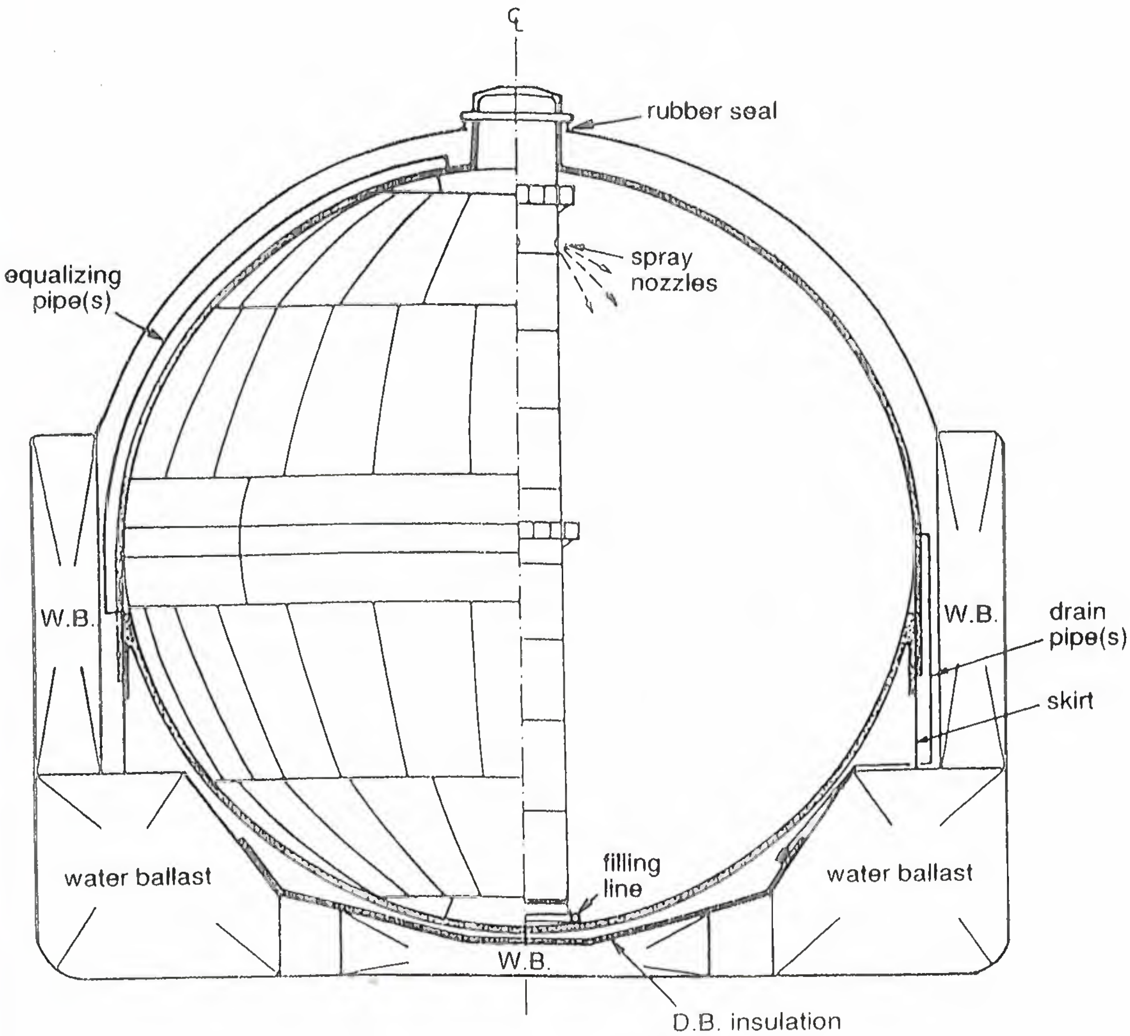


Section of
primary barrier

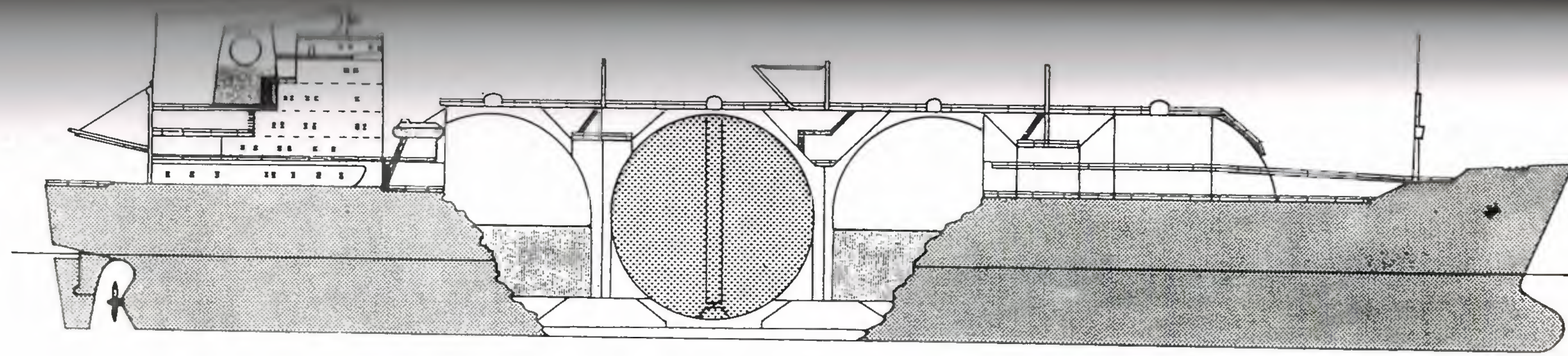
A Technigas membrane tank



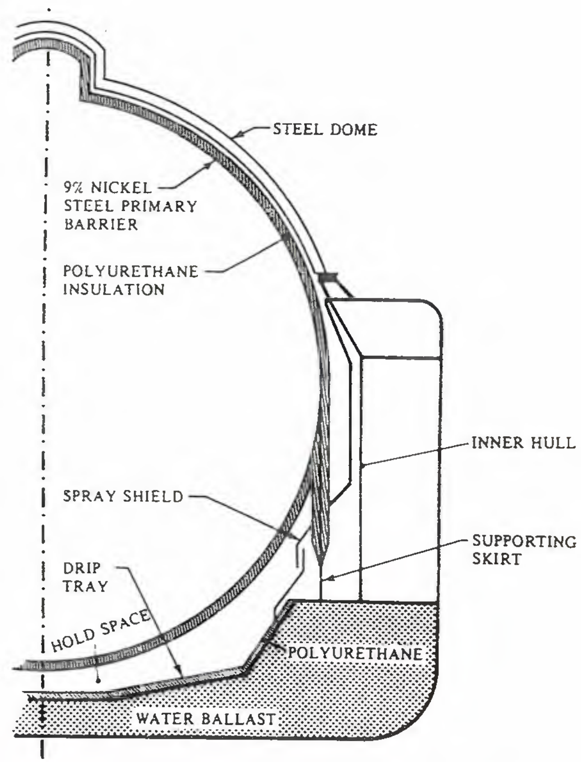
A Gas Transport membrane tank



An Independent tank of type B



LNG/ethylene/LPG tanker



Independent self-supporting spherical tank (type B)

4) CARGO PIPING SYSTEM

4.1 Main cargo pipe lines

1.1 Cargo Liquid lines
Cargo Liquid Header (Liquid main)
Cargo Liquid Crossover
Cargo Liquid Branch
Cargo Filling Line
Cargo pump Discharge Line

1.2 Cargo Vapour Lines
Cargo Vapour Header (Vapour Main)
Cargo Vapour Crossover
Cargo Vapour Suction Line
Compressor Suction Line
Cargo Vapour Return Line

1.3 Spray Lines
Spray Header (Spray Lines)
Spray Crossover (cool down crossover)
Spray Branch
Spray Pump Discharge Line
Spray Return Line
Spray Nozzle Inlet Line

1.4 Cargo Tank Vent Line
1.5 Cargo Pipe Vent Line
1.6 Inert Gas Line
1.7 BOG Fuel Gas Line
1.8 Pressure Build-Up Line

4.2 System Colour (example)
Cargo Liquid Line (Blue, Cyan)
Cargo Vapour Line (Yellow, Orange)
Nitrojen Line (Light Green)
Inert Gas line (Magenta)

4.3 Valve Numbering
3.1 Valve number is composed of five characters
3.2 1st code is equipment code
3.3 2nd code is system code
Cargo Liquid Line (L)
Cargo Vapour Line (G)
Spray Line (S)
Nitrojen Line (N)
Inert Gas Line (I)
3.4 3 rd code is location code
Manifold crossover (O)

Tank Dome (1-4)
Flying Passage (7)
Compressor Room top (8)
Compressor room (9)
3.5 4th code is Line code
Cargo Liquid Line (0-4)
Spray Line (5-6)
Cargo Vapour Line (7)
Nitrojen Line (9)
Inert gas Line (9)
3.6 5th code is serial number

4.4 Main Cargo Valves

4.1 Tank dome
Branch valve (Throttle valve)
Filling valve
Cargo pump discharge valve
Spray pump discharge valve
Spray master valve
Spray nozzle inlet valve
Spray return valve
Vapour suction valve

4.2 Manifold Crossover
Liquid manifold ESD valve
Liquid manifold valve (W shut valve)
Liquid manifold vent valve (sampling valve)
Liquid manifold drain valve
Liquid manifold cool down valve
Liquid crossover cools down valve
Vapour manifold ESD valve
Vapour manifold vent valve
Vapour manifold by pass valve
Vapour return to crossover valve
Vapour return to header valve

5. CARGO VALVES AND RELİEF VALVE

5.1 Types of cargo valves

1.1 Stop valve
Ball valve
Glove valve
Gate valve (sluice valve)
Butterfly valve
1.2 ESD valve
Same as stop valve
1.3 Check valve (non return valve)
Swing check valve

Lift check valve
Ball check valve

Structural feature of cargo valve:

1) Long stem and extension bonnet
2) Soft seal of body sheet
3) Flexible wedge, split wedge (gate valve)
4) Vent hole (Gate valve)

5.2 Types of relief valves
1) Spring loaded relief valve
2) Pilot operated relief valve belows type diaphragm type

To be completed before loading an inhibited cargo

SHIP.. DATE..

PORT & BERTH.. TIME ....

1. CORRECT TECHNICAL NAME OF CARGO..

2. CORRECT TECHNICAL NAME OF INHIBITOR ....

3. AMOUNT OF INHIBITOR ADDED..

4. DATE ADDED..

5. EXPECTED LIFETIME OF INHIBITOR..

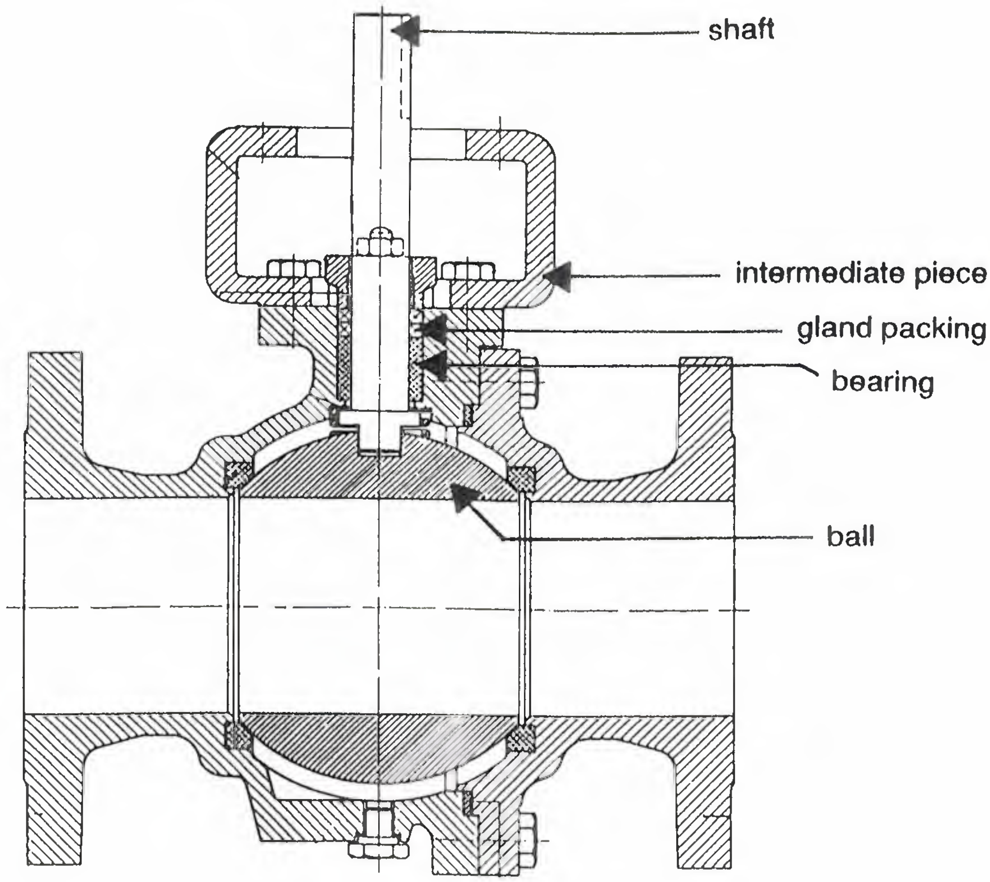
6. ANY TEMPERATURE LIMITATIONS AFFECTING INHIBITOR..

7. ACTION TO BE TAKEN IF VOYAGE EXCEEDS EFFECTIVE LIFETIME OF INHIBITOR ....

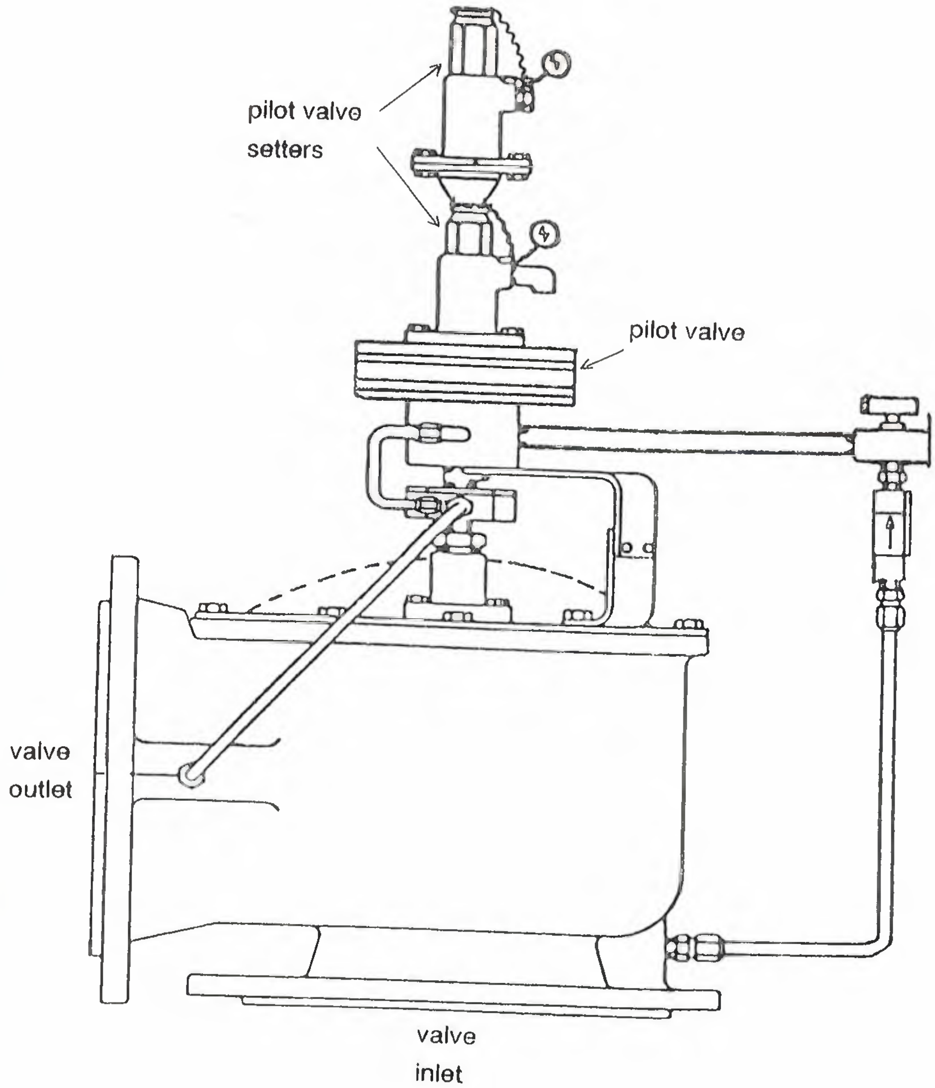
IF ABOVE INFORMATION NOT SUPPLIED, CARGO SHOULD BE REFUSED (IMCO Codes 18.1.2)

FOR SHIP.. FOR SHORE..
(Signed) (Signed)

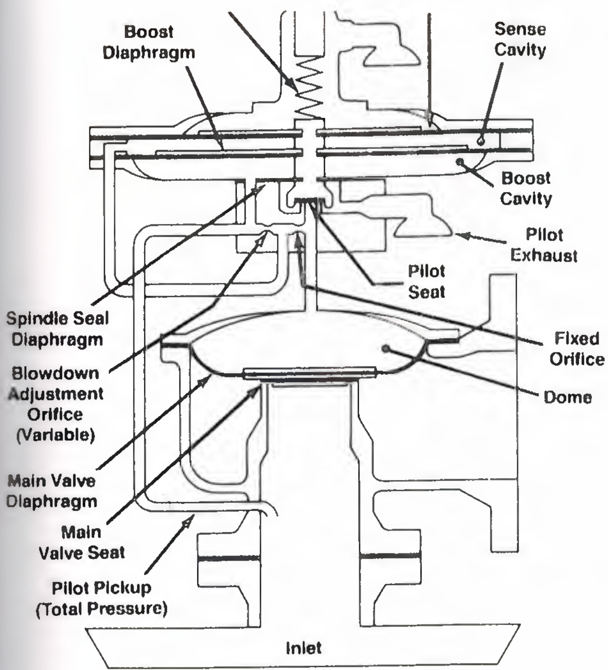
Liquified Gas-Inhibitor Information form



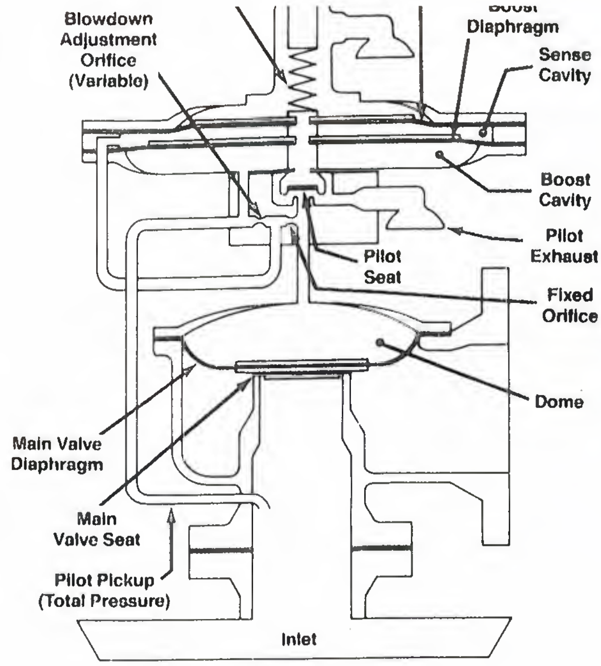
Example of a ball valve



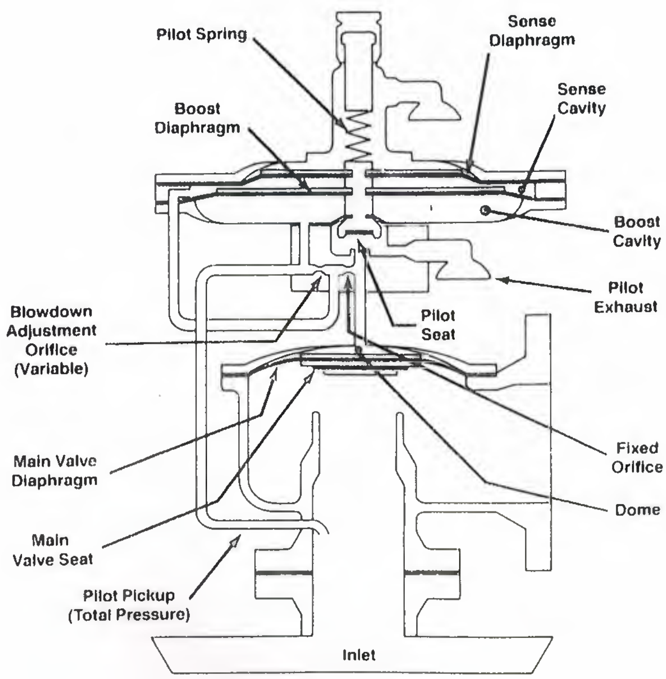
A cargo tank safety relief valve



(Closed)
Positive Pressure Relief

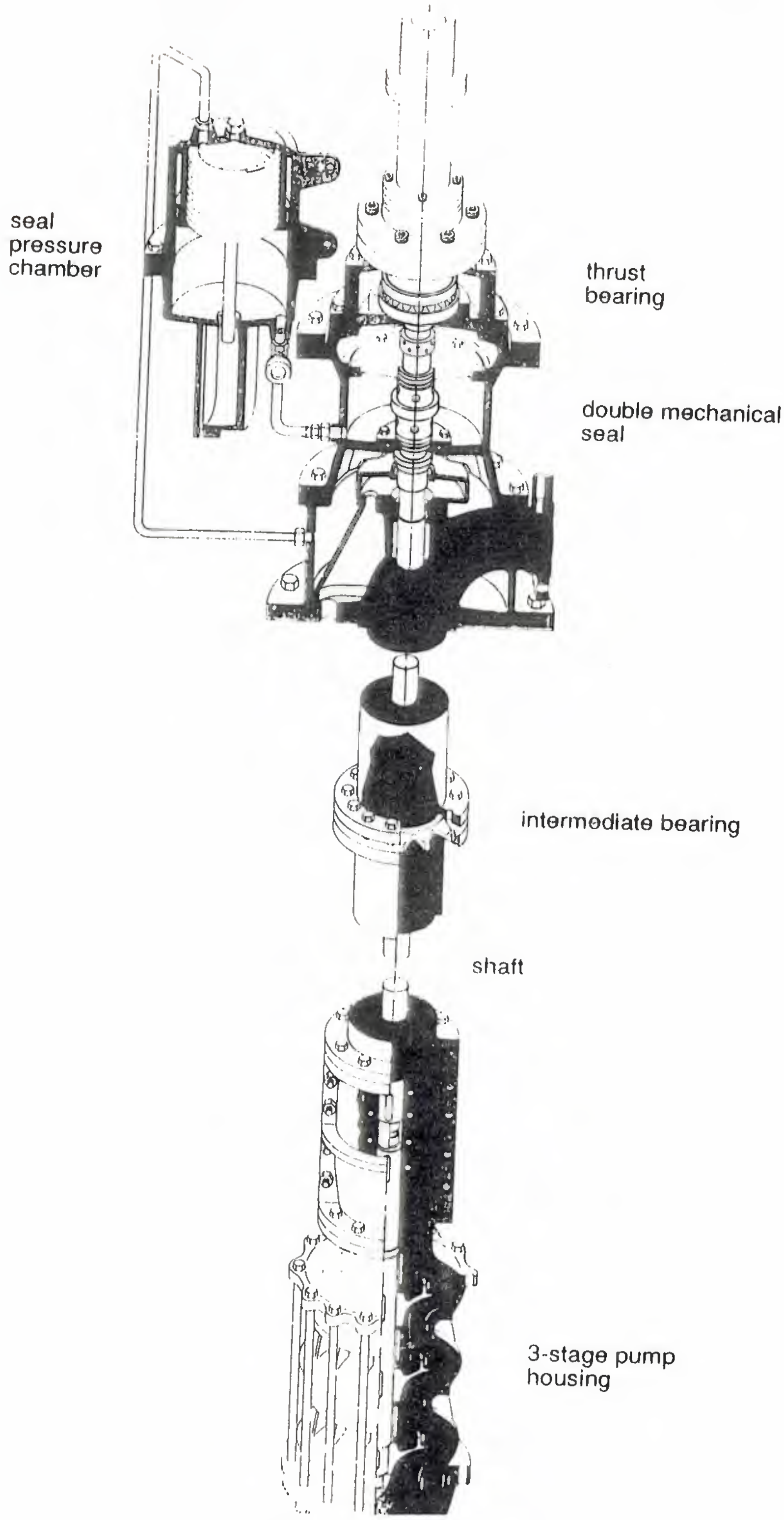


(Pilot Open)
Positive Pressure Relief

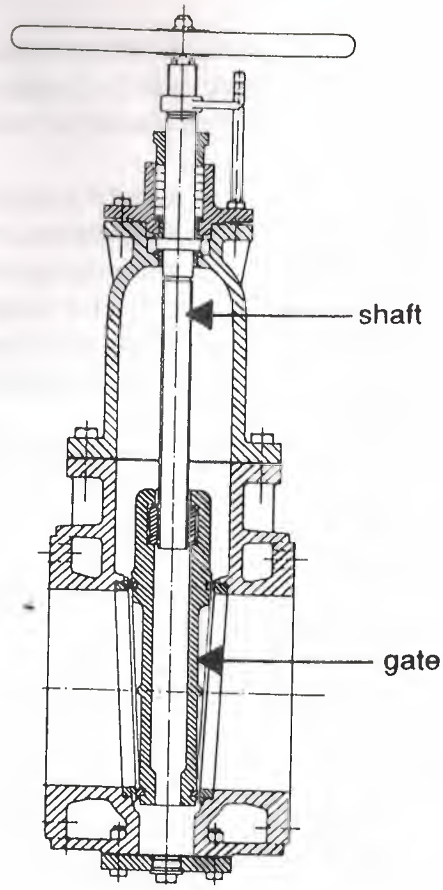


(Open and Flowing)
Positive Pressure Relief

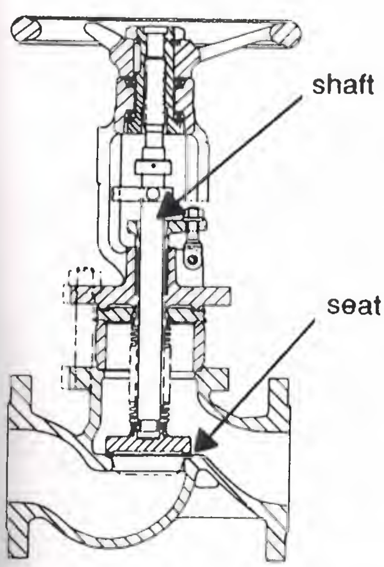
Operational principle of a tank safety relief valve (AGCO)



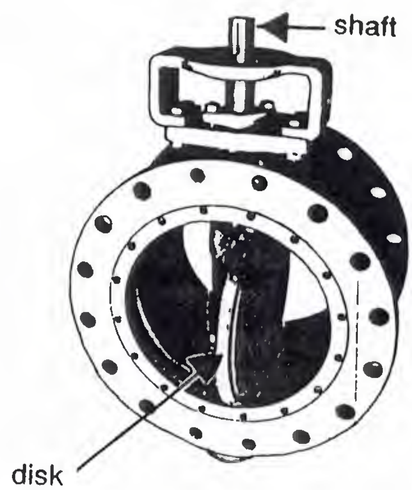
Deepwell Pump



Gate valve



Globe valve



Butterfly valve

Examples of gate, globe and butterfly valves

6) PRESSURE SURCE

Pressure surges can be created when the flow in a liquid is stopped too quickly. The hazard is greatest when cargo is being transferred over long distances and at high velocity. Pressure surges may be caused by ESD system is well maintained and properly adjusted.
A pressure surge can be created when a valve maintaining a pressure difference in the liquid line opened. If the pressure difference is high and the valve is opened too quickly, a high velocity and a high surge pressure will be created.
This could occur when liquid is trapped between valves in a liquid line and becomes warm. In such cases the valve should be opened very carefully to equalize the pressure slowly. Liquid lines shold be drained after use to prevent this problem.

7) CARGO AND SPRAY PUMPS

GENERAL:

1) Each tank is provided with two cargo pumps and one spray pump .
2) The cargo and spray pumps are of the electric motor-driven centrifugal type
The cargo pums are single-stage; the spray pumps have two-stages or the single
3) As a LNG is a non conductor of electricity, ıt is used as the cooling medium for the pump motor windings. Electrical components of the pumps maybe in contact with LNG without risk.
4) Pump bearings (ball bearings) are lubricated by LNG, there for it is most important that the cargo and spray pumps are not operated in the dry condition, even momentarily
5) Pump components are manufactured from stainless stell and aliminium alloys as these materials are suitable for use under cryogenic temperatures.
6) Electric motor junction boxes are designed for easy disconnection during pump exchange operation.

7.1 Cargo pumps

1) The cargo pumps located at the bottom of the central pipe tower, one pumps each side of the buffer on the filling line outlet, in each tank.
2) The pump suction is each located approximately 75mm from the tank bottom are protected byfine stainless steel mesh screens.
3) Inducers are fitted to direct the flowof LNG and assist suction at low head pressure.
4) Cargo pump discharge lines rise vertically in the pipe tower to the cargo tank dome. Each pums are bolted directly at its discharge flange to the bottom of its discharge line. The discharge pipeline is suspended from a single anchor point which is located at the op of the pipe tower just below the insulatio disc. Guides are fitted to the pump and at the intervals up to the pipeline to prevent lateral movement, but no additional vertical support is provided. The pump is thus free to move vertically to allow for differential expansion between the pipeline and the pipe tower.
5) Each cargo pump has a capacity of 1400 m3/h at 145 head of LNG.

7.2 Spray pumps

1) One spray pump is located beside no 1 cargo pump at the bottom of the central pipe tower in each tank.
2) The pump suction, protected by a fine mesh screen, is located 25mm above the tank floor . This allows the pump to strip the tank of liquid prior to warning up operation. Like the cargo pumps, the spray pump is fitted with an inducer.
3) The spray pipe discharge line rises vertically through the pipe tower to the tank dome. The pipeline is fitted with anchor stoppers and off-set bends at four location within the pipe tower the secure the pipeline and to allow for differential expansion between the pipe and pipe tower.
4) The bottom 2.7 meter section of discharge pipeline is increased in size to 80 mm other pipes are 50 mm and spray pump discharge flange is bolted directly to the lower end of this section . The weight of the pump is taken by an anchor stopper located at the top end of this 80 mm section.
5) Each spray pump has a capacity 40 m3/h at 135 m head of LNG.
6) During ballast voyages, the spray pumps are used to supply LNG for cargo tank spraying in order to maintain the required cargo tank equatorial temperatures ready for loading. If additional boiler fuel gas is required, the spray pump will be used to supply LNG to the forcing vaporiser.
7) Spray pumps also used for initial cooldown of cargo piping on board and discharge arms ashore prior to operation of cargo pumps.

7.3 Instructions:

Cargo pumps:
1) The cargo pumps can be started from the centralized administration and control center of cargo control room (CCR), in the unlikely event of problems with the IAS of monitoring system.
2) The normal starting method is by using the IAS of operation Manuel.
3) In the case of NWS, using the IAS will require.

a) Display one
- Set up usual operation starting
- Set up initial discharge valve opening
- Set up finishing level
- Set up initial motor load

b) Display two
- Will then be used to start the pump
- The starting sequences also control discharge valve, filling valve and branch valve manipulation.

c) The cargo pumps stop automatically should any of the fallowing occur.
- ESDS initiation
- Tank protection system initiation
- Undercurrent of motor.
- Overcurrent of motor

d) The cargo pumps can be stopped manually from the centralized administration and control center the cargo switchboard room and each tank dome.
e) Under normal operation, where stripping is not required, The IAS will stop the pump at a present level and close the discharge valve.

Spray pumps:
1) Normal control of the spray pumps are via the IAS or control console.
2) In case of NWS, the spray pumps will stop automatically should any of the fallowing occur.
a) ESDS initiation
b) *Tank protection system initiation*
c) Under current of motor
d) Over current of motor

Notes:
1) At tank levels below approximately 1 meter, cargo pumps should not be restarted as difficulty will experienced in taking suction, with the consequent risk of bearing damage. Minimum tank level for the spray pumps is approximately 700 mm
2) Should a pump fail to start or prime after two attempts, a delay of 15 minutes must be observed before a further attempt is made. This avoids overheating of the motor windings. No more than four attempted starts should be made in one hour.
3) All cargo and spray pumps are fitted with online insulation monitorng which will prevent motor starting should the insulation resistance fall below 1 megahm. Prior to motors being meggered, the monitor earth link must be disconnected.

8) CARGO INSTRUMENTATION AND CONTROL SYSTEM

8.1 Monitoring system
a) Temperature
b) Pressure
c) Cargo liquid level
d) Gas concentration
e) Cargo spesific gravity

a) Temperature Measurement:
As for LNG carriers which transport LNG of –160C degrees, the temperature measurement is mainly to measure the temperature of LNG in cargo tank for density correction at the time of CTMS and the prevent dangers detecting the temperature – distribution of tank equator ring and hold part for controlling the tank cooldown rate and foreseeing a part of tank leakage etc.

b) Pressure gauge:
Pressure either above or below the design range can be damage a system and operating personnel should be fully aware of any limitation for each part of the cargo system , pressures should be kept between the specific maxima and minima .

1) Custody Transfer Measurement System (CTMS)

Pressure sensor shall be provided for each cargo tank to measure each cargo tank pressure. The pressure shall be read out directly by the CRT or printer in cargo control room.

2) Operation Purposes

Pressure transmitter, differential pressure transmitter and pressure switch shall be provided for cargo protection, alarm, monitoring and emergency shut down system.

The pressure sensors are installed in the fallowing parts.
- Cargo tank and hold
- Cargo line
- N2 line
- Inert gas-aerating line
- Cargo handling machineries

c) Cargo Tank/Hold Pressure Control

Pressure in cargo tanks and holds should be closely monitores, especially during cargo operation and equipment provided should be used to make the necessary adjustments. Particular care is necessary with membrane or semi membrane systems which are vulnerable to damage from vacuum or incorrect differential pressure because of the thin barrier materials.

- Prevention the ingress of the air to cargo tank

Tank pressure > Atmospheric pressure

- Prevention the ingress of air to hold space being filled with dry air

Hold pressure > Atmospheric pressure

- Protection for cargo tank

Tank pressure > Hold pressure

c1) Level Measurement

Level gauges are important because LNG carrier's cargo system is closed and levels can not sounded. Level measurement is intended to measure LNG volume in cargo tanks on demand and to display the LNG level for custody transfer purpose. The gauges may be linked to high level alarms to give warning of tank being over-filled, and shut down systems, to prevent the cargo over filling the tank or over pressuring the tank and causing fracture.

The types of level gauges are follows.
- Float gauges
- Capacitance gauges
- Bubler gauges
- Untrasonic gauges

c2) Gas Detection

Main purposes of gas detection are as follows
- Detecting the existence of leakage from cargo tank, pipeline and relief valve at early stage to ensure the safety. In addition, preventing the loss of cargo and nitrojen by detecting such gases.
- Increasing efficiency of inerting or purging operation. Personal should fully understand the principles, uses and limitations of gas detection equipment, whether

fixed or portable. For all instruments referenceshould also be made to the manufacturer's instruction. Some of the most common principles for gas detection are as follows.

- Absorption of infrared light
- Combustion principles
- Difference in thermal conduction
- Paramagnetism
- Colour reaction in chemical reagents

8.2 Safety equipment

Tank protection system

The fallowing safety equipment relating to cargo tank is provided
- Pressure monitoring and alarm control
- Temperature monitoring and alarm
- Level monitoring and alarm
- Gas detection and alarm
- Emergency shut down
- Integrated monitoring and control

These above mentioned safety equipment fulfil their function , being closely connected with CTMS and trip system , to ensure the safety while cargo handling and during a voyage .

Emergency shut down system (ESDS)

The object of ESDS is to stop cargo operation or cargo operating equipment for tank protection automatically in case of accidents or emergencies. Where gas carriers and terminals are dedicated to each other as in most LNG projects, the terminal and the ship's ESDS are linked during cargo transfer and act safety in combination.

ESDS is activated by:
- ESDS loop pressure low operating of an air release cock or melting of fusible plug
- Cargo tank pressure low
- Cargo tank level, extreme high
- Manual activation of ESDS switch
- Electric power failure
- Cargo hydraulic pressure low
- Control air pressure low

Initiation of ESDS cause the follow
- ESD valves shut
- Gas compressor HD or LD
- All cargo and spray pumps stop
- ESD loop and ESD signal transmitted to shore terminal equipment trip .

Emergency shut down valve (ESDV):
- ESDV is fitted on liquid vapour manifold and fuel gas line. It is fail-close type which closes automatically upon low hydraulic pressure.

Relief valve:

The following relief valves are fitted on each cargo tank hold or liquid/spray lines to protect them from abnormal pressure.
- Cargo tank relief valve
- Hold relief valve
- Differential pressure relif valve
- Relief valve for cargo line

8.3 Custody transfer measurement system (CTMS)

CTM System
LNG trading differs from the generality of other liquefied gas trading in two respect affecting cargo quantification. LNG is traded with in long-term projects with dedicated production, transportation and reception. Secondly , cargo boil off during loaded and ballast voyages is used as ship's fuel .Commercial cargo quantification is accordingly tailored to the particular project circumstances and contract agreements but is usually on the basis of calorific values of cargo delivered . Calorific value is derived from a knowledge of cargo composation and the mass of liquid transferred with an adjustment made for the calorific content of the volme of the vapour displace. Thus weight in air is not involved in the quantification of LNG cargoes and mass is invariable calculated from liquid volume and density at tank conditions. The following works are necessary to determine the calorific content for trading.

Outline of the system
This system is composed of capacitance type level gauges, temperature sensor and pressure sensor . Float level gauge system is also provided independently as the back up system

Operation
It is common practise to use ship's figures to determine cargo volumes for custody transfer at both and receiving terminals. It is therefore usual for a surveyor to be employed as an independent third party to varify the shipboard volume measurements. At the both discharging and loading. It is necessary to quantify the ship's tanks content both before handling and after hanling in order to determine the cargo discharge or the cargo loaded. Net quantities of transfer cargo are the difference between before opening custody and after closing custody quantities. The liquid level, liquid/vapour temperature, pressure in each tank and list/trim are indicated on printer or CRT of CTMS.

8.4 Nitrogen Generating System

General:

1) Nitrogen is required on board for the following purposes;
- Cargo line purging
- Cargo compressor gland sealing (shaft sealing)
- Cargo tank insulation space inerting (annular space)
- Vent room gas line purging
- Nitrogen bleeds to hold space

2) Nitrogen is supplied by two nitrogen generator units of the semi-permeable membrane type. Nitrogen generated is stored in a buffer tank, thus allowing continuous unit operation when the demand rate fluctuates.

3) A semi-permeable membrane is barrier which prevents hydrodynamic flow so that transport through the membrane us by absorption and diffusion. Different molecules transport at different rates so that fast gases such as oxygen can be separated from slow gases such as nitrogen.

4) The semi-permeable membranes are enclosed within a pressure vessel and are so disposed as to present the maximum possible surface area for gas to transport through. As compressed air flows across the surface of the membranes, oxygen, and carbon dioxideand water vapour contained in the air permeate faster than nitrogen through the membrane to the low pressure side. Thus the air on the high pressure side of the membrane becomes depleted of fast gases and becomes rich in nitrogen, whilst the air on the low pressure side of the membrane becomes enriched with oxygen. The oxygen-enriched air is vented to the atmosphere at a safe location whilst the nitrogen on the high pressure side of the membrane is directed to yhe nitrogen buffer tank.

5) A part from sharing a common pressure controller and control valve the two nitrogen generator trains are identical. Each train comprises a feed air compressor, one side of the valve instruments module. The two sides of the VIM and MSM are largely back to back images of each other, a minor difference in layout being due to the accommodation of one side.

8.5 Inert Gas Generator System

8.5.1 Inert gas

Three condition undermentioned must be coexist in order for a fire or an explosion to occur.

- Flammable vapour
- A source of ignition
- The proper amount of oxygen to form a flammable mixture.

To eliminate of the risk of the fire or an explosion ina cargo tank or hold space on a LNG vessel, the oxygen content in a space is reduced to a point where the atmosphere cannot support combustion. This is accomplished by introducing inert gas into the spaces until the oxygen content is reduced to an acceptable level before LNG vapour support combustion. Inert gas produced by a inert gas generator IGC, is fed to cargo holds and tanks etc. After the dew point to be lowered by a cooler and dryer.

8.5.2 Out line of IGC system

Inert gas is produced by light oil combustion. The produced inert gas is made of mainly 85% nitrogen, 15% carbon dioxide and a little oxygen. This high temperature combustion exhausted gas is firstly cooled.
Water vapour as it is found in inert gas, has to be removed.

- If water is harmful in contact with the cargo
- If condensation caused by cooling of the inert gas is not accept able in tank or piping system. Above the amount of water at acertain dewpoint. Inert gas a product of combustion is saturated with water vapour at a temperature about 2 degrees above cooling water temperature will be at 34 degrees. Drying to the required dew point may be done by cooling the inert gas and removed the condensate and or absorbing by means of absorbents in drying chambers that can be regenerated.

8.6 Duel Fuelling System

8.6.1 Outline of the BOG system

BOG means methane gas which is boiled off from cargo tanks. This BOG is used as boiler fuel with fuel oil. Methane gas is only cargo which is permitted to use as fuel because methane gas is lighter than the air. So, even ıf a leakage trouble occurs, is the gas will be dispersed easily, not so dangerous.

One method is:
- To spray LNG by using a spray pump and spray nozzle to cool down cargo tanks before arrival of a loading port.
- To vapourize forcedly LNG by using a forcing vapouriser and a spray pump.
- This three methods are used in combination, it depends on the case. For example, when slowing down a ship's speed, ıt is enough to use only a natural evaporated gas.

8.6.2 Cargo spray system

During a ballast voyage, a small percentage of cargo (heel) is left in one or more cargo tanks and used to maintain the tanks being cool by spraying the liquid into the cargo tanks through spray nozzles. The sprayed liquid turns to vapour with, absorbing heat from the tank walls. Any excess vapour is sent to boilers as fuel since the tank pressure increases due to a continuous spraying. A cargo tank spraying is usually carried out during daytime.

8.6.3 Steam dump system

Boilers generate system for propulsion and other purposes by means of burning fuel oil and gas. However a surplus steam is directly dumped from boilers to a dump condenser through a dump control valve in case that steam consumption is less than a generated steam in boilers even though a burning rate is minimized. Because the lowest burning rate is limited in order to keep the cargo tank pressure below the designed value for safety. Otherwise, extra BOG must be dispersed in the air.

8.6.4 Components of Dual Fuelling System

As for a gas burning, vent lines and nitrogen purge lines are required for safety in addition with gas lines and facilities to feed a fuel gas.

- L/D compressor:
A L/D compressor is used to remove BOG from the tanks in order to maintain cargo tank pressure. BOG removed is used as boiler fuel .
- BOG heater
A BOG heater is used for heating BOG to supply as fuel to boilers in conjuction with a L/D compressor.
- Forcing Vapouriser
A forcing vapouriser is used to vapourize LNG supply from a cargo spray system.
- Master gas valve
A master gas valve is a main gas block of boiler fuel gas lines. The following events will off fuel gas to the boilers.

- ESDS system actuated
- Both vent duck exhaust fans stop
- Gas leak detection
- Main turbine trip
- BOG temperature low
- L/D compressor trip
- Both boilers trip

- Vent lines:
Vent lines consist of a vent hood, vent ducks, exhaust fans, and a gas detection system. Fuel gas pipes in a engine room are covered with an annular jacket, and all gas valves concerning with gas burning are in the vent hood.
The annular space between inner and outer pipes and also the vent hood are netilated by the exhaust fan . Gas detectors are fitted in the duck and checking constantly that methane gas leakage or not to vent lines. If a gas detector would catch a gas leakage, the gas trip system will be initiated.
- Nitrogen purges lines:
Fuel gas lines will be purged with nitrogen gas before and after gas burning operation in order to not explode in the pipe lines. This purge system is exactly described.
- Duel fuel combustion burner:
Duel fuel combustion burners are fitted on each burner. These burners have one F.O nozzle and two types of gas nozzles and are arranged alternately around.

8.6.5 Fuel modes of dual fuel burning

A fuel mode is selected from among a F.O mode a F.O gas dual mode and a gas mode
- Fuel mode: This mode means to burn only fuel oil. The fuel F.O flow is controlled so that a pressure of a superheated steam is to be kept constant.
- Dual fuel mode: This mode means to burn fuel oil and fuel gas simultaneously. The fuel gas flow is not controlled. All BOG are burned in boilers accordingly after in a constant pressure by the L/D compressor. In case that BOG less than the total fuel quantity matching with the steam demand required, the fuel oil flow is increased automatically.
Next, the surplus steam is to be dumped in the dump condenser if the generated steam is more than the steam demand required even though the fuel oil flow reaches the minimum controllable range.

- Gas mode: This mode means to burn only fuel gas and is to be used in the event of a F.O burner maintenance etc. And be a entire manual operation, not a normal operation.
- Selection of fuel mode: Three fuel modes are selected by a manual ON / OFF switch for each boiler's burner. However, direct changings from the F.O mode to the gas mode and from the gas mode to the F.O mode are unable.

Reference:

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