COMPARATIVE ECONOMY OF LNG AND PIPELINES IN GAS TRANSMISSION

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1. INTRODUCTION

This paper discusses a model and how various factors affect the comparative economic costs of LNG and pipelines, eventually to find how more attractive LNG is for developing courtiers than in the past.

LNG has been traditionally used in industrial economies by importing it from developing countries, if not all. But this trade pattern is changing around the turn of the century when more countries are considering use of LNG. This is because, that, e.g., the size of economy of certain developing countries is rapidly growing while they also move forward to better local and global environment necessitating more use of clean energy, as well as that the depletion of indigenous oil resource is seen on the horizon in some regions.

LNG is priced in the market of importing countries with terms different from project to project. The cost of the LNG chain is rarely openly discussed in energy consuming economies since it may not directly affect the prices, which rather depends on the market of crude and product oils. It is also difficult for them to tackle with since the costs are actually not known to consumers and also are different from plant to plant and ship to ship. An entity or individual is not normally involved in all the chains from upstream to downstream, prohibiting it to access the whole information. The author does not know actual costs of any project either.

Nevertheless general project cost numbers appear in bits and pieces from time to time in the news media. A trend may exists that the costs have been decreasing substantially in the last decade.

The LNG/pipeline relationship may have dramatically changed to date. A statement that LNG is more economical when the transportation distance is longer than say 4000 km used to be a common knowledge in the gas industry ten years ago. Technology progress and competition as well as economy of scale seem to have made LNG more competitive than in the past. How economical that is quantitatively and comparatively is a question. How costs generally compare to each other may be still serious in the market pricing environment and may affect real gas prices especially at the time of supply surplus.

This will also affect future gas use development in developing countries that consider to use it. The energy market prices in developing countries are normally different from industrial economies even if they are both indexed to international prices; i.e., prices are lower there due to lower consumption and lower handling costs at least. They might not have a reason to pay the same prices for LNG as in industrial countries if prices are said to target at energy market. What is the cost to them, rather than prices, at least comparatively, may be a key question.

2. BACKGROUND

The author was involved in a few master plan and feasibility studies on natural gas market development in Indonesia and the Philippines from late 1990s to early 2000s and found that many pipelines are planned or envisaged for future in the archipelago of the South East Asian countries. Many gas fields are offshore and a number of sea-bottom pipelines are already laid in the archipelago, making it natural to think that those pipelines and their extension will eventually connect most gas fields and markets in the region.

The ASEAN countries, comprising 10 nations in South East Asia, plan the well known Trans-ASEAN Pipelines, which will connect all the nations in the archipelago region as well as gas fields, sizable amount of which already exist due to the development in the last decade. A future extension is planned or envisaged for gas transportation to the Philippines which is on the eastern rim of the region.

The Philippines has just come in the world's natural gas market community since the inception of the new Camago-Malampaya gas field in October 2001, which is the first sizable indigenous gas field in the country. The nation has embarked on developing the natural gas industry with the plan of a pipeline to Manila starting from the landfall of the Malampaya gas pipe for industries and other purposes in addition to the gas power plants already in operation. It is conceived thereby that the long term sustainable development of the natural gas industry requires additional gas supply in the future and the Trans-ASEAN is an important candidate.

In considering additional alternatives of the future gas supply to the Philippines, together with various factors for secured systems of natural gas network encompassing Central Luzon and Metro Manila region of the nation, LNG has emerged as a possibly effective alternative.

Comparison of advantages and disadvantages are already discussed in other occasions, some of which are included in the Report of the IGU/Working Committee 10 in this World Gas Conference 2003. What are the costs of LNG and pipeline gas is only briefly discussed there.

This author wants to elaborate on the topic of the cost comparison which emerged from the above discussions, which may have broader implication in the world.

3. MODEL DESCRIPTION

3.1 Objectives and Outline of the Model

The author has developed a set of Excel programs to assess whole economic costs of LNG and pipeline gas transmissions simultaneously. The model will examine the average gas costs in both the pipeline and LNG cases, integrated eventually to produce the comparative results. Finally computed costs are basically in terms of average incremental costs per thermal value as well as other results.

The assumptions on variables used and the cost numbers are from published data and own estimate as well as judgment; thus accuracy is not guaranteed but a resultant trend of the costs may be certain at least. Since an actual cost changes from project to project, general accuracy even does not exist.

Conditions and assumptions common to both the pipelines and LNG are first set. These include physical/commercial and financial/economic assumptions. Some of the former are the distance of transportation, gas quality, gas flow capacity at plateau, period of construction, sales buildup years, economic life, contingency, the cost of feasibility, etc. The latter includes period of calculation, starting year, definition of currency, discount rate, wellhead gas price or the price at the inlet of the gas processing or liquefaction, etc.

Economic costs exclude all the taxes and duties which are different from country to country; the resultant costs are different from actuality at a rate by that portion.

3.2 Transmission Pipeline Model

In addition to the common conditions, the transmission cost of gas through pipelines in the model is a function of further technical conditions. The relevant conditions are gas pressure, allocation of compressor stations, choice of the gas flow formula, choice of single line or parallel lines, installation cost of pipes per size and length, that of compressors per horsepower, physical and economic life of use, fixed and variable O&M costs that are hopefully adequately set in the model.

Figure 1 shows the conceptual model for cost estimation of pipelines. This show that the total cost consists of the costs of gas processing, pipelines and gas compressor stations. Actually we add the cost of feasibility studies or relevant preparation cost to the first portion. We give the interval between compressor stations and calculate resultant length of two parts, i.e., ones of conceptual equal length and another of different at the end of the line. For the segments of equal length, the beginning and ending pressures are naturally assumed the same to all segments respectively.

Figure 2 shows how these two parts are created to find the number of compressor stations required and the pipeline length of segments. A gas flow formula is applied to the both segments separately to find the pressure at the destination.

The gas flow calculation is performed to find a right pipe size through a reverse computation system to give the desired pressure at the destination. A two-inch larger size than theory is selected.

The cost of the pipelines is calculated based on the given unit cost of pipe installation in terms of US$/km/inch (nominal diameter). While the average or standard unit cost of pipe installation varies from region to region, it normally spans over from 18 to 80 US dollars in non-Japan world, excluding exceptional cases like deep seas or high mountains as well as river or channel crossings. We will tentatively set it as 35 US Dollars /km.inch considering majority of pipelines in our case for comparison may be offshore.

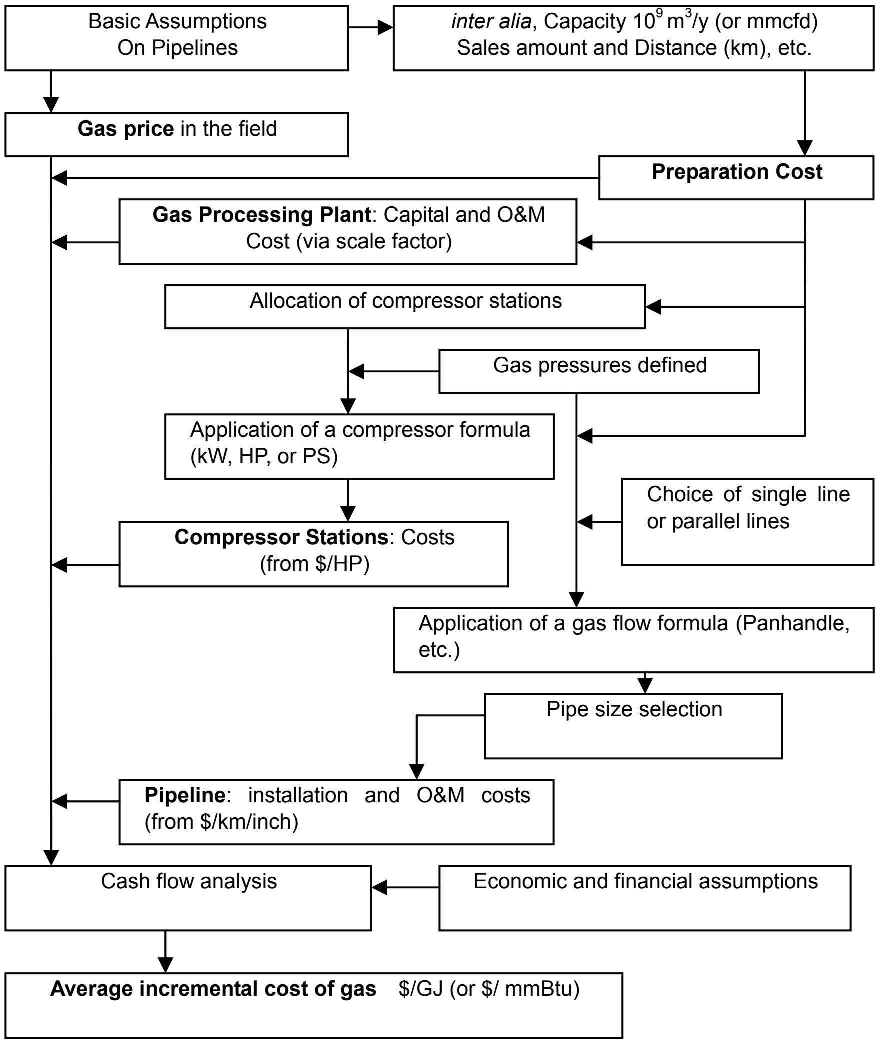

Figure 1: Pipeline Cost Calculation Flow

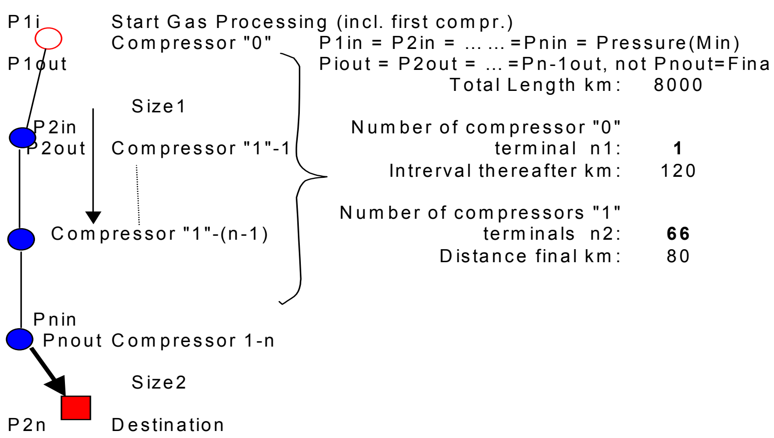

Figure 2: Allocation of Compressor Stations (example)

Given an annual quantity of gas and target gas pressures, as well as other factors, the program computes necessary pipe sizes and then capital costs, which, together with other information on O&M costs, lead to cash flow analysis in the given period. The gas flow or annual quantity of gas can be in 10^9 m^3 (billion cubic meters or "bcm") per year or in any other unit. Compressor horsepower is calculated and reflected on the capital and O&M costs. A gas flow formula is automatically chosen among Panhandle A, New Panhandle or others by an indicator in a variable in the outside user functions.

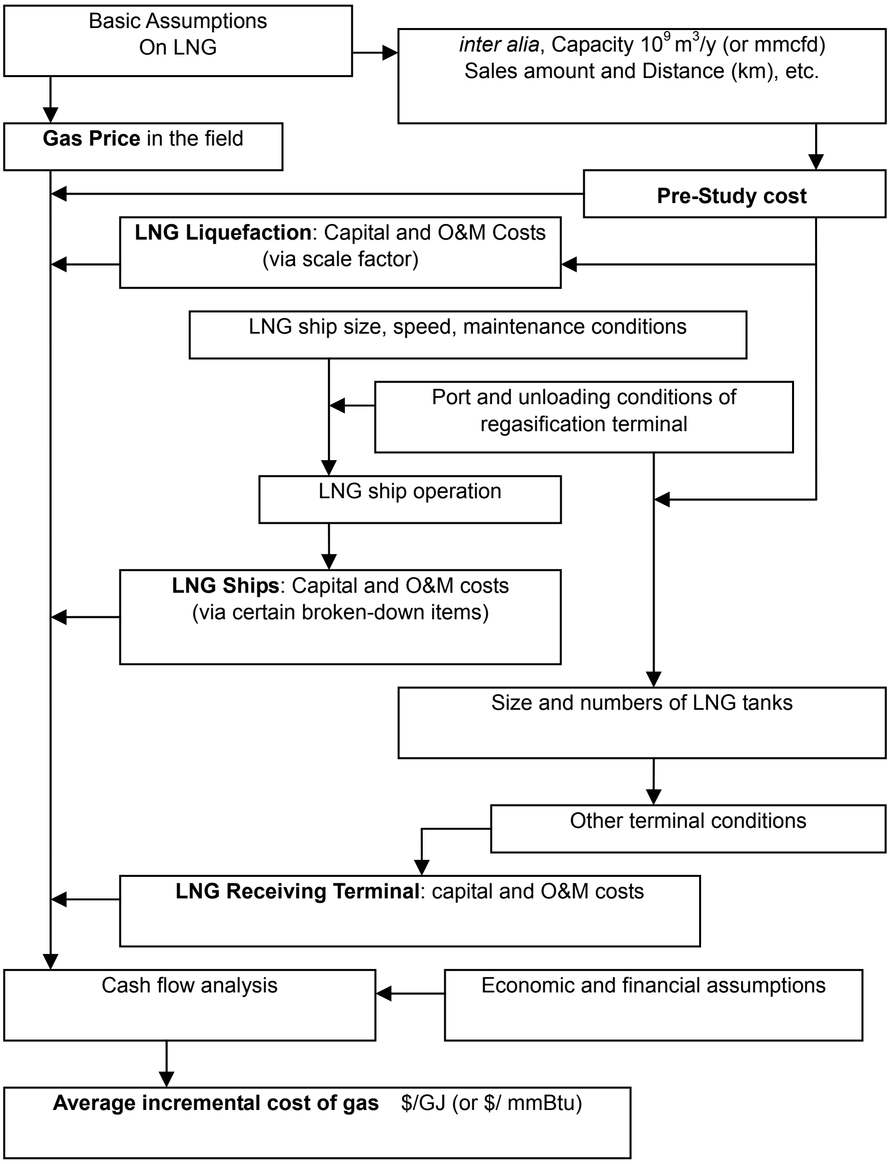

Figure 3: LNG Chain Cost Calculation Flow

3.3 LNG Model

The LNG costs in the model consist of the capital and O&M costs of the gas field, liquefaction, LNG shipping and regasification. The cost calculation method of an LNG chain is illustrated in Figure

3. The costs are affected by similar factors as in the case of pipelines as well as different ones characteristic to LNG. Those factors unique to LNG are: amount of stock pile of LNG which is desired or required, the basic size of an LNG tank, the size and speed of LNG ships, harbor and loading/ unloading conditions (time duration), the dry-dock conditions, etc. Capital cost functions are incorporated in the model, as well as for O&M, which are elaborated in the later paragraphs. The size of the stockpile is given in the number of days to accommodate the gas consumption.

The necessary size of LNG storage, the frequency of LNG ship voyages, the required number of ships, etc. are calculated from these data, leading to the total CAPEX (capital expenditure) and OPEX (operating expenditure).

Those data are then put into cash flow analysis of the total LNG chain to find average economic incremental cost of gas in terms of price per thermal value for the given period as the net present value in the first year.

This cost is then repeatedly calculated for sensitivity analysis in relation to any variables like transportation distance. The Excel program offers such calculation performed instantly by using the TABLE function.

3.4 Model of Cost Comparison

The cost results of both pipeline and LNG are then jointly treated as the functions of the distance of transmission. The cross point of the two lines are calculated to find the distance which we will call the “dross distance” and gives the same cost of gas in terms of thermal value to both the LNG and pipelines.

Our question is how factors will change the cross distance. This simple algorithm is illustrated in Figure 4 and the resultant relationship will be illustrated later.

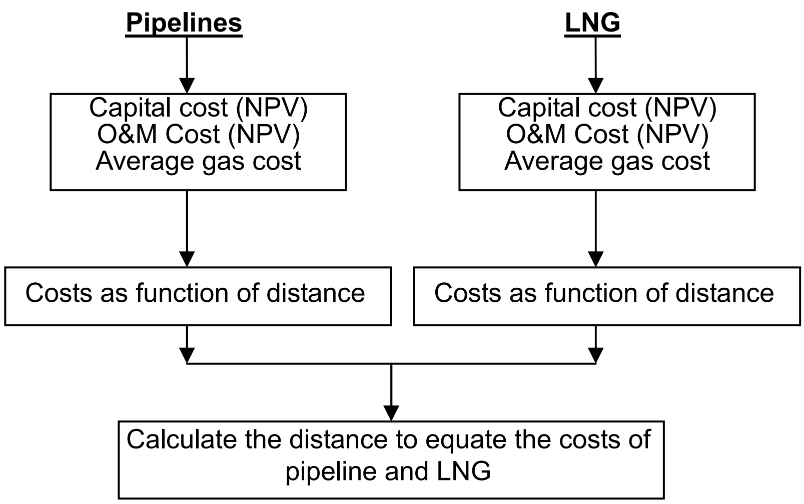

Figure 4: Cost Comparison of Pipeline and LNG

4. COST FORMULAE

The cost functions are often tough to define for outsiders and also due to diversity of conditions over various regions. They can never be uniquely defined or even average or standard costs widely applicable may not exist. Nevertheless approximate project costs are often reported in the media without details which we have to rely on this time. We will discuss how we have assumed relevant costs below.

4.1 Pipeline Cost

Pipeline costs in the US have been adapted from the data annually reported in the Oil & Gas Journal as sourced from the US Federal Energy Regulatory Commission (FERC) together with various information of the relevant pipeline and compressor projects. The costs are indeed varied even within the US and it is dangerous to directly apply those to developing countries. The recent average costs of pipelines are little higher than ten years ago, on the current basis, being around 20 to 60 US dollars per km.inch for normal onshore and certain long pipelines in 1999. Figure 5 illustrates the aggregate US pipeline cost distribution in 1999 sourced from the said journal in November 2000. The variation is large for cases of off-shore lines or river or channel crossings or any other conditions like loop lines. A pipeline installation cost consists of 24% material, 42% labor, 26% miscellaneous and the rest for right of way (ROW) acquisition in the average here.

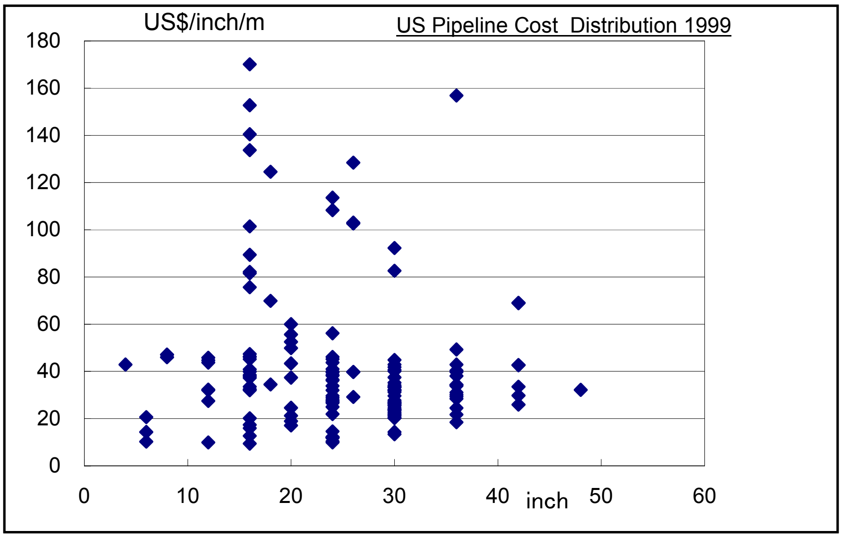

Figure 5. Distribution of US Pipeline Costs over Size in 1999

At the same time the author has looked into the cost numbers in the world which appear in the media from time to time especially for developing countries. Pipeline costs in developing countries are relatively lower than in the US, setting aside exceptional cases, due to apparent lower costs of labor. ROW and miscellaneous costs may be also lower. Instead at the same time, more workers may be necessary in those countries which may lack expertise and pipe construction industry to accommodate laying secured pipelines.

When we consider “pipeline or LNG?”, we normally suppose that much of the transportation routes may be offshore, although potential cases of comparison with totally onshore pipes may exist, too. Recent offshore pipelines are often laid in challenging conditions as seen in the Blue Stream Line in the Black Sea, whose cost should not be low at least in the beginning. Involving the investment in pipe installation ships and other technological development, the cost for those pipes may heavily deviate from the proportional relationship to the distance. We will exclude those technology edge cases in our simulation of comparison.

Considering all these conditions, i.e. factors of nature of developing status, offshore pipelines and closer to regular pipelines, the author has chosen US$ 35.00 / km/inch as a typical starting cost for comparing with LNG later. The simulation model of course can easily change any such cost instantly but we will take it as the base case.

Loop lines are often implemented to match the growth of demand in the course of time to avoid excessive one time advance investment, but are author believes also considered for security. The second line added to the original one is assumed cheaper than the first one. While how cheaper it is can be set freely, we assume in the base case that the cost of the second one is 40% lower.

As such, the pipeline cost may not necessarily be totally proportional to the distance, but the author has no means to define how to relate them otherwise generally.

The compressor stations also need a cost estimate. How compressors will be arranged for the offshore pipelines assumed for comparison with LNG may have to be defined. Possibly much longer average intervals will be adopted using smaller islands on the route. While somewhat uncertain, we assume the cost of the compressor stations tentatively as US$ 1341 / kW (i.e., $1000 / HP (British horsepower)).

4.2 LNG Liquefaction Cost

LNG liquefaction capital costs may be said as 40-50 % lower compared to 10 years ago in terms of thermal thanks to the effect of technology breakthroughs, general plant market competition and economy of scale.

Figure 6 shows how LNG liquefaction cost has decreased in the last 30 years, based on Shell’s presentation in the Asia Pacific Energy Forum in Manila in 1999, excepting a number for 2000 which was converted from other data from media.

Also a published brochure of BP in 2002 says that a typical construction of a liquefaction plant costs more than 200 US Dollars per ton per annum. Assuming this number is US$205 / (t/y), a typical LNG liquefaction plant of, e.g., 4×10^6 (i.e., 4 million ton) may cost 820 million US Dollars. There may be large differences in the costs between the first plant train and other trains to be completed thereafter. Also we may not assume all sizes of plants to be available; there will be optimum sizes depending on market and physical conditions. We will, however, disregard this factor and assume any sizes in the model.

Year	Index of Capex $/ton/y (Brunei=100)	
1969	Brunei	100
1975	Malaysia 1	80
1985	West Australia	86
1990	Malaysia 2	67
1993	Nigeria	64
1995	Oman	50
1999	(not identified)	45
2002	Ras Laffan	40

Figure 6. Trend of Liquefaction Plant Cost (Shell, 1999)

Our model cost function for a liquefaction plant is based on a set of data derived from a World Bank Report on LNG projects of 1994, which is not necessarily published and shows that the cost (CAPEX) of a 5 x 10^6 ton plant was about US$1870 million then. We have adjusted this number by a factor of five (0.5) to meet recent cost conditions discussed in the above. A scale factor of 0.7 is used to meet the cost of a required size of the plant, as well as another small adjustment term is added.

For the operation and maintenance (O&M) costs, we are simply assuming a 4.5 % of CAPEX for annual fixed cost and 0.0474 $/GJ (or, 0.05 $/mmBtu) for the variable O&M, considerations being given to the complexity of the plant.

4.3 LNG Ship Cost

We will consider only the cases of ocean gas transportation while LNG is also transported onshore by trucks and trains. LNG ship building costs are widely reported as to be less than 200 million US Dollars for a one of 135000 m^3 cargo size while it used to be more than 300 million.

A Japanese gas utility news paper (the Gas Jigyo Shinbun in Japanese) reported in February 16, 2000, that the average cost of LNG ships has changed as in Figure 7, citing an article in a Poten & Partners report.

The size of majority of LNG ships is around 125000 m^3, the size having been generally gradually increasing. The recently contracted one reportedly reaches 145000 m^3, the cost being reported as less than US$ 170 million. Also several smaller ships of varied sizes less than 40000 m^3 exist to meet the requirement of local markets recently, which partly affects the data in the table (of Figure 7).

In our model, the cost of a ship is expressed by a function:

Ship Cost (CAPEX) = *a* * Ship Size + *b*

where the coefficient (*a*) and the constant (*b*), with further breakdown for each, are adjusted to meet the recent cost conditions stated before.

Year	US$ million
1990	260.3
1991	235.2
1992	218.0
1993	219.7
1994	230.5
1995	214.7
1996	221.5
1997	191.9
1998	187.3
1999	172.9

Figure 7. Cost of LNG Ship Building

The fixed O&M cost may be a function of: the annual repair cost, the dry-dock cost and the crew cost. The model considers several factors affecting these costs. It assumes, e.g., that a ship is put into dry-dock for six weeks a year for an assumed cost.

The variable O&M cost should be a function of boil-off gas rate, bunker fuel price, and transportation distance, which are simulated to meet in an actual case. The function is eventually expressed as:

Variable O&M = *c* * transportation distance*amount of LNG (thermal value)

where the coefficient "*c*" reflects the considerations stated above.

4.4 LNG Receiving Terminal

The largest cost of an LNG terminal is normally incurred in LNG tanks, of which various types and sizes exist. The quantity of LNG storage required changes from region to region according to the climate, market characteristics, availability and size of other gas storage, LNG ship cargo size, energy stock policy, etc.; these factors have to be first defined and the defined size and number of tanks are a variable in the cost function.

Other facilities normally required are the LNG berth, the unloading facility, LNG pumps, return gas blowers, vaporizers, odorization facilities, sampling and measuring, etc.,

Considering the heavy weight of the tank cost, we have defined a formula of the terminal CAPEX as follows:

Receiving Terminal Cost = *d* * Size of LNG Storage + *e* where "*d*" and "e" are coefficient and constant, with breakdowns, adjusted to produce the a value closer to actual cases. The required amount of storage is computed separately.

Operation cost may depend on power consumption quantity and power price, repairs and labor, as well as others. The fixed O&M cost reflects the labor and repair cost, and the variable O&M cost reflects the power use expenditure.

5. ANALYSIS

5.1 Gas Sales and Economic Analysis

Gas sales amount is defined for each year from the information of gas flows at plateau, operation start year and the number of buildup years automatically for economic analysis. Cashflow tables are automatically created to give net present values of the costs and gas sales volume to produce the values of economic cost. A terminal value is given at the end of the calculation period based on the economic book value of the facilities calculated on the assumed economic life.

The average incremental economic cost (AIC) is given by the following formula:

AIC = NPV (costs) / NPV (gas volume)

Where, NPV is the net present value over the calculation period and can be conveniently given by a Worksheet function:

=The first year's value + NPV(discount rate, 2nd year: last year)

5.2 Assumptions for the Analysis

A set of the assumptions for the base case simulation is summarized in the tables in Figure 8-1 to Figure 8-4.

The physical conditions are tabulated in Figure 8-1. For the comparison, the quality of gas is assumed to be the same to both the pipeline and LNG cases.

Changeable Item	Assumed Number	Remarks
Distance	2000 km	
Gas quality (gross)	39.69 MJ/m3(15C)	=1063 Btu/scf = 10000 kcal/Nm3 (0 C)
LNG liquid density	0.45 t/m3	
Transport capacity	6.207 10^9m3/y (0dC)	= 635.2 mmscfd (60F) = 5.00 million t/y
Wellhead gas price	US$ 1.000 /mmBtu	

Figure 8-1 Physical Assumptions

Figure 8-2 shows economic, financial or general conditions common to the both. No inflation is assumed for real term price calculation and no tax or duty is considered for the economic analysis.

Changeable Item	Assumed Number	Remark
Project begins in	2003	
Period	20 years	
Discount rate	8%	real
Economic life of facilities	30 years	
Inflation	0%	Calculation in real terms.
Taxes & inflation	neglected	
Installation contingency	5%	
FS or Preparation costs	$ 15 million	

Figure 8-2 Common Economic Assumptions

Figures 8-3 and 8-4 shows the specific base case assumptions for pipeline and LNG respectively.

Changeable Item	Assumed Number	Remark
Project capacity	6.207x 10^9 m3/y (0 C)	=LNG 5 million t/y
Initial pressure	5000 kPa	= 50 bar
Pipeline pressure (Max)	7500 kPa	= 75 bar
Pipeline pressure (Min)	5500 kPa	= 55 bar
Final pressure	4000 kPa	= 40 bar
Interval between compressors	200 km	
Construction yrs	3 years	
Demand buildup yrs	5 yeas	
Starting gas price	US$ 0.948 /GJ	=$ 1 /mmBtu, at process inlets
Pipeline cost	US$ 35 /m/ inch	
Compressor cost	US$ 1000 /HP(US)	
Gas processing plant	US$ 160 million	(fixed)
Choice of one (1) pipe or two	1	
Cost of 2nd parallel line	60%	

Figure 8-3 Assumptions on Pipeline

Changeable Item	Assumed Number	Remark
Project capacity:	5 million ton/y	635.2mmcfd(60F)
Ship cargo size	135000 m3	= 60,750 t
Ship speed	18 -21 knots	
Loading + unloading time	25 hours	Port maneuver inclusive
Dry dock	40 days/ 2.5years	
Storage at Receiving terminal	2 tanks	
Construction period	4 years	
Ship Building	4 years	

Figure 8-4 Assumptions on LNG

Assumptions in these tables are for a beginning case and the model can change them for simulation cases.

6. RESULTS

6.1 Results from the Base Case

Tables in Figure 9-1 and Figure 9-2 show the typical simulation results derived from the set of assumptions defined in the above tables.

The total costs are somewhat comparative between pipeline and LNG on the given assumptions. The table also shows that while the both are capital intensive, the pipeline is more dependent on the capital expenditure. (with respect to the unit gas cost, \$1.00/mmBtu is equal to \$1.055 /GJ.)

Costs Summary:

Case of 2000 km 5.00 mil. ton/y		Capital Cost (NPV) US$ million	O&M Cost (NPV) US$ million	Total Cost (NPV) US$ million	**Unit** **Gas Cost** $/mmBtu
Long term cost:	**LNG**	1,762	738	2,499	2.695
(Ave. levelized)	**Pipelines**	2,216	333	2,549	2.626

Figure 9-1 Cost Summary of LNG and Pipeline

LNG:	$/mmBtu	Pipeline:	$/mmBtu
Process inlet	1.000	Process inlet	1.000
Liquefaction	0.967	Gas processing	0.134
Shipping	0.265	Transmission	1.492
Re-gasification	0.463		
	2.695		2.626

Figure 9-2 Breakdown of Unit Gas Cost of LNG and Pipeline

Some of these costs shown in the tables are imaginary only based on the assumptions like the starting gas cost of US\$ 1.00/mmBtu and exclusion of all taxes and duties as well as others as stated before; thus the values may not represent real costs. Rather, significant is only the comparison between pipeline and LNG and if the stated assumptions are right, the costs of the both are now found close to each other for the distance of transportation of 2000 km.

6.2 Relationship with Distance

How the difference in the distance will affect the comparative costs is the next question. The model can show the relationship with the distance as in Figure 10.

The two cost curves for pipeline and LNG with respect to distance are distinctive. The cost of pipeline quickly increases with distance since we have assumed that the pipeline cost is calculated simply based on the cost per length; the almost whole cost depends on the length here, regardless of how real this is or not.

On the other hand, in the case of LNG, much of the investment is made in the liquefaction and re-gasification which are not distance dependent. The parts of the shipping in the whole LNG chain is surely distance dependent, but its share in the total cost of the chain is rather small and the recent ship cost decrease further affects the less dependence on the distance.

Gas Transportation Cost vs. Distance - Base Case

5 mil. t/y= 635 mmscfd Cross at: **2,107** km

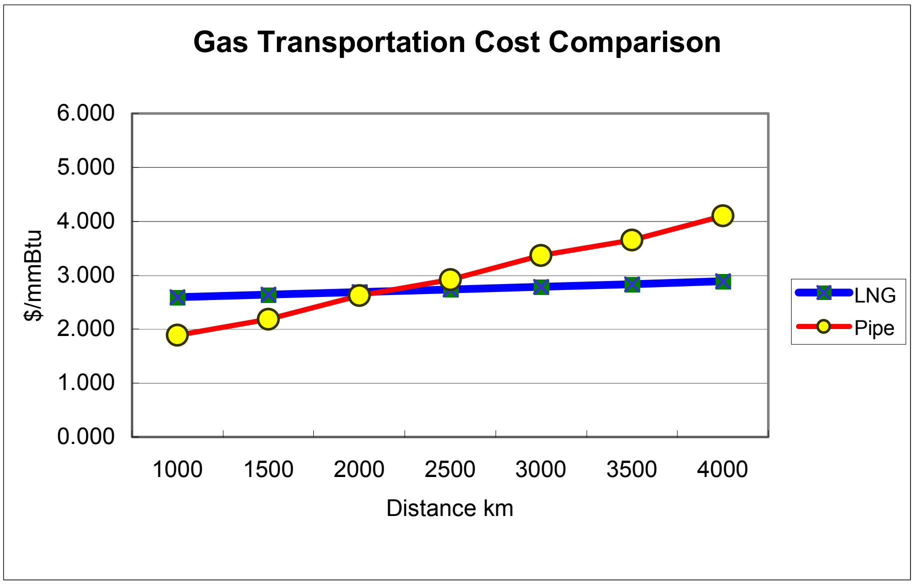

Figure 10 Cost Changes with Distance

We assume that the transportation connects only two points, i.e. supply and receiving. In fact a distinctive characteristic between pipeline and LNG is that the pipeline may deliver the gas to the markets located on the pipeline route. Long onshore pipelines with certain markets on the route may show a different pattern of project economics from our case. Therefore the additional benefit of pipelines will have to be separately considered and discussed beside our model, as well as that of LNG, although we do not elaborate in this paper.

The “cross distance”, which we have defined in this paper and gives the same cost to the pipeline and LNG in our model, is calculated as 2107 km, for the transportation distance above which LNG is economically more advantageous as shown at the top right of Figure 10. This number used to be around 4000 to 5000 km when the liquefaction and shipping cost were almost twice in terms of gas thermal value decades ago.

7 FACTORS AFFECTING THE CROSS DISTANCE

7.1 Project Size and Choice of Parallel Pipes

What other factors will affect the cross distance which is defined in the preceding paragraph? Next several tables show several factors considered to affect the choice of pipeline or LNG.

Figure 11 shows the effect of the project size and the choice of one pipeline or two parallel pipelines on the cross distance above which LNG is economically cheaper. The curves are not necessarily smoothly continuous since the compressor station arrangement is involved and the amount of computation occasionally prohibits a small laptop to make a decisive output. In the case of parallel lines, the second line is assumed to cost 60% the first one (in CAPEX).

The results show that the cross distance decreases by 400 to 600 km in case of the choice of two pipes compared to one pipe; meaning that LNG is further more competitive if pipeline side plans parallel lines from the beginning by that extent.

This also shows that the bigger the project, the pipeline is more advantageous; up to 2900 km in case of one pipe choice.

Effect of Project size:	2 pipes	1 pipe
Million ton / year	Cross Distance in km	
3	1,503	1,841
4	1,504	1,921
5	1,771	2,262
6	1,866	2,425
7	1,944	2,565
8	2,009	2,687
9	2,063	2,634
10	2,262	2,888

Figure 11 Effect of Project Size and Choice of Two Pipes on the Cross-Distance

7.2 Effect of Potential Pipeline Cost Cut

For the pipeline to be more advantageous than LNG in shorter distance, a simple solution may be to lay cheaper pipelines if possible through any means. Although we have set the base pipeline installation cost as $35/m/inch, the actual cost varies from project to project and much lower cost also exists as well as higher. Figure 12 show that when LNG related costs are set at the basic conditions stated before, how the unit cost of the pipeline changes the cross distance. The project size in the base case is annual 5 million ton of LNG.

On the pipeline side, only the one pipe case is shown here. This shows that when the pipeline is installed at lower than US$25 /m/inch, it is more advantageous than LNG at a distance longer than 3000 to 4000 km. Since we sometimes hear of actual implementation at such a cost level or even lower, we think this still real in some regions. The author hopes the cost of pipelines be lowered in the future in view of that the general decrease of the cost of pipelines have been slow compared to LNG in the last decade, while technological development in pipeline laying in challenging conditions have been remarkable.

Unit Pipe Cost in US $/m/inch	Cross Distance in km
15	5,647
25	3,069
35	2,107
45	1,604
55	1,295
65	1,086
75	935
85	821
95	731
105	660
115	601

Figure 12 How Pipeline Cost Affects Cross Distance

7.3 Effect of the Cost of Liquefaction Plant and LNG Ships

The assumed cost of liquefaction plant in the Base Case is US$ 1092 million for a project of 5 million ton per year. This level may be already a result of remarkable technological breakthroughs and economy of scale everyone would appreciate. Figure 13 shows the effect of further cost cut of an LNG liquefaction plant on the cross distance, while the author is not aware of any physical possibility of such cost cutting in liquefaction.

Liquefaction Cost Decrease by %	Cross Distance in km
0	2,107
2	2,078
4	2,050
6	2,021
8	1,993
10	1,964

Figure 13 Effect of Cost Cutting of LNG Liquefaction on Cross Distance

Similarly Figure 14 shows the effect of the cost cutting on LNG ships. In the base case we started from US $165 million for a ship of 135000 m3, which appeared in the media recently.

LNG Ship Cost Decrease by %	Cross Distance in km
0	2,107
5	2,089
10	2,070
15	2,053
20	2,035

Figure 14 Effect of Cost Decrease of LNG Ships on Cross Distance

7.4 Effect of Discount Rate

We will finally look at the effect of the discount rate. The rate in our base case model is 8 %, which reflects recent general low interest rate in the world financial market as well as investor's desire for firm conditions for participation in the risk exposed projects combined. The rate in our model should be in real terms which excludes the inflation rate.

Figure 15 shows how the discount rate affects the cross distance in our model in the Base Case. The case here again means the one pipe case and the project size of 5 million ton per year.

Discount Rate %	Cross Distance in km
8%	2,107
9%	2,045
10%	1,993
11%	1,948
12%	1,910
13%	1,878
14%	1,850
15%	1,825

Figure 15 Effect of Discount Rate on the Cross Distance

A trend found in the table of Figure 15 means that with a higher discount rate LNG will be more advantageous. This is explained by lower CAPEX of LNG projects compared to the pipelines for a longer distance, since the capital expenditure is normally spent in earlier years of the project period with lower level of discount in the discounted cash flow.

8. CONCLUSION

We have tried to respond to the question of how LNG and pipelines compete in the recent economic environment raised in the World Gas Conference 2003 Call for Papers as straightly as possible. The cost data are taken from media and the economic considerations exclude tax and duties as well as inflation, resulting in only theoretical simulations. We have to recognize that actual costs are different from project to project.

Cases exist where LNG is more economical at less than 2,000 km of gas transportation taking into consideration recent project costs. LNG may be competitive especially when there is security issue that enforces a pipeline to be planned for loop or in two parallel lines.

The cost cutting competition in the last decade of relevant chemical and gas plants including LNG schemes, has shown dynamic changes in the comparative relationships between the pipeline and LNG. Pipeline costs in ordinary cases, in fact, have not changed too much apparently, but pipelines are now being materialized in such conditions as had been previously thought impossible or very tough, e.g., in thousands of meters deep or across wide rivers, within certain economic reach. After initial frontier development of challenging pipelines that is going now, there is hope for lower cost of such pipelines in the near future. At present LNG cost has caught up in the shorter transportation distance.

We have not assessed real benefit of pipelines and LNG outside the cost comparison either. Within a large continent, pipeline is the only possibility prohibiting such comparison. When there are many markets scattered on the transmission route, the pipeline may be a better selection for supplying broader markets. LNG on the other hand has benefit from storage function and access to diversified natural gas supply sources. Energy stock function of an LNG receiving terminal may be serious in gas lean countries which lack old gas fields for gas storage.

The author writes this paper mainly considering Southeast Asian countries. The Southeast Asian archipelago has possibility of both pipelines and LNG, where everyone concerned may be interested in which is more economical. Differently from long haul transmission of gas to remote industrial countries, the case of LNG has long been ignored in intra-regional transportation. The author has developed this simulation in the course of natural gas studies in Indonesia and the Philippines, and found that LNG can be a possibility for much shorter distance than in the past.

9. ACKNOWLEDGMENT

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Also the author used several media information, which is mentioned in the text rather than listing them here. I have been grateful for such information that enabled necessary calculation in this paper.