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ANALYSIS OF THE INTEGRATED GAS CHAIN

by

Hemantha Herath and Anil K. Malhotra

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TABLE OF CONTENTS

FOREWORD

In recent years, the Bank has been involved in the development of gas infrastructure in a number of countries in the Asia region. But the development of gas reserves is different from oil, although gas is often discovered by the international oil industry during its search for oil. Since gas is almost exclusively linked to transportation by pipelines which entail high initial fixed investments and cannot be changed easily or at all once they have been made and since the gas market is primarily in the power and fertilizer plants in most developing countries, there are in addition to geological risks also considerable market risks. These risks, which are intrinsic to natural gas production and marketing, make it essential that the development of gas reserves be looked upon as an integrated chain linking exploration and production, transmission and marketing.

This study is aimed at achieving three objectives: first, to demonstrate the need to analyze gas projects as an integrated system; second, to describe an integrated cash flow modeling approach for gas projects which can be used to determine the returns to various parties under different parameters and perform sensitivity analysis; and finally, to provide a practical tool to help governments negotiate gas contracts. The advantage of an integrated cash flow model is its ability to analyze the impact of upstream production sharing contract (PSC) terms for exploration, transmission tariffs and power plant generation profitability on the electricity tariffs. The results of two case studies of Vietnam and Philippines indicate the power of the model in helping negotiate terms in the integrated gas chain.

The views and interpretations set forth in the paper are those of the authors. However, it is hoped that disseminating this information among the Bank staff advising borrower governments on gas infrastructure development issues will lead them to bring this analytical tool and approach to the attention of the Asian policy and decision makers, and thus to bolster the effectiveness of the Bank's operations in the region.

Harold W. Messenger
Director
Asia Technical Department

Analysis of the Integrated Gas Chain

by
Hemantha Herath and Anil K. Malhotra

INTRODUCTION

The development of gas reserves is different from oil although gas is often discovered by the international oil industry during its search for oil. Comparing the oil and gas chains clarifies some of the essential issues which have be considered in the development of gas reserves. It is important to remember that gas is almost exclusively linked to transportation by pipelines which entail high initial fixed investments and cannot be changed easily or at all once they have been made. Unlike oil, which can be marketed at any place at any time, gas is limited to specific locations and periods of consumption . Also while gas can substitute oil (or coal) in many cases, gas itself can almost always be substituted by other products. The gas market is primarily in the power and fertilizer plants since in most developing countries, home heating does not provide an adequate volume of consumption. These risks which are intrinsic to natural gas production and marketing make it essential that the development of gas reserves be looked upon as an integrated chain linking exploration and production, distribution and marketing.

This study is aimed at achieving three objectives: first, to demonstrate the need to analyze gas projects as an integrated system; second, to describe an integrated cash flow modeling approach for gas projects which can be used to determine the returns to various parties under different parameters and perform sensitivity analysis; and finally to provide a practical tool to help governments negotiate gas contracts. While most cash flow models analyze the production sharing contracts (PSC) terms separate from the power plant economics, this study is an attempt to model gas exploration and production, distribution, power generation and government cash flows as an interconnected system. The advantage of looking at an integrated cash flow model compared with mutually exclusive models for each of the above activities is the ability to analyze the impact of PSC terms, distribution tariffs and power generation profitability on the electricity tariffs. This cash flow model would also be useful in determining the economic and financial viability of the exploration and production, distribution and power generation and in determining negotiating boundaries for gas prices and PSC terms.

Table 1: Estimates of Average prices: Offshore natural gas, transmission and power.

Prices/tariffs	Vietnam	Philippines	Thailand	Indonesia
Natural gas ($/mcf)	3.00	3.35	2.75 - 3.2	2.45 - 3.0
Transmission US$/mcf	1.00	1.00 - .1.15		
Power US cents/kwh	4.26 - 7.10	5.98 - 11.60	4.13 - 8.77	5.09 - 11.96*

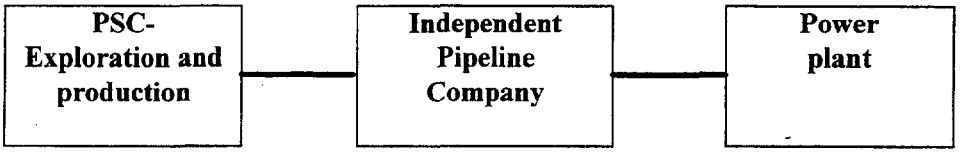
Source: A survey of Asia's Energy Prices, 1994., AST price surveys
*Power tariff ranges are as of Jan 1993 for typical customers

A FRAMEWORK FOR ANALYZING THE GAS CHAIN

For purposes of an integrated analysis, the gas *chain* may be considered to consist of activities related to exploration and production of natural gas, its transportation from the well-

head to the terminal and distribution to the end users in the gas market. The initial consideration in the gas chain is usually given to *production sharing contracts* (PSCs) for exploration and production. The next component in the chain is the transmission company usually an independent pipe-line company- IPC which would be involved in the transportation of gas from the production facility to a whole sale buyer. The final component in the gas chain is the power plant (or it could be a fertilizer plant) which would use the natural gas to generate electricity.

The gas chain



A necessary condition for the long-term stability of the gas chain is that it should be competitive with other projects for the investors and that the end product is competitive with possible alternative products and services. The government is normally involved in the gas chain in all stages in terms of fiscal, energy policy, ownership, loan guarantees, impact on balance of payments and developing legal framework for contracts. It thus has the capacity to influence the economics of the gas chain at a number of points. A critical part of the analysis has to be to design an appropriate form and extent of government intervention. A detailed review of the major components of the chain and international practices are indicated in Annex 1 while the next section indicates the cash flow model which can be utilized to analyze the impact of different government interventions in the gas chain.

Main characteristics of the gas chain

- **Long and firm chain**
- **Physically fixed links from well-head to power consumers**
- **Interruptions in up-stream affect down-stream and vice versa**
- **High capital investment along the chain**
- **Inflexible market with fixed capacities**

Source:ESMAP- Long -Term Gas Contracts; Principles and applications

THE CASH FLOW MODEL

The cash flow model for the gas chain is a simple spreadsheet simulation consisting of three cash flow modules-(1) upstream activity (PSC), (2) transmission and distribution activity and (3) the CC power plant, interconnected by the price and fiscal relationships. The link between the upstream activity and gas transmission is the *well-head price of gas* (WP) and the link between the pipe-line activity and the power company is the *selling price of gas* (SP). Each of the above activities are linked to the government through the fiscal relationships, production royalty and the profit share under the PSC terms and the transmission charges that are levied for gas transport to the power plant. Finally, the impact of these cost, profit and fiscal interrelationships are reflected in the power tariffs to be charged from electricity consumers. While the proposed model does not have optimization capability, it can be used to perform sensitivity analysis to evaluate the economic returns to various parties under different parameters and business scenarios. The model is relatively simple to use as such the parameters can be changed sequentially to capture some of the complex inter-relationships.

The inputs for the proposed model are relatively simple and consists of capital expenditures, operating costs, production data for gas and condense, initial set of gas and condense prices, plant capacity, load factors, efficiency rate, heat rate and electricity price for the power plant. The inputs for the model would have be changed according to requirements of each country prior to carrying out the sensitivity analysis to determine negotiating boundaries for gas prices, and PSC terms. The inputs for each of the three modules is summarized in Table 3.

Table 3: Inputs

PSC	Pipeline Company	Power plant
Exploration cost (US$m)	Pipeline capital costs (US$m)	Plant capacity (MW)
Upstream capital cost (US$m)	Pipeline operating cost (%)	Capital cost (US$/kw)
Upstream operating cost (%)	Selling price of gas (SP)	Plant load factor
Gas production rate (bcm/yr)		Efficiency rate
Condense gas ratio		Heat rate -
Well head price of gas (WP)		Heat content
Condense price $/bbl		Operating cost $/kwh
Discount rate (%)		Maintenance cost (cents/kwh)
Cost recovery percentage (CR)		**Electricity price (US cents/kwh)***
Profit share percentage (PS)		

* Note: Some of these inputs in effect can be considered as the output (e.g.: electricity price) in the process of sequential analysis.

Once the data pertaining to a specific country is input and the model setup, it would provide output information pertaining to the net present value (NPV) of government share of cash flow under the given CR and PS terms, rate of return (ROR) and NPV of contractor cash flows both excluding and including sunk costs, ROR and NPV for the pipeline company, ROR and NPV for the power plant given a specific power tariff. Alternately, the model can be used to determine a power tariff or gas price for fixed RORs for the pipeline and power company and the PSC contractor.

Sensitivity Analysis

The main advantage of the proposed cash flow model is the ability to perform sensitivity analysis under different business scenarios and negotiating conditions in order to maximize the government take while taking into consideration the power tariffs, power plant and pipeline profitability and risks. There are numerous sensitivity analysis that can be carried out depending on the user interest and country specific situation as indicated below:

Typical Sensitivity Analysis

A) Effects of sunk cost on the government take and contractor returns.
B) Government take and contractor returns under different gas build up profiles.
C) Influence on government take and contractor returns due to changes in capital and operating costs.
D) Effects on the government take and contractor returns due to changes in gas production rate.
E) Effects due varying discount rates.
F) Impact on power tariffs and government take for fixed CR and PS ratios.
G) Impact on gas prices, government take, contractor returns and power tariffs under different PSC terms and conditions (various CR and PS ratios) given fixed returns for the pipeline company and power plant.

APPLYING THE MODEL - TWO CASE STUDIES

1. Vietnam Case Study

The use of this model can be illustrated by an application of the model to the development of a specific gas project in Vietnam. This could help - to identify a set of negotiating alternatives for the PSC, determine a suitable pipeline tariff for an independent pipeline company and a gas purchase price for the power plant. Sensitivity analysis can be carried out using the model which could help in negotiating production sharing contracts and determining pipeline, power tariffs and gas prices.

The Vietnam example consist of the development of an offshore gas field, which have an estimated reserve of about 2 tcf and an Independent Pipeline Company for transportation of gas to the proposed CC power plants. Detailed assumptions and data along with sensitivity analysis performed to develop a set of negotiating strategies for the PSC terms of the proposed field is given in Annex 2.

Determining PSC terms

The model can be set up to input various values for the well-head gas price and CR and PS ratios to determine the governments take, PSC contractor, pipeline and power plant returns. For example assume that we are interested in finding the government and contractor returns for a fixed 15% ROR for the pipeline company and the power plant. If the pipeline and power plant returns are below the minimum required (15%), the selling price of gas and the power tariff can be adjusted in the model to obtain the required minimum return. The model inputs can be changed in this sequential manner not only to obtain the required power plant and pipeline returns but also to analyze the government take and contractor returns under a set of power tariffs and gas prices. Therefore, by performing the sensitivity analysis under different scenarios the user can obtain several alternate PSC terms with different government take which give the stipulated returns to the contractor, pipeline and power plant under a suitable power price.

In this example several different well-head gas prices, cost recovery and profit share ratios for the government are considered. The minimum required returns to both the power plant and the pipeline company is fixed at 15%. A 10% discount rate is used throughout the analysis. The set of values for each parameter of interest used in the analysis is given below. Note however that these parameters can be changed depending upon the project and the price range for negotiations.

Table 4: Data

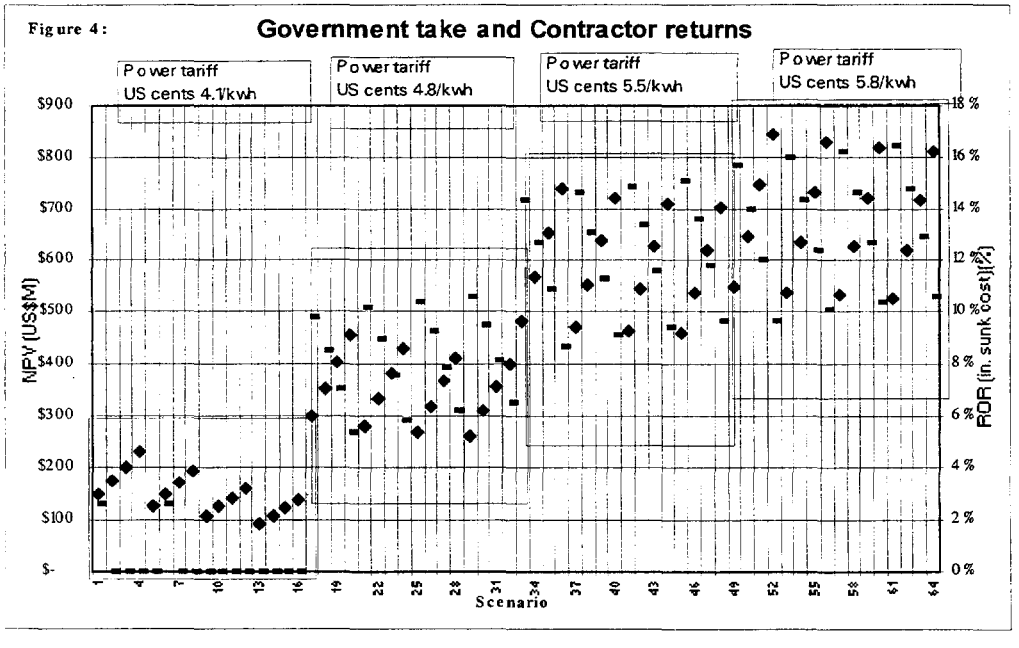
Variable Parameter	Set of values			
WP of gas US $/mcf	1.00	2.00	3.00	3.50
CR	40%	50%	60%	70%
Government PS	50%	60%	70%	80%

Fixed Parameter	Value
Discount rate	10%
Pipeline ROR	15%
Power Co. ROR	15%

Possible Strategies

We summarize below some alternate negotiating boundaries for Vietnam which were obtained from the sensitivity analysis exercise. In Figure 3 both the government take and contractor returns are shown for each of the different CR and PS ratios and offshore gas prices. The large diamond plots refer to the government take and the small square plots correspond to contractor ROR. The government take and contractor returns include sunk cost of US $ 155 m.

Assume that (1) contractor is seeking a minimum ROR of 13%. and the government is willing to give a maximum contractor ROR of 15%, (2) the government is further seeking a minimum NPV of US$ 500 million. From the sensitivity analysis results there are 12 possible strategies which gives the above returns to the various parties (see Figure 4). These refer to scenario numbers - 34, 38, 42, 46, 50, 54, 57, 58, 59, 61, 62, and 63. Next, assume that the government wishes to maintain the power tariffs at the current level of US cents 5.5/kwh, then the number of possible alternatives would reduce to those pertaining to scenario nos 34, 38, 42, and 46. These alternative strategies are listed in Table 5.



A 40% CR and 60% PS with a well head gas price of $3.00/mcf and a pipeline tariff of $1.00/mcf would yield government the maximum NPV of 567m, but would only give the PSC contractor a NPV of $122 million and ROR of 13%. On the other-hand the alternative with 70% CR and 60% PS would give the contractor a 14% return but the government would get only $ 539 million. In case the PSC contractor negotiates for a 13% ROR, then there are three possible strategies for the government and the government should clearly negotiate for the 40% CR and 60% PS option which maximizes the government take. This option is theoretically optimal but it is more likely that as ROR is a relative measure, the contractor would consider the alternative pertaining to CR of 60% and PS of 60% since it gives the contractor the highest NPV. This

alternative would give the government a NPV of $ 545 million. Assuming, that both parties are likely to agree on the 60% CR and 60% PS, in the next section sensitivity analysis can be performed to see what happens to returns of each party under some typical situations.

Table 5: Alternatives for Vietnam

Scenario No,cr,ps:	Vietnam take	Contractor	
	NPV- (US$m)	NPV- ($m)	ROR
36-40%cr,60%ps	*567*	*122*	*13%*
38-50%cr,60%ps	554	136	13%
42-60%cr,60%ps	**545**	**145**	**13%**
46-70%cr,60%ps	*539*	*151*	*14%*

Notes 1. The price of power is a constant US cents 5.5/kwh
2. Offshore price of gas is US $ 3/mcf
3. Pipeline and power company RORs are fixed at 15%

Sensitivity Analysis Results

Given the assumption that both the contractor and the government agree on the 60% CR and 60% PS terms under a power price of US cents 5.5/kwh, well-head gas price of US$ 3 and a transportation tariff of US $ 1.00/mcf, a series of sensitivities were performed to illustrate the impact of different variables on returns of the parties.

(A) Effect of sunk costs

Sunk costs are capital costs which have already been incurred at the exploration stage. Since the contractors seek to recover all their costs in full, it is usual for them to include these sunk costs for negotiating PSC terms. Since sunk cost are those stated by the contractor, it might be worth analyzing the effects on the government take and contractor returns if actual sunk costs are lower than what is stated in contractor proposal or if sunk costs are totally excluded. The effect on government take and contractor returns for a 20% lower sunk cost (US$124m vs US$155 m) was analyzed using the model, and the sensitivity results indicate that both government and contractor returns are sensitive to the level of sunk cost.

Table 6: 20% drop in sunk costs, base US$ 155m

Sunk cost	Government take
	NPV- (US$m)
Base	545
20% drop ($124m)	552
No sunk cost	580

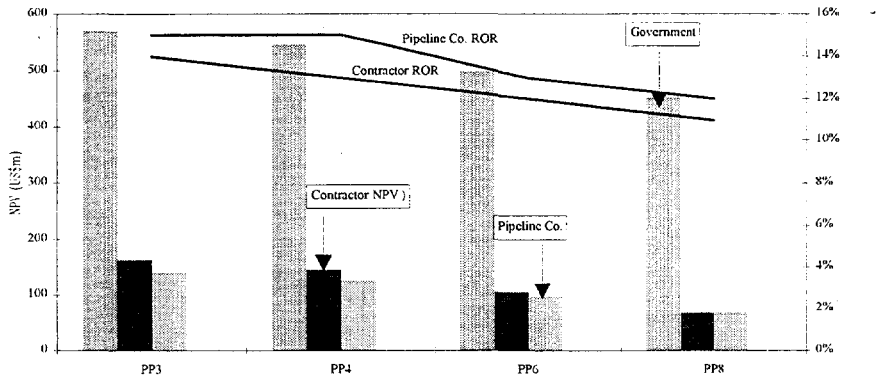
Note: 1. Pipeline and power plant ROR are fixed at 15%
2. Offshore gas price $ 3.00/mcf, Onshore gas price $4.00/mcf
3. CR and PS 60%

(B) Delay in gas production.

Considering the risks associated with gas production and marketing, in the negotiations, it is useful both from point of view of government and contractor to consider the effect of different gas production build-up rates on the government take and contractor returns. The sensitivity of government take, contractor and pipeline returns for the base case of 4 years and three different gas build up profiles- 3 year , 6 year and 8 year respectively are shown below in Figure 4. The only variable considered is different rates of gas build-ups[1].

Figure 4:

Government take and contractor, pipeline co. returns for different gas build up profiles



According to the results if the gas production is delayed by two years, the contractor ROR would drop from 13% to 12% while the pipeline ROR would drop from 15% to 13%. The NPV of government cash flows would drop by about 9% to $ 498 million. If the project gets delayed by 4 years the government take would drop from $545 million to 452 million, while both the contractor and pipeline company returns would be less than 12%. As the timing of cash flows affect contractor NPVs more than the government's, naturally contractors would seek to negotiate for higher percentage of cost recovery or seek some guaranteed uplift in the early stages of the project.

(C) Effects of changes in capital costs

It might be useful to look at what happens to contractor returns for increases in upstream capital costs. Table 7 presents sensitivity results if the up stream capital costs increase or decrease by 5%, 10%,15% and 20% while keeping the other data fixed. The selling price and well-head price of gas was fixed at US $ 4.00 and 3.00 respectively, and the cost recovery and profit share to government were fixed at 60%. Since only the upstream capital costs were varied, the returns to the pipeline and power company remains constant at 15%.

[1] The CR and PS ratios are fixed at 60%, power price is US cents 5.5/kwh, pipeline and power plant RORs are fixed at 15%, offshore gas price is constant at US $ 3.00/mcf

Table 7: Government take and contractor returns with increases in upstream capital costs

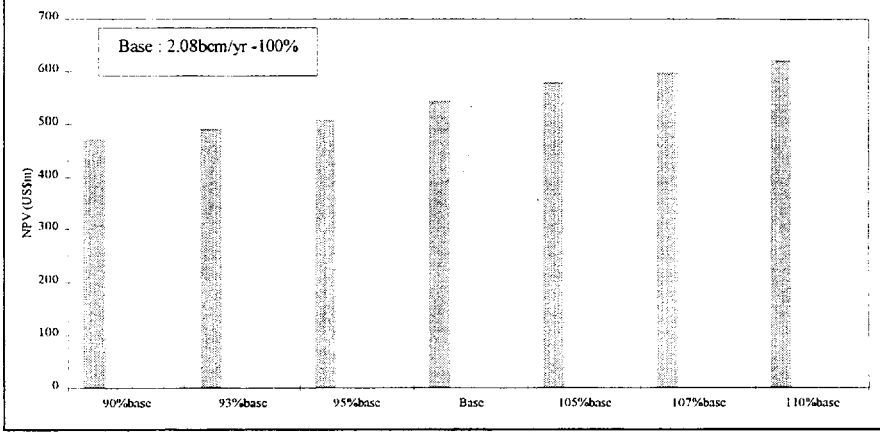
% change in upstream capital costs from Base	Vietnam take	Contractor (including sunk costs)	
	NPV- (US$m)	NPV- ($m)	ROR
Base (US$ 409m)	545	145	13%
5% increase	537	131	13%
10% increase	530	117	13%
15% increase	522	103	12%

The results indicate that the government returns are relatively insensitive to increases in upstream capital costs compared with contractor returns. Therefore, under the given PSC terms the contractor has an incentive to reduce costs. Note however that the contractor's minimum return condition of 13% is violated if costs escalate by 15%.

(D) Changes in gas production rate

It is worth analyzing the effect on government share and contractor returns due to variation in the gas production rate since the government take is based on the revenues after cost recovery. While a plateau production level of 2.08 bcm/yr is assumed as the base case (100%), Figures 5,6 and 7 show the returns to each party where the gas production rate is below and above the base level. In the analysis only the production rate is varied while the gas prices and PSC terms are kept constant as in earlier examples.

Figure 5: **Government take for different gas production rates**



The government take is sensitive to changes in the gas production rate, for example a 5% drop in production rate from the base level of 2.08bcm/year would reduce the government take by 6.5%. The contractor returns and pipeline returns on the other hand are much more sensitive to changes in the production rate as they bear the capital and operating costs. For example a 5% drop in the production rate from the base level would reduce the contractor NPV by 18% and the pipeline company NPV by 15%. Therefore, major portion of the project risk is borne by the PSC contractor and the pipeline company and as a result they would seek a committed market from the power plant.

Figure 6:

Contractor returns for different gas production rates

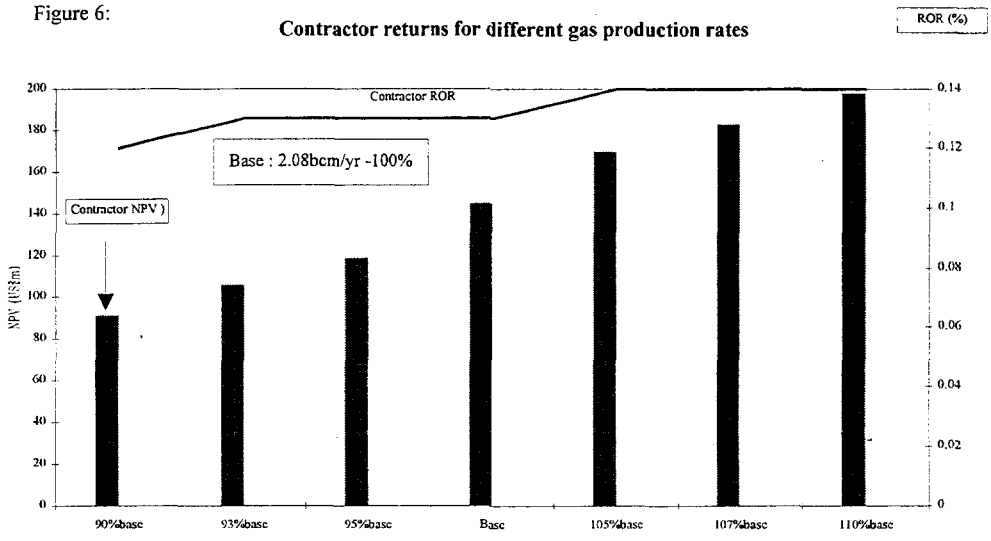
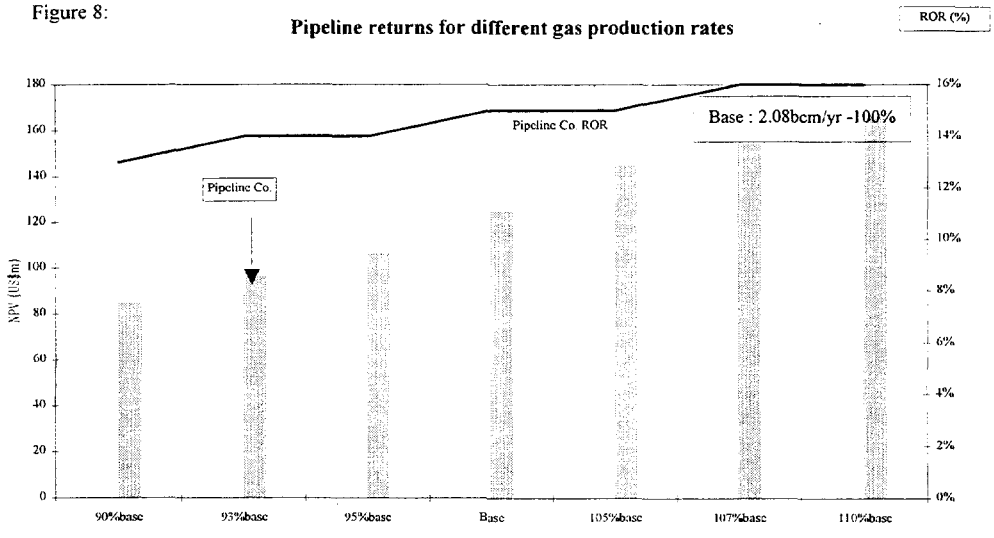


Figure 8:

Pipeline returns for different gas production rates



(E) Effects due to varying discount rates

The model further can be used to analyze returns to various parties including the government, contractor, pipeline company and power plant under different discount rates. Analyzing the effects on returns under different discount rates would enable the user to consider the uncertainty involved in cost of funds. Table 8 presents returns to various parties under several different discount rates. The results indicate that the contractor NPV and pipeline NPV are highly sensitive to variations in the discount rate. If a 14% discount factor is used in the analysis instead of 10%, the contractor NPV would change from positive $145m to negative $ (19)m indicating that the alternative is not feasible. The government take is also sensitive to higher discount factors and a 14% discount factor would reduce the government share from $ 545m to $ 281m. As a result the contractor may tend to use a slightly higher discount rate to evaluate the PSC terms.

Table 8: Returns to various parties under different discount rates

Discount rate	Vietnam take	Contractor (including sunk costs)	Pipeline co.	Power plant
	NPV- (US$m)	NPV- ($m)	NPV- ($m)	NPV- ($m)
10%	545	145	125	132
12%	413	49	59	63
14%	318	(19)	13	12
15%	281	(46)	(5)	(8)

Note: 1 Pipeline and power plant RORs are fixed at 15%
2 The Contractor ROR is <= 13%

(E) Effects due to variations in gas prices with fixed CR and PS ratios.

Another analysis performed is to see the effects on government take, and power prices due to variations in gas prices for fixed CR and PS ratios. The sensitivity results are summarized in Table 9.

Table 9: Government take and power tariffs for a fixed CR and PS ratios

Well-head price	Selling Price of gas	Vietnam take	Contractor (including sunk costs)		Power plant
		NPV- (US$m)	NPV- ($m)	ROR	Power tariff
1.00	2.00	125	(240)	-	4.1
2.00	3.00	318	(30)	9%	4.8
3.00	4.00	545	145	13%	5.5
3.35	4.35	627	203	15%	5.8

Note: 1 Pipeline and power plant RORs are fixed at 15%
2 The CR and PS ratios remained fixed at 60%
3 The offshore gas price is varied from $ 1.00/mcf to 3.35/mcf

From the analysis one can study the effect of changes in the upstream gas prices and pipeline tariffs on the power prices. For example, given the fixed PSC terms of 60% CR and PS if the power plant buys the gas at US $ 4.00/mcf then to get a 15% return, power will have to be sold at US cents 5.5/kwh. On the other-hand, if the power plant is able to buy gas at $ 3.00 including the pipeline tariff of $1.00, then the power plant will be able to sell power at US cents 4.8/kwh. Note that this will only give a 9% return to the PSC contractor which is not likely to be a feasible option. In conclusion the above analysis demonstrates the ability of the model to identify issues and ranges of various parameters that can be used to move towards an acceptable framework for the parties in negotiating a contract.

2. Philippine Case Study

In the Philippines case the PSC terms for the offshore gas field had already been agreed to between the contractor and the government and therefore the model is initially used to determine a viable power tariff for the power plant and a transportation tariff for the pipeline company. Next, as in the Vietnam example, sensitivity analysis are performed to study the effect on returns to parties under some typical situations.

The example refers to the development of an offshore gas field, an independent pipeline company and a 3000 MW combined cycle power plant. For the purpose of analysis, the distribution of the gas has been separated from exploration and production.

The PSC terms for the gas field do not have any royalty on gas to be produced but instead has a provision for an incentive allowance (FPIA) of 7.5% of total revenues for the contractor. The maximum cost recovery allowed is 70% and governments effective profit share is 13.5%.

Determining viable power and pipeline tariffs

Since the PSC terms for the gas field have already been negotiated, the model can be used to study the economic feasibility of the integrated gas chain including the 3000 MW combined cycle plant. With the given PSC terms and current off shore gas prices in the country, the model was used to obtain transportation and power tariffs which give a 15% ROR to both the pipeline company and the power plant. Based on the model output it can be seen that an off-shore gas sale price $3.35/bcf and a transportation tariff of US$ 1.15/mcf would give the upstream contractor a 15% return and the pipeline company a 15% return (18% excluding sunk costs). The corresponding return to the power plant is 15% which is based on power generation at a price of US cents 5.4/kwh and gas purchase price of US $ 4.5/mcf. Currently, this is the same level of power tariff as the coal based Sual power plant (1.39 peso/kwh) in Philippines. Under the agreed PSC terms the Philippine government's take is US$ 178 million and the PSC contractor return is 15%.

Table 10: Government take for proposed PSC terms and power price of 5.4 cents/kwh

Well-head price	Selling price	CR	PS	Government take	Contractor		Pipeline co.		Power plant		
				NPV- (US$m)	NPV- ($m)	ROR	NPV- ($m)	ROR	NPV- ($m)	ROR	Power tariff
3.35	4.50	77.5%	13.5%	378	746	17%	251	15%	827	15%	5.4

Sensitivity analysis

In this section typical sensitivity analysis is indicated.

(A) Effect of sunk costs

Since 1989, the contractor has incurred capital expenditures which amount to US$ 198 million for exploration activities. Table 10 shows how the government take and contractor returns would change if the sunk costs were $ 158m instead of $ 198 m. As seen, the government returns are relatively less sensitive to sunk costs. On the other-hand contractor returns are sensitive to changes in sunk costs. The direct impact of sunk cost on contractor returns may in a way provide an incentive to keep exploration costs down while on the other hand since under the PSC terms the contractor is entitled to high cost recovery (70%) the incentive may not be effective.

Table 11: 20% drop in sunk costs, base US$ 198m

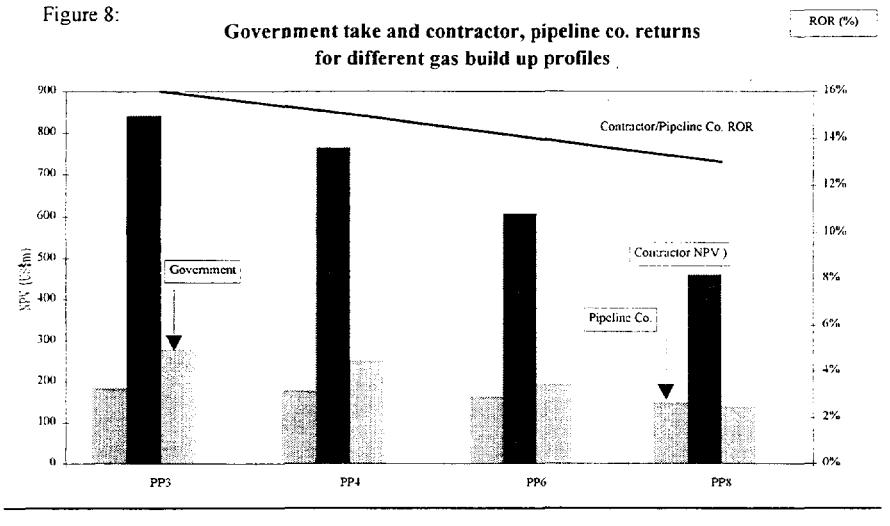
Sunk cost	Government take
	NPV- (US$m)
Base	178
20% drop ($124m)	180
No sunk cost	186

Note: 1 Pipeline and power plant RORs are fixed at 15%
2 CR = 70%, PS = 13.5% (Philippine's government)
3 Offshore gas price is $3.35/mcf, selling price of gas = $4.5/mcf
4. Power tariff = US cents 5.4/kwh

(B) Delay in gas production

In Figure 8, we show the government take, contractor and the pipeline returns for different gas build up profiles. Note that the same set of data as in the previous example was used with different production build up periods. As seen from the graph, since the contractor bears the costs and hence the total risk of production, his returns are significantly affected by production delays. In addition, as the contractor is allowed a CR of 70 % and an FPIA of 7.5%, the Philippine government take is relatively less sensitive to delays in gas production. Compared to the government, the pipeline company is also exposed to a higher operating risk due to the interdependencies associated with the "gas chain". Note that under the agreed PSC terms the contractor RORs for different build-ups are same as the pipeline company ROR which is a coincidence.

Figure 8:



(B) Effects of changes in capital costs

While the 70% CR, 60% PS with a contractor incentive of 7.5% of total revenues is assumed to remain unchanged, the impact on government take and returns to various parties if the upstream capital costs increase by 5%, 10% and 15% is studied. For example a 15% increase in upstream capital costs would reduce the contractor ROR from 15% to 13%, and NPV by 31%,

from $766m to $531m. The government take would reduce by about 10% from the base case. If upstream costs are likely to increase, the contractor returns would erode much faster than the government take.

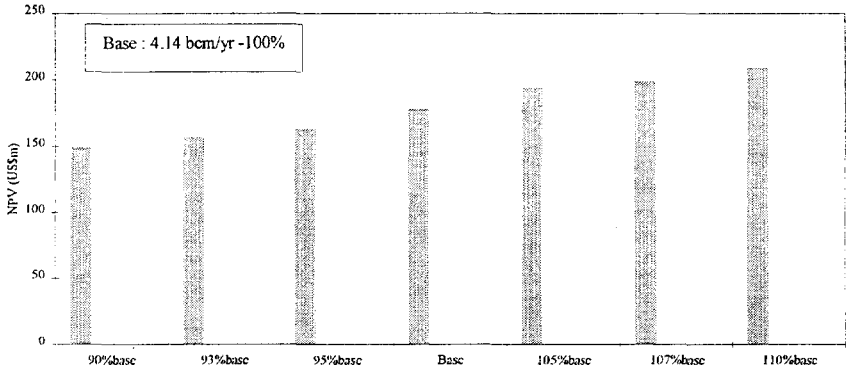
Table 12: Government take and contractor returns under with different upstream capital costs

% change in upstream capital costs from Base	Philippines take	Contractor (including sunk costs)	
	NPV- (US$m)	NPV- ($m)	ROR
Base (US$ 409m)	178	766	15%
5% increase	173	688	15%
10% increase	167	610	14%
15% increase	161	531	13%

(C) Changes in gas production rate

Government take, contractor returns and pipeline returns are directly influenced by the gas production rate. The base case assumes a committed gas market of 146 bcm (base level), while Figures 9, 10 and 11 show what happens to returns of each party, if the gas production rate drops or increases by a certain percentage from the base production rate of 4.14 bcm/year (for the purpose of analysis, a 10%, 7% and 5% drop and a 5%, 7% and 10% increase from base level is considered.)

Figure 9: ***Government take for different gas production rates***



As Figure 9 indicates, government returns are insensitive to changes in the annual production rate mainly because under the given PSC terms the governments effective profit share is only 13.5%. For example if the production rate increases by 10% from the base level of 4.14 bcm/year the government NPV would increase by about 17% to US $ 209 million. On the other-hand, contractor returns are highly sensitive to the changes in production levels. For the same 10% increase in the production the contractor ROR would increase from 15% to 17% and NPV by 32% to $ 1012 million. As Figure 12 indicate, compared to the government take the pipeline company returns like contractor returns are highly sensitive to any changes in the rate of production. The pipeline company ROR would change from 15% to 17% and NPV would increase by 37% to 342 million. Therefore a committed market is essential for the viability of integrated gas projects. This is a major focus for the contractor. He is interested in both how

quickly the market develops and negotiating for quicker ways of recovering costs for example by an uplift factor.

Figure 11:

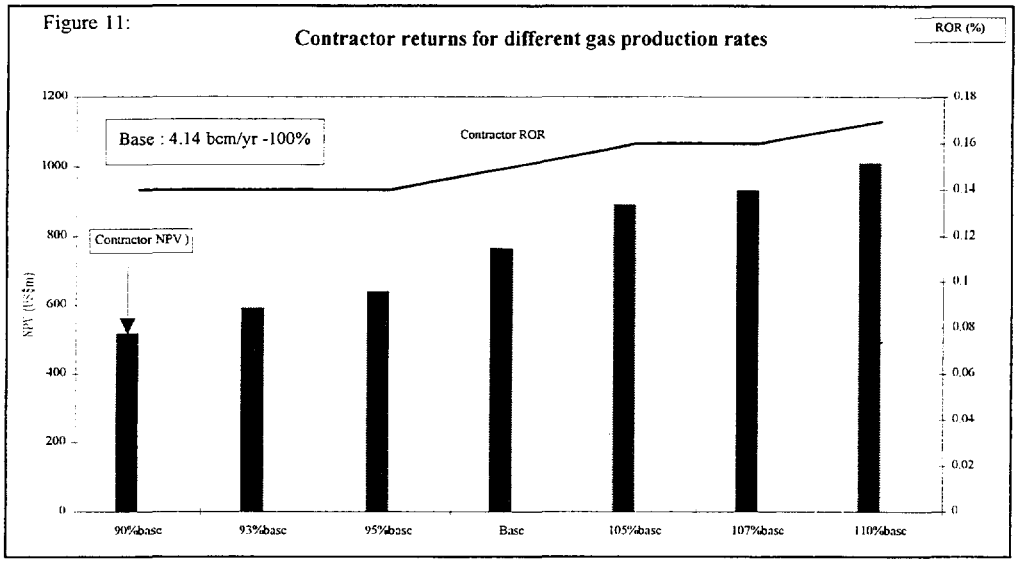
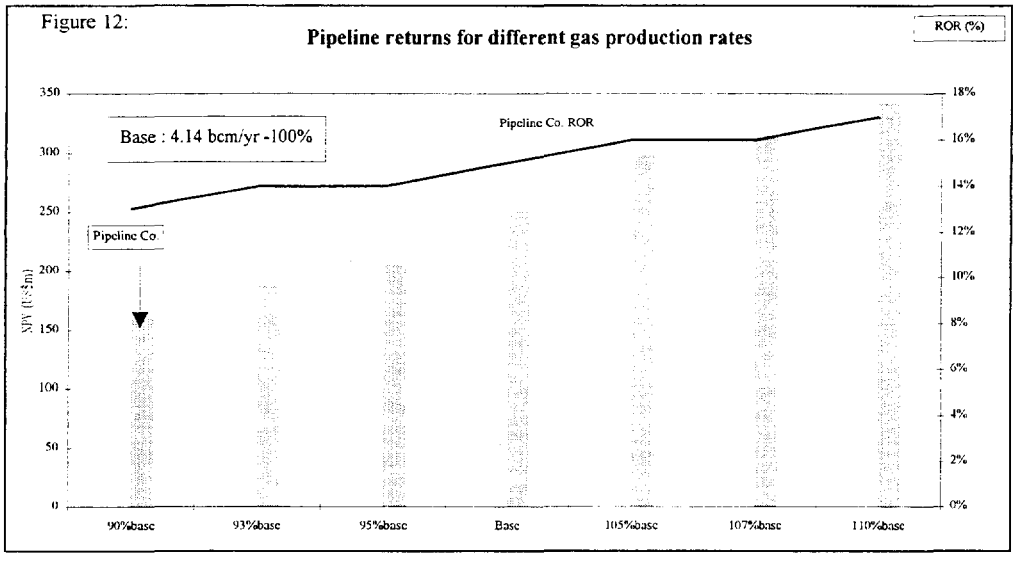


Figure 12:



(D) Effects due to varying discount rates

With the 60% CR and PS ratios, Table 11 shows what happens to returns of each party if the discount rate is varied at three different rates - 12%, 14% and 15%. As the government take is based on a 13.5% profit share and only occur after year 4, the change in government's NPV under higher discount rates are relatively small compared to the contractor's NPV. In the contractors case, due to high cost recovery-of 70% and the early cash outflows the NPVs are very sensitive to different discount rates. The high capital investments in pipeline and power generation activities results in early cash out flows and as a result the NPVs are highly sensitive

Table 12: Returns to various parties under different discount rates

Discount rate	Philippines take	Contractor (including sunk costs)	Pipeline co.	Power plant
	NPV- (US$m)	NPV- ($m)	NPV-US$m)	NPV- ($m)
10%	178	766	251	827
12%	133	391	125	419
14%	101	127	38	116
15%	89	26	4	(5)

Note: 1 Pipeline and power plant RORs are fixed at 15%
2 Contractor ROR remains unchanged at 15%

(E) Effects due to variations in gas prices with fixed CR and PS ratios.

The model can be used to see the effects on government take, and power prices due to varying gas prices for fixed CR and PS ratios. In this example we have assumed that the 70% CR to contractor and the 13.5% PS to Philippine's government remain fixed. The well-head price of gas is varied from $2.00/mcf - $3.5/mcf and the pipeline and power plant returns are fixed at 15%. The sensitivity results are summarized in Table 13.

Table 13: Government take and power tariffs for a fixed CR and PS ratios

Well-head price	Selling Price of gas	Philippines take	Contractor (including sunk costs)		Power plant
		NPV- (US$m)	NPV- ($m)	ROR	Power tariff
2.00	3.15	73	(210)	8%	4.4
2.50	3.65	108	155	11%	4.8
3.00	4.15	148	515	14%	5.1
3.35	4.50	178	766	15%	5.4
3.50	4.65	192	872	16%	5.5

Note: 1 Pipeline and power plant RORs are fixed at 15%
2 The CR and PS ratios remained fixed at 70%, 13.5%
3 The offshore gas price is varied from $ 200/mcf to 3.50/mcf

As indicated in Table 13, although a power tariff of US cents 4.4/kwh and 4.8/kwh gives both the pipeline company and the power plant a 15% ROR, they are not financially viable options for the PSC contractor and the Philippines government. On the other hand an offshore gas price of $ 3.00/mcf would give the PSC contractor a 14% ROR while a Offshore gas price of $ 3.50/mcf would give a 16% return which are both financially attractive. The price range for electricity given the offshore gas price of $3.00 to 3.50/mcf is between US cents 5.1 and 5.5/kwh. The corresponding pipeline tariff which gives a fixed 15% ROR is $ 1.15/mcf.

CONCLUSION

The results of the sensitivity analysis for the two case studies of Vietnam and Philippines indicate the power of the model in helping negotiate terms in the integrated gas chain.

In case of both Vietnam and Philippines the contractor's returns were found to be more sensitive to changes in sunk costs than the government take. The primary reason being that all

cost are borne by the contractor and occur in the early years of the project. Therefore it would be usual for the contractor to use the ROR including sunk cost in the negotiations. While this seem quite fair it must be noted that only actual costs which are reasonable should be allowed to be charged as sunk. costs.

Where any production delays occur-for example the build up period extends to six years instead of four years, both the contractor, pipeline company and the government take is adversely affected. While the contractor and pipeline returns are more sensitive to any changes, even the government take is markedly affected and as such appropriate action should be taken by all parties to ensure that the project is implemented on time. Due to the high cost recovery allowed in the Philippines case any production delays have a significantly more impact on the returns than Vietnam where the cost recovery is relatively less.

In Vietnam case the government returns were relatively less sensitive to increase in capital costs compared to Philippines example as the Vietnam gas project investment is only half of the proposed project in Philippines. In both cases however, it was found that the contractor returns are more sensitive to changes in upstream capital costs. As a result in the negotiations the contractors would seek for high cost recovery or a gas uplift to ensure early payback.

In case of Vietnam since we assumed a high profit sharing ratio, the government take is more sensitive to changes in the production level than Philippines. In both situations however the government take is directly linked to the level of production and as such steps should be taken to ensure a committed market from the power plants. A committed market from the power plant and undisrupted gas transmission and production is essential for the viability of the gas chain both in the short and long term. As the contractor take and the pipeline profitability is a direct function of the production rate both the producer and transporter bears the greater risk in integrated gas projects.

It is usual for the contractor, pipeline and power plant to seek a high ROR competitive with industry practices and other alternate investment opportunities. A higher discount rate which represent the cost of capital should be used in the analysis for the benefit of all parties and the viability of the gas project. Since costs are borne by the contractor, pipeline company and power plant and costs occur in the early years the returns of these parties are extremely sensitive to changes in the discount rates.

There are several additional variations that can be incorporated in to the basic model discussed in this study. For example in both the Vietnam and Philippine's cases we have considered the cash flows before corporation taxes since there can be several alternate ways of treating fiscal issues and the CR and PS ratios. However, the basic model can be easily modified to incorporate the taxes in the PSC as well as any turnover taxes, withholding taxes or profit taxes for both the pipeline activity and power generation according to the general fiscal laws pertaining to each country. Second, effects of inflation could also be incorporated in the model without much difficulty. While the basic model could be expanded to incorporate these additions the model without any modifications could be used to arrive at some initial boundary conditions in the negotiation of PSCs, transport charges and electricity tariffs in the hydrocarbon sector.

ANNEX 1

COMPONENTS OF THE GAS CHAIN

The details of each component of the gas chain, in terms of typical structures, values, price formulas and terms of production sharing contracts, gas distribution alternatives and down stream users which make up the integrated gas system, are indicated.

A. Production Sharing Contracts

Production sharing contracts vary from country to country and from case to case since there are large number of possible arrangements between parties and as such its impossible to design a standard contract. Therefore, in this study we have attempted to discuss some general contract terms found in production sharing contracts and provide examples of typical values proposed/applied in various countries.

Contract parties

A PSC is a contractual agreement between two or more parties for the exploration and production of natural gas. The State automatically becomes one such party to the contract while the other may be a single or consortium of investors usually foreign companies with experience, state of the art technologies and financial stability.

Contract duration

Production sharing contracts are long term contracts usually for the full potential of the Producible area. A typical PSC would be for about 20 years or more with the option to extend the contract if required to enable any contract obligations to be met. Due to the long-term nature of a PSC its utmost important for all parties to come to an agreement which reflect the balance of commercial interest of all involved.

Cost Recovery (CR)

In a production sharing contract, the investor is allowed to take a percentage of revenues as *cost gas* for recovery purposes. Usually, the percentage allowed for cost recovery would vary form country to country and from one gas field to another. In a production sharing contract, the cost recovery is never fixed through out the contract period and is usually a *maximum allowed.* For example, the full percentage allowed would only apply till the investment costs are recovered and thereafter cost recovery would pertain to only the operating costs which would be substantially lower than the maximum allowed.

Profit Share (PS)

The profit split between the government and the contractor is expressed as a percentage and is referred to as *profit gas*. The profit gas percentage is usually negotiated by the contractor and government and agreed upon in a PSC. The may be several variations in the PS ratio,- a simple percentage expressing the split or a percentage modified by a gas uplift factor etc.

Royalty

In some production sharing contracts, governments may include a royalty on natural gas which could take several forms. For instance a flat charge which may be a percentage of revenues or a sliding scale tied to the level of output. The advantage of a sliding scale is that it is progressive on higher prices and higher production and the government take would increase in case of favorable developments. Royalties are a direct source of income to the government but should not be too excessive as it would work adversely and provide no benefit to the consumers. Where royalties are not explicitly stated in production sharing contracts its usual to include them in the profit share.

Standard PSC terms and Typical Values

The PSC terms differ from across gas fields as well as across countries. Some countries may have a flat royalty percentage while others may have a progressive royalty scheme tied to the level of production. In United Kingdom for gas field contracts signed before July 1975, the royalty payable was 12.5%, while for fields which received development consent from April 1982, there is no royalty payable. In Australia a 10% royalty was applicable to primary licenses and onshore, while 11 - 12.5% was applicable offshore. Denmark and Thailand are examples where the royalty is progressively tied on to the level of production. In Vietnam as well a progressive royalty structure is proposed. (see box)

The cost recovery and profit sharing terms also vary across countries and gas fields. In Malaysia for example under standard terms the cost gas is 60% of production and profit gas is shared 50:50 for the first 2.1 tcf of gas recovered and 70:30 in favor of government when recovery exceeds 2.1 tcf. For water depths exceeding 200 meters, the profit sharing is 40:60 (state 40) for the first 2.1 tcf and 60:40 in favor of government for excess of 2.1 tcf. In Indonesia, under more recent schemes applicable to offshore with water depth exceeding 200 meters and to other onshore designated frontier areas a 15% First Tranche Petroleum and 60:40 after tax profit gas share in favor of state is used. No investment credit is available. In Philippines in the recent negotiations a 70% cost recovery ceiling and a 13.5% profit share for the government along with a 7.5% contractor incentive allowance instead of royalty was suggested. In the boxes below we highlight some typical examples of PSC terms proposed/applied in a few countries.

Denmark (second license round)

Royalty scheme	
Gas production (mmcfd):	
0 - 25	2%
25 - 100	8%
over 100	16%
Taxes	
Income tax	34%
Hydrocarbon tax	70%
(exploration and development cost relief as for income taxes)	
Cost relief	
Exploration relief (first year)	100%
Depreciation of development cost 30% declining balance	
Hydrocarbon allowance = 25% of field development costs over 10 years	
Third and subsequent license rounds	
Same as above except royalty = 0	

Malaysia (Standard Terms)

(a) Royalty 10%

(b) Cost recovery ceiling 60%

(c) Profit gas sharing :

First 2.1 tcf	50:50
Over 2.1 tcf	70:30 in favor of state

(d) Income tax = 40%

(e) State participation

Frontier terms

Same as above except

Profit gas sharing :

First 2.1 tcf	40:50 (state 40%)
Over 2.1 tcf	60:40 in favor of state

Indonesia (Standard Terms-New agreements)

(a) First tranch petroleum = 20% of production divided between investor and state according to profit gas shares.

(b) Cost recovery : intangible drilling costs 100% first year. Capital costs accelerated, double declining balance. Investment credit 17% of development costs.

(c) Profit gas sharing : 70:30 in favor of state. 44.3% after tax , 57.6% before tax

(d) Income tax = 48%

Depreciation as for cost recovery, investment credit taxable

Frontier terms

(a) First tranch petroleum 15%

(b) Profit gas sharing 60:40. after tax = 23%, pre tax 77%

Vietnam : proposed

Royalty scheme

0 1.825 bcm/year	0%
1.825 - 3.65 bcm/year	5%
over 3.65 bcm/year	10%

Tan Do Tan Lay Field

Cost recovery (CR)	60%
Profit split (favor government)	60:40

Philippines proposed

Royalty

Not applicable

PSC terms for Malampaya Field

Gross Proceeds	100%
Less FPIA (contractor incentive)	(7.5)%
Cost Recovery (up to)	(70)%
Net Proceeds	22.5%
Contractor Share (40%)	9%
Government Share	13.5%
Less Income tax	(4.85)%
DOE share	8.65%
Less Local Government share	3.46%
Net Dept of Energy share	5.19%

B. PRICES

There are three basic approaches to gas pricing. These are:

(a) *Opportunity cost pricing* where the price is determined based on the highest market value for gas assuming a number of buyers. The opportunity cost is determined by finding the market value of LNG or converted products and then computing the net-back value which is the export price less the conversions, transportation and treatment cost.

(b) *Value based pricing* which relates the price of natural gas at the burner tip to the cost of next best alternative fuels. When a value based price is determined the well-head price still remains to be found. If supplier's net-back is calculated individually there will be several well-head prices.

(c) *Cost plus pricing* which relates the price of gas to exploration, development and operating cost incurred by the producing company with an additional margin to allow the company a return on capital invested.

The pricing mechanism for natural gas would vary from across countries. While in some countries such as Bolivia, Pakistan, and Egypt the prices are fixed by the government and usually a percentage of crude or fuel oil prices, on the other-hand in countries like Trinidad and Argentina natural gas prices are based on a cost plus pricing system. In USA and Canada which have a more competitive gas market the prices are usually lower than the fuel equivalents. In Japan, Brazil and some European countries natural gas prices are linked to fuel oil, diesel fuel or sometimes coal. Argentina regulates transmission and distribution tariffs through a price gap but the upstream sector is competitive. In most West European countries an *additive* form price formula is to determine the gas price between producers and wholesale buyers. A simplified additive formula is shown in the box. The gas price (Y) is decided by the negotiated base price (B), the price of competing fuel (X) and a coefficient (a) referred to as the "pass through factor" in gas contracts which is usually between 0.8 and 1.0.

Gas prices - Indonesia

Bulk gas Consumers - West Java
Prices - US$/mcf

Fertilizer	1.00
Steel - 1	0.65
Steel - 2	2.00
Steel Pipe	3.00
Major power generation	2.45
Private power generation	2.64
Gas distribution 1 (Current equivalent of Rupiah price)	~1.38
Gas distribution 2 (Current equivalent of Rupiah price)	~1.84
Gas distribution -3	2.70

Gas prices - Thailand
World bank Estimates

Producer Prices
Prices - US$/mcf

Unocal (Gulf of Thailand)	1.77 to 2.08
Total Company (Bongkot)	1.98 to 2.25

Consumer Prices
Prices - US$/mcf

Estimated price = 3.06

Formula

Base price for power = WP + ACT + Vat

WP = Well -head price
ACT = Average cost of transmission (includes returns to PTT)
Vat = Value added taxes

Gas price formula (West European Countries)

$$Y = aX + B$$

Y: Gas price at any given time at the border
B: Base gas price
X: Price of competing fuel
a: *Pass through factor* (between 0.8 and 1.0)

C. PIPELINE TRANSMISSION AND DISTRIBUTION SYSTEMS

Gas transmission and distribution through pipelines is a natural monopoly due to the high capital investment required and the economies of scale in the industry. In many countries the past trends has been to seek vertical integration during the early phase of the industry which has resulted in concentrated and monopolistic structures. While there are advantages of vertical

integration there are also disadvantages specially the concentration of monopoly power. In the analysis of gas chains there are two choices for treating transmission activity.

The transmission of gas from the production site to the power plant could either be treated as a separate activity by an independent pipeline company (IPC) or carried out by the same upstream investor. While the concept of a IPC for transmission of gas is relatively new to developing countries, most gas in the US is being transited through a third party. The advantages of an IPC compared to the gas transportation done by the producers is that it provides a source of government income through pipeline taxes as well it creates a leveled playing field for all parties without too much control of the chain to one particular investor. Where the transportation is separated from the upstream activity the government will have to create the necessary regulatory and legal environment to ensure undisrupted gas distribution and unfair pricing. In this study we have separated the distribution from upstream activity.

The IPC would serve as an intermediate transmission company which purchases gas from the seller/producer and resells to the power plant. In this case a *transit agreement* will be required to ensure that the seller, transported and the customer interests are fulfilled and the gas chain operates smoothly. The transportation tariffs may be negotiated and included in the agreement along with quantities, and other requirements of pressure, quality and temperature. Transportation tariffs are computed using a transmission formulae which is usually based on *replacement costs* of the utilized system and typically cover actual capital and operating costs, depreciation, taxes, a rate of return on invested capital. The tariffs are based on the booked capacity and not the volume transported. If the tariff is linked to transported volume then the transportation agreement will contain a "transport - or - pay" clause.

Transmission formula

In the box we present a transmission formulae which can be used to determine the pipeline tariff structure. The transportation tariff are usually based on replacement costs of the system utilized and include actual investment and operating costs, ROR on capital invested, depreciation, cost allocation relevant to gas and taxes. Since the tariff is based on booked capacity which is constant, the tariffs are more or less fixed. However, under this pricing method, when the quantity of gas transported is less than the booked capacity the tariff applied is lower than a tariff which is linked to transported volume. Although this will affect the pipeline company profitability in the build up period where the full booked capacity is not transported, in the long-run these initial losses will even out as the booked capacity will be utilized.

Transmission formula

$$\text{Tariff} = \frac{OC + D + I + ROR + Tax + Adj}{\text{Volume}}$$

OC : Operating Cost
D : Depreciation
I Financial charges (Interest)
ROR: Rate of return on equity
Tax: Pipeline and other corporation taxes
Adj: Annual adjustment

D. DOWN STREAM USERS - CC POWER PLANTS

The market for natural gas is primary large utilization facilities such as power and fertilizer plants. Compared to coal and oil power plants there are many advantages of using natural gas for power generation. A distinct advantage that gas is ecologically attractive. Another advantage is that natural gas powered plant have lower operating and average total costs per kwh than both an coal based steam plant and an oil based steam plant. Further, the fuel cost per kwh for a gas based combined cycle plant is almost comparable to coal based plant and about 25% less than the fuel cost per kwh for an oil based steam power plant. In this study we have considered the gas market solely to be created by combined cycle power plants for generating electricity. In Table 2 we present the average leveled costs for coal, oil and gas power plants.

Table 2: Comparison of average leveled costs for coal, oil and gas power plants

	Coal based steam plant (US cents/kwh)	**Oil based steam plant (US cents/kwh)**	**Gas based combined cycle (US cents/kwh)**
Capital cost	2.0	1.6	1.1
Fuel cost	2.0	2.9	2.1
O & M Cost	0.5	0.3	0.3
Average cost of generating power	4.5	4.8	3.5

Source: Financing Energy Projects in Emerging Economies, Penn Well ,1996

Power plant assumptions

The assumptions for a typical gas based combined cycle power plant is given below in box. In the application examples while we have assumed a combined cycle plant, some of these assumptions have been modified to the suit individual country cost and operating requirements.

Assumptions for a CC gas power plant

Capacity (MW)	300
Cost ($/kW)	650
Plant cost ($m)	270
Plant life	25 years
Efficiency (%)	48
Heat rate (BTU/kwh)	7145
Fuel price ($/mcf)	3
Heat content (MMBTU/MCF)	1
O & M cost	$ 8/kW per year + 0.2 cents/kwh

Source: Financing Energy Projects in Emerging Economies, Penn Well ,1996

ANNEX 2

Vietnam Case Study

Data and Assumptions

The data and assumptions used in the Vietnam example are summarized below. The objective of the modeling and sensitivity exercise is to determine the CR, PS terms which would maximize Vietnam's take in the privatization process and to determine a negotiating price for gas and the distribution tariff under a set of reasonable power tariff alternatives.

Assumptions

The assumptions and cost estimates for the development of offshore gas are as follows: It is assumed that gas production would commence in 1998 with an annual plateau production of around 73 bcf. Considering the relatively slow build up of gas compared to oil in inception and development periods a four year incremental build up profile is assumed. Total gas production over the planning horizon is assumed to be utilized for power generation by a combined cycle power plant while condensate would be used for fertilizer manufacture. The pipeline for distribution of gas is assumed to be independent from the exploration and production activities and possible a separate company. The total capital cost of the upstream activities is estimated as US $ 564m which includes a sunk cost of $155m and the balance of $407m for platform drilling, and sub-sea facilities. Annual operating cost of the upstream activities is assumed as 6% of the capital costs. Royalty on gas is based on the daily production output and are as follows: 0 -1.825 bcm/yr (0%), 1.825 - 3.65 bcm/yr (5%), over 3.65 bcm/yr (10%).

The pipeline activities are considered separate from the upstream activities. The total capital cost of the pipeline (onshore and offshore) is estimated at US $ 329m of which the offshore pipe-line capital cost is estimated as $311m. An annual pipeline operating costs of 2% capital cost is assumed.

A total plant capacity of 450 MW and a capital cost of US $ 750/kw is assumed under proposed project. The plant is assumed to operate at an annual plant capacity factor of 68% and an efficiency rate of 45.9%. An operating and maintenance cost of $8/kw per year and 0.2 cents/kwh respectively which are typical for a CC power plant are assumed.

Sensitivity Analysis

In this case several different well-head gas prices, cost recovery and profit share ratios for the government are considered. The minimum required returns to both the power plant and the pipeline company is fixed at 15%. A 10% discount rate is used throughout the analysis. The set of values for each parameter of interest used in the analysis is given below. Note, however that these parameters can be changed depending upon the project and the price range for negotiations.

Table 1: Data

Variable Parameter	Set of values			
WP of gas US $/mcf	1.00	2.00	3.00	3.50
CR	40%	50%	60%	70%
Government PS	50%	60%	70%	80%

Fixed Parameter	Value
Discount rate	10%
Pipeline ROR	15%
Power Co. ROR	15%

For the above set of data a total of 64 (4x4x4) scenarios were generated. The results of the sensitivity analysis is summarized in Figures 4. Annex 3 gives details of contractor ROR and NPV, NPV of government share of cash flow, ROR and NPV for both the pipeline company and power company and the resultant power tariff for each scenario given the minimum 15% ROR requirement for the pipeline and power plant. Although, we have performed the sensitivity analysis using a fixed discount rate of 10%, as discussed earlier the user can perform the analysis for several different discount rates in order to evaluate the power generation and distribution viability and the impact on government take in case of higher costs of capital. Although the ROR for the pipeline company and the power plant is fixed at 15% in the example, this can be varied to allow for different ROR requirements.

Figure 3 is used mainly for explaining the different scenario plots of the sensitivity results. Given the initial well-head gas price of 1$, as there are 4 possible CR ratios and 4 possible PS ratios considered there will be a total of 16 different combinations of CR and PS ratios for this price alternative. Similarly, there will be 16 possible CR and PS combinations for each of the other 3 well-head price alternatives. Therefore, in total there will be 64 possible well-head price, CR, PS combinations or scenarios. Each of the sixteen CR, PS combinations under a single well-head price alternative is treated a block for explanatory purposes. For example block S1 refers to the 16 possible scenarios of CR, PS combinations under the well-head price alternative 1$./mcf.

The four different blocks (S1-S4) in Figure 3, shows the NPV of government cash flows, for the four different well-head price alternatives $1.00/mcf, $2.00/mcf, $3.00/mcf and $3.50/mcf. Since the selling price of gas and power tariff were adjusted to obtain the fixed 15% ROR for the pipeline and power plant, each of the four blocks also in effect refer to a particular set of gas prices and power tariffs for a fixed 15% ROR for the pipeline company and the power plant. For example, block S2 refers to a set of plots with a WP of $2/mcf and a SP of $3/mcf and a power price of US cents 4.8/kwh. Note that the selling price of $3.00/mcf and power price of US cents 4.8/kwh were obtained by adjusting the prices to arrive at the 15% fixed ROR requirement for the pipeline and power plant.

The plot circled in block S3 therefore would correspond to scenario no 41-which pertains to the following:- gas selling price (SP) of $ 4/mcf, well-head price (WP) of $ 3/mcf, a cost recovery (CR) of 60%, a government profit share (PS) of 50%. Note that the pipeline and power company returns were fixed at 15% and the resulting power tariff which gives this return to the power plant is US cents 5.5/kwh which was obtained by trial and error. Also note that the $1.00 pipeline margin (selling price less the well-head price of gas) for this case gives the required 15% ROR to the pipeline company. The corresponding government take for scenario no 41 is a NPV of US $ 463 m.

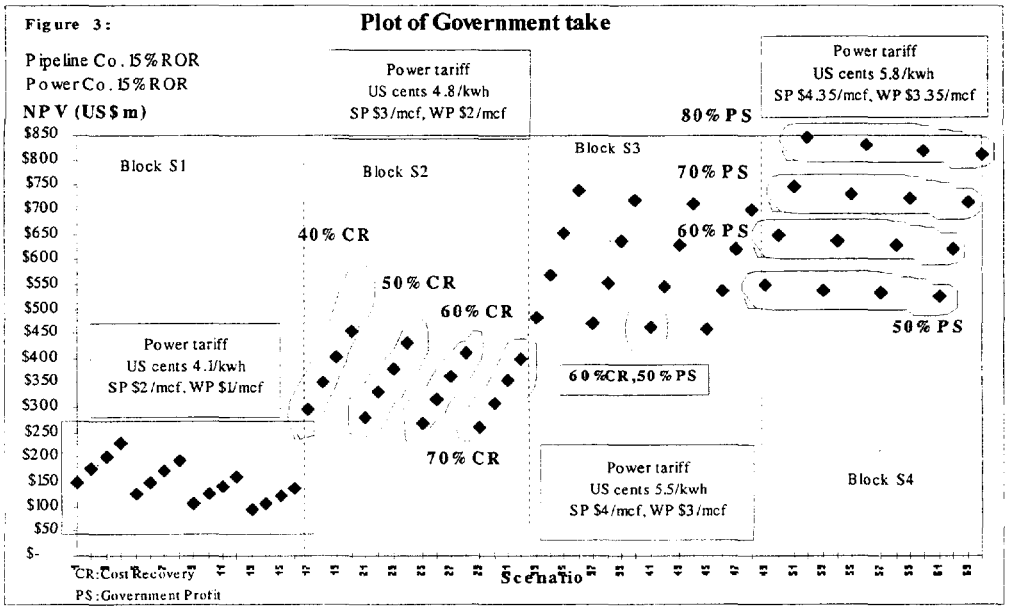


Figure 3:
Plot of Government take
Pipeline Co. 15% ROR
Power Co. 15% ROR
NPV (US$ m)
$850
$800
$750
$700
$650
$600
$550
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$-
Block S1
Power tariff
US cents 4.1/kwh
SP $2/mcf, WP $1/mcf
Block S2
Power tariff
US cents 4.8/kwh
SP $3/mcf, WP $2/mcf
40% CR
50% CR
60% CR
70% CR
Block S3
Power tariff
US cents 5.5/kwh
SP $4/mcf, WP $3/mcf
60%CR,50% PS
80% PS
70% PS
60% PS
Block S4
Power tariff
US cents 5.8/kwh
SP $4.35/mcf, WP $3.35/mcf
50% PS
Scenario
CR:Cost Recovery
PS:Government Profit

ECONOMIC ANALYSIS SHEETS VIETNAM CASE STUDY

Vietnam:PSC/Pipe-line/CC Power Plant - Model

ASSUMPTIONS

Capital costs in $ million

Exploration	155			
Upstream facilities (CCU)	409			
Pipe-line (CCP)	329	offshore	311 onshore	18
Total	893			

Annual operating costs as a % of capital costs

	%
Up-stream operating costs (OCU)	6
Pipeline operating costs (OCP)	2

Production data

Gas production rate (plateau)	bcm/year	2.08
	bcf/year	73.3897
Condensate gas ratio (cgs)	bbl/mmc	9

Gas and condensate production build-up to plateau in year n : (PPn)

Prices

Cost of gas @ well head			3	$/mcf
Sale price at point of use			4	$/mcf
Condensate price			16	$/bbl
Royalty	contract	0	64.6	128.8 bcm/yr
Gas royalty	(%)	0	5	10
Condensate royalty (%)			0	

Government/Contractor cost/profit splits

		%
Cost Recovery (CR)		50
Profit Share (PS)	Contractor	50
	Government	50

Discount rate % 10

Input

Prod'n Build-u	sp	Data Price $m	CR %	Gov PS
PP3				
PP4	4	3	50	50
PP6				
PP8				

Results

Prod'n Build-u	PSC including sunk cost ROR	NPV	Gov. NPV	PSC excluding sunk cost ROR	NPV	Pipeline ROR	NPV	Power Company ROR	NPV	Price US cents/kwh
PP3	15%	241	491	22%	382	15%	140			
PP4	15%	220	470	21%	361	15%	125	15%	132	5.5
PP6	14%	174	429	20%	315	13%	96			
PP8	13%	130	390	18%	271	12%	67			

Economic Analysis- Combined Cycle Plant

ASSUMPTIONS

Plant capacity	450	MW
Capital Cost	750	$/kw
Plant cost (CCP)	337.5	$ million
Plant life	25	Years
Plant load factor	68	%
Efficiency	45.9	%
Heat Rate	7445	BTU/Kwh
Heat content	1	MMBTU/MCF
Operation/Maintenance cost	8	$/KW per year +
	0.2	cents/kWh
Gas Price	4	$/MCF
Electricity price	5.5	cents/kWh

Production Build-up profile 4 Years						
Capital & Operating Costs			(US$ m)			
	Up-stream Project			Pipe-line Project		
		PP4			PP4	
Year	CCU	OCU	TCU	CCP	OCP	TCP
0	155	0	155	0	0	0
1	61	0	61	49	0	49
2	164	0	164	132	0	132
3	184	0	184	148	0	148
4	0	6	6	0	2	2
5	0	12	12	0	3	3
6	0	18	18	0	5	5
7	0	25	25	0	7	7
8	0	25	25	0	7	7
9	0	25	25	0	7	7
10	0	25	25	0	7	7
11	0	25	25	0	7	7
12	0	25	25	0	7	7
13	0	25	25	0	7	7
14	0	25	25	0	7	7
15	0	25	25	0	7	7
16	0	25	25	0	7	7
17	0	25	25	0	7	7
18	0	25	25	0	7	7
19	0	25	25	0	7	7
20	0	25	25	0	7	7
21	0	25	25	0	7	7
22	0	25	25	0	7	7
23	0	25	25	0	7	7
24	0	25	25	0	7	7
25	0	25	25	0	7	7
26	0	25	25	0	7	7
27	0	25	25	0	7	7
28	0	25	25	0	7	7
29	0	25	25	0	7	7
30	0	25	25	0	7	7
31	0	25	25	0	7	7
Total	564	650	1214	329	174	503
NPV(i%)	$ 440	$134	$ 575	$ 241	$ 36	$ 277
NPV(i%) with out sunk cost						
IRR						
IRR (without sunk cost)						
Cost of gas/Mcf			$1.12			$0.54
			$1.43			$0.69

Pipeline Seperated					
Pipe-line Project				Cash Flows	
	PP4		US$m	US$m	US$m
CCP	OCP	TCP	PCG	PR	NPCF
0	0	0	0	0	0
49	0	49	0	0	-49
132	0	132	0	0	-132
148	0	148	0	0	-148
0	2	2	55	73	17
0	3	3	110	147	33
0	5	5	165	220	50
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
0	7	7	220	294	67
329	174	503	5834	7779	1441
$ 241	$ 36	$ 277	$ 1,207	$ 1,609	$ 125
					15%
		$0.54			
		$ 0.69			

Up-stream Project																				
					Gross Revenues		Royalty			Cost Recovery (CR)					Profit Split		Cash Flows			
	PP4		Prod. profile-PP4		US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m
CCU	OCU	TCU	GP(bcf)	c.P(bbl)	GR4	c.R4	Gr4	c.r4	NTR	Entl.CR	NCT(CR)	CNCF	CR	Tot. PS	Gov.	Cont.	Gov.	Cont.	Total
155	0	155	0	0	0	0	0	0	0	0	-155	-155	0	0	0	0	0	-155	-155
61	0	61	0	0	0	0	0	0	0	0	-61	-216	0	0	0	0	0	-61	-61
164	0	164	0	0	0	0	0	0	0	0	-164	-380	0	0	0	0	0	-164	-164
184	0	184	0	0	0	0	0	0	0	0	-184	-564	0	0	0	0	0	-184	-184
0	6	6	18	165	55	3	0	0	58	29	23	-541	29	29	14	14	14	37	52
0	12	12	37	330	110	5	0	0	115	58	45	-496	58	58	29	29	29	74	103
0	18	18	55	495	165	8	0	0	173	87	68	-428	87	87	43	43	43	111	155
0	25	25	73	661	220	11	11	0	220	110	85	-342	110	110	55	55	66	140	206
0	25	25	73	661	220	11	11	0	220	110	85	-257	110	110	55	55	66	140	206
0	25	25	73	661	220	11	11	0	220	110	85	-172	110	110	55	55	66	140	206
0	25	25	73	661	220	11	11	0	220	110	85	-86	110	110	55	55	66	140	206
0	25	25	73	661	220	11	11	0	220	110	85	-1	110	110	55	55	66	140	206
0	25	25	73	661	220	11	11	0	220	110	85	84	26	194	97	97	108	98	206
0	25	25	73	661	220	11	11	0	220	110	85	170	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	255	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	340	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	425	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	511	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	596	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	681	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	767	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	852	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	937	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1023	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1108	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1193	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1279	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1364	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1449	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1535	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1620	25	195	98	98	109	98	206
0	25	25	73	661	220	11	11	0	220	110	85	1705	25	195	98	98	109	98	206
564	650	1214	1945		5834	280	275	0	5839	2920	1705		1214	4615	2313	2313	2588	2313	4900
$ 440	$ 134	$ 575			$ 1,207	$ 58	$ 51	$ -	$ 1,213	$ 607	$ 32		$ 375	$ 838	$ 419	$ 419	$ 470	$ 220	$ 690
																	$ 470	$ 361	$ 831
																	Inf	15%	21%
																	Inf	21%	29%
		$1.12																	
		$ 1.43																	

Economic Analysis- Combined Cycle Plant

Assumptions

Plant capacity	450	MW
Capital Cost	750	$/kw
Plant cost (CCP)	338	$ million
Plant life	25	Years
Plant load factor	68	%
Efficiency	45.9	%
Heat Rate	7145	BTU/Kwh
Heat content	1	MMBTU/MCF
Operation/Maintenance cost(OCP)	8	$/KW per year +
	0.2	cents/kWh
Gas Price	4	$/MCF
Electricity price	5.5	cents/kWh

	C&OM Costs						Cash Flows	
Year	CCP	O@M	Gas req	Fuel Cost	TC	Power Generated	TR	NCF
	US$m	US$m	MMcf	US$m	US$m	(GWh)	US$m	US$m
1	169				169			-169
2	135				135			-135
3	34				34			-34
4		9	19.15	77	86	2680.56	147	62
5		9	19.15	77	86	2680.56	147	62
6		9	19.15	77	86	2680.56	147	62
7		9	19.15	77	86	2680.56	147	62
8		9	19.15	77	86	2680.56	147	62
9		9	19.15	77	86	2680.56	147	62
10		9	19.15	77	86	2680.56	147	62
11		9	19.15	77	86	2680.56	147	62
12		9	19.15	77	86	2680.56	147	62
13		9	19.15	77	86	2680.56	147	62
14		9	19.15	77	86	2680.56	147	62
15		9	19.15	77	86	2680.56	147	62
16		9	19.15	77	86	2680.56	147	62
17		9	19.15	77	86	2680.56	147	62
18		9	19.15	77	86	2680.56	147	62
19		9	19.15	77	86	2680.56	147	62
20		9	19.15	77	86	2680.56	147	62
21		9	19.15	77	86	2680.56	147	62
22		9	19.15	77	86	2680.56	147	62
23		9	19.15	77	86	2680.56	147	62
24		9	19.15	77	86	2680.56	147	62
25		9	19.15	77	86	2680.56	147	62
26		9	19.15	77	86	2680.56	147	62
27		9	19.15	77	86	2680.56	147	62
28		9	19.15	77	86	2680.56	147	62
Total	338	224		1915	2477		3686	1209
NPV@15%	$290	$81	$174	$695	$874	$24.332	$1.338	$132
IRR								15%
Gas Price								4.00 $/MCF

Vietnam				Sensitivity Results			Discount rate 10 %								
					PSC		Gov.	PSC		Pipeline		Power Company			
Scenario		Data			including sunk cost			excluding sunk cost							
	sp $/mcf	WHP $/mcf	CR %	Gov PS%	ROR	NPV	NPV	ROR	NPV	ROR	NPV	ROR	NPV	Price US cents/kwh
1	2	1	40	50	3%	$ (265)	$ 150	6%	$ (124)	15%	$ 125	15%	$137	4.1
2	2	1	40	60	#NUM!	-291	177	#NUM!	-150	15%	125	15%	137	4.1
3	2	1	40	70	#NUM!	-318	203	#NUM!	-177	15%	125	15%	137	4.1
4	2	1	40	80	#NUM!	-344	230	#NUM!	-203	15%	125	15%	137	4.1
5	2	1	50	50	#NUM!	-242	128	7%	-102	15%	125	15%	137	4.1
6	2	1	50	60	3%	-265	150	6%	-124	15%	125	15%	137	4.1
7	2	1	50	70	#NUM!	-287	172	#NUM!	-146	15%	125	15%	137	4.1
8	2	1	50	80	#NUM!	-309	194	#NUM!	-168	15%	125	15%	137	4.1
9	2	1	60	50	#NUM!	-222	107	8%	-81	15%	125	15%	137	4.1
10	2	1	60	60	#NUM!	-240	125	7%	-99	15%	125	15%	137	4.1
11	2	1	60	70	#NUM!	-258	144	6%	-117	15%	125	15%	137	4.1
12	2	1	60	80	#NUM!	-276	162	5%	-135	15%	125	15%	137	4.1
13	2	1	70	50	#NUM!	-208	93	8%	-67	15%	125	15%	137	4.1
14	2	1	70	60	#NUM!	-223	109	8%	-82	15%	125	15%	137	4.1
15	2	1	70	70	#NUM!	-239	124	7%	-98	15%	125	15%	137	4.1
16	2	1	70	80	#NUM!	-254	139	6%	-113	15%	125	15%	137	4.1
17	3	2	40	50	10%	-10	298	15%	131	15%	125	15%	134	4.8
18	3	2	40	60	8%	-63	350	13%	78	15%	125	15%	134	4.8
19	3	2	40	70	7%	-115	403	12%	26	15%	125	15%	134	4.8
20	3	2	40	80	5%	-168	456	10%	-27	15%	125	15%	134	4.8
21	3	2	50	50	10%	6	281	16%	147	15%	125	15%	134	4.8
22	3	2	50	60	9%	-43	331	14%	98	15%	125	15%	134	4.8
23	3	2	50	70	8%	-93	380	13%	48	15%	125	15%	134	4.8
24	3	2	50	80	6%	-142	430	11%	-1	15%	125	15%	134	4.8
25	3	2	60	50	10%	-7	270	16%	158	15%	125	15%	134	4.8
26	3	2	60	60	9%	-30	318	15%	111	15%	125	15%	134	4.8
27	3	2	60	70	8%	-77	365	13%	64	15%	125	15%	134	4.8
28	3	2	60	80	6%	-125	412	11%	16	15%	125	15%	134	4.8
29	3	2	70	50	11%	25	263	16%	168	15%	125	15%	134	4.8
30	3	2	70	60	9%	-21	308	15%	120	15%	125	15%	134	4.8
31	3	2	70	70	8%	-67	354	14%	74	15%	125	15%	134	4.8
32	3	2	70	80	6%	-112	400	12%	29	15%	125	15%	134	4.8
33	4	3	40	50	14%	208	481	21%	349	15%	125	15%	132	5.5
34	4	3	40	60	13%	122	567	19%	263	15%	125	15%	132	5.5
35	4	3	40	70	11%	38	653	17%	177	15%	125	15%	132	5.5
36	4	3	40	80	9%	-50	739	14%	91	15%	125	15%	132	5.5
37	4	3	50	50	15%	220	470	21%	381	15%	125	15%	132	5.5
38	4	3	50	60	13%	138	554	20%	277	15%	125	15%	132	5.5
39	4	3	50	70	11%	52	638	18%	193	15%	125	15%	132	5.5
40	4	3	50	80	9%	-32	721	15%	109	15%	125	15%	132	5.5
41	4	3	60	50	15%	227	463	22%	368	15%	125	15%	132	5.5
42	4	3	60	80	13%	145	545	20%	288	15%	125	15%	132	5.5
43	4	3	60	70	12%	62	628	18%	203	15%	125	15%	132	5.5
44	4	3	60	80	9%	-20	710	16%	121	15%	125	15%	132	5.5
45	4	3	70	50	15%	232	457	22%	373	15%	125	15%	132	5.5
46	4	3	70	60	14%	151	539	21%	292	15%	125	15%	132	5.5
47	4	3	70	70	12%	70	620	19%	211	15%	125	15%	132	5.5
48	4	3	70	80	10%	-11	701	16%	129	15%	125	15%	132	5.5
49	4.35	3.35	40	50	16%	281	549	23%	422	15%	125	15%	141	5.8
50	4.35	3.35	40	60	14%	183	648	21%	324	15%	125	15%	141	5.8
51	4.35	3.35	40	70	12%	85	746	18%	226	15%	125	15%	141	5.8
52	4.35	3.35	40	80	10%	-14	844	16%	127	15%	125	15%	141	5.8
53	4.35	3.35	50	50	16%	291	539	23%	432	15%	125	15%	141	5.8
54	4.35	3.35	50	60	14%	195	636	21%	336	15%	125	15%	141	5.8
55	4.35	3.35	50	70	12%	99	732	19%	240	15%	125	15%	141	5.8
56	4.35	3.35	50	80	10%	2	828	16%	143	15%	125	15%	141	5.8
57	4.35	3.35	60	50	16%	206	532	24%	439	15%	125	15%	141	5.8
58	4.35	3.35	60	60	15%	203	627	22%	344	15%	125	15%	141	5.8
59	4.35	3.35	60	70	13%	108	722	20%	249	15%	125	15%	141	5.8
60	4.35	3.35	60	80	10%	13	817	17%	154	15%	125	15%	141	5.8
61	4.35	3.35	70	50	16%	303	528	24%	444	15%	125	15%	141	5.8
62	4.35	3.35	70	60	15%	209	622	22%	350	15%	125	15%	141	5.8
63	4.35	3.35	70	70	13%	115	716	20%	256	15%	125	15%	141	5.8
64	4.35	3.35	70	80	11%	21	810	18%	162	15%	125	15%	141	5.8

Note Pipeline ROR 12%

Vietnam — Sensitivity Results — Discount rate 10 %

Scenario		Data			PSC including sunk cost		Gov.	PSC excluding sunk cost		Pipeline		Power Company		
	sp $/mcf	WHP $/mcf	CR %	Gov PS%	ROR	NPV	NPV	ROR	NPV	ROR	NPV	ROR	NPV	Price US cents/kwh
1	1.8	1	40	50	3%	-265	150	5%	-124	12%	45	15%	145	4
2	1.8	1	40	60	#NUM!	-291	177	#NUM!	-150	12%	45	15%	145	4
3	1.8	1	40	70	#NUM!	-318	203	#NUM!	-177	12%	45	15%	145	4
4	1.8	1	40	80	#NUM!	-344	230	#NUM!	-203	12%	45	15%	145	4
5	1.8	1	50	50	#NUM!	-242	128	6%	-102	12%	45	15%	145	4
6	1.8	1	50	60	3%	-265	150	5%	-124	12%	45	15%	145	4
7	1.8	1	50	70	#NUM!	-287	172	#NUM!	-146	12%	45	15%	145	4
8	1.8	1	50	80	#NUM!	-309	194	#NUM!	-168	12%	45	15%	145	4
9	1.8	1	60	50	#NUM!	-222	107	7%	-81	12%	45	15%	145	4
10	1.8	1	60	60	#NUM!	-240	125	6%	-99	12%	45	15%	145	4
11	1.8	1	60	70	#NUM!	-258	144	5%	-117	12%	45	15%	145	4
12	1.8	1	60	80	#NUM!	-276	162	4%	-135	12%	45	15%	145	4
13	1.8	1	70	50	#NUM!	-208	93	7%	-67	12%	45	15%	145	4
14	1.8	1	70	60	#NUM!	-223	109	7%	-82	12%	45	15%	145	4
15	1.8	1	70	70	#NUM!	-239	124	6%	-98	12%	45	15%	145	4
16	1.8	1	70	80	#NUM!	-254	139	5%	-113	12%	45	15%	145	4
17	2.8	2	40	50	10%	-10	298	14%	131	12%	45	15%	142	4.7
18	2.8	2	40	60	8%	-63	350	13%	78	12%	45	15%	142	4.7
19	2.8	2	40	70	7%	-115	403	11%	26	12%	45	15%	142	4.7
20	2.8	2	40	80	5%	-168	456	9%	-27	12%	45	15%	142	4.7
21	2.8	2	50	50	10%	6	281	15%	147	12%	45	15%	142	4.7
22	2.8	2	50	60	9%	-43	331	13%	98	12%	45	15%	142	4.7
23	2.8	2	50	70	8%	-93	380	12%	48	12%	45	15%	142	4.7
24	2.8	2	50	80	6%	-142	430	10%	-1	12%	45	15%	142	4.7
25	2.8	2	60	50	10%	17	270	15%	158	12%	45	15%	142	4.7
26	2.8	2	60	60	9%	-30	318	14%	111	12%	45	15%	142	4.7
27	2.8	2	60	70	8%	-77	365	13%	64	12%	45	15%	142	4.7
28	2.8	2	60	80	6%	-125	412	11%	16	12%	45	15%	142	4.7
29	2.8	2	70	50	11%	25	263	16%	166	12%	45	15%	142	4.7
30	2.8	2	70	60	9%	-21	308	15%	120	12%	45	15%	142	4.7
31	2.8	2	70	70	8%	-67	354	13%	74	12%	45	15%	142	4.7
32	2.8	2	70	80	6%	-112	400	11%	29	12%	45	15%	142	4.7
33	3.8	3	40	50	14%	208	481	20%	349	12%	45	15%	130	5.35
34	3.8	3	40	60	13%	122	567	18%	263	12%	45	15%	130	5.35
35	3.8	3	40	70	11%	36	653	16%	177	12%	45	15%	130	5.35
36	3.8	3	40	80	9%	-50	739	14%	91	12%	45	15%	130	5.35
37	3.8	3	50	50	15%	220	470	21%	361	12%	45	15%	130	5.35
38	3.8	3	50	60	13%	138	554	19%	277	12%	45	15%	130	5.35
39	3.8	3	50	70	11%	52	638	17%	193	12%	45	15%	130	5.35
40	3.8	3	50	80	9%	-32	721	15%	109	12%	45	15%	130	5.35
41	3.8	3	60	50	15%	227	463	22%	368	12%	45	15%	130	5.35
42	3.8	3	60	60	13%	145	545	20%	286	12%	45	15%	130	5.35
43	3.8	3	60	70	12%	62	628	18%	203	12%	45	15%	130	5.35
44	3.8	3	60	80	9%	-20	710	15%	121	12%	45	15%	130	5.35
45	3.8	3	70	50	15%	232	457	22%	373	12%	45	15%	130	5.35
46	3.8	3	70	60	14%	151	539	20%	292	12%	45	15%	130	5.35
47	3.8	3	70	70	12%	70	620	18%	211	12%	45	15%	130	5.35
48	3.8	3	70	80	10%	-11	701	16%	129	12%	45	15%	130	5.35
49	4.15	3.35	40	50	16%	281	549	22%	422	12%	45	15%	139	5.65
50	4.15	3.35	40	60	14%	183	648	20%	324	12%	45	15%	139	5.65
51	4.15	3.35	40	70	12%	85	746	18%	226	12%	45	15%	139	5.65
52	4.15	3.35	40	80	10%	-14	844	15%	127	12%	45	15%	139	5.65
53	4.15	3.35	50	50	16%	291	539	23%	432	12%	45	15%	139	5.65
54	4.15	3.35	50	60	14%	195	636	21%	336	12%	45	15%	139	5.65
55	4.15	3.35	50	70	12%	99	732	19%	240	12%	45	15%	139	5.65
56	4.15	3.35	50	80	10%	2	828	16%	143	12%	45	15%	139	5.65
57	4.15	3.35	60	50	16%	298	532	23%	439	12%	45	15%	139	5.65
58	4.15	3.35	60	60	15%	203	627	22%	344	12%	45	15%	139	5.65
59	4.15	3.35	60	70	13%	108	722	19%	249	12%	45	15%	139	5.65
60	4.15	3.35	60	80	10%	13	817	17%	154	12%	45	15%	139	5.65
61	4.15	3.35	70	50	16%	303	528	24%	444	12%	45	15%	139	5.65
62	4.15	3.35	70	60	15%	209	622	22%	350	12%	45	15%	139	5.65
63	4.15	3.35	70	70	13%	115	716	20%	256	12%	45	15%	139	5.65
64	4.15	3.35	70	80	11%	21	810	17%	162	12%	45	15%	139	5.65

ANNEX 3

Philippines Case Study

Data and assumptions

The data and assumption for the offshore gas project, an independent pipeline company and proposed 3000 MW power plant is summarized below. Our analysis, is based on the worst case scenario of $1.5 billion for upstream capital costs since the gas find is in deep water. Offshore gas is assumed to be available to the power plants four years from the project initialization. The operating costs of upstream activity is assumed as 7% of capital costs with a four year gradual gas build up to plateau level. Under the existing PSC terms, there is no royalty on gas but an agreement by the Philippine's government on an incentive allowance of 7.5% of total revenues for the contractor.

We have separated the pipeline from exploration and production to analyze the possibility of setting up an independent pipeline company for gas distribution and marketing. Transportation of gas from the offshore platform to the market would require a 500 km pipeline with a total cost of US$ 600m. and the onshore pipeline cost to the markets is estimated around $44m. Annual pipeline operating cost for the pipeline is assumed as 7% of the capital costs.

According to present estimates, upstream development is only feasible if there is a committed gas market of 146 bcm/year at plateau which would require a minimum aggregate power plant base of 3000 MW. Our analysis is based on an aggregate 3000 MW combine cycle power plants at a capital cost of US$ 650/kw. In addition, a plant load factor of 75% and an efficiency rate of 44.9% which is typical for a combined cycle power and an annual operating costs of $8/kw and maintenance cost of US cents 0.2/kwh is assumed.

In the Philippines case, there is no royalty on gas to be produced at the offshore gas field but instead an incentive allowance (FPIA) of 7.5% of total revenues for the contractor. The maximum cost recovery allowed is 70% and governments effective profit share as per the agreed terms is 13.5%.

PSC terms for gas Field

Gross Proceeds	100%
Less FPIA (contractor incentive)	(7.5)%
Cost Recovery (up to)	(70)%
Net Proceeds	22.5%
Contractor Share (40%)	9%
Government Share	13.5%
Less Income tax	(4.85)%
DOE share	8.65%
Less Local Government share	3.46%
Net Dept of Energy share	5.19%

ECONOMIC ANALYSIS SHEETS PHILIPPINES CASE STUDY

Philippines:PSC/Pipe-line/CC Power Plant - Model

ASSUMPTIONS

Capital costs in $ million

Exploration	198				
Upstream facilities (CCU)	1500				
Pipe-line (CCP)	600	offshore	500	onshore	100
Total	2298				

Annual operating costs as a % of capital costs

	%
Up-stream operating costs (OCU)	7
Pipeline operating costs (OCP)	7

Production data

Gas production rate (plateau)	bcm/year	4.14
	bcf/year	146
Condensate gas ratio (cgs)	bbl/mmc	9

Gas and condensate production build-up to plateau in year n : (PPn)

Prices

Cost of gas @ well head	3.35	$/mcf
Sale price at point of use	4.5	$/mcf
Condensate price	16	$/bbl

Incentive to contractor 7.5 %

Government/Contractor cost/profit splits

		%
Cost Recovery (CR)		70
Profit Share (PS)	Contractor	86.5
	Government	13.5

Discount rate % 10

Input

Prod'n Build-up	sp	Data Price $m	CR %	Gov PS
PP3				
PP4	4.5	3.35	70	13.5
PP6				
PP8				

Results

	PSC including sunk cost ROR	PSC including sunk cost NPV	Gov. NPV	PSC excluding sunk cost ROR	PSC excluding sunk cost NPV	Pipeline ROR	Pipeline NPV	Power Company ROR	Power Company NPV	Price US cents/kwh
PP3	16%	841	186	19%	1021	16%	279			
PP4	15%	766	178	18%	946	15%	251	15%	827	5.4
PP6	14%	609	163	17%	789	14%	195			
PP8	13%	460	149	16%	640	13%	142			

Economic Analysis- Combined Cycle Plant

ASSUMPTIONS

Plant capacity	3000	MW
Capital Cost	650	$/kw
Plant cost (CCP)	1950	$ million
Plant life	25	Years
Plant load factor	75	%
Efficiency	45.9	%
Heat Rate	7145	BTU/Kwh
Heat content	1	MMBTU/MCF
Operation/Maintenance cost(	8	$/KW per year +
	0.2	cents/kWh
Gas Price	4.5	$/MCF
Electricity price	5.4	cents/kWh

Production Build-up profile 4 Years						
Capital & Operating Costs			(US$ m)			
	Up-stream Project			Pipe-line Project		
		PP4			PP4	
Year	CCU	OCU	TCU	CCP	OCP	TCP
0	198	0	198	0	0	0
1	225	0	225	90	0	90
2	600	0	600	240	0	240
3	675	0	675	270	0	270
4	0	26	26	0	11	11
5	0	53	53	0	21	21
6	0	79	79	0	32	32
7	0	105	105	0	42	42
8	0	105	105	0	42	42
9	0	105	105	0	42	42
10	0	105	105	0	42	42
11	0	105	105	0	42	42
12	0	105	105	0	42	42
13	0	105	105	0	42	42
14	0	105	105	0	42	42
15	0	105	105	0	42	42
16	0	105	105	0	42	42
17	0	105	105	0	42	42
18	0	105	105	0	42	42
19	0	105	105	0	42	42
20	0	105	105	0	42	42
21	0	105	105	0	42	42
22	0	105	105	0	42	42
23	0	105	105	0	42	42
24	0	105	105	0	42	42
25	0	105	105	0	42	42
26	0	105	105	0	42	42
27	0	105	105	0	42	42
28	0	105	105	0	42	42
29	0	105	105	0	42	42
30	0	105	105	0	42	42
31	0	105	105	0	42	42
Total	1698	2783	4481	600	1113	1713
NPV(i%)	$ 1,278	$575	$ 1,853	$ 439	$ 230	$ 669
NPV(i%) with out sunk cost						
IRR						
IRR (without sunk cost)						
Cost of gas/Mcf			$1.81			$0.66
			$2.31			$0.84

Pipeline Seperated					
Pipe-line Project				**Cash Flows**	
	PP4		US$m	US$m	US$m
CCP	OCP	**TCP**	**PCG**	PR	**NPCF**
0	0	**0**	0	0	**0**
90	0	**90**	0	0	**-90**
240	0	**240**	0	0	**-240**
270	0	**270**	0	0	**-270**
0	11	**11**	122	164	**31**
0	21	**21**	245	329	**63**
0	32	**32**	367	493	**94**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
0	42	**42**	489	657	**126**
600	**1113**	**1713**	**12968**	**17419**	**2739**
$ 439	**$ 230**	**$ 669**	**$ 2,682**	**$ 3,602**	**$ 251**
					15%
		$0.66			
		$ 0.84			

Up-stream Project																				
					Gross Revenues		Incentive to contractor			Cost Recovery (CR)					Profit Split		Cash Flows		
	PP4		Prod. profile-PP4		US$m	US$m	US$m		US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m
CCU	OCU	TCU	GP(bcf)	c.P(kbd)	GR4	c.R4			NTR	Entll CR	NCF(CR)	CNCF	CR	Tot. PS	Gov.	Cont.	Gov.	Cont.	Total
198	0	198	0	0	0	0	0		0	0	-198	-198	0	0	0	0	0	-198	-198
225	0	225	0	0	0	0	0		0	0	-225	-423	0	0	0	0	0	-225	-225
600	0	600	0	0	0	0	0		0	0	-600	-1023	0	0	0	0	0	-600	-600
675	0	675	0	0	0	0	0		0	0	-675	-1698	0	0	0	0	0	-675	-675
0	26	26	37	329	122	5	10		118	83	56	-1642	83	35	5	31	5	97	101
0	53	53	73	657	245	11	19		236	165	113	-1529	165	71	10	61	10	193	203
0	79	79	110	986	367	16	29		354	248	169	-1360	248	106	14	92	14	290	304
0	105	105	146	1315	489	21	38		472	330	225	-1134	330	142	19	123	19	386	405
0	105	105	146	1315	489	21	38		472	330	225	-909	330	142	19	123	19	386	405
0	105	105	146	1315	489	21	38		472	330	225	-683	330	142	19	123	19	386	405
0	105	105	146	1315	489	21	38		472	330	225	-458	330	142	19	123	19	386	405
0	105	105	146	1315	489	21	38		472	330	225	-232	330	142	19	123	19	386	405
0	105	105	146	1315	489	21	38		472	330	225	-7	330	142	19	123	19	386	405
0	105	105	146	1315	489	21	38		472	330	225	219	112	360	49	312	49	357	405
0	105	105	146	1315	489	21	38		472	330	225	444	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	669	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	895	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	1120	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	1346	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	1571	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	1797	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	2022	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	2248	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	2473	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	2699	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	2924	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	3150	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	3375	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	3601	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	3826	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	4052	105	367	50	318	50	356	405
0	105	105	146	1315	489	21	38		472	330	225	4277	105	367	50	318	50	356	405
1698	2783	4481	3871		12968	557	1014		12511	8758	4277		4481	8030	1084	6946	1084	7961	9045
$ 1,278	$ 575	$ 1,853			$ 2,682	$ 115	$ 210		$ 2,587	$ 1,811	$ (42)		$ 1,267	$ 1,321	$ 178	$ 1,142	$ 178	$ 766	$ 944
																	$ 178	$ 946	$ 1,124
																	Inf	15%	16%
																	Inf	18%	19%
		$1.81																	
		$ 2.31																	

Economic Analysis- Combined Cycle Plant

Assumptions

Plant capacity	3000	MW
Capital Cost	650	$/kw
Plant cost (CCP)	1950	$ million
Plant life	25	Years
Plant load factor	75	%
Efficiency	45.9	%
Heat Rate	7145	BTU/Kwh
Heat content	1	MMBTU/MCF
Operation/Maintenance cost(OCP)	8	$/KW per year +
	0.2	cents/kWh
Gas Price	4.5	$/MCF
Electricity price	5.4	cents/kWh

	C&OM Costs						Cash Flows	
Year	CCP	O@M	Gas req	Fuel Cost	TC	Power Generated	TR	NCF
	US$m	US$m	MMcf	US$m	US$m	(GWh)	US$m	US$m
1	975				975			-975
2	780				780			-780
3	195				195			-195
4		63	140.83	634	697	19710.00	1064	367
5		63	140.83	634	697	19710.00	1064	367
6		63	140.83	634	697	19710.00	1064	367
7		63	140.83	634	697	19710.00	1064	367
8		63	140.83	634	697	19710.00	1064	367
9		63	140.83	634	697	19710.00	1064	367
10		63	140.83	634	697	19710.00	1064	367
11		63	140.83	634	697	19710.00	1064	367
12		63	140.83	634	697	19710.00	1064	367
13		63	140.83	634	697	19710.00	1064	367
14		63	140.83	634	697	19710.00	1064	367
15		63	140.83	634	697	19710.00	1064	367
16		63	140.83	634	697	19710.00	1064	367
17		63	140.83	634	697	19710.00	1064	367
18		63	140.83	634	697	19710.00	1064	367
19		63	140.83	634	697	19710.00	1064	367
20		63	140.83	634	697	19710.00	1064	367
21		63	140.83	634	697	19710.00	1064	367
22		63	140.83	634	697	19710.00	1064	367
23		63	140.83	634	697	19710.00	1064	367
24		63	140.83	634	697	19710.00	1064	367
25		63	140.83	634	697	19710.00	1064	367
26		63	140.83	634	697	19710.00	1064	367
27		63	140.83	634	697	19710.00	1064	367
28		63	140.83	634	697	19710.00	1064	367
Total	1950	1586		15843	19379		26609	7230
NPV@15%	$1,677	$576	$1,278	$5,752	$6,432	$178,908	$9,661	$827
IRR								15%
Gas Price								4.50 $/MCF