REPORT

Of the

Committee

On

Natural Gas Pricing

December, 1996

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PREFACE

I am happy to enclose the Report of the Committee on Natural Gas Prices. I regret that the Report could not be done earlier due to reasons which are set out in Chapter - I of the Report.

The Report has two additional notes which are appended to the Report at Anneuxres - I & II. Shri B. Narasimhan, Chairman, BICP has proposed a different approach for computing prices and has suggested some lower prices for the producers and the transporters. The note by Shri Santosh Kumar, Joint Secretary, Ministry of Finance suggests a fuel oil parity price and a transition within three years to market driven prices. The Government may consider the Report with the notes appended while taking decisions on this Report.

I take this opportunity to place on record the cooperation given by the Members of the Committee in finalising the Report. Mention needs to be made of the very hard work put in by Shri Ardhendu Sen, Member Secretary, in trying to align the different views and in explaining computations. The Committee has also benefitted enormously by the assistance provided by Shri S.V. Nagarajan, Member, BICP.

T.L. Sankar
Chairman of the Committee

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LIST OF ABBREVIATIONS

1.	BCM	Billion Cubic Meters
2.	BICP	Bureau of Industrial Costs and Prices
3.	CIS	Commonwealth of Independent States
4.	FERC	Federal Energy Regulatory Commission
5.	GAIL	Gas Authority of India Limited
6.	HFC	Hindustan Fertilizers Corporation
7.	LNG	Liquefied Natural Gas
8.	LRAC	Long Run Average Cost
9.	LRMC	Long Run Marginal Cost
10.	MCM	Thousand Cubic Meters
11.	MGO	Minimum Guaranteed Offtake
12.	MMBTU	Million British Thermal Unit
13.	MMCM	Million Cubic Meters
14.	MMCMD	Million Cubic Meters per Day
15.	MOPNG	Ministry of Petroleum and Natural Gas
16.	OIL	Oil India Limited
17.	ONGC	Oil and Natural Gas Corporation
18.	RCF	Rashtriya Chemicals and Fertilizers Limited
19.	TEC	Tata Electric Company
20.	USD	United States Dollar

Reports referred to:

1. Kelkar Committee Report- Report of the Committee on Pricing of Natural Gas - May, 1990.

2. Sunderarajan Committee Report - Hydrocarbon Perspective : 2010 Meeting The Challenges - February, 1995

CHAPTER - I

INTRODUCTION

1.1 A Committee was set up to examine the changes required in the level and structure of prices of natural gas and to review the entire question of natural gas pricing by the Ministry of Petroleum and Natural Gas vide their Order No.L-12015/2/88-GP (Vol.III) dated January 28, 1995. A copy of the order is placed as **Annexure-III at** the end of the report.

1.2 The Committee consisted of:

i.	Shri T.L. Sankar Principal, Administrative Staff College of India, Hyderabad.	Chairman
ii.	Chairman, Bureau of Industrial Costs and Prices.	Member
iii.	Additional Secretary Ministry of Petroleum & Natural Gas.	Member
iv.	Adviser (Energy), Planning Commission.	Member
v.	Adviser (PAMD), Planning Commission.	Member
vi.	Joint Secretary (Exploration) Ministry of Petroleum & Natural Gas.	Member
vii.	Joint Secretary (Foreign Trade) Department of Economic Affairs Ministry of Finance.	Member
viii.	Executive Director Oil Coordination Committee	Member
ix.	Director (Natural Gas) Ministry of Petroleum & Natural Gas.	Convenor

1.3 During the tenure of this Committee the following functioned as members:

		From	To
i.	Shri T.L. Sankar Principal, Administrative Staff College of India.	Jan, 1995	Till date
ii.	Shri N. Biswas Chairman, Bureau of Industrial Costs & Prices.	Jan, 1995	Nov, 1995
iii.	Shri B. Narasimhan Chairman, Bureau of Industrial Costs & Prices.	Feb, 1996	Till date
iv.	Shri Javed Chowdhury Additional Secretary, Ministry of Petroleum & Natural Gas.	June, 1995	Jan, 1996
v.	Shri Prabir Sengupta Adviser (Energy), Planning Commission.	Apr, 1995	Till date
vi.	Dr. Udesh Kohli, Adviser (PAMD), Planning Commission	Jan. 1995	June,1995
vii.	Shri Najeeb Jung Joint Secretary (Exploration) Ministry of Petroleum & Natural Gas.	Jan, 1995	July,1995
viii.	Shri Sanjiv Misra Joint Secretary (Exploration) Ministry of Petroleum & Natural Gas.	Sept,1995	Till date
ix.	Shri Santosh Kumar Joint Secretary(Foreign Trade) Department of Economic Affairs Ministry of Finance.	Jan, 1995	Till date
x.	Shri D.C. Lahiri Executive Director, Oil Coordination Committee.	Jan, 1995	Aug, 1996
xi.	Shri S. Raha Executive Director, Oil Coordination Committee.	Sept, 1996	Till date
xii.	Shri A. Sen Director (Natural Gas) Ministry of Petroleum & Natural Gas.	Jan, 1995	Till date

The Committee was assisted by Shri U.K. De of GAIL till January, 1996.

1.4 It will be noticed that the Terms of Reference were extensive and they included the review of the current pricing policy and the principles on which the pricing is determined now, the assurances given to multilateral agencies regarding introduction of market related prices, the review of the needs of the existing consumer industries and the assurances given to the private sector developers of oil/gas fields, etc.

1.5 The Committee met 17 times in Delhi. The Committee heard the representatives of ONGC, OIL, GAIL on a number of occasions. The Committee also received the views and had interactions with user Ministries in the Government of India, State Governments and user industries. The names of the organisations met by the Committee are listed in **Annexure-IV**. The Committee also sent questionnaires to user Ministries and State Governments and received written comments from many of them. The help provided by these agencies is gratefully acknowledged. The Committee's work went beyond the time assigned and its life was extended by the Ministry of Petroleum and Natural Gas. This was done to facilitate the gas producing industries especially ONGC to provide information in the formats required. It was also partly due to the request made by ONGC to consider the production cost of the year 1995-96 which was more representative than the production costs of 1994-95.

1.6 The Committee is aware that this report will affect consumers, public sector producers and a large number of private industries who want to enter natural gas exploration and production as well as a larger number of potential users of natural gas as a fuel. As there will be a number of organisations connected with natural gas keen to examine this Report, we have attempted to make the Report "reader-friendly"; an attempt is made to spell out in simple terms as much of the details as possible on the various issues examined by the Committee and the various assumptions which have gone into the fixation of gas price.

CHAPTER- II

THE HISTORY OF NATURAL GAS PRICING IN INDIA

2.1 Supply of gas by Oil India Ltd (OIL) started in February 1959, in Assam, and by the Oil and Natural Gas Commission (ONGC) in Gujarat in December 1964. By the time ONGC started selling gas, OIL was charging a gas price of around Rs.9/MCM in the upper Assam region, the prices being exclusive of royalties, duties, etc. However, the price charged by ONGC was governed by the V K R V Rao award and was Rs.50/MCM exclusive of sales tax, royalty etc. This price was valid upto 31st March, 1971.

2.2 The price of gas for the period 1-4-1971 to 31-3-1976 was fixed by the award given by Shri Shriman Narayan, the then Governor of Gujarat and Shri P C Sethi, the then Minister of Petroleum. The price of gas under this award was fixed at Rs.66/MCM exclusive of royalty, sales tax and transportation charges. This award was valid upto 31-3- 1976.

2.3 It may be pointed out that the above awards were applicable for the supply of gas from Cambay and Ankleshwar in Gujarat.

2.4 Meanwhile, OIL had also renegotiated the price of gas with their consumers, and in the late 1960s, OIL was supplying gas at the rate of Rs.52.50/MCM, exclusive of taxes, duties and transportation charges. In 1969, ONGC started supplies in Assam and they too adopted the same price.

2.5 In the early 1970s, ONGC started supplying gas to new consumers at mutually negotiated prices. Thus, the prices varied from consumer to consumer. While the old consumers in Gujarat were governed by the prices given by the Shriman Narayan Sethi award, the negotiated prices with new consumers were in the range of Rs.115 to 135/MCM.

2.6 In 1974, ONGC took a decision to start charging new consumers or old consumers entering into new contracts, on the basis of thermal equivalence, based on coal. As a result, the price of gas rose further to Rs.210/MCM. Since the gas price was now linked to the price of coal, the price of natural gas kept rising as the price of coal rose from time to time. In 1977-78, the price rose to Rs.350/MCM, inclusive of royalty but exclusive of transportation charges.

2.7 In 1978, consequent to the commissioning of off-shore fields in the Western Offshore region, ONGC started supplying gas to consumers in the Uran region of Maharashtra. Here, from the beginning, ONGC adopted the principle of charging consumers on the principle of opportunity cost. The prices, therefore, varied from consumer to consumer and use to use. For example, for consumers like Tata Electric Company (TEC) and Rashtriya Chemicals & Fertilizers Ltd (RCF), which were power and fertiliser plants respectively, the prices varied not only amongst the two plants, but also within the same plant, if gas was used for different purposes. While TEC paid Rs.1170/MCM for the gas which was replacing coal, it paid Rs.2630/MCM for the gas that was replacing liquid fuels. Similarly, RCF paid prices varying from Rs.633 to Rs.3,438/MCM.

2.8 In 1979, the Government of India sought a study on gas pricing by the then Chief Cost Adviser, Dr. R Rajagopalan. He submitted his report in 1979, recommending gas prices of Rs.320/MCM for the tea industry, Rs.250/MCM for the Hindustan Fertilizer Corporation Ltd and other consumers, and Rs.185/MCM for the Assam State Electricity Board. These prices were also exclusive of royalties, taxes, etc., and the transportation cost. OIL adopted these prices for the supplies made by it in Assam. However, ONGC continued with the principle of thermal equivalence in determining prices of gas in the Assam region.

2.9 Having successfully implemented the principle of charging prices on the basis of opportunity cost in the Bombay region, ONGC took a decision on 1-1-1982 to adopt the same principle in case of consumers in Gujarat. As a result, since 1982, prices in Gujarat started varying from unit to unit, and within a unit, from use to use. The prices were in the range of Rs.2100 to 2500/MCM for fertilizer and other industries, and in the range of Rs.850/MCM in the case of power plants.

2.10 In 1986, a decision was taken that the price of natural gas would henceforth be fixed by the Government. In pursuance of this decision, the price of natural gas was fixed w.e.f. 30-1-1987 as follows:

i.	Off-shore gas at landfall point or on-shore gas	Rs.1400 / MCM
ii.	Transportation charges for gas sold along HBJ pipeline	Rs.850 / MCM
iii.	Gas sold in North-Eastern States	Rs.1000 / MCM (with a concession of Rs.500 / MCM on a case to case basis)

The prices were exclusive of royalty, all taxes, duties, etc.

2.11 The prices fixed by the Government of India in 1987 were challenged in the Gujarat High Court, which held that the prices fixed were reasonable. It may be noted that earlier, the Supreme Court had in a different case upheld ONGC's decision that they could charge gas prices at the replacement value.

2.12 In 1988, a decision was taken to set up a committee under the Chairmanship of Dr Vijay L Kelkar, Chairman - BICP, to go into the entire question of pricing. The Committee submitted its report in May 1990. The report of the Committee was considered by the Government and the price of natural gas was fixed as follows with effect from 1-1- 1992:

i.	Off-shore gas at landfall point and on-shore gas	Rs.1550/MCM with effect from 1-1-1992 to be increased each year by Rs.100/MCM till it reached Rs.1850/MCM
ii.	Transportation charges for gas sold along HBJ pipeline	Rs.850/MCM
iii.	Gas sold in Northern-States	Rs.1000/MCM (with a concession of Rs.400/ MCM on a case to case basis)

2.13 The prices were exclusive of royalty, tâxes, duties, etc. The producer price payable to ONGC was kept fixed at Rs.1500/MCM and the difference between the producer price and the consumer price was credited to the Gas Pool Account.

2.14 The present Gas Pricing Committee was constituted by the Government with a view to revise the above prices w.e.f. January 1, 1996.

2.15 The following table sets out the progressive movement of the price of natural gas in India, in different regions and for different purposes.

Table 2.1

Movement of Price of Natural Gas In India between 1959 & 1995 (Rs./MCM)

Date of Price Fixation	Regions	Sectors of Use	Price
1959	Assam (OIL)	All	9
1964	Gujarat (ONGC)	All	50
1969	Assam (OIL & ONGC)	All	52.50
1970	Gujarat (ONGC)	New Consumers	115-135
1971	Gujarat (ONGC)	All	66
1974	Gujarat (ONGC)	All	210
1977	Gujarat (ONGC)	All	350
1978	Maharashtra (ONGC)	Power	1170-2630
		Fertilisers	633-3438
1979	Assam (OIL)	Power	185
		Fertilisers	250
		Industries	320
1982	Gujarat (ONGC)	Power	850
		Fertilisers	2100-2500
1987	Assam (ONGC & OIL)	All	1000*
	Rest of India (ONGC)	All	1400+
1992	Assam (ONGC & OIL)	All	1000**
	Rest of India (ONGC & OIL)	All	1550-1850+

* There was also a provision for a discount of Rs.500/MCM.

** The above discount was reduced to Rs.400/MCM.

\+ The price was linked to calorific value. A 15% discount was allowed for interruptible supplies and for gas supplies from developing fields.

CHAPTER- III

NATURAL GAS IN INDIA

3.1 In India, natural gas is a relatively new entrant in the energy market. Until the development of the South Bassein gas field in the Western Off-shore region, most of the production was of associated gas, and its use was largely localised. Natural gas production was a mere 2.3 Billion Cubic Meters (BCM) during 1980-81. Of this 33% was flared. Production rose to 19 BCM in 1994-95, of which about 2 BCM (i.e. 10.5%) was flared. Of the 17 BCM utilised, 56% was for energy (mainly power generation) and 44% as feedstock for fertiliser production. In 1995-96, production was 22.6 BCM and the gas flared was only 1.4 BCM.

3.2 Maharashtra, Gujarat, Uttar Pradesh and Assam account for about 75% of the total consumption of gas in the country. Local distribution networks supplying to domestic consumers are confined to only four cities in Gujarat and a few towns and tea gardens in Assam. Total gas consumption in the domestic sector during 1994-95 was a meager 0.2 BCM representing only 1.25% of the total consumption. A city gas distribution project has, however, been started in Bombay which will be supplying gas to 600,000 households. In terms of the gas use policy adopted by the Ministry of Petroleum and Natural Gas, LPG and C_2/C_3 is extracted from natural gas before the lean gas is used as fuel or feedstock for the fertiliser industry.

3.3 India's recoverable gas reserves of about 707 BCM as on 1-4-1995 would sustain a level of production of 30 BCM for a period of about 23 years. Major reserves are located in South Bassein, Krishna-Godavari region, Tripura, Rajasthan and offshore areas of the Kutch basin.

3.4 Almost all activities relating to natural gas exploration, production, marketing and distribution are being presently carried out by public sector companies. While upstream activities (exploration and production) are carried out by Oil and Natural Gas Corporation Ltd (ONGC) and Oil India Ltd (OIL), midstream (pipeline transportation and ancillary functions) and downstream (local distribution) activities are being carried out by the Gas Authority of India Ltd (GAIL), OIL, the Gujarat Gas Company and the Assam Gas Company.

3.5 GAIL was formed in August 1984 with the objectives of transportation, distribution, fractionating, processing and marketing of natural gas. GAIL operates over 3600 Kms of pipeline in various parts of the country for transmission of natural gas from production/landfall points to the ultimate consumers.

3.6 The available gas is allocated by the Government of India based on the Imputed Economic Value of gas use and macro economic considerations. The power sector is the largest consumer of natural gas in the country followed by the fertiliser sector.

Demand-Supply Projections

3.7 Natural gas availability, from indigenous sources, is expected to go up from the current level of 18 BCM to a level of 28 BCM by 2001-2002. As against this, the demand registered with GAIL is approximately 96 BCM per annum. The materialisation of this demand is subject to several uncertainties including the comparative price of gas to the consumers at the burner tip vis-a-vis alternative fuels. However, it is certain that the demand for gas will far exceed supply from domestic sources. Since indigenous gas availability is not expected to go up in the short or medium term, the only way to augment gas availability is to import natural gas either through trans-national pipelines or in the form of LNG.

3.8 The geographical proximity of India to the Middle-East and South-East-Asia, both gas exporting regions, make the import of gas through pipelines attractive. The Government is currently pursuing proposals for the Oman and Iran pipeline projects.

Further, possibilities like a pipeline network linking Bangladesh, Burma and India are also being explored. Natural gas can also be transported in liquid form. This requires capital intensive installations at loading ports and at receiving terminals. Despite the high cost of LNG, this may be the only practical option for power generation specially in Southern India, if the production of domestic coal and other domestic energy resources do not increase in step with demand.

Policy initiatives

3.9 Faced with the growing demand for natural gas and limited domestic availability, the Government have taken a number of policy initiatives. The emphasis is on increasing the domestic availability through increased exploration and production. While the national oil companies will take the lead in this area, the Government is keen to involve the private sector also. To the extent that a gap will remain between the demand and the possible supplies from domestic sources, import of natural gas/LNG would be necessary. Here also, private initiative can supplement the efforts of the national oil companies. In order to attract private investment in domestic transportation of natural gas, the feasibility of installing a Regulator for the gas industry is being examined. To sum up, the policy initiative taken by the Government to meet the demand for Natural Gas have to address the following issues:

i. Enhancement of indigenous gas production;

ii. Meeting the demand by import of gas either by pipeline or in the form of liquefied natural gas (LNG);

iii. Development of pipelines including a national gas grid.

iv. Increased participation by public/private sectors to step up supplies.

v. Moving towards market determined prices; and

vi. Ensuring a level playing field for all players - private and public.

CHAPTER - IV

NATURAL GAS PRICING : INTERNATIONAL EXPERIENCE

4.1 Unlike crude oil, natural gas does not have an international price. The costs of transportation of gas over long distances is much higher. It has to be either transported through pipeline from the gas fields to the ultimate points of consumption or it has to be liquefied at the source and transported in specially constructed vessels and regassified at the user end. In the latter alternative huge investments are involved both for the liquefaction into LNG and the conversion to gas at the other end. These problems are further compounded by the problem of securing convergence of the needs of the seller and the buyer on a long term basis. The natural gas market systems remain fragmented. In most countries, gas consumption is limited to the local production. However, the three major natural gas consuming regions of the world namely USA, continental Europe and Japan import gas. In 1994 the total world gas production was 2,693 billion cubic metres.

4.2 In spite of the difficulties in natural gas transportation, international gas trade has been steadily increasing in volume. It has reached the level of 362.75 billion cubic metres in 1994 which is 13.5% of total hydrocarbon trade. Almost 25% of this is traded as LNG and the remaining 75% through pipelines. The major exporting countries are CIS, Russia, Canada, Netherlands, Indonesia, Argentina and Norway, while the major importing countries are USA, Germany, Japan, France and Italy. The natural gas major import-export details are in the following figure (Figure 4.1).

4.3 The three major markets namely USA, UK and Europe have their own history and characteristics. These are discussed below:

4.3.1 USA

In USA, natural gas prices were regulated by the Federal Energy Regulatory Commission (FERC) till 1985. Upto 1978, the price was kept very low and this inhibited investments in gas production and supplies fell far short of the possibilities. Between the years 1978 and 1985, gas price was set very high and potential customers were turned away from natural gas! Since 1985 the natural gas prices have been deregulated and the sellers and buyers settle the price through negotiations. There are over 10,000 gas producers in USA at present. Competition was intensified by declaring the gas pipelines as "public pathways". The open access system introduced in the gas pipeline, and the increased competition has steadily brought down the price. The prices to be charged for pipeline transportation is regulated by the Federal Energy Regulatory Commission (FERC) in the inter-state markets and by state Energy Regulatory Commissions in the case of intra-state markets. Gas prices have gradually come down from USD4.2 to between USD1.7 and USD2.17/MMBTU. (The Indian price as on 1-4-96 will be around 1.45/MMBTU at the landfall point and about USD2.1/MMBTU along the HBJ pipeline)*.

4.3.2 UK

In UK, the gas industry was a government monopoly till 1986. "British Gas" owned by the government had no competition and the price for the consumers were strictly controlled. In 1986, British Gas was privatised. Since then a number of competitors, though relatively small in size, have entered the market. The competitors settle the prices through negotiations except for the small consumers (called tariff consumers ,usually the domestic consumers). British Gas had the monopoly of supplying users of less than 2,500 therms per year but beginning this year, other suppliers are entering this market. As a result of the competition, general prices are low compared to the prices that existed during the monopoly regime. Encouraged by the then prevailing prices, British Gas had entered into a number of "take or pay" contracts for future supplies with producers of gas from the North Sea, at high prices.

This has become a heavy burden now and British Gas cannot afford to take up the supplies under these contracts. The Government of UK is taking active steps to get the North Sea producers who have such contracts to renegotiate them! The transportation charges over the pipeline are regulated through "price cap" regulation.

4.3.3 EUROPE

The European market has, till now, been conditioned by the exporting countries. The bulk of the European supplies of gas are obtained from the CIS and Norway. The national governments in Europe play a significant role in the price formation of natural gas. There is no attempt to change the existing procedure.

4.4 The price of natural gas in major centres over the last two decades from 1980 are set out in Table 4.1 in the next page:

Table 4.1

Evolution of Natural Gas Prices on the Major International Markets

(CIF Price - USD/million Btu)(1)

Year	Importing Country		
	United States(2)	Western Europe(3)	Japan
1980	4.42	3.0-3.7	5.01
1981	4.84	3.3-4.7	5.83
1982	4.94	4.1-5.2	5.74
1983	4.51	3.5-4.4	5.16
1984	4.08	3.5-4.2	4.90
1985	3.19	3.4-4.4	4.99
1986	2.53	3.2-3.6	3.98
1987	2.17	2.5-2.8	3.29
1988	2.00	1.9-2.5	3.22
1989	2.04	1.7-2.5	3.26
1990	2.03	1.8-2.5	3.60
1991	2.02	2.9-3.2	3.98
1992	1.97	2.4-2.8	3.61
1993	1.99	2.5-2.75	3.51
1994	1.71	2.3-2.6	3.17
Jan-1995	1.70	2.6-2.9	3.36

(1) Estimated import price (after regassification of LNG) (figures rounded off).

(2) Border price

(3) Mid-year price

Source: Natural Gas in the World, 1995 Survey.

4.4.1 General Trend in Prices:

As the Table 4.1 indicates, the price of gas in all the major markets has been steadily coming down except for some variations in the European market (for the obvious reason on account of fluctuations of supplies from the CIS). It is also seen that there is a trend for the natural gas price to be independent of the price of crude. This is due to the fact that the price of natural gas is fixed on negotiations on a long term basis. It is noteworthy that in all new contracts, gas prices are indexed to crude or other product prices like heavy fuel oil. One might see a more closer correlation between liquid fuel prices and natural gas prices in future. The prices shown in the table are the average price for the whole country. One could expect a fairly wide variation within the country depending on the landing place and the source of import. It is also the average of LNG and pipeline gas prices. It is noticed that LNG prices in each country are generally a little above the average prices for example, CIF price of LNG in USA towards end of 1995 varied between USD3.6 to USD4 per million BTU as compared to the average price of about half of that. The monthly prices within the yearly averages show large variations in countries where a significant part of the gas is used for domestic heating. In such cases the weather condition i.e., hot summer, or cold winter affects the demand and consequently the price. The price in India during 1985-90 has been considerably lower than international prices.

CHAPTER - V

ISSUES IN THE PRICING OF NATURAL GAS

5.1 The major issues considered by the Committee are:

i. Should administered pricing be continued beyond December, 1995?

ii. What should be the basis for fixing the price of Natural Gas?

a) Cost of production plus a reasonable return on investment OR

b) International parity price OR

c) With reference to prices of alternative fuels OR

d) Prices indexed to the administered price of some liquid petroleum product.

iii. Should the same price be fixed for all users or should there be differential pricing based on end-use, such as power generation, fertiliser production etc?

iv. How to reconcile the price fixed by the committee with other pricing arrangements separately agreed to by the Government of India?

v. Should a premium be paid for natural gas over the price of alternative fuels due to its environment-friendly nature?

vi. Should transportation charges be equalised over large transportation systems or should they be distance related?

vii. Should gas prices be nominated on thermal basis as against the current volumetric basis?

viii. Should the gas price be different for interruptible supplies and guaranteed supplies?

ix. What changes are required in the consumer supply specification in GAIL's contracts with its customers?

x. Should there be a guarantee fee for committed levels of supply demanded under Fuel Purchase Agreements by the Independent Power Producers?

xi. In case private developers are in a position to sell gas, should the prices be fixed by the Government?

xii. Should competition be encouraged in the transportation/distribution of gas?

5.2 Questionnaires on the above points were circulated to all State Governments and to the relevant Ministries/Departments of Government of India and Organisations representing the major consumers. Written replies were received from most of the addressees. Apart from that, oral presentations were made by the Ministries of Power, Chemicals & Fertilizers and the Governments of Assam, Gujarat and Tripura.

5.3 The issues listed above have been examined at the releant places in Chapter 6 & 7. A Summary of the points made by the various State Governments and Ministries are set out in the paragraphs below:

Views of State Governments.

i) **Andhra Pradesh:**

- Gas price should be linked to the prices of alternative fuels.
- Transportation cost should be distance related.
- Private gas producers be guided by the market mechanism..
- Competition be introduced in transportation/ distribution
- The State Government proposes to set up a transportation distribution company.
- A regulatory body should be set up.

ii) **Assam:**

- Administered price regime should continue, and gas price Should be Rs.600/MCM.
- The price of gas should not be linked to calorific value.
- Transportation cost should be distance related.
- Competition be introduced in transportation/ distribution
- A regulatory body should be set up.

iii) <u>Gujarat</u>:

- Transportation charges should be distance related on slab basis.
- Price of gas should be as follows:

Onshore	:	Coal equivalent
Existing Offshore	:	Present price
New fields to private parties	:	Cost plus

iv) <u>Himachal Pradesh</u>:

- Gas price should be administered
- Transportation cost should be equalised
- The State Government would not set up any company for transportation/ distribution
- Competition be introduced in transportation/ distribution
- A regulatory body should be set up.

v) <u>Karnataka</u>:

- Gas price should be related to alternative fuel
- Transportation cost should be equalised
- Government would not set up any company for transportation/ distribution
- A regulatory body should be set up
- Prices for private gas producers should be fixed by the Government.

vi) <u>Madhya Pradesh</u>:

- Gas price should be related to Short Run Marginal Cost.
- Transportation cost should be distance related
- Competition be introduced in transportation/distribution.
- A regulatory body should be set up
- Prices should be fixed by Government, even for private gas producers.

vii) Punjab:

- Gas price should be related to alternative fuel
- Transportation cost should be equalised
- Government would not set up any company for transportation/ distribution
- Competition be introduced in transportation/ distribution
- A regulatory body should be set up
- Prices for private gas producers should be fixed by the Government.

viii) Tripura:

- There are several distinct handicaps in the industrialisation of the State due to its remote location and high costs of transportation. In case natural gas is to be utilised to its full potential, natural gas prices should continue to be pegged at Rs.600/MCM for all new projects on the lines agreed to by the Government of India in the case of the Assam Gas Cracker.

5.4 The view of the Ministries of the Government of India are as follows:

i. Department of Chemicals & Petrochemicals:

- C_2/C_3 prices should be related to Naphtha price.
- Alternative fuel price linkage.

ii. Department of Fertilizers:

- Gas price be reduced
- Relate it to gas price in urea exporting countries or fix it by cost of production methodology.
- Do not collect pool contribution from fertilizer industry.
- Exploration and production should be funded from the Central plan outlay.
- Cost of gas should be a weighted average for offshore and onshore.
- Transportation cost be reduced.
- Increase depreciation period to 25 years.

- Link price to calorific value.
- Supply at an agreed pressure of 40-45 kg/cu.cm
- Include NG in declared item list (as per Kelkar Committee) to bring about uniformity of Sales Tax.
- Imported gas to be priced the same as domestic gas.
- Remove royalty from gas price.
- Concessional price for gas above the committed (contracted) quantity of gas.
- Penalty on GAIL for deviation in quality, pressure etc.
- Set up a Gas Pricing Authority.
- No premium to be charged on the gas price on account of gas being a clean fuel.
- Equalised transportation charges be continued.
- Price on thermal basis.

Contract:

- Penalty for non-supply be included.
- No MGO for first year of supply.
- Delivery pressure to be atleast 45 kg/cu.cm.
- Requirement of LC should be abolished.
- No commitment charges should be levied.
- Competition in transportation/distribution be introduced.
- Regulator should be appointed.

iii. Ministry of Power:

- Administered price be replaced by prices on reasonable return (on capital).
- Cross subsidies should be removed
- No premium over alternative fuel.
- Price be related to heat value.

- Equalised transportation cost. Exclusive lines to be owned by users after expected life of system.
- Different price for firm and fallback supplies be continued.
- System deficiency & transmission constraint of power producer be considered a Force Majeure condition.
- Contracts be negotiated between the supplier & consumer
- No guarantee fee. Penalty on non-supply be introduced.
- Private sector gas price be fixed on the same normative parameters as for public sector.
- Competition be introduced in gas transmission/ distribution.
- Regulatory body needed.
- No change in price linkage to volume.

5.5 The views of Industries & Industrial Organisations are:

i. <u>Gujarat Chambers of Commerce</u>:

- Gas price should have parity with coal.
- Price should be controlled.
- Transportation charges be distance related.
- Payment within 15 days (not 3 days).
- Private distribution.
- Price of natural gas be linked to calorific value. Band over which the price does not change with calorific value to be narrowed.
- Price be stable for 5 years and escalation linked to coal price.
- Royalty should be fixed amount and not a percentage of the gas price.
- Sales tax on uniform basis.
- Higher commitment to Gujarat for domestic and imported gas.

II. IPCL

- Continue administered price.
- Premium of 5% on natural gas for environmental factors.
- Transportation cost to be distance related.
- Price of gas on thermal basis.
- Existing differential for firm/fallback to continue
- No guarantee fee for continuous supply.
- Price to be fixed and regulated by Government.
- Competition in transportation/distribution be encouraged.
- Regulators be appointed.

CHAPTER - VI

COST OF PRODUCTION AND TRANSPORTATION OF NATURAL GAS IN INDIA

6.1 The costs of production and transportation of natural gas are important elements in the determination of the natural gas price. The price paid to natural gas producers such as ONGC and OIL and the transportation charge paid to GAIL must meet their costs and also provide a reasonable return to them on their investments. The Sunderarajan Committee* has estimated that the exploration and production sector of the petroleum industry alone would require investments of Rs.1,80,000 to 3,40,000 crores by the year 2010 AD. For resource generation of this magnitude, it is imperative that the industry gets the appropriate prices for crude oil and natural gas which includes adequate incentives to attract investment.

6.2 There are various ways of computing the cost of production and transportation of natural gas. The most appropriate from the national point of view is the calculation of the Long Run Marginal Cost (LRMC) or Long Run Average Cost (LRAC). If the LRMC, LRAC computation becomes problematic for want of adequate data, one could calculate the cost of production on the basis of the production costs of a new project, if it is seen to be a representative project, i.e., a project whose cost trends are likely to be observed in all other new projects. (The Kelkar Committee** in 1990 adopted the production cost of South Bassein as a representative cost configuration for gas production for the next five years). Natural gas producing companies, however, normally adopt a financial accounting method, setting out the expenditure and production benefits each year, as this helps in taking the normal managerial decisions and also helps in tax planning. ONGC and OIL follow this practice. BICP follows the same procedure while determining the "fair price" to be recommended to government.

* Hydrocarbon Perspective : 2010 Meeting The Challenges : February, 1995
** Report of the Committee on Pricing of Natural Gas - May, 1990

However, BICP makes certain corrections to the companies figures of expenditure and benefits by introducing certain normative assumptions regarding efficiency.

6.3 The observations of the Kelkar Committee on the different methods of computing costs succinctly brings out their relevance to the task of price fixation. The observations are summarised below:

a. In the Financial Accounting Method, annual expenditure includes expenditure on exploration and the income gives the benefit from sale of natural gas. There is, however, no deterministic correlation between expenditure incurred on exploration and the value of oil and gas reserves consequently discovered or produced in a particular year.

b. The quantity of oil and gas produced, the production life of the reserves and ultimate costs to be incurred may be subject to major variations over the life of a field. This leads to difficulties in correlating reserves proved and expenditure and reporting of financial results for a comparatively short span of time.

6.4 Having regard to the shortcomings of each of these procedures for computing the cost of production, we shall attempt to derive the cost of production and transportation under each of these methods and attempt to harmonise the results.

Cost Accounting System of ONGC & OIL

6.5 Both ONGC and OIL follow the internationally accepted "Successful efforts method" of accounting for determining the exploration and development costs. This method prescribes capitalisation of only those costs which relate directly to the discovery and development of commercially exploitable oil and gas reserves while general exploration costs including geological and geophysical survey costs, costs of exploratory wells determined to be dry, etc., are written off as revenue expense in the year in which these are incurred or when the wells are finally declared dry. The unit cost of production (i.e. cost per ton of crude oil and per 1000 cubic metres of natural gas) is compiled under the following major heads:

a. Operating costs
b. Recouped costs
c. Financing costs
d. Statutory levies

6.6 Operating Costs

Operating costs consist of the cost of manpower, stores and spares, repairs and maintenance, support services, pollution control, insurance, overheads, etc., and costs like workover operations, water injection etc., to the extent the same are related to the production activities. These also include the cost of transporting crude oil/natural gas through pipeline/tankers from the oil/gas collection stations to the refineries in case of oil and custody transfer points in case of gas.

6.7 Recouped Costs

Recouped cost comprises (1) expenditure on survey and dry wells, (2) depreciation on fixed assets deployed to maintain the producing fields and facilities; and (3) depletion of producing properties.

6.7.1 Survey Costs

Geological and geophysical survey costs including depreciation on assets deployed for survey, are booked as revenue expenditure in the year of incidence and included in Recouped Costs. Exploratory drilling cost including depreciation on assets deployed in exploratory drilling is initially capitalised as cost of exploratory wells-in-progress. If the well is determined to be dry, the related cost is charged to the profit and loss account in the year of such determination.

6.7.2 Depreciation

Depreciation on fixed assets viz., plant, equipment and other capital items is charged on the diminishing balance method by ONGC and on straight-line method by OIL at the rates prescribed under Schedule-XIV of the Companies Act, 1956. Depreciation on assets deployed in exploration and development activities is initially capitalised as part of activity cost and recovered over the years or written-off in the year's income depending on whether the activity proved successful or unsuccessful. Depreciation on assets deployed to maintain the producing fields and facilities are charged from the year of commissioning of the fields.

6.7.3 Depletion Costs

If exploratory efforts in an area prove successful and the hydrocarbon reserves in the area are categorised as proven, all accumulated exploratory drilling cost and development cost including depreciation on support equipments are capitalised as producing property. The capitalised producing property cost is recovered by following the depletion method. In this method, the unit rate is arrived at by dividing the balance cost of the property and the related production facilities by the proved developed balance recoverable reserves at the beginning of the year and the same is multiplied by the quantity of hydrocarbons produced to arrive at the amount of depletion for that year to be included in the Recouped Costs.

6.8 Financing Costs

Financing cost consists of interest and exchange loss/gain on repayment/revaluation of foreign loans. Exchange losses/gains relating to the loans/credits utilised for acquisition of fixed assets are capitalised to the relevant assets. Loss or gain due to exchange fluctuations relating to other loans/credits is charged to the profit and loss account. In other words, exchange rate fluctuations relating to loans taken for non-capital needs is charged to the profit and loss account of the year.*

6.9 Statutory Levies

Statutory charges include royalty, sales tax, turnover tax, cess, octroi and port trust charges. With the exception of turnover tax, the other levies are recovered from the consumers. In Maharashtra, turnover tax has been merged with sales tax from 1995-96 and would be recovered from customers in future.

6.10 Allocation of Joint Costs

While some of the operating expenses are directly identifiable with either crude oil or natural gas, most of the costs, particularly those incurred in fields producing associated gas, are joint costs. These common costs relating to crude oil and gas are allocated between the two products in the proportion of the actual quantum of production taking 1000 cubic metres of natural gas as equal to one metric ton (MT) of crude oil. This is based on the approximate thermal equivalence of the two products.

6.11 Determination of Unit Cost

For arriving at the cost per 1000 cubic metres of gas, the total cost attributed to gas is divided by the quantity of gas utilised (i.e., gas produced minus gas flared).**

* This practice is reported to be approved by the C&AG but could for purposes of tariff fixation create a problem as the devaluation would impact in a single year instead of over the years.

** No distinction is made between gas flared due to technical and unavoidable reasons and gas flared due to the gas utilising facilities not being set up in time.

6.12 The Calculation of Fair Price of Production by ONGC & OIL

At the request of the Committee, the BICP constituted an Expert Group to calculate the fair price of natural gas and the transportation charges along the HBJ pipeline based on the accounts furnished by ONGC/OIL and GAIL. The Expert Group examined the accounts of ONGC and OIL for 1994-95. At the request of ONGC, the Expert Group also agreed to calculate the production costs as per 1995-96 accounts, as significant new investments were made by ONGC in 1995-96. As OIL had no such investments, the production costs of 94-95 were taken as "representative" for OIL. **The production cost as estimated by ONGC for 1995-96 was Rs.2208/MCM and by OIL for 1994-95 was Rs.2607/MCM.**

6.13 1994-95 Production Costs

These costs have been computed by the Expert Group on the basis of the booked expenditure as per the published Annual Accounts for the year 1994-95 after appropriate adjustments for expenses relating to activities other than exploration and production of crude oil and natural gas. The common expenses relating to crude oil and gas have been allocated between the two products in proportion to the actual quantum of production taking 1000 cubic metres of gas as equal to 1 metric ton of crude oil as per the prevailing practice in this industry. The details of the cost of production including the capital related charges per MCM of gas on this basis for the year 1994-95 (in the case of ONGC, the figures have been prorated to 12 months) is given in the following table:

Table-6.1

Accounting Cost of Gas Production In 1994-95
BICP Expert Group

(Rs./MCM)

		ONGC	OIL
Production (MMCM)		14710	1048
I.	Cost of Production		
i.	Operating cost	275	565
ii.	Recouped cost	479	589
iii.	Exchange Loss/Gain	224	-58
	Total	978	1096
II.	Calculation of Return on Capital Employed		
A.	Capital employed		
i.	Average Net Fixed Assets	1759	2060
ii.	Working Capital	170	187
iii.	Average Producing Properties	1609	1813
	Capital Employed	3538	4060
B.	Financed by:		
	a. Debt	(46%) 1646	(20%) 812
	b. Equity	(54%) 1892	(80%)3248
C.	Return on Capital Employed		
	a. Interest on debt @	(10%) 165	(11.4%) 93
	b. Return on equity @ post tax	(15%) 498	855
	Total	663	948
III. Calculation of Fair Price			
i. Cost of production		978	1096
ii. Return on Capital Employed		663	948
Fair Price		1641	2044

6.14 To assess the fair price of natural gas, interest and return on capital employed have been added to the cost of production. Capital employed consists of net fixed assets (NFA), working capital and net producing properties (NPP). Average NFA and average NPP have been taken as given by the respective companies for the accounting year 1994-95. Working capital has been taken as equivalent to three months cost of sales excluding depreciation and depletion. The capital employed has been divided on the basis of debt-equity ratio of the companies based on the Annual Report for the year 1994-95. Interest on loans has been provided at the average rate of 10% in case of ONGC and 11.4% in case of OIL as worked out for the year 1994-95. For making tax provision, the current rate of tax @ 40% plus surcharge @ 7.5% thereon has been adopted.

6.15 Cost of Production of Gas by ONGC 1995-96

The cost of production of gas has been computed on the basis of expenditure booked as per the audited Annual Accounts for the year 1995-96 after carrying out appropriate adjustments of expenses relating to the past period e.g., arrears of pay revision or activities not related to oil/gas production. These costs were normalised by critically examining the appropriateness of booking the amounts in one year towards cost of production of gas for that year. Costs of production as furnished by ONGC and as adopted by the Expert Group and the fair price for 95-96 assessed by the Expert Group are given in the following tables :

Table 6.2

Estimated Cost of Production of Gas for ONGC in 1995-96

(Rs./MCM)

	Actuals	Reported by ONGC	Estimated by Expert Group
	Production (MMCM)	18330	18330
a.	Operating Cost	314	301
b.	Recouped Cost		
	Depreciation	217	134
	Depletion	169	169
	Expenditure on Surveys & Dry Wells	335	238
	Sub-Total	721	541
c.	Exchange loss during the year	3	3
d.	Deferred Exchange Loss	59	39
e.	Turnover tax	21	21
	Cost of Production	1118	905

Table-6.3

Calculation of Fair Price of Gas by the Expert Group

(Rs./MCM)

A.	Capital Employed	
a.	Average Net Fixed Assets	1763
b.	Average Producing Properties	1502
c.	Working Capital	136
	Capital Employed	3401
B.	Financed by:	
	a. Debt (42.2%)	1435
	b. Equity (57.8%)	1966
C.	Return on Capital Employed:	
	a. Interest on debt @ 10% (Average rate)	143
	b. Return on equity @ 26.32% pre-tax (post tax 15%)	517
	Sub-Total (C)	660
II.	Calculation of Fair Price	
i.	Cost of Production	905
ii.	Return on Capital Employed	660
	Fair Price	1565

6.16 **Thus the fair price assessed by the Expert Group for gas production by ONGC was Rs.1641/MCM based on 94-95 accounts and Rs.1565/MCM based on 95-96 accounts.** The producer price allowed from 1986 to date for ONGC is Rs.1500/MCM. ONGC in a detailed note has set out several reasons for reassessing the fair price as calculated by the Expert Group. The complete notes on assessing the fair price by the Expert Group are given in the Appendix at page No.1 and the comments of ONGC on the same are given in the Appendix at page No.27.

6.17 Having considered the report of the Expert Group and the points raised by ONGC, the Committee identified a number of issues which needed resolution. These are discussed below:

i. **Return on Investment:**

The Expert Group has examined ONGC's claim for a return of 15% (post-tax) on capital employed on account of the high-risk exploration and development that has to be carried out by ONGC. **The gas price calculated using the Expert Group methodology along with a 15% post-tax return on the capital employed comes to Rs.1800/MCM.** The Expert Group has not agreed to this rate of return on investment on the ground that expenditure incurred on surveys and dry wells are separately taken care of. It was also pointed out to the Committee that allowing a 15% post-tax return on capital employed implies the computation of a tax on the interest payment which being an expenditure item is not taxable. The Committee, however, noted that the Government has allowed a return of 15% post tax on the capital employed for calculating the crude oil price. This return is allowed irrespective of the debt equity ratio.

ii. **The ICP-Heera trunkline:**

The Expert Group has not included the ICP-Heera pipeline for the purpose of calculating the gas production cost for 95- 96 on the ground that this is a standby facility which has not been put to use in 95-96. ONGC has represented that the ICP-Heera pipeline has been laid after obtaining the approval of the supreme decision making body viz., the Cabinet Committee on Economic Affairs (CCEA), which considered the issue of security of transportation of gas from the Western Off-shore. Under-utilisation of this pipeline in a particular year does not justify its exclusion for the purpose of calculating the depreciation or the return on capital employed. At the suggestion of the Expert Group, the Committee examined the note approved by CCEA.

It was noted that the ICP-Heera Trunkline was approved with the following objectives:viz.

i. It will provide additional transportation facilities from offshore to onshore, thereby bringing down flaring of gas.

ii. It will provide an early contingency response capability in case of failure/repair etc. of the existing Bombay High to Uran oil/gas pipeline.

iii. By enhancing gas transportation capacity to Uran, it will facilitate optimal utilisation of gas processing capacity at Uran.

As the notes reveal that ICP Heera pipeline was more as a stand by, it was, therefore, decided to agree with the views of the Expert Group and to exclude the ICP-Heera line in the computation of the production cost of gas for 1995-96.

iii. **Foreign exchange loss:**

ONGC has claimed that losses due to fluctuations in the foreign exchange rate on the loans taken by ONGC in 91-92 be allowed as a cost. These loans were taken by the ONGC at the instance of the Government and not for any specific project. The Expert Group has calculated the incidence of this loss in 95-96 as Rs.42/MCM but has observed that exchange loss is not normally treated as part of cost of production. The Committee has examined the point carefully and is inclined to agree with the views of the Expert Group that this loss be excluded.

iv. **Turnover tax:**

ONGC has informed that turnover tax has been merged with sales tax w.e.f. October 1995 in the State of Maharashtra and hence is now recoverable from consumers. In other States viz., Gujarat, Tripura and Tamil Nadu, turnover tax is levied at the rate of 2.0%, 0.5% & 2.5% respectively on the aggregate of the basic price and royalty. The weighted average impact of turnover tax works out to 1.45% of the existing producer price of gas for the year 1995-96 excluding Maharashtra. At this rate, the impact of turnover tax works out to Rs.21/MCM. The Expert Group has left it to the Committee to take a view on whether this will be an allowable cost item or not. The Committee has considered this point. The amount involved is small and it may be quite some time before the other states introduced the VAT as Maharashtra has done. The Committee has therefore allowed this cost but would like to suggest that when more States convert turnover tax to sales tax this element of cost allowed could be deleted by adjusting it against the inflation allowance proposed under para 7.32.

6.18 Long Run Average Cost

Another approach to determine the cost of production would be to compute the Long Run Average Cost. The Kelkar Committee adopted, for this purpose, the cost of one particular field, namely South Bassein, as it was the last major oil/gas field then developed by the ONGC and was considered as a representative field owing to its large size. In 1996, this Committee found that most of the new investments are on small fields and a substantial capital investment is proposed to be made to restore the Bombay High structure and bring up the decreasing production. The Committee, therefore, proposed that the LRAC for ONGC now may be calculated as follows:

i. Take the net fixed assets of the ONGC as per the books on 1996 as the base;

ii. Project the expenditure flow for ONGC for the next 20 years by the summation of all the items of expenditure proposed year-wise from 1996-97 onwards as per the project reports of new fields and as per the best estimates of ONGC with regard to the major replacements in the existing projects;

iii. On the benefit-side year-wise gas production from each field would be summed up;

iv. The two streams would be subjected to a net present value assessment by using a discount rate of 15% and;

v. Cost per unit of natural gas could be calculated.

6.19 The appropriateness of this method was discussed in detail. It was explained that irrespective of the depreciation allowances permitted so far on the existing fixed assets of ONGC, the book valuation of the assets can be taken as the fair value at which a new buyer would be willing to take over the assets. In fact, if the market perceptions are considered one could say the book value of the assets of ONGC are conservative estimates of the assets. After that the projecting of the costs and benefits was exactly as done by the Kelkar Committee in assessing the LRAC for South Bassein which was acceptable in fixing the natural gas price in 1992. However, the Committee considered the importance in any such computations of carefully assessing the year-wise expenditure flows from now on different fields and also the anticipated production. The ONGC was made to recheck this expenditure items and the production items. This was done. In all such procedures, the best assessment can only be what is made without any bias by the organisation concerned.

6.20 **The result of the analysis shows that the cost of natural gas would be Rs.1854/MCM.** The results are given in Table 6.4 :

Table 6.4

LONG RUN AVERAGE COST OF OIL & OIL EQUIVALENT OF GAS

Sl. No.	Year ending 31st March	Cash out flow (Rs. in Crores) CAPEX	Prod.Prop Dev.Drill	Opex	Total	Quantity (MMMT) Oil	OEG	Total
Open Bal. as on 1.4. 96		10772.46	10932.41		21704.87			
Less:JVC		237.24	515.69					
Less LPG/C2-C3 etc		143.40						
Net Op.Balance		10391.82	10416.72		20808.54			
1	1997	1441.01	697.11	2269.00	4407.12	27.74	18.50	46.24
2	1998	2246.15	744.01	2172.00	5162.16	26.35	19.26	45.61
3	1999	3133.15	701.50	2240.00	6074.65	26.69	20.51	47.20
4	2000	2728.25	831.71	2118.00	5677.96	27.60	20.58	48.18
5	2001	1143.42	945.86	2298.00	4387.28	28.39	20.65	49.04
6	2002	582.29	1113.75	2421.00	4117.04	28.39	21.38	49.77
7	2003	572.60	500.00	2614.68	3687.28	27.25	20.09	47.34
8	2004	1132.60	525.00	2771.56	4429.16	25.78	19.05	44.84
9	2005	1272.60	551.25	2937.85	4761.70	24.63	18.40	43.03
10	2006	715.72	578.81	3114.13	4408.66	23.11	17.85	40.96
11	2007	572.60	607.75	3300.97	4481.33	21.59	17.23	38.82
12	2008	572.60	638.14	3499.03	4709.77	20.34	16.75	37.09
13	2009	572.60	670.05	3708.97	4951.62	19.05	15.97	35.01
14	2010	572.60	703.55	3931.51	5207.66	17.96	15.64	33.60
15	2011	572.60	738.73	4167.40	5478.73	22.14	15.42	37.56
16	2012	572.60	775.66	4417.45	5765.71	18.97	15.09	34.06
17	2013				0.00	0.00	0.00	0.00
18	2014				0.00	0.00	0.00	0.00
19	2015				0.00	0.00	0.00	0.00
20	2016				0.00	0.00	0.00	0.00
	Total	28795.21	21739.61	47981.56	98516.38	385.98	292.38	678.36
	NPV @ 15%				43214.82			233.01
	Cost Rs.per 1000 M3					1854.63		

DETAILS OF CAPEX 1996-97 TO 2001-02

(Rs. in Crores)

Name of Project/Scheme	1996-97	1997-98	1998-99	1999-00	2000-01	2001-02	Remarks
1. L II Development	7.57						CCEA approved
2. LIII Development	18.86						CCEA approved
3. Neelam	4.80						CCEA approved
4. Heera Ph.II	71.04						CCEA approved
5. HSA/HSB	27.05						CCEA approved
6. SBHT,GSP III & BE P/F	185.78						CCEA approved
7. ICP Heera Pipelines	3.76						CCEA approved
8. B-121/119	74.09						CCEA approved
9. B-173 A	37.40						CCEA approved
10. S1 Sand	2.38						CCEA approved
11. B-131,B-57,BH-22,25	7.23						CCEA approved
12. PBDE	8.12						CCEA approved
13. BPA/BPB Upgradation	23.75						CCEA approved
14. Dev. of B-55	.2.39	74.53	149.48	44.31			CCEA approved
15. Heera Ph.III	81.37	300.45	64.91				CCEA approved
16. Booster Compressor		378.00	630.00	252.00			DFR submitted to Govt. & circulated to appraisal agencies
17. Neelam Gas Lift		218.40	141.60				FR prepared;to be approved by Board
18. BH Additional Dev.		160.00	1240.00	1440.00	360.00		FR for BH North portion prepared & being submitted to Govt. Concurrent Board approval being obtained. For South portion FR under preparation.
19. Dev. of C-24		50.00	114.17				FR under prepn.
20. BS-12/BS-13				30.00	50.00		FR under prepn.
21. Dev.of WO-15/16				30.00	80.00	50.00	FR under prepn.
22. Gandhar Ph.II	77.03	25.67	52.00				CCEA approved
23. Balol	37.43	63.70					CCEA approved
24. Santhal	24.76	128.70	56.60	21.90			CCEA approved
25. Lanwa Insitu		0.50	95.00	150.00	4.50		Pilot under implementation. FR to
26. Becharaji		0.50	30.00	40.00	4.50		be finalised thereafter.
27. Dev.of new Structures				30.00	80.00	50.00	
28. Steam Inj. Lanwa		5.00	10.00	10.00	20.00	5.00	Items costing less than
29. Other Misc. Capital	649.20	792.83	505.65	636.86	498.27	429.05	Rs.50 crores each - Within
30. R&D	97.00	47.87	43.74	43.18	46.15	48.24	ONGC's powers
Total CAPEX	1441.01	2246.15	3133.15	2728.25	1143.42	582.29	

TABLE 6.4 CONTD

DETAILS OF CAPEX 1996-97 TO 20001-02

(Rs. in Crores)

Name of Project/Scheme	1996-97	1997-98	1998-99	1999-00	2000-01	2001-02
1. L II Development	7.57					
2. LIII Development	18.86					
3. Neelam	4.80					
4. Heera Ph.II	71.04					
5. HSA/HSB	27.05					
6. SBHT,GSP III & BE P/F	185.78					
~~7. ICP Heera Pipelines~~	~~3.76~~					
8. B-121/119	74.09					
9. B-173 A	37.40					
10. S1 Sand	2.38					
11. B-131,B-57,BH-22,25	7.23					
12. PBDE	8.12					
13. BPA/BPB Upgradation	23.75					
14. Dev. of B-55	2.39	74.53	149.48	44.31		
15. Heera Ph.III	81.37	300.45	64.91			
16. Booster Compressor		378.00	630.00	252.00		
17. Neelam Gas Lift		218.40	141.60			
18. BH Additional Dev.		160.00	1240.00	1440.00	360.00	
19. Dev. of C-24		50.00	114.17			
20. BS-12/BS-13				30.00	50.00	
21. Dev.of WO-15/16				30.00	80.00	50.00
22. Dev.of new Structure				30.00	80.00	50.00
23. Gandhar Ph.II	77.03	25.67	52.00			
24. Balol	37.43	63.70				
25. Santhal	24.76	128.70	56.60	21.90		
26. Lanwa Insitu		0.50	95.00	150.00	4.50	
27. Steam Inj. Lanwa		5.00	10.00	10.00	20.00	5.00
28. Becharaji		0.50	30.00	40.00	4.50	
29. Other Misc. Capital	649.20	792.83	505.65	636.86	498.27	429.05
30. R&D	97.00	47.87	43.74	43.18	46.15	48.24
Total CAPEX	1441.01	2246.15	3133.15	2728.25	1143.42	582.29

TABLE 6.4 CONTD.

DETAILS OF QUANTITIES OF OIL & GAS CONSIDERED FOR
CALCULATION OF LRAC OF OIL & OEG

Year ending 31st March	Crude Oil (MMMT) Produ-ction	Supplies (95%)	Natural Gas Prodn. (MMSCMD)	Prodn. (BCM)	Supply (BCM)	(+)Inter. consump. (BCM)	Total Gas
1997	29.20	27.74	62.50	22.81	17.00	1.50	18.50
1998	27.74	26.35	62.75	22.90	17.76	1.50	19.26
1999	28.09	26.69	63.80	23.29	19.01	1.50	20.51
2000	29.05	27.60	65.39	23.87	19.08	1.50	20.58
2001	29.88	28.39	65.19	23.79	19.15	1.50	20.65
2002	29.88	28.39	63.34	23.12	19.88	1.50	21.38
2003	28.68	27.25	62.79	22.92	18.59	1.50	20.09
2004	27.14	25.78	59.28	21.64	17.55	1.50	19.05
2005	25.93	24.63	57.08	20.83	16.90	1.50	18.40
2006	24.33	23.11	55.22	20.16	16.35	1.50	17.85
2007	22.73	21.59	53.12	19.39	15.73	1.50	17.23
2008	21.41	20.34	51.52	18.80	15.25	1.50	16.75
2009	20.05	19.05	48.86	17.83	14.47	1.50	15.97
2010	18.90	17.96	47.76	17.43	14.14	1.50	15.64
2011	23.31	22.14	47.01	17.16	13.92	1.50	15.42
2012	19.97	18.97	45.89	16.75	13.59	1.50	15.09
2013		0.00					
2014		0.00					
2015		0.00					
2016		0.00					
Total	406.29	385.98	911.50	332.70	268.38	24.00	292.38

LONG TERM PRODUCTION POTENTIAL - CRUDE OIL (MMT).

YEAR	B R B C FIELDS									WRBC	ERBC	SRBC		Total
	BH	A2H	Neelam	Heera	South Heera	B-173A	B119/ B121	Condensate	Total BRBC	Cambay	Assam	Cauvery	Krishna Godawari	ONGC
1996-97									0.00				0.00	0.00
1997-98	10.77	—	2.45	1.71	1.12	0.11		2.00	18.16	6.88	2.46	0.20	0.04	27.74
1998-99	9.88	—	2.47	2.40	1.05	0.43		2.00	18.24	7.06	2.60	0.16	0.03	28.09
1999-00	9.08	1.47	2.32	2.64	1.00	0.39		2.00	18.90	7.26	2.70	0.16	0.03	29.05
2000-01	8.47	2.94	2.20	2.61	0.95	0.24		2.00	19.42	7.30	2.84	0.15	0.03	29.74
2001-02	8.03	3.92	2.09	2.38	0.91	0.13		2.00	19.46	7.36	2.90	0.14	0.02	29.89
2002-03	7.53	3.92	2.01	2.27	0.91	0.08		2.00	18.72	7.08	2.72	0.14	0.02	28.68
2003-04	7.28	3.53	1.88	1.95	0.91		0.07	2.00	17.62	6.82	2.55	0.13	0.02	27.14
2004-05	6.90	3.25	1.75	1.71	0.91		0.08	2.00	16.61	6.79	2.39	0.12	0.02	25.93
2005-06	6.52	3.00	1.75	1.71	0.61		0.03	2.00	15.62	6.29	2.23	0.12	0.02	24.33
2006-07	6.14	2.74	1.62	1.46	0.61			2.00	14.57	5.89	2.15	0.11	0.01	22.73
2007-08	5.76	2.48	1.49	1.22	0.61			2.00	13.56	5.73	2.00	0.11	0.01	21.41
2008-09	5.38	2.22	1.48	0.98	0.61			2.00	12.67	5.40	1.87	0.10	0.01	20.05
2009-10	5.13	2.09	1.35	0.98	0.60			2.00	12.15	4.89	1.75	0.10	0.01	18.90
2010-11	4.89	1.96	1.35	0.97	6.00			2.00	17.17	4.40	1.63	0.10	0.01	23.31
2011-12	4.40	1.78	1.21	0.97	6.00				14.36	3.96	1.54	0.10	0.01	19.97
2012-13									0.00				0.00	0.00
2013-14									0.00				0.00	0.00
	106.16	35.31	27.42	25.96	22.82	1.38	0.18	28.00	247.23	93.11	34.38	1.94	0.29	376.95

LONG TERM PRODUCTION POTENTIAL - GAS (MMSCMD)

YEAR	B R B C FIELDS													WRBC	ERBC	SRBC		CRBC	Total
	BH	ABH	Neelam	Heera	S.Heera	SI Sand	LII/LIV	C-24	B119/ B121	B-55	Bassien	Other B-Fields	Total BRBC	Cambay	Assam	Cauvery	Krishna Godawari	Tripura	ONGC
1996-97													0.000						0.00
1997-98	10.620		1.950	0.745	0.412	3.350	0.500				30.000		47.577	10.08	1.66	0.25	2.28	0.90	62.75
1998-99	9.260		1.930	1.066	0.408	3.350	0.750		1.500		30.000		48.264	10.330	1.750	0.25	2.310	0.90	63.8[illegible]
1999-00	7.970	1.240	1.730	0.983	0.330	3.350	1.600	0.850	1.500	2.640	28.000		50.193	9.790	1.900	0.25	2.360	0.90	65.[illegible]
2000-01	6.890	2.300	1.650	0.976	0.315	3.758	1.600	0.850	1.500	2.640	28.000		50.479	9.260	1.930	0.25	2.370	0.90	65.1[illegible]
2001-02	6.400	3.000	1.560	0.931	0.298	3.423	1.000	0.850	1.230	2.640	27.000	0.500	48.832	9.050	1.940	0.25	2.370	0.90	63.3[illegible]
2002-03	6.000	3.000	1.500	0.800	0.300	3.099	1.300	0.850	0.330	2.640	27.000	1.000	47.819	8.280	1.840	0.25	3.000	1.600	[illegible]
2003-04	5.800	2.700	1.400	0.700	0.300	2.731	1.300	0.850	0.030	2.640	25.000	1.500	44.951	7.730	1.750	0.25	3.000	1.600	59.[illegible]
2004-05	5.500	2.500	1.300	0.700	0.300	2.731	1.200	0.850	0.106	1.451	25.000	1.500	43.138	7.430	1.660	0.25	3.000	1.600	57.[illegible]
2005-06	5.200	2.300	1.300	0.600	0.200	2.196	1.200	0.850	0.291	1.112	25.000	2.000	42.249	6.520	1.600	0.25	3.000	1.600	55.2[illegible]
2006-07	4.900	2.100	1.200	0.500	0.200	1.996	1.200	0.750		0.812	25.000	2.000	40.658	6.080	1.530	0.25	3.000	1.600	53.1[illegible]
2007-08	4.600	1.900	1.100	0.400	0.200	1.483	1.000	0.600		0.610	25.000	2.000	38.893	5.570	1.460	0.25	3.000	2.350	51.5[illegible]
2008-09	4.300	1.700	1.100	0.400	0.200	0.758	1.000	0.200			25.000	2.000	36.658	5.210	1.390	0.25	3.000	2.350	[illegible]
2009-10	4.100	1.600	1.000	0.400	0.200	0.758	1.000				25.000	2.000	36.058	4.780	1.320	0.25	3.000	2.350	[illegible]
2010-11	3.910	1.500	1.000	0.400	0.200	0.758	1.000				25.000	2.000	35.768	4.390	1.250	0.25	3.000	2.350	[illegible]
2011-12	3.520	1.360	0.900	0.400	0.200	0.758	1.000				25.000	2.000	35.138	3.950	1.200	0.25	3.000	2.350	[illegible]
2012-13													0.000						0.00
2013-14													0.000						0.00
	88.970	27.200	20.620	10.001	4.063	34.499	16.650	7.500	6.487	17.185	395.000	18.500	646.675	108.450	24.180	3.75[illegible]	41.690	24.250	847.[illegible]

NOTES :

1. Opening capex represents aggregate of net fixed assets, capital works-in-progress, advances for capital works and capital items on stock as per balance sheet of ONGC as on 31.3.1996.
2. Opening balance of producing property is as per balance sheet of ONGC as on 31.3.1996.
3. Capital additions, development drilling and opex for 1996-99 is as per ONGC's draft Revised estimates - 1996-97 for ONGC.
4. Capex, development drilling and Opex for the period 1997-98 to 2001-02 is as per draft IX Plan (Base Case).
5. While most of the major projects would have been completed by the terminal year of the IX Plan, for the period beyond IX Plan, there would be some miscellaneous capital expenditure requirements like Compressors, Group Gathering Stations, Flow Lines, Central Tank Farm, Gas Collecting Stations etc. falling within the powers of ONGC and beyond. This has been estimated taking the average expenditure on this account proposed for the IX Plan period i.e Rs. 572.60 crores. Capex for Booster Compressor Plant Phase - II has been added which is ;- 2003-04 Rs. 560 crores, 2004-05 Rs. 700 crores and 2005-06 Rs. 143.12 crores.
6. Development drilling would be required beyond IX Plan period in Onshore areas. This expenditure on this account for the period beyond IX Plan has been estimated taking expenditure for 2001-02 as the base and escalating the same @ 5% p.a.
7. Opex for the period falling beyond IX Plan has been estimated taking estimated expenditure for 2001-02 as the base and escalating the same by 8% p.a.
8. Details of expenditure in respect of major schemes for the period 1996-97 to 2001-02 are enclosed.
9. Quantity of oil and gas for the period are based on RE 1996-97 and draft IX Plan (base case). For the period beyond IX Plan, best estimates of production profiles have been made through extrapolation and keeping in view World Bank estimates for gas supplies from Western Offshore.
10. Costs do not include expenditure on Survey and exploratory drilling.

6.21 The recommended cost of production

As seen above, we have four costs of production of gas per 1000 M^3:

1.	ONGC Assessment	Rs.2208/MCM.
2.	Expert Group	Rs.1565/MCM (for 1995-96)
3.	Expert Group price modified with 15% (post-tax) return on capital employed in place of 15% (post-tax) return on equity:	Rs.1800/MCM
4.	DCF Method of LRAC	Rs. 1854/MCM

6.22 Each of the four methods have some shortcomings. The ONGC's initial assessment uses the discounting procedure for computing LRAC, but has included depreciation as cost. This is not acceptable at least for purposes of estimation of cost of production of gas.

6.23 The financial accounting method used by the Expert Group takes the expenditure of a particular year and the production in that year as the basis. As pointed out in the Kelkar Committee report there is no deterministic relationship between expenditure and the benefits arising in a particular year. Unlike the fertiliser and chemical industry where, given a production facility of a particular size and good management, the output is predictable, in the mineral industry, especially oil exploration and production, there are enormous uncertainties and it will not be appropriate to go on the basis of any single year's estimate for fixing the price. The Expert Group study itself shows that the year to year variation are very large whatever be the course. The method also involves inclusion and exclusion of items of expenditure which become arguable. The LRAC method adopted by the Committee also has limitations especially arising out of the initial value of assets and the precise estimate of the stream of expenditure and benefits. The Committee felt that the appropriate course would be to take all the results of the various methods into account and arrive at a value which should be reasonable from the point of view of consumer as well as the producer. Noting the close correspondence of the values calculated with a 15% post-tax return on capital employed and the LRAC, **the Committee considers that Rs.1800/MCM could be taken as the fair price for gas produced in the next 5 years. It represents a 20% increase over Rs.1500/MCM which is the producer price fixed 5 years back.**

THE COST OF TRANSPORTATION OF GAS ALONG THE HBJ PIPELINE

Actual Cost of Transporting Gas through Existing HBJ Pipeline

6.24 The Expert Group has computed the cost of transportation of gas along the HBJ pipeline based on the audited accounts of GAIL. A summary of the cost for the years 1992-93, 1993-94 and 1994-95, is given in the following table:

Table-6.5

Transportation cost along the existing HBJ pipeline
Expert Group

Year	1992-93	1993-94	1994-95
Installed Capacity : 18.2 MMCMD or 6643 MMCM per annum			
Gas through put (in MMCM)	4979	5454	5284
Capacity Utilisation	75%	83%	80%
Gas Sold (in MMCM)	4894	5371	5204

Particulars		Cost per Unit (Rs/MCM)		
1.	Salaries & Wages	18.72	18.55	24.75
2.	Utilities	33.25	26.95	31.95
3.	Stores & Spares	8.68	11.80	13.07
4.	Repairs & Maintenance	6.19	9.96	11.06
5.	Depreciation	433.27	376.67	382.27
6.	Administration & others	24.70	26.82	40.25
7.	Total (1 to 6)	524.81	470.73	503.95
8.	Interest	182.24	151.26	128.57
9.	Total Cost (7 + 8)	707.05	621.99	632.52
10.	Expenses Transferred to CWIP	-3.09	-0.23	-
11.	Total Cost of Trans (9-10)	703.96	621.76	632.52

6.25 The Expert Group has further estimated the transportation cost for 1996-97 and 1997-98 as Rs.576/MCM and Rs.522/MCM. respectively. The downward trend in the cost as calculated by the Expert Group is explained by the decreasing capital charges in this method as the system has been in operation for 9 years. It is also seen from the figures for the three years considered by the Expert Group that the interest gets reduced over the years. In the initial years from 1987 when the pipeline went into operation, the gas transported was much short of the planned quantity due to demand deficiency. The actual costs were also higher due to higher interest payment. GAIL has suffered as a consequence. It needs to be mentioned that the current rate allowed to GAIL is Rs. 850/MCM. GAIL have separately represented that, in view of the actual pipeline throughput being much lower than was assumed for working out the transportation cost, it is entitled to a higher rate of transportation charge for the past period. The Committee has taken into consideration all factors and decided that the issue of transportation cost of GAIL (i.e. Rs. 850/MCM) for the existing HBJ pipeline for the past period need not be reopened and should be continued for the period covered by this report.

6.26 HBJ Upgradation Project

The present HBJ gas pipeline system was designed and commissioned during 1987-89 to transport 18.2 MMCMD of natural gas. The pipeline capacity is now being enhanced from the existing 18.2 to 33.4 MMCMD. The proposal envisages enhancing the capacities of existing compressor stations at Hazira & Jhabua and setting up of 2 new compressor stations at Vaghodia & Khera together with the laying of a 36" diameter 505 Kms direct pipeline between Bijaipur & Dadri, thereby providing a direct access to Dadri in addition to the existing line. The overall projected capital cost of this project as approved by the Government in March 1994, is Rs.2376.15 crores. The scheduled date of commissioning of this project is July 1997 but the Bijaipur-Dadri pipeline is expected to be completed by December 1996. After expansion, the design capacity of HBJ and HBJ Upgradation system would be as under:

Table-6.6

Designed capacities of HBJ and HBJ Upgradation

(MMCMD)

Project	Design Throughput	Internal Consumption	Net Available for sales
HBJ Existing Project	18.2	0.6	17.6
HBJ Expansion Project	15.2	1.0	14.2
Total HBJ System	33.4	1.6	31.8

6.27 The existing HBJ pipeline system was designed with 4 compressor stations at Hazira, Jhabua, Bijaipur and Auraiya to transport 18.2 MMCMD of gas at 86 Kg/cm2 pressure. The internal consumption of gas will go up from 0.6 to 1.6 MMCMD due to enhancement of capacities of the existing compressor stations and installation of two new compressor stations at Vaghodia & Khera with higher compression ratio of 92 Kg/cm2 as against current ratio of 86 Kg/cm2.

Normative Rate of Transportation along the HBJ Upgradation

6.28 As this is an expansion project with substantial fresh capital investment, the Expert Group has followed their practice of working out a Long Run Marginal Cost (LRMC) of transportation for the HBJ Upgradation project. In this method, capital related cost such as depreciation, interest on loans and return on equity, are spread equally over the estimated life of the project and an arithmetic average is taken to determine the cost items for a year. With regard to estimated life of the project, the pipeline and related facilities have a life of 20/25 years and components like Gas Compressors & Turbines, etc. have been assumed to have a life of 15 years as indicated by GAIL. The LRMC has been calculated taking the life of the project as 20 years and 25 years. The other parameters adopted for the calculation of LRMC are as follows:

Expected Commissioning of HBJ Upgradation	-	July 1997
Capital cost	-	Rs.2376.15 Crs.
Annual Operating Cost	-	Rs.109.02 Crs.
Financing Pattern : Loan	-	Rs.1154.00 Crs.
Equity	-	Rs.1222.15 Crs.
Rate of interest on Term Loans:		
a. Rs. 704 Crs from ADB/EXIM	-	6.9% p.a
b. Rs. 450 Crs from OIDB	-	14.5% p.a.
Loan repayment period: ADB	-	16 years
OIDB	-	8 years

Working Capital	-	One month
Rate of interest on working Capital Loans	-	16.5%
Return on Equity (post tax)	-	12%
Tax provision	-	40 & 7.5% (surcharge)

6.29 The Expert Group has pointed out that the annual operating cost of Rs.109.02 crores projected for the expansion project as compared to the operating cost of Rs. 63.31 crores during the year 1994-95 for the existing pipeline appears to be on the high side. The internal consumption of the gas and consumables and repair costs in the expansion project are Rs. 62.53 crores and Rs. 40.61 crores respectively as compared to Rs. 16.59 crores and Rs. 12.86 crores in case of existing project. These aspects were discussed by the Expert Group with GAIL who have explained that the higher internal consumption of gas and consumables and repair costs resulting in high operating costs are the results of adopting a cheaper alternative of increasing the capacity of existing pipeline by upgrading/adding compressors instead of adding another pipeline. Also, since the expansion project has been approved by the Government on the basis of the operating cost of Rs. 109.02 crores with internal consumption of 1.0 MMCMD, the same have been adopted for working out LRMC based rates.

6.30 Based on the above parameters and assuming a 100% capacity utilisation for all the years the LRMC of transportation for the HBJ upgradation project has been worked out by the Expert Group for a project life of 20 years (Alternative I) and 25 years (Alternative II) as follows:

Table 6.7

LRMC based Normative Rate for HBJ upgradation
Expert Group

Particulars	(Rs/MCM)	
	Alternative-I (20 years)	Alternative-II (25 years)
Operating cost	210	210
Depreciation	221	177
Interest	99	80
Return on equity	505	503
Total	1035	970

6.31 The Expert Group note on the cost of transportation of gas along the HBJ is reproduced in the Appendix at page No.40. GAIL has submitted detailed comments on the above calculations of the Expert Group. The full comments of GAIL are also in the Appendix at page No.50.

6.32 As mentioned earlier at para 6.29, for estimating the transportation cost of gas for HBJ Upgradation Project under implementation, the Expert Group have adopted the "LRMC methodology". In this method the annual payments towards interest and depreciation (which occur only for the first few years) are added arithmetically and divided over the life of the project.

6.33 However, adopting the same method, four important assumptions made in the Expert Group calculations which were not agreed to by GAIL were examined by the Committee. These are discussed below:

a. Gas Sales have been assumed by the Expert Group for all the 365 days of the year at the rate of 14.2* MMCMD which is the full pipeline capacity. This assumption is reasonable only when we have a two part tariff and the pipeline capacity is sold to the full extent even while launching the pipeline. As per GAIL, sales volumes per day should be assumed for 330 days (90% capacity utilization). Taking into account the annual shutdowns of 30 days allowed by GAIL to the consumers and shutdowns taken by the producer and the liberalised MGO recommended by this Committee, (see para 7.42), the Committee considered that a 90% capacity utilisation may be assumed.

b. The Expert Group has argued for uniform gas sales of 14.2 MMCMD over the entire life of the project as the very capital intensive pipeline project has been designed and is implemented for the high capacity, it would not be reasonable to shift the burden of extra expenses of the over provision to the consumers in the initial years. There is merit in this argument. At the same time, the theoretical solution of segregating the capital cost incurred in advance for future use and adding interest on such amount and bringing it into the capital cost when the imported gas becomes available is not very practical. The problem of computing the apportionment of the capital cost incurred between what is legitimately allocable to current use and future use is formidable. Finally, the Expert Group argument raises some fundamental questions of "what is cost" for purposes of tariff fixation in such cases. Should all investment decisions taken in the light of certain factors at a particular time be reopened in the light of later developments or hindsight or should we introduce the concept of "stranded cost" as the US Utility Regulation? Taking all these facts, the Committee decided to take the past investments as given and future levels of operation at the most optimal projection. On this basis, the gas availability profile given by ONGC upto 2001-02 was taken instead of a normative quantity of 14.2 MMCMD as GAIL does not have the opportunity of increasing the availability of gas in this period. Beyond 2001-02, GAIL is in a

* This is derived by subtracting 1 MMCMD for internal use from the total capacity addition of 15.2 MMCMD.

position, if steps are taken in time, to import the required quantity of LNG to ensure the utilisation of the full capacity of the upgraded HBJ pipeline. With this assumption, the gas available for transportation in 2002-03 has been increased by 5 MMCMD over 2001-02 and a full capacity utilisation of 31.8 MMCMD has been taken beyond 2002-03.

c. Interest on foreign loan has been assumed at the nominal interest rate of 6.9% without taking into account the Government Guarantee. GAIL has contended that the rate to be used is the effective rate in the loan swap market which is more than 18% and covers the exchange rate variation as well. This contention of GAIL was not accepted by the Committee, as it involves several speculative assumptions. The Committee felt that the interest rate as charged should be allowed and if the project costs get significantly changed due to exchange rate variations, the tariff would need to be revised. However, the Government guarantee fee of 1.2% should be added to the interest rate.

d. The Expert Group has not provided for compressor replacement costing Rs.998 crores in the fifteenth year. As the pipeline system is not being fully utilised for several years, the need for the compressor replacement may arise later. The Committee, therefore, agreed with the Expert Group.

6.34 If the assumptions made by the Expert Group are modified as above, the LRMC cost of gas transportation for HBJ Upgradation Project on the same methodology followed by the Expert Group would be as follows:

Table 6.8

Modified rates for HBJ Upgradation

(Rs./MCM)

	Alternative-I (20 year project life)	Alternative-II (25 year project life)
Operating Cost	289	280
Depreciation	327	306
Interest	148	110
Return on Equity (12% post-tax at 43% rate)	783	732
	1548	1429

Details of these calculations are at **Annexure-V**.

6.35 Thus, as far as HBJ upgradation is concerned, two sets of figures emerge:

Table 6.9

Cost of gas transportation in HBJ upgradation system

(Rs./MCM)

Alternative - I (Project life of 20 years)		Alternative - II (Project life of 25 years)	
Expert Group	Modified Expert Group	Expert Group	Modified Expert Group
1035	1548	970	1429

6.36 To find the combined transportation cost for the HBJ and the HBJ Upgradation project, a weighted average cost has been worked out taking Rs.850/MCM for the supply through the present system as discussed at para 6.25 and the two sets of figures in the para above. The combined costs are as follows:

Table 6.10

Combined Transportation Cost for HBJ and HBJ Upgradation

			Rs./MCM
Alternative-I	Expert Group estimate	a.	932
(20 year project life)	Modified estimate	b.	1162
Alternative-II	Expert Group estimate	a.	903
(25 year project life)	Modified estimate	b.	1109

6.37 Long Run Average Cost (LRAC):

As in the case of ONGC, the Committee has also worked out the LRAC for the HBJ transportation cost using the DCF method. For this calculation the book value of the HBJ pipeline as on 31-3-96 has been taken along with all the projected outlays on the HBJ upgradation project. GAIL has been allowed a return of 12% on equity. The other parameters assumed are the same as in para 6.28. The transportation cost worked out by this method comes to Rs.1144/MCM. The details of the calculation are at **Annexure-VI**. If the interest rate on the ADB/Exim Japan loan were taken as 18% as claimed by GAIL, the transportation cost would come to Rs.1248/MCM as detailed at **Annexure-VII***.

Committee's view on Transport Cost

6.38 **Taking note of the two results in para 6.36 and the value of Rs.1144/MCM obtained in para 6.37, the Committee recommends a transportation charge on HBJ pipeline of Rs.1150/MCM. It is to be noted that if import of LNG does not materialise by 2001-02 and if there are very large foreign exchange value variations, the tariff may require a revision.**

* GAIL has pointed out that the effective interest rate of the ADB loan currently works out to 7.22% against 6.9% due to Rupee devaluation against dollar.

CHAPTER -VII

PRICING OPTIONS FOR NATURAL GAS

HISTORICAL DEVELOPMENT

7.1 The principles of pricing of natural gas in India are by now well established. A high level Committee on Natural Gas Pricing was set up by the Ministry of Petroleum and Natural Gas in 1979. Recognising that natural gas is an exhaustible resource, the Committee recommended that the natural gas pricing could sub serve the over all energy policy objectives of the country, namely,

i. promote efficient energy use,

ii. generate resources to achieve greater degree of self reliance, and

iii. encourage optimal inter-fuel substitution.

The Committee also recommended that the principle of opportunity cost be accepted for determining the price of natural gas.

7.2 The Committee of Secretaries accepted the general approach and suggested that the delivered price of natural gas for different users should be determined on the principle of replacement cost by using alternative fuel prices of the three major sectors, namely fertilisers, petro-chemicals and power.

7.3 These principles were further elaborated by Kelkar Committee, which spelt out the following additional objectives for the natural gas pricing policy:

i. The pricing system should be transparent and simple to understand and administer so as to enable both consumers and producers to take long-term investment decisions, and

ii. Prices should be fixed in such a way that the markets were cleared on the basis of prices and not physically fixed quotas.

7.4 It could be seen that both in 1987 and 1992 while fixing the prices the implicit assumption was that only indigenously produced gas would be available for use in India. Though technically it was feasible even in those days for gas to be traded across the national boundaries, it was assumed for the purpose of pricing that there will be very little of import and export of gas. It was also implicitly assumed that gas will be produced only by ONGC and OIL and be transported only by GAIL. This Committee had to take note of a few major developments in the natural gas sector as discussed below:

i. That gas is proposed to be imported in significantly large quantities and several industrial and power generation proposals using imported gas have been identified and are being actively pursued. The Terms of Reference laid down for the Committee has explicitly suggested that this development should be taken note of while fixing the natural gas price.

ii. Natural gas would be produced by a few private sector enterprises also; the oil/gas fields like Ravva, Panna, Mukta and Tapti have already been awarded to private enterprises and some more fields may be awarded in the near future. This issue has also been specifically mentioned in the Terms of Reference for this Committee.

iii. In the proposals for import of natural gas through major pipelines, the price of natural gas has been fixed with reference to a basket of crude oils, fuel oils etc. While awarding some of the gas fields to private sector companies it has been agreed that the gas produced by them would be purchased by GAIL at a price which is indexed to the price of a basket of fuel oils with a floor and ceiling price.

7.5 These developments have enlarged the options available for fixing of gas price in India. The Committee had to take note of all these before coming to the specific pricing option to be adopted. In this Chapter, we discuss the options considered and the reasons that lead to the adoption of a specific option.

OPTION I: PRICES BASED ON COST OF PRODUCTION

7.6 The administered price of gas would have two elements, a producer price and a consumer price. In India there are two major producers, ONGC and OIL. As the costs of production of these two producers vary significantly, there is a case to fix the producer price separately for each.

7.7 To arrive at the consumer price, the element of transportation charges will have to be added to the producer price, wherever applicable. Over and above these two elements, the Government may impose a levy to meet certain special needs in the price regime and the three elements will then together make-up the price to the consumer. This would be an extension of the methodology so far used in fixing gas prices.

7.8 Whether the cost based prices should include an element towards the depletion of resources **(the depletion premium)** was considered by the Committee. The royalty on natural gas should ideally reflect the depletion premium. How far the royalty being charged adequately reflects the depletion premium is difficult to judge as there are no universally approved principles and procedure for computing the depletion premium. Even if the principles and methods are decided there are grave uncertainties regarding the parameters to be used like the replacement fuel and its cost etc. Since royalty is separately accounted for, the Committee decided against including any element on account of depletion in the cost.

OPTION II: MARKET DETERMINED PRICES

7.9 In this option the consumer price of natural gas could be completely market determined. In this case the Government will no longer have any control over the gas prices and the gas price would theoretically approach values equivalent to prices of alternative fuels, such as, fuel oil, naphtha etc. if natural gas is not imported. The Power and Energy Division of the Plånning Commission has calculated the replacement values of gas for the power and the fertiliser sectors at various locations in India with reference to domestic and imported coal and naphtha. The Kelkar Committee has defined replacement value neatly as below:

"The replacement value of natural gas is a price of gas at which the unit cost of the final product (electricity, fertiliser) will be the same as their cost of production based on the alternative fuel/feedstock in each of these sectors. In financial terms, the replacement value of this gas provides an indication of the maximum price that the consumer is capable of paying for gas in replacement of the existing fuel/feedstock". This is also referred to as "imputed values". These values are shown below:

Table 7.1

Replacement value of natural gas (1995 prices)*
P&E Division, Planning Commission

Rs./MCM

Location		Power Sector		Fertiliser Sector	
		Domestic Coal	Imported Coal	Domestic Naphtha	Imported Naptha
1.	Delhi	520	7655	4409	7234
2.	Baroda	3173	6409	4409	6556
3.	Madras	3114	6347	3992	6335
4.	Calcutta	1726	6398	4014	6175

* The full report of Adviser (Energy), Planning Commission is given in the Appendix at page No.89.

7.10 The above values show that the transition to market price would mean a substantial rise in the consumer prices of gas compared to the existing price levels. Further, since we have a monopoly transporter of gas and an oligopoly of producers of gas there can be a fierce contest relating to the sharing of consumer price between the producer and the transporter.

7.11 The committee noted that the GOI has given some assurances to the multilateral agencies (ADB, World Bank) that the gas pricing regime would move towards a market driven pricing system at the end of the current pricing system which is based on the Kelkar Committee report. The Committee also noted that the Sunderarajan Committee had also recommended a move towards a market driven pricing mechanism. These were under the implied assumption that free import of natural gas through pipelines or as LNG would be allowed. It is difficult and wellnigh impossible to fix an administered price on the basis of market driven price, as there is no real gas market, on the lines of the liquid fuel market.

7.12 Having regard to the structure of the natural gas producing and consuming industries and the problems of changing from the current pricing regime to a market driven pricing mechanism, this Committee is of the view that a well conceived stepwise steady progress should be planned for a transition to a market driven pricing mechanism. As and when the market driven pricing mechanism is introduced, there will be a large rent available to the domestic producers on account of the low cost of production. The Government will have to mop up this rent through suitable fiscal measures.

OPTION III: IMPORT PARITY PRICE

7.13 The difficulties, the long distances involved and the huge upfront costs required for organising the import of gas have been mentioned earlier. Notwithstanding these problems, in view of the need to have more gas than what could be produced from our known resources, Government has been considering importing of natural gas from Oman and Iran through pipeline. The import of LNG is also under consideration.

While the details of the proposals and the actual costs are not available to this Committee, the general indication is that the gas price would be indexed to the price of some selected fuel oils and crude. The price as landed in India is not likely to be less than USD 3/MMBTU which will be equivalent to about Rs.3600/MCM. In addition, the inland transportation cost will have to be accounted for. Therefore, the adoption of an import parity price will result in a sudden steep increase in the consumer price.

7.14 The Committee feels that there are a number of serious problems in the introduction of such a price regime with immediate effect. If the consumer prices are increased suddenly in anticipation of imports, that would be resented by the consumers. There are also problems of estimating what is the relevant import parity price while the actual import to India have not yet materialised. The Committee, therefore, is reluctant to recommend this option for the producer price.

7.15 It is, however, clear that in the near future import of natural gas as LNG or piped gas is inevitable to supplement indigenous production. At that time, the consumer price of natural gas should be closer to import parity prices. It is necessary, therefore, to prepare the consumers gradually towards that transition.

RECOMMENDED OPTION FOR PRICE OF GAS

7.16 Having considered these options the Committee is of the view that for the period 1997 to 2002, we should adopt a pricing system **for the producer price which compensates the producer the cost of production including a rate of return on investment which is large enough to act as an incentive. The recommended consumer price is designed to gradually increase every year and approach the import prices as discussed later.**

ONGC AND OIL PRODUCER PRICES:

7.17 The Committee then had to take a view on whether the ONGC and OIL should be given producer prices differentially based on the respective cost of production. The cost of production for OIL is likely to be significantly higher than the cost for ONGC. This is the result of a number of factors, of which the most important is the geology of the gas fields in Assam where OIL operates as compared to the geology of gas fields operated by ONGC all over India including the very prolific off-shore structures of Bombay High. Assam is also a remote area and not easily accessible from other parts of India. Under no circumstances can production of oil and gas from the fields now operated by OIL be phased out. The Committee is convinced that the increased cost of production of oil/gas in OIL is not due to any identifiable mismanagement on the part of the company. Further, since OIL operates in a small area, mainly in the North-East, the spread in its cost of production is limited. **The Committee, therefore, recommends that ONGC and OIL be given producer prices which are different.** It was pointed out during discussions within the Committee that differential gas prices have not been allowed so far to ONGC and OIL. The crude oil prices allowed to them were also the same. However, the Committee noted that the concept of differential prices for producers has been already introduced as private gas producers have already been allowed different prices. The Oil Coordination Committee also uses the retention price concept for fixing the ex-refinery prices of petroleum products. The Committee, therefore, felt that differential prices for ONGC and OIL would be appropriate. The Committee, however, does not consider it appropriate to allow the full difference in the cost of production. If the element of return on capital employed which causes an increase of Rs.300/MCM is excluded, the difference in cost of production would be about Rs.100/MCM (see Table 6.1). Taking all these factors, the Committee recommends the following producer prices:

ONGC	Rs.1800/MCM.
OIL	Rs.1900/MCM.

TRANSPORTATION COST

7.18 There are three different pipeline systems in operation:

i. The large, dominant HBJ pipeline.

ii. The smaller pipeline systems in other areas like Assam, Gujarat, Maharashtra and Andhra Pradesh.

iii. Pipelines laid by the consumer themselves from the Gas gathering station, or specific pipelines laid for consumer at their request and operated by ONGC/GAIL.

7.19 The transport pricing options are the following:

i. Total equalisation of transport price.

ii. Equalisation of transport price on GAIL owned transport.

iii. The equalisation of the transportation cost on each pipeline individually.

iv. Distance related transport charges.

Option-I

7.20 In this the transport cost of all the three pipeline systems, that is the HBJ, smaller pipelines in Assam, Andhra Pradesh, Gujarat, Maharashtra as well as the specific pipelines built at the request of consumers would all be added together and the total cost divided by the total quantity to arrive at the unit cost of transportation. This could be added to the unit producer price and the consumer price arrived at. The only point in favour of this option is the simplicity and the uniform price for all consumers. However, the price being paid for the gas transportation on dedicated lines and small grids have been separately settled by commercial contracts between GAIL and the consumers. Further, unless each pipeline is seen as a viable project by itself, GAIL would be discouraged from putting up small pipelines in future.

Option-2

7.21 Here the transportation cost along the HBJ pipeline and the minor systems like Gujarat, Assam, Andhra Pradesh, Maharashtra etc. would be added up and the gas transported on all the systems could be used as the divisor to arrive at the unit cost. This has some logic as the consumer was not responsible for the pipeline decisions or the availability of the resources and the transportation costs which GAIL has to incur. However, this option leads to transport price equalisation which is a concept which has been given up in India. This option is inappropriate especially in the case of natural gas where the transport cost is very large relative to the gas price and the advantages of locating industries with reference to the availability of gas nearby would be lost completely. This option is, therefore, not recommended.

Option-3

7.22 This is what is being followed now. The cost of each pipeline transport system is divided by the quantity of gas transported on the particular system. This gives unit cost of transportation in each region or pipeline system. The specific transport cost for each pipeline is added to the producer price to arrive at the consumer price. This is a reasonable and an acceptable option.

Option-4

DISTANCE RELATED TRANSPORTATION CHARGES:

7.23 The next question to be decided is whether the total cost of operating the transport system should be divided proportionately to all the users of that system on the basis of the quantity of gas transported or the transportation charge should be related to the distance through which the gas is transported. The transportation charges fixed since 1987 provide for a uniform tariff for all gas users on HBJ irrespective of their locations along the pipeline. The States which are closer to the gas fields like Gujarat have raised before the Kelkar Committee as well as before this

Committee, a strong plea that the transportation charges should be related to distances. In this regard the observation of the Kelkar Committee is relevant:

"The suggestion for having non-uniform price along the HBJ pipeline has also been considered. Ideally transportation charges along the HBJ pipeline should vary according to the distance over which the gas is transported. However, there are some difficulties in precisely computing the distance wise transportation cost along the HBJ line, as the activity along the pipeline were visualised and implemented as an integral part of the HBJ gas utilisation system. It is, therefore, not possible precisely to identify the investment cost for each sector of the HBJ pipeline. Further, certain investment decisions have already been taken based on the consideration that the cost of gas along the pipeline would be uniform. Keeping this in mind, it is recommended that the transportation cost along the present HBJ pipeline be retained at Rs.850/MCM."

7.24 At this point of time also, the Committee found it difficult to separate the pipeline cost for each segment. The Committee discussed the feasibility of dual pricing to pass on the cost of HBJ upgradation to the new consumers while the old consumers continue to pay the existing transportation charges. It was found that the upgradation project involved both new pipelines as well as improving the capacity of the old pipeline by installing new compressors. The upgradation project, therefore, serve the interest of the old consumers also. The investment decisions for the new projects along the HBJ pipeline have been taken on the understanding that they will be uniform tariffs along the pipeline. Changes in the pricing principles may change the choice of locations. The Committee, therefore, felt that uniform tariffs should be continued till the Administered Pricing Regime remains in force. The transport tariff as estimated in para 6.38 of Rs.1150/MCM is recommended for all gas transported on the HBJ pipeline.

7.25 The Committee, however, recommends that for pipelines to be set up in future, the transport charges should be distance related. The potential consumers along these pipelines should be notified of this in advance so that the appropriate investment decisions can be taken in regard to gas utilising industries and their locations. Regarding existing pipelines, the concession cannot be in perpetuity. It will be appropriate to consider introducing distance related transportation charges after the period of recovery of investments made by the units and after undertaking a study to determine the segmentwise fixed and variable costs which could then be allocated to the different consumers.

TRANSPORTATION CHARGES ALLOWED TO THE OTHER PIPELINES

7.26 Besides HBJ, a number of minor pipeline transport systems have come up in different gas fields. These pipeline systems have been designed with reference to certain specific needs of local consumers. As such the Committee felt that it is not necessary to fix a tariff at the national level. The tariff should be fixed by negotiation between the consumers and GAIL. However, the Committee recommends that in the case of non HBJ pipelines, the principles of fixing the tariff to be adopted by GAIL should be same as adopted by this Committee in the HBJ case. The total stream of investment on the pipelines and the annual operating cost should be projected along with the levels of utilisation of the pipeline system. A DCF computation should then be made allowing a 12% post tax return to derive the reasonable level of tariff around which the parties could negotiate. In case of pipelines serving more than one consumers, distance related charges could be introduced.

CONSUMER PRICE

7.27 The consumer price will have to be the sum of the producer price and the transportation charges wherever pipeline services are availed of. In addition, an element has to be added to the consumer price so as to provide funds for meeting the requirements towards (a) subsidising the North-Eastern region consumer (as discussed in the following para), (b) the higher payment of Rs.100/MCM to OIL as the producer price and (c) the increments in the producer price of gas to compensate for inflation in the economy which would affect a portion of their operating cost.

7.28 There is a further issue which also needs consideration. Producers, whether in the public or private sector, who bid for new areas of natural gas for exploration/exploitation would expect compensation in terms of not just the cost of production but on the same or similar lines to what has been agreed to private enterprises who have been awarded the new fields of Panna, Mukta, Tapti, etc. Further, in the next five years, India will have to make arrangements for importing significant quantities of natural gas in addition to the indigenous production to meet the increasing demand. In realisation of the last factor, GOI have already given assurances to multilateral agencies that the natural gas price regime will move towards a market-driven-pricing system. It appears necessary, therefore, to evolve a consumer pricing system during the next five years which would help in the smooth transition from the cost of production based prices to market driven prices. **Taking all these factors, the Committee recommends that the consumer price has to be gradually delinked from cost of production and should autonomously move towards import parity price. The difference between the consumer price and the producer price is a rent which should be impounded by the Government in a fund for the development of gas industry. Therefore, the Committee recommends that in addition to the producer price, the consumers must pay a contribution which could be called the contribution to the Gas Pool Account.** The Committee recommends that the Gas Pool Contribution should be slowly stepped up at the rate of Rs.200/MCM per year. In the next five years, the consumer price would be as shown in the following tables and in the 5th year it may still be lower in comparison to the price of imported gas which may be based on fuel oil parity.

Table-7.2

Recommended Consumer Price of Gas 1997-2002
HBJ Pipeline

(Rs./MCM)

Year	Producer Price	Transport Charges	Gas Pool Contribution	Total
1.4.97-31.3.98	1800	1150	250	3200
1.4.98-31 3.99	1800	1150	450	3400
1.4.99-31.3.2000	1800	1150	650	3600
1.4.2000-31.3.01	1800	1150	850	3800
1.4.01-31.3.02	1800	1150	1050	4000

Table 7.3

Recommended Consumer Price of Gas 1997-2002
Landfall Point*

(Rs./MCM)

Year	Producer Price	Gas Pool Contribution	Total
1.4.97-31.3.98	1800	250	2050
1.4.98-31.3.99	1800	450	2250
1.4.99-31.3.2000	1800	650	2450
1.4.2000-31.3.01	1800	850	2650
1.4.01-31.3.02	1800	1050	2850

* Exclusive of transportation charges.

Note: (i) The average producer price will be slightly more than what has been shown above on account of the higher producer price for OIL.

(ii) The producer price and transport charges may increase marginally over the years due to compensation being paid for inflation which would affect a part of the operating cost.

(iii) The inflation will not affect the consumer price as the inflation allowance would be paid out of the gas pool contribution.

7.29 The Committee is conscious of the fact that even after the suggested gradual increase in the gas price, the price in 2001-02 will be short of the price of imported gas or the price of gas from privately developed fields which would be linked to select fuel oil prices. The Committee considered whether the Gas Pool contribution could be increased so as to have a smoother transition to the possible import parity price. The Committee, however, felt that a steeper price increase could be recommended only after a more definite policy announcement by the Government regarding the calender for transition towards Market Determined Prices. On the same considerations, if the international gas price becomes low, appropriate reduction should be made in the gas pool contribution to ensure that the consumer price in India does not exceed such "international" price.

7.30 The Committee also considered whether it would be appropriate to continue the price of indigenous gas on a cost plus basis while the imported gas, as and when it comes, is sold at market determined prices, i.e whether a dual price regime should be allowed. The Committee is not inclined to accept this arrangement for the following reasons:

i. In the Terms of Reference given to the Committee, the Government have clearly indicated that "in making the recommendations the Committee may have due regard to the assurances given to the multilateral agencies regarding the market related price of petroleum products and natural gas".
ii. A gradually increasing gas price will prepare the consumers for the imported gas and also encourage private efforts for the import of LNG.
iii. The continued supply of natural gas at prices much lower than the prices of alternative fuels, will distort the downstream sectors such as the power sector.
iv. The Ministry of Petroleum and Natural Gas is reported to have drawn up a plan for a phased dismantling of the Administered Pricing Mechanism for petroleum products. The proposal is awaiting the approval of the Government.

CONCESSIONAL PRICE IN NORTH-EASTERN INDIA

7.31 This Committee heard strong representations from Tripura and Assam that the price as prevailing now should not be increased any further as even at this price a substantial quantity of gas remains unutilised and is flared. The industrial growth of this region depends entirely on the use of natural gas as it has no other industrial raw material. Therefore, special consideration should be given to the pricing of natural gas so as to stimulate the gas based industrialisation in this region. This issue is further complicated by the fact that a concessional gas price of Rs.600/MCM for 15 years has been allowed for a very major proposal for the use of natural gas for a gas cracker. Taking all these factors the Committee found a lot of merit in the recommendations of the Kelkar Committee as approved by the Government in fixing the price of gas in the North-Eastern region at a level different from that of other regions. Therefore, the Committee recommends that a concessional price of Rs.1200/MCM be fixed for the North-Eastern States. This figure is arrived at by increasing the current price of Rs.1000/MCM in the same proportion as the rise in the producer price of Rs.1500/MCM to Rs.1800/MCM in the rest of the country. At the same time, the discount of Rs.400/MCM now allowed may be reduced to Rs.300/MCM. For all new projects to be set up within the pricing period of 1997-2002, the discount may be allowed for the first five years.

ADJUSTMENTS FOR PRICE INFLATION

7.32 In all administered prices, if significant inflation is anticipated in the future, it is advisable to provide for an inflationary allowance to be added to the producer price and the transportation charges. This inflationary allowance in the case of natural gas price would have to be limited strictly to the legitimate impact of inflation on the production and transportation costs. In the case of production, much of the capital costs are by way of loans which are scheduled for fixed repayments which are not inflation indexed. It is an arguable case whether the return on investment should be subjected to an inflation allowance. In the case of administered price regime, when the rate of return is guaranteed in post-tax term, it is really not a risk-capital as the equity in other industry. The Committee feels that it would be reasonable to treat it on the same lines as debt and not allow any inflation indexing of return on investment. The Committee was also influenced in these conclusions by the fact that any surplus over and above the projected level due to productivity increase would accrue to equity holders only. However, some of the operating costs including interest on working capital requirements will increase and has to be compensated. Inflation would also have an impact on salaries and wages. However, it is to be expected that improvements in productivity should compensate for a part of the effects of inflation. Taking a fairly reasonable view, on the basis of some computations done by GAIL, the Committee recommends that for every 10% increase in the CPI, a 1% increase should be allowed in the producer price and the transportation charges. In order that the consumers are not overburdened, the Committee recommends that these amounts be paid from the Gas Pool Account. The amounts to be paid to ONGC, IOC and GAIL from the Gas Pool Account will be paid at the end of the year, on production of the prescribed accounts to the agency managing the Gas Pool Account. In other words, the consumer price will not increase due to inflation.

PRICE OF GAS FROM PRIVATE FIELDS

7.33 The Committee has been asked to take note of this matter vide para 4 of the Terms of Reference. The Government have been offering small fields for development by private parties and medium sized fields for development through joint ventures. 13 small and 5 medium sized fields have been offered so far. The developers of these fields have been given the right to sell gas at negotiated prices. It was indicated that GAIL has the right of first refusal for the gas from Mukta, Panna, Tapti and Ravva to be produced by private parties. If GAIL does not buy this gas, the private producers will be required to pay to GAIL only for the use of the latter's infrastructure. If GAIL buys this gas to meet existing commitments, GAIL will have to pay a price linked to international fuel oil prices. GAIL will, however, have to sell the gas at the price fixed by the Government. The Committee considered whether any system could be suggested for including this aspect in the pricing now proposed. However, it is not possible to forecast the production through the private enterprise in the next 5 years and the prices likely to be paid to them. It would be highly speculative to suggest the precise method of including this element in the pricing system now proposed by the Committee. The Committee, therefore, suggests that the Government may evolve a suitable method of meeting any likely cost arising on account of gas purchased from private enterprise by GAIL after examining the following options:

(i) To allow GAIL to realise market related prices from identified consumers,

(ii) To compensate GAIL through the budget, or

(iii) To compensate GAIL from out of the accretions in the Gas Pool Account to the extent feasible

PRICING PERIOD

7.34 The present pricing Committee was asked to recommend the gas price with effect from January 1, 1996. No pricing period was laid down in the order constituting the Committee. The Committee has deliberated on the selection of an appropriate pricing period. In 1987, when the gas price was fixed by the Government for the first time, a pricing period of three years was contemplated. However, the next price revision could be made effective only with effect from January, 1992. The Government order of 1992 did not lay down any pricing period, but it was decided by the Ministry that a new set of prices could be appropriately introduced with effect from January, 1996. Thus the second pricing period effectively came to four years. The Committee considers five years to be a more appropriate pricing period as a three year period was too short for assessment of the impact of the gas pricing regime, which forms the basis for subsequent price revision. The Committee also considers that the next pricing period would also coincide with a period of transition between administered prices and market determined prices, which can only be gradual so that the impact on the consumers is softened. With these factors in mind the Committee recommends that the pricing period may be fixed upto March 31, 2002.

7.35 A view was strongly expressed that the Committee should recommend a shorter pricing period in view of the need to usher in market determined prices earlier. This was discussed. The Committee, however, felt that gas was not a tradeable commodity and that it would take atleast 5 years to build the infrastructure for the import of natural gas/LNG. The Committee was, therefore, not in favour of recommending a shorter pricing period.

Table 7.4

Build up of the gas prices

(Rs./MCM)

Period	Producer Price	Transportation Charges - HBJ	Gas Pool Account	Total
21.4.97 - 31.3.98	1800	1150	250	3200
1.4.98 - 31.3.99	1800	1150	450	3400
1.4.99 - 31.3.2000	1800	1150	650	3600
1.4.2000 - 31.3.01	1800	1150	850	3800
1.4.01 - 31.3.02	1800	1150	1050	4000

DENOMINATION OF GAS PRICE IN TERMS OF CALORIES

7.36 The present gas price is denominated in terms of volume. The price is, however, linked to the calorific value. The current producer price of Rs.1500/MCM and the consumer price of Rs.1850/MCM (Rs.1000/MCM in the North-East) apply to gas with calorific values between 9000 and 9500 K Cal per cu.mtrs. If the calorific value lies below 9000 and above 9500 K Cal per cu.mtrs., there is a discount/premium proportionate to the difference in the calorific value from the average value of 9250 K Cal per cu.mtr.

7.37 The international practice is to denominate the gas price and transportation charges in terms of thermal content. This provides the consumers with a ready comparison with the price of alternative fuels which are also quoted in thermal terms. A demand for a price quoted in thermal terms has been received from the gas consumers of our country specially from the fertiliser sector. Objections have also been raised against keeping the gas price the same over the band of 9000-9500 K Cal per cu.mtrs.

7.38 In case of ONGC/OIL, the conversion from volume to calorific value can be made using a factor of 10,000 K Cal per cu.mtrs. which is the average calorific value of the gas supplied by them. In converting the transportation charges along the HBJ pipeline to calorie basis, we could use the factor of 8500 K Cal per cu.mtrs. which is the average calorific value of the gas supplied by GAIL along the HBJ pipeline.

7.39 Using the above conversion factors, the producer price of ONGC, OIL and the transportation charge for HBJ and the contribution to the Gas Pool Account may be designated as follows:

ONGC producer price:	Rs.1800/MCM	-	Rs.180/million K Cal.
OIL producer price:	Rs.1900/MCM	-	Rs.190/million K Cal.
North-East concessional price:	Rs. 900/MCM	-	Rs. 90/million K Cal.
HBJ transportation charge:	Rs.1150/MCM	-	Rs.135/million K Cal.
Gas Pool contribution:	Rs.200/MCM		
Along the HBJ		-	Rs. 24/million K Cal.
At landfall points		-	Rs. 20/million K Cal.

7.40 ONGC and GAIL have been consulted in the matter of conversion of prices/transportation charges on the above lines. Both ONGC and GAIL have agreed to the conversion in principle. However, both have pointed out the practical difficulties of installing the required meters for online determination of the calories supplied. The comments of ONGC and GAIL are reproduced at **Annexures-VIII & IX**.

7.41 In view of the difficulties expressed by ONGC/GAIL, the Committee recommends that the gas price/transportation charge may continue temporarily to be in volumetric terms. The conversion to thermal terms may be effected in the HBJ pipeline by April, 1998 and in other areas within one year thereafter.

MINIMUM GUARANTEED OFFTAKE

7.42 There is no uniformity in the existing MGO conditions in the various gas supply contracts. Most of the contracts provide for an MGO of 80% calculated on a monthly basis. MGO for the fertiliser plants along the HBJ pipeline is 76% calculated on a quarterly basis. Further, the payment for the shortlifted quantity is only in respect of the transportation charges. The Committee recommends that the MGO clause be standardised.

7.43 The MGO clause in the Gas Supply Contract has been criticised by the consumers as one-sided since no penalty is payable by ONGC/GAIL for failure to supply. The Committee sees merit in the contention and recommends that the MGO provision should be made lenient to the extent permitted by the available storage. The Committee feels that all consumers may be allowed a Minimum Guaranteed Offtake of 76%* on a quarterly basis as at present allowed to consumers along the HBJ pipeline. For the consumers along the HBJ pipeline, payment for the shortfall will continue to be chargeable only in respect of the transportation charges.

* This percentage was arrived at by reducing 80% by a further 5%.

PENALTY FOR NON SUPPLY

7.44 At present neither ONGC nor GAIL is liable to pay any penalty in case of failure to supply the contracted quantity of gas. It has been a long standing demand of the consumers that such a penalty provision be introduced in the gas supply contract. The issue has become important in recent times because of the proposals for power generation by Independent Power Producers. ONGC/GAIL have pointed out that gas has been over committed by the Government. Besides, the price of natural gas has been kept at such low levels that any penalty which would necessarily be related to the price of alternative fuels would impose an unacceptably large risk on them. The Committee is inclined to agree with ONGC/GAIL on this issue. However, the Committee feels that the question of guaranteed supplies will have to be addressed as soon as possible and recommends that ONGC/OIL may examine the feasibility of entering into contracts with guaranteed supplies. In such cases, ONGC/OIL may be authorised to charge guarantee fees which may be related to the price of alternative fuels and they should be liable to pay penalty for non-performance. The Committee also recommends that the Government closely examine the existing gas allocations with a view to rationalising them so that the gas producing and transporting companies could make supply commitments with greater firmness.

SALES TAX

7.45 Both in 1987 and in 1992, an attempt was made to bring natural gas within the meaning of "declared goods" under the Central Sales Tax Act, so that the sales tax on natural gas cannot exceed 4%. However, this was not implemented. As a result there is a wide variation in the rates of sales tax in the various states as shown below:

1. Maharashtra - 10%
2. Gujarat - 19% + 2.5% (Turnover tax)
3. Madhya Pradesh - 10%
4. Rajasthan - 10%

5. Uttar Pradesh - various slabs 5-10%

6. Delhi - Nil

7. Northeast - 8%

8. Tamilnadu - 9%

9. Andhra Pradesh - 16%

10. Haryana - Nil

7.46 The Committee finds this situation unsatisfactory and recommends that the proposal to bring natural gas within the meaning of declared goods under the Central Sales Tax Act be effectively pursued.

DISCOUNTS FOR GAS FROM DEVELOPING FIELDS AND FOR INTERRUPTIBLE SUPPLY OF GAS

7.47 At present, a discount of 15% is allowed for gas from developing fields. The Committee was informed that an appreciable quantity of gas was being flared at a number of isolated fields where low pressure associated gas was available in small volumes. The small volume of gas available makes it economically non viable to connect the gas to the nearest grid. Potential consumers willing to utilise this gas locally may be discouraged by the high cost of compression and transportation. In view of the urgency in the utilisation of such associated gas which is otherwise flared, the Committee recommends that the gas available from such isolated fields should also qualify for the discount of 15%.

7.48 Regarding interruptible supplies, the Committee was informed that the discount of 15% has not been extended to most of the consumers with fallback allocation as the supplies to these consumers and the drawal by these consumers are also more or less steady and at par with consumers with firm allocations. In fact, the Ministry of Petroleum and Natural Gas has converted many of these fallback allocations to firm allocations. The Committee feels that a distinction should be made between consumers who are getting steady supplies and consumers who are genuinely fallback consumers. The concession of 15% to fallback consumers with interruptible supplies should be continued.

THE GAS POOL ACCOUNT

7.49 There are a number of factors which call for the operation of a Gas Pool Account or an equivalent mechanism in the period 1997-2002:

i. Since the gas price is based on the average of the ONGC production cost and OIL production cost, there will be a need to transfer some money from the general collection to OIL as its production costs will be he higher than the average producer price.

ii. ONGC and OIL will get a producer price in the North-Eastern region which will be only 2/3rds of the producer price in the rest of the country and therefore, some amounts will have to be transferred to OIL and ONGC to meet the difference.

iii. As the price fixed by this Committee is substantially below the import parity price, there is need to gradually step up the price within India so as to reach the import parity price at the end of five years. This calls for a step up over the price by Rs.200 per year as recommended by us at para 7.28. This annual and gradual increment would help the orderly transition from the administered pricing regime to a market driven pricing regime. This amount could be collected as part of the Gas Pool Account and used for the purposes mentioned above. Any additional amounts available could be used for appropriate gas development projects and purposes.

7.50 The Committee does not find the present arrangement for the maintenance of the Gas Pool Account appropriate. A Pool Account has been proposed in this report as a measure of smooth transition from the existing cost based system of pricing towards a market driven pricing system. The accumulations in the Pool Account should be used for the gas development and not be used by any one agency involved in the natural gas sector. A separate Group/Committee should oversee the Pool Account and the accumulation and disbursement from the Pool Account. The Government may either set up a new Committee or use one of the existing Committees functioning in the Ministry of Petroleum and Natural Gas for this purpose. This Committee should be subjected to public accountability by mandating that the Annual Accounts of the Gas Pool Account with the memorandum explaining receipts and disbursals and balances should be submitted to the Parliament at the time of the Budget discussions.

7.51 The contribution to the pool will be Rs.250/MCM in the first year. This will then increase by Rs.200/MCM each year. In keeping with the concessional price of gas in the North-East, the contribution to the Gas Pool Account from the consumers in the North-East will increase by Rs.100/MCM per year.

7.52 In addition to compensating ONGC/OIL for concessional prices in the North-East and OIL for the higher cost of production, the accumulations in the Gas Pool Account could be utilised for development of specific small gas fields and for research and development for the exploration and exploitation of small and associate fields, importing of gas through deep water pipelines etc. Private producers who develop isolated gas fields will be allowed to charge market related prices. However, a subsidy from the Gas Pool Account may be required when these fields are developed by ONGC/OIL and the gas supplied by GAIL at administered prices. As of now, it is not clear how much subsidy will be required to be paid out of the Gas Pool Account. The objective of the Gas Pool Account was to mop up the difference between the producer price and the gradually increasing consumer price. Any unspent amount left at the end of the pricing period or when market related prices are introduced will have to merge into the central exchequer.

7.53 A view was expressed that till such time as the capacity of the upgraded HBJ pipeline is fully utilised, GAIL could continue to be paid the transportation charge of Rs.850/MCM while the customers are charged Rs.1150/MCM. The difference of Rs.300/MCM could be kept in the Gas Pool Account. This arrangement would ensure that GAIL would realise the benefit from the investment made in the upgradation at the appropriate time and not earlier. The Committee noted that the gas availability figures till 2001-02 do not justify an immediate investment in the upgradation project. A regulator would be competent to disallow infructuous investments in calculating transportation charges. However, GAIL has made the investment in the upgradation project in terms of the gas availability projections earlier made by ONGC and after obtaining Government approval for the project. It would not be appropriate, therefore, to penalise GAIL for the mismatch between the upgraded capacity and the gas availability. The suggestion of withholding a part of the transportation charges from the current consumers by crediting the amount to the Gas Pool Account would be a departure from principles of pricing followed so far. The Committee, therefore, do not recommend such a course of action.

CHAPTER - VIII

CONCLUSIONS AND RECOMMENDATIONS

8.1 The Committee has examined various issues relevant to the pricing of natural gas and its conclusions of the Committee have been set out in different places all through the report. Important among these are extracted and set out seriatim from para 8.10 onwards in this chapter. Before that the Committee would like to discuss in this chapter some of the issues involved in the study as a whole.

Regulatory Agency for Natural Gas

8.2 The Committee found that there was no general agreement on the various principles to be used in computing the price of natural gas among the concerned agencies. The Committee, therefore, feels that an essential part of the exercise on fixing of price and moving towards market driven prices should be the setting up of a regulatory agency for natural gas at the earliest. One of the first tasks of the Regulatory Agency would be to prescribe the appropriate mode of maintaining the cost of production data by the hydrocarbon industry and delineate the principles of pricing of gas.

Administered Prices vs Market Driven Prices

8.3 Even while spelling out the terms of reference, the Government has clearly indicated the new factors which have emerged in the gas sector. The demand for hydrocarbons in the country can be satisfied in future only by augmenting the indigenous supply with imports. The Government considered this option and has decided to import natural gas either through pipelines or as LNG. Imported gas would be priced at the international rate which is likely to be substantially higher than domestic price. With a view to attract private investment to hydrocarbon exploration and production, it has been decided to allow the private sector producers of natural gas to charge prices indexed to a combination of fuel oils. This price would be higher than the price applicable to gas produced by ONGC/OIL. It does not appear desirable to have a dual price system in which one set of consumers obtains natural gas at the lower price and others obtain imported gas at a higher price. The Committee has, therefore, decided to have the consumer price gradually increasing from the current levels towards what might be the import price. However, in the absence of a time-table for shift to a market determined pricing system, we have only the proposed increase which takes the consumer price nearer the likely price of imported gas; this might still fall short of the import price in the year 2001-02. The difference between the consumer price and producer price should be considered the rent accruing to the Government on account of its near monopoly over production and transportation of natural gas. This rent will constitute the Gas Pool Account to be used as suggested by the Committee.

8.4 The Committee would like to emphasise that natural gas has no market as in the case of liquid fuels. One cannot import natural gas unless large investments are made on front-end facilities. This would materialise only if the policy and the date by which market driven prices would be fully operational are announced adequately in advance.

8.5 Any immediate attempt to deregulate the price would be counter productive as the industries using natural gas cannot bear the impact of trebling of fuel/feedstock cost. At the same time, the Committee would suggest that such industries should not be lulled into a sense of complacency of expecting eternal protection.

8.6 The Committee has considered various factors and recommends the prices as follows:

Table 8.1

Recommended Price Build-up

(Rs./MCM)

Period	Consumer Landfall	Price Pipeline HBJ	Gas Pool Contribution
Apr 97 - Mar 98	2050	3200	250
Apr 98 - Mar 99	2250	3400	450
Apr 99 - Mar 2000	2450	3600	650
Apr 00 - Mar 01	2650	3800	850
Apr 01 - Mar 02	2850	4000	1050

8.7 In the year 2001-02, the consumer price at the landfall point would still be Rs.2850/MCM which is Rs.285 per million K Cal or USD 2.3/MMBTU. All studies suggest that the import of natural gas would be at USD 2.7 - 3.5/MMBTU i.e. the indigenous prices will still be lower than import prices.

8.8 The Committee has also computed that as a result of higher price at the current level of consumption, the subsidy to be paid to the fertiliser industry may increase by Rs.150 crores per year which is a small percentage of the current subsidy of around Rs.6000 crores per annum.

8.9 As far as the power industry is concerned, the price of fuel is pass through i.e. the producer passes it to Electricity Boards and from Electricity Boards it is passed to the consumers. The cost of natural gas per KWH is around Rs.0.50 now and it will increase by Rs.0.05 - 06/KWH per year which is not a steep increase.

The need for a time-table for introducing market determined prices.

8.10 Investment decisions for the import, domestic transportation and utilisation of natural gas cannot be taken only on the basis of the gas prices for the next pricing period. The investor needs to know the kind of pricing regime that he will be confronted with after this pricing period is over. There is a need, therefore, for the Government to adopt a time-table for the introduction of market determined prices and to announce the same in advance so that the right signals can be given to potential investors. It is not desirable that at the end of the pricing period, we are faced with a number of investments which have been made on the assumption that the Administered Pricing Regime would be continued. The representative of the Ministry of Finance has argued in favour of a shorter transition period to market determined prices. His note is reproduced at **Annexure-II**.

COST ESTIMATION

8.11 There are a number of ways in which the cost of production and transportation of gas can be computed. The Kelkar Committee has gone into the merits and demerits of the accounting method of calculating costs. This Committee feels that the Long Run Marginal Cost or the Long Run Average Cost provides the most appropriate estimate of the cost of production and transportation of gas. However, since data and projections over long periods would have to be used, computations based on this methodology may be validated by comparison with cost estimates obtained by the accounting method.

8.12 ONGC and OIL have claimed that the losses incurred by them on account of foreign loans taken at the instance of the Government of India be allowed as a cost item. Both ONGC and OIL are booking these losses due to the fluctuation in the foreign exchange rate in their Profit and Loss Account. The Committee felt that only for the loans taken for specific projects related to exploration and production, the losses on account of foreign exchange fluctuation could be included in the cost of production. In case of loans taken for other purposes, these losses could not be allowed as cost items.

8.13 Owing to the high risk activities undertaken by ONGC/OIL, a 15% post tax return on capital employed should be allowed to them in calculating the production cost of gas as has been allowed by the OCC in fixing crude oil prices.

8.14 The accounting cost of gas transportation along the HBJ has been estimated by the Expert Group for 1995-96 and 1996-97 as Rs.576/MCM and Rs.522/MCM respectively. The downward trend is explained by the decreasing capital charges owing to the fact that the pipeline has been in existence for nine years.

8.15 The Long Run Marginal Cost of gas transportation for the HBJ upgradation project as calculated by the Expert Group takes the depreciation, interest etc. over the project life and computes the arithmetical averages.

8.16 In calculating the normative transportation cost, a 100% capacity utilisation can be assumed where a two-part tariff is in vogue and the entire pipeline capacity is booked in advance. In the case of GAIL, a 90% capacity utilisation would be a more reasonable assumption.

8.17 The capacity utilisation of the HBJ pipeline would continue to be restricted by the availability of gas from ONGC and the joint venture fields of Panna, Mukta and Tapti at least upto 2001-02. Accordingly, the latest profile as adopted by the Sub-Group for the IXth Plan has been used to decide the capacity utilisation of the pipeline upto 2001-02. It has been assumed that GAIL would be able to ensure the optimum utilisation of the pipeline beyond this period by importing LNG, if required.

PRICING OPTIONS

8.18 Substantial resource generation would be required in the hydrocarbon sector during the IXth Plan period and beyond to meet the imperatives of accelerated exploration and production. To this end, it is necessary that the appropriate prices be fixed for crude oil and natural gas.

8.19 Gas prices have so far been fixed on a cost plus basis. Gas prices as fixed for the next pricing period has to take into account the possibility of imports of natural gas/LNG. The policy of moving towards market determined prices has also to be taken into account.

8.20 Introduction of possible import parity prices or market determined prices with immediate effect would steeply increase the existing gas prices and is not a feasible option. The transition to such prices should be mediated by a period where the gas prices are increased gradually.

8.21 There is a significant difference between the cost of gas production between ONGC and OIL. This difference is due to factors such as gas field geology and is not due to mismanagement on OIL's part. A higher producer price has, therefore, to be allowed to OIL.

8.22 The option of equalising transportation cost along the HBJ and the other smaller pipeline systems in Gujarat, Assam etc. was not considered feasible by the Committee. The transportation cost should be calculated separately for each pipeline so that the viability of each pipeline can be assessed separately.

8.23 The option of introducing distance related transportation charges along existing pipelines such as the HBJ pipeline is not feasible at present as investment decisions have already been taken and units have already come up all along the pipelines based on the assurance of uniform transportation charges. However, distance related charges should be introduced along new pipeline systems and potential customers should be notified in advance.

8.24 The transportation charges along other pipelines may continue to be fixed by GAIL adopting the same principles of 12% post tax return on equity as adopted by the Committee in respect of the HBJ pipeline. In case of pipelines serving more than one consumers, distance related charges could be introduced.

8.25 The consumer prices would be the sum of producer prices and transportation charges and a contribution to the Gas Pool Account which will be Rs.250/MCM w.e.f 1.4.1997 and would increase by Rs.200/MCM every year throughout the pricing period. The recommended gas price is as follows:

Producer price of ONGC	Rs.1800/MCM
Producer price of OIL	Rs.1900/MCM
Transportation charge along HBJ	Rs.1150/MCM
Contribution to Gas Pool Account and increased by Rs.200/MCM every year.	Rs 250/MCM w.e.f 1.4.1997

The above prices refer to gas with the calorific value of 10000 K Cal/Cu.Mtr. and the transportation charge along the HBJ refers to gas with calorific value 8500 K Cal/Cu.Mtr.

8.26 The Committee recommends that the pricing period should extent upto March 31, 2002.

8.27 The Committee recommends that the concessional price for the North-Eastern States be continued. The current consumer price of Rs.1000/MCM be increased to Rs.1200/MCM and the current discount of Rs.400/MCM be reduced to Rs.300/MCM. The discount may be extended to all new units set up within the pricing period for the first five years.

8.28 In order to meet existing commitments of gas, GAIL may buy gas from the privately developed fields of Panna, Mukta and Tapti. The price to be paid by GAIL over the next five years cannot be computed at present as the price will depend on the international price of fuel oil and the value of the US Dollar. However, this price will be higher than the consumer price recommended above. The Government may evolve a suitable method of compensating GAIL for the price difference.

8.29 The international practice is to denominate gas prices and transportation charges in terms of thermal content instead of the volumetric basis currently in use in India. The Committee recommends that gas prices and transportation charges be denominated in terms of calories. However, there are practical problems connected with the proposed changeover. The new system may be introduced in the HBJ pipeline within one year and in other areas within two years.

8.30 There is no uniformity in the Minimum Guaranteed Offtake (MGO) to be agreed by consumers with GAIL/ONGC/OIL. The Committee recommends that the MGO be fixed at 80% of the forecast for a month to be given by the consumer two months in advance. Along the HBJ pipeline, transportation charges will be payable to GAIL on the quantity shortlifted with reference to the MGO.

8.31 ONGC and OIL have so far not agreed to any penalty for short supply owing mainly to the low price of gas compared to alternative fuels. In the context of demands for guaranteed supplies specially from Independent Power Producers, ONGC and OIL may examine the feasibility of guaranteed supplies and penalty for failure to fulfil the guarantees. Appropriately, higher gas prices linked to the price of alternative fuels may be charged in such cases.

8.32 The Sales Tax on natural gas varies among the States. The variation is from nil (Delhi) to 19% (Gujarat). The Committee feels that the proposal of bringing natural gas within the meaning of "declared goods" under the Central Sales Tax Act should be pursued so that a uniform tax at the rate of 4% is chargeable in all States.

8.33 At present, a discount of 15% is allowed on the gas price for supplies from developing fields. This discount may be extended to all isolated fields which cannot be economically connected to the existing gas grids. The present discount of 15% for interruptible supplies is, in practice, not being allowed as these consumers are being treated at par with consumers with firm allocations. This discount may accordingly be withdrawn. However, consumers with fallback allocations should be permitted to negotiate with the gas suppliers for firm allocations at contracted prices.

8.34 Since the consumer price recommended is higher than the sum of the producer price and the transportation cost, it will be necessary to operate a Gas Pool Account for the surplus. Accumulations in this account may be used to compensate ONGC and OIL for concessional prices in the North-East and OIL for the higher cost of production. The balance could be used for development of small and marginal gas fields in the private or the public sector and for funding research and development activities in respect of the development of small fields, deep water pipelines etc. The Gas Pool Account should be administered by a Committee to be designated by the Ministry of Petroleum and Natural Gas.

Sd/-
(P. SENGUPTA)

Sd/-
(SUBIR RAHA)

Sd/-
(ARDHENDU SEN)

Sd/-
(T.L. SANKAR)

Sd/-
SUBJECT TO NOTE AT ANNEXURE - I
(B. NARASIMHAN)

Sd/-
SUBJECT TO NOTE AT ANNEXURE - II
(SANTOSH KUMAR)

B. Narasimhan, IAS
Chairman
and
Secretary to Govt

भारत सरकार
उद्योग मंत्रालय
औद्योगिक लागत एवं मूल्य ब्यूरो
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फैक्स : 011-4690770, 011-4622901

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ANNEXURE

No.3/22)/95-BICP

The Note of Exceptions by Shri B. Narasimhan, Chairman, BICP, and a Member of the Committee on Natural Gas Pricing.

1. I have given considerable thought to the contents of the Report, proposed to be submitted by the Committee to the Government, on Natural Gas Pricing. While, I am in general agreement with the approach of the Committee recommending a move towards market driven prices in the context of general economic liberalisation, I have strong reservations about some of the concepts and principles followed by the Committee in arriving at its recommendations on prices for gas and transportation.

Price of Gas produced by ONGC

2. In recommending a price for Rs.1800/MCM for the production of gas by ONGC, the Committee has been largely guided by the figure of Rs.1854/MCM indicated by Discounted Cash Flow (DCF) method for working out LRAC. The Committee has relied entirely upon the projections of costs and benefits given by ONGC. A careful perusal of the trend of figures given in Table-6.4 would bring into focus the infirmities in the DCF method. In my view, this method is unreliable if there are great uncertainties in the projections of the flow of benefits and costs. In the present case, the basis for figures indicated at Sl.Nos. 16 to 21 and 25 to 30 is highly suspect and these account for the major portion of the costs anticipated in future. The item 'other misc. capital' accounts for 45%, 35.29%, 16.14%, 23.3%, 43.6%, 73.68 of the capital expenditure projected for the years upto 2001-02 and the basis for these projects is not even indicated. The projections for the subsequent years are much less justified. Even if one assumes that these could be extrapolations of the empirical annual incidence so far, they would have to be justified, particularly in the case of expenditure on surveys and explorations, with reference to potential in future and a well defined action plan. Figures emanating from the realm of intentions and surmises\as to investment in the long term cannot be used to influence the calculations for arriving at the cost of production in the immediate and near future. There is an inherent danger of inflated figures of expenditure when there is not even a vague assertion of certainty. In view of the total uncertainty about the gas exploration activities, the DCF method, in my view, is not a suitable guide for the determination of price adequate enough to compensate for the cost of production at present and in near future. For working out a just price for a given pricing period, the concept of exploration of costs at the margin of the period, adopted by the Expert Group, would be the more appropriate basis.

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Contd...p/3....

3. The proposal of the Committee is to allow a 15% post-tax return on capital employed, which includes both equity and debt. In respect of debt, the company is entitled to be compensated for the interest, and not a post-tax return. In working out an administered price, it will be improper to permit any post-tax return on this portion of the capital employed. The appropriate course would be to allow interest on debt and a post-tax return of 15% on equity. The Expert Group's calculations, modified by 15% post-tax return on equity, should be the basis for determination of price.

4. In view of the fact that the price is proposed for a period of about 5 years, it may be appropriate to allow an escalation of the costs subject to inflation. If a provision is made for escalation in operating costs at 8% per annum, a rate adopted by the Committee, the price of Gas produced by ONGC would work out to Rs.1657/MCM. I would, therefore, recommend Rs.1675/MCM as the fair price to be given to ONGC for the pricing period 1997 (Jan.) to March, 2002.

Cost of Gas Transported by GAIL

5. In regard to transportation of gas, the explanation offered by GAIL, for assessing its capacity at 90% on 330 days basis is not convincing. GAIL has failed to justify, on empirical or technical grounds, the need for writing down the duration of annual operations. The claim that GAIL's customers have been allowed to shut down for 30 days does not imply that GAIL cannot operate the pipeline for 365 days. It is only necessary for GAIL to enlist additional customers appropriately so as to operate the line to its capacity, since all customers will not, and need not, resort to shut down at the same time. Normation lies at the heart of determination of administrative prices. Since the authority has to strike a balance between the consumer and producer interests and ensure that considerations of efficiency are not sacrificed in the determination of reasonably prices, technical and marginal constraints would have to pass the test of reasonableness before credit can be given. In this case, no justification exists for writing down the capacity of the pipeline. So, it is not proper to assume sales only for 330 days. Further, the LRAC method seems unsuitable in this case also, particularly in view of the fact that the upgraded pipeline will not be fully operational till 2003-04, while the proposed pricing period extends only upto March, 2002.

6. It has been proposed to take the weighted average of the current price of Rs.850/MCM and the figure worked out for Transportation of gas through the upgraded system. The logic of this approach is not evident. In working out a combined transportation cost, the calculated costs of transportation of production for the existing line and the upgradation line and not the current price should be taken into account. BICP had conducted a study on the costs and prices of transportation of gas along the HBJ pipeline and submitted a Report to the Government in August, 1994. The study revealed that a price of Rs.700/- would be appropriate having regard to the actual

Contd...p/3....

capacity utilisation and actual capital expenditure incurred year-wise upto 1992-93 and projections thereafter. As against this, the Expert Group has now arrived at a figure of Rs.576/MCM for 1996-97 and Rs.522/MCM for 1997-98 on the basis of 1994-95 results of GAIL's operations. It would, therefore, not be proper to take the cost of transportation along the existing pipeline higher than Rs.700/-, even though the current notified price is Rs.850/MCM.

7. As regards the upgradation project, the modified figure of the Expert Group for a 20 year project life will be Rs.1035/-. The weighted average of these two figures would be the appropriate price. If an escalation of 8% per annum is allowed on costs subject to inflation during the pricing period, the weighted average would come to Rs.983/MCM, based on a pipeline life of 20 years. Therefore, I would favour recommending a transportation charge of Rs.1000/MCM.

Recommendations

8. To sum up, I would recommend a price of Rs.1675/MCM for the gas produced by ONGC and a combined transportation charge of Rs.1000/MCM for GAIL.

9. Subject to the contents of this note, I subscribe to the rest of the Report, as formulated by other Members of the Committee.

Narasimhan 31/12/96

(B. Narasimhan)

Subjedt: Draft Report of Committee on Natural Gas Pricing.

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Once the broad objective of market alignment of natural gas prices is accepted, the following issues arise:

(i) The period of transition to market-aligned prices.

(ii) Determination of what would constitute market prices.

(iii) Mechanism for absorbing the surplus between consumer and producer prices, given that the costs of domestic producers/transporters will be substantially lower than 'market prices' irrespective of how this is to be determined.

2. It is felt that market alignment of consumer prices of natural gas should broadly proceed in tandem with the broader processes of deregulation of the domestic petroleum sector, including LPG. A complete phase-in petiod of 3 years for market aligned consumer prices would be desirable.

3. As regards the determination of 'market-aligned prices', there are conceptual difficulties and ambiguities arising from the absence of an accepted international price for natural gas and the absence of pipeline imports at present. To the extent that fuel oil is accepted as the nearest replacement liquid fuel for natural gas, the expected import parity price of fuel oil is a useful reference point.
We could aim to align the consumer prices to this level over a three year transitional period. It should be noted, however, that linkage with import parity price of fuel oil may introduce some volatility in natural gas prices, since the former could fluctuate with international crude price movements. This may require factoring an appropriate deflator in the pricing structure so as to ensure a measure of price stability for the consumers.

4. Under the above approach, it would be logical to examine the feasibility of an immediate alignment of consumer price of natural gas to atleast the prevailing

domestic consumer price level of fuel oil. The feasibility of this would have to be seen in the context of the need to ensure a smooth and non-disruptive transition to full import parity over a three year period.

5. The issue of differential consumer and producer prices needs further consideration. If the natural gas sector is to be open for domestic and foreign private investment (a limited opening up has already been allowed under the PSC modality), there could be a case for phasing in border prices for natural gas producers and transporters, on the analogy of proposals under consideration in respect of producers of crude. We could consider a price structure providing for gradually escalating producer prices, so as to incrementally level the playing field between domestic PSU producers and private investors, both domestic and foreign.

6. If a gradual phase in of border pricing for domestic PSU producers of natural gas is provided for the differential between producer and consumer prices will progressively disappear. However, there will be an additional budgetary outgo on account of the fertiliser subsidy. The Committee's recommendation should clearly bring out the magnitude and mechanisms for ensuring budget neutrality at each stage of the proposed price alignment.

7. As regards distance-related transportation charges, it is felt that definite recommendations could be made for its immediate implementation since the economic rationale is not in doubt.

ANNEXURE-III

No:L-12015/2/88-GP (Vol.III)
Government of India
Ministry of Petroleum & Natural Gas

New Delhi; Dated January 28, 1995.

ORDER

The price of natural gas was last fixed by the Government in December 1991. In order to examine the changes required in the levels and structure of prices, it has been decided to constitute a Committee to review the entire question of natural gas pricing. The composition of the Committee would be as follows:

i.	Sh. T.L. Shankar, Principal, ASCI	-	Chairman.
ii.	Chairman, BICP	-	Member.
iii.	Adviser (Energy), Planning Commission	-	Member.
iv.	JS (E), MOPNG	-	Member.
v.	Santosh Kumar, JS (FT), DEA Ministry of Finance.	-	Member.
vi.	Director (NG), MOPNG	-	Convener.

2. The Committee will review the existing pricing policy, including structure and levels of the prices and recommend changes required either in the principles for determining these prices and in the actual levels of the prices.

3. In making their recommendations, the Committee may have due regard to the assurances given to multilateral agencies regarding the introduction of market related prices of petroleum products and natural gas. The Committee may also take into account the requirements of the existing consumer industries as well as the need and the feasibility of encouraging new markets of utilising natural gas.

4. The recommended gas prices may also take into account the production sharing contracts signed with private sector developers of oil/gas fields and should in general be such as to attract investment in the production, transportation and distribution of natural gas.

5. The Committee may recommend the principles for determination and the incidence of transportation charges to be allowed to natural gas transporters.

6. The Committee may also take note of decisions on the pricing of gas proposed to be imported from Oman, Iran etc.

7. The Committee may examine the terms of reference of the Gas Linkage Committee and recommend the changes that are required to be introduced as and when market related prices are introduced.

8. A study is proposed to be commissioned for the introduction of an appropriate regulatory framework for the gas industry in India. The Committee may assist the Ministry in guiding and supervising the study.

9. The report of the Committee may be submitted by July 31, 1995.

(A. Sen)
Director (NG)

To:

1. Sh. T.L. Shankar, Principal, ASCI, Hyderabad.
2. Secretary, Planning Commission, New Delhi.
3. Finance Secretary, New Delhi with a request to nominate a suitable representative to the Committee.
4. Chairman, BICP, New Delhi.
5. Adviser (Energy), Planning Commission, New Delhi.
6. JS (E),), Ministry of Petroleum & Natural Gas.

Copy for information to:

1. JS & FA, Ministry of Petroleum & Natural Gas.
2. CMDs, ONGC, OIL, GAIL.

ANNEXURE-IV

List of Organisations met by the Committee

1. Ministry of Power.
2. Department of Fertilizers.
3. Department of Chemicals & Petrochemicals.
4. ONGC
5. OIL
6. GAIL
7. NTPC
8. IPCL
9. Government of Assam
10. Government of Gujarat
11. Governemnt of Tripura
12. Government of Andhra Pradesh
13. Government of Himachal Pradesh
14. Government of Karnataka
15. Government of Madhya Pradesh
16. Gujarat Chambers of Commerce

CALCULATION OF TRANSPORTATION CHARGES ON LRMC BASIS - (WITHOUT COMPRESSOR REPLACEMENT)

0.00

HBJ UPGRADATION

		Replacement
CAPITAL COST (RS CRORES)	2,376.15	
EQUITY	1222.15	
LOAN	1154.00	
PERIOD (YEARS)	20	
TAX RATE (%)	41.00%	
POST TAX RETURN(%)	21.05%	

TRANSPORTATION CHARGES
31.429

PARTICULARS	1 1997	2 1998	3 1999	4 2000	5 2001	6 2002	7 2003	8 2004	9 2005	10 2006	11 2007	12 2011	AVG 25 YEARS	CHARGES	[illegible]	CHARGES
YEARLY CAPACITY (MMSCM)	440	490	651	523	794	1,996	3,479	4,660	4,060	4,660	4,660	4,660	3,690.09		[illegible]	
INTERNAL CONSUMPTION (MMSCM)	67	67	67	67	67	108	335	335	335	335	335	335				
INTERNAL CONSUMPTION (VALUE)	13.81	13.81	13.84	13.84	13.84	34.61	69.21	69.21	69.21	69.21	69.21	69.21				
OTHER OPERATING COSTS	5.79	42.04	48.57	48.57	48.57	48.57	48.57	48.57	48.57	48.57	48.57	48.57				
OPERATING COST (RS CRORES)	20	56	62	62	62	83	118	118	118	118	118	118	103.33	280	[illegible]	[illegible]
DEPRECIATION (RS CRORES)	112.87	112.87	112.87	112.87	112.87	112.87	112.87	112.87	112.87	112.87	112.87	112.87	112.87	306	[illegible]	[illegible]
INTEREST (RS CRORES)	122.27	121.50	115.79	105.84	95.71	85.37	74.81	64.00	52.93	41.55	33.92	0.00	40.77	118	[illegible]	[illegible]
RETURN ON EQUITY (RS CRORES)	264.39	268.94	270.49	270.49	270.49	270.49	270.49	270.49	270.49	270.49	270.49	270.49	270.18	732	[illegible]	[illegible]
														1,429		[illegible]

LOAN REPAYMENT SCHEDULE

	1	2	3	4	5	6	7	8	9	10	11	12
ADB												
OP. BALANCE	704	704	685	664	641	615	587	556	521	483	442	396
ADDITION												
REPAYMENT		19	21	23	26	28	31	34	38	42	46	51
CL. BALANCE	704	685	664	641	615	587	556	521	483	442	396	343
INTEREST (6.9%+GOVT GTY 1.2%)	57	56	55	53	51	49	46	44	41	37	34	30
ODB												
OP. BALANCE	450	450	450	394	338	281	225	169	113	56		
ADDITION												
REPAYMENT			56	56	56	56	56	56	56	56		
CL. BALANCE	450	450	394	338	281	225	169	113	56	0		
INTEREST (14.5%)	65	65	61	53	45	37	29	20	12	4		

NOTE: 1) WORKING CAPITAL ADDED TO EQUITY FOR WORKING RETURN ON EQUITY
2) INTEREST ON ADB LOAN TAKEN AT 6.9% P.A. + 1.2% GOVT. GTY. FEE
3) GAS QTY AVAILABLE TAKEN AS PER 9TH PLAN SUB GROUP. FROM 2002-03 FULL UTILISATION CONSIDERED TAKING LNG IMPORT.
4) COST OF GAS FOR INTERNAL CONSUMPTION INCLUDED IN OPERATING COSTS HAS BEEN REDUCED AS PER CAPACITY UTILISATION. GAS PRICE FOR INTERNAL CONSUMPTION IS @ Rs 1300/MSCM
. THE TPTN CHARGES WOULD GO UP BY Rs [illegible]/MSCM FOR EVERY Rs 100 MSCM INCREASE IN GAS PRICE.

ANNEXURE - VI

DISCOUNTED CASH FLOW METHOD (WITH HBJ WDV COST AS PER BOOKS)
COMBINED HBJ SYSTEM

(Rs IN CRORES)

YEAR ENDING		1 1997	2 1998	3 1999	4 2000	5 2001	6 2002	7 2003	8 2004	11 2007	14 2010	15 2011	19 2015	20 2016
TOTAL INVESTMENT														
HBJ EXISTING														
NFA OF HBJ (31 3 90)	682													
ADDITION DURING THE YEAR	198													
WORKING CAPITAL	98													
DEBT (AS ON 31 3 96)	480													
EQUITY INVESTMENT	498	498						416	0	0	0		0	0
HBJ UPGRADATION														
TOTAL INVESTMENT	2,376													
WORKING CAPITAL	63													
DEBT	1,164													
EQUITY	1,285	1,285												
SALVAGE VALUE												960		1,002
GAS QTY TRANSPORTED (MMSCM)		6,248	6,298	6,459	6,331	6,602	7,804	9,287	10,468	10,468	10,468	10,468	10,468	10,468
TRANSPORTATION REVENUE		715	720	739	724	755	893	1,062	1,197	1,197	1,197	1,197	1,197	1,197
OPERATING EXPENSES		161	197	204	204	204	225	259	259	259	259	259	259	259
DEBT SERVICING		384	337	324	272	251	232	200	187	90	83	84	0	0
TAX @ 43%		94	94	94	94	95	201	319	431	431	431	411	411	432
NET CASH FLOW		(1,707)	91	116	154	205	235	(132)	319	417	424	(545)	527	1,508
RETURN ON EQUITY		12.00%												
TRANSPTN. CHARGES/MCM		1,144												

NOTES

1 GAS QTY AVAILABLE FOR SALE HAS BEEN ASSUMED AS PER 9TH PLAN SUB GROUP PROFILE TILL 2001-02 FOR 2002-03 ADDITIONAL 5 MMSCMD OF GAS HAS BEEN ASSUMED TO BE AVAILABLE VIA LNG ROUTE AND BEYOND 2002-03 FULL CAPACITY UTILISATION HAS BEEN ASSUMED CONSIDERING PROBABLE AVAILABILITY OF ADDITIONAL GAS VIA LNG ROUTE

2 OPERATING EXPENSES FOR HBJ TAKEN AS PER 1996-97 LEVEL AND KEPT CONSTANT THEREAFTER FOR EXPANSION PROJECT THE INTERNAL GAS CONSUMPTION TAKEN AS PER SALES BUILT UP THE REST OF THE OPERATING COST RESTRICTED TO APPROVED DFR

3 INTEREST ON FOREIGN LOAN PRIMARILY FROM ADB TAKEN AT 6.9% WITH GOVT GTY FEE OF 1.2%

4 COST OF GAS FOR INTERNAL CONSUMPTION TAKEN AT Rs 1500/- PER MCM. INCREASE IN GAS COST BY Rs 100/MCM WOULD INCREASE THE TRANSPORTATION COST BY Rs 6/MCM

ANNEXURE - VII

DISCOUNTED CASH FLOW METHOD (WITH HBJ WDV COST AS PER BOOKS)
COMBINED HBJ SYSTEM

(Rs IN CRORES)

YEAR ENDING		1 1997	2 1998	3 1999	4 2000	5 2001	6 2002	7 2003	8 2004	11 2007	14 2010	15 2011	19 2015	20 2016
TOTAL INVESTMENT														
HBJ EXISTING														
NFA OF HBJ (31 3 96)	682													
ADDITION DURING THE YEAR	198													
WORKING CAPITAL	98													
DEBT (AS ON 31 3 96)	480													
EQUITY INVESTMENT	498	498						416	0	0	0		0	0
HBJ UPGRADATION														
TOTAL INVESTMENT	2,376													
WORKING CAPITAL	63													
DEBT	1,154													
EQUITY	1,285	1,285										989		
SALVAGE VALUE														1,002
GAS QTY TRANSPORTED (MMSCM)		6,248	6,298	6,459	6,331	6,602	7,804	9,287	10,468	10,468	10,468	10,468	10,468	10,468
TRANSPORTATION REVENUE		780	786	806	790	824	974	1,159	1,307	1,307	1,307	1,307	1,307	1,307
OPERATING EXPENSES		161	197	204	204	204	225	259	259	259	259	259	259	259
DEBT SERVICING		453	406	391	337	313	292	257	241	131	108	103	0	0
TAX @ 43%		94	94	94	94	107	231	372	502	502	502	482	482	503
NET CASH FLOW		(1,712)	88	117	155	200	227	(145)	304	414	437	(526)	565	1,546
RETURN ON EQUITY		12.00%												
TRANSPTN. CHARGES/MCM		1,248												

NOTES
1 GAS QTY AVAILABLE FOR SALE HAS BEEN ASSUMED AS PER 9TH PLAN SUB GROUP PROFILE TILL 2001-02 FOR 2002-03 ADDITIONAL 5 MMSCMD OF GAS HAS BEEN ASSUMED TO BE AVAILABLE VIA LNG ROUTE AND BEYOND 2002-03 FULL CAPACITY UTILISATION HAS BEEN ASSUMED CONSIDERING PROBABLE AVAILABILITY OF ADDITIONAL GAS VIA LNG ROUTE
2 OPERATING EXPENSES FOR HBJ TAKEN AS PER 1996-97 LEVEL AND KEPT CONSTANT THEREAFTER FOR EXPANSION PROJECT THE INTERNAL GAS CONSUMPTION TAKEN AS PER SALES BUILT UP THE REST OF THE OPERATING COST RESTRICTED TO APPROVED DFR
3 INTEREST ON FOREIGN LOAN PRIMARILY FROM ADB TAKEN AT 18% TO COVER FOREIGN EXCHANGE RISK
4 COST OF GAS FOR INTERNAL CONSUMPTION TAKEN AT Rs 1500/- PER MCM. INCREASE IN GAS COST BY Rs 100 MCM WOULD INCREASE THE TRANSPORTATION COST BY Rs 6/MCM.

गैस अथॉरिटी ऑफ इंडिया लिमिटेड
(भारत सरकार का उपक्रम)
Gas Authority of India Limited
(A Govt. of India Undertaking)

DLH/GAIL/GAS PRICING/96/97 १३५७ July 31, 1996

Sh. A. Sen,
Director(NG),
Ministry of Petroleum & Natural Gas,
Shastri Bhawan,
NEW DELHI.

Sir,

This has reference to the letter dated 25.6.1996 from Sh. T.L. Sankar, Chairman Gas Pricing Committee regarding comments of GAIL on issues raised in the letter The issues mentioned in the letter have been in a way covered in the draft report circulated earlier Nevertheless the following points have emerged further on revisiting the issues

1. The quantity of production and sale of gas for purposes of pricing should be referred to in calorific value and not in cubic metres.

➤ The price of gas on calorific value is fixed when it is linked to alternative fuels soa s to be competitive. In case of Administered Prices, it is based upon volumetric basis, which is an absolute number. The calorific value (K. Calories or MMBTU) are derived numbers based upon heat content per unit vilome of gas multiplied by gas volume.

The issue of supplying gas in calorific value terms has been studied vis-a-vis the available equipments in various consumer terminals. The gas sales in calorific value terms is based on measurement in volume terms only multiplied by the average calorific value of the gas measured periodically. The same system is prevailing in metering stations of large consumers built recently. Through an auto sampler the delivered gas is analysed at regular intervals to arrive at average calorific value of the gas being supplied. Such measuring systems being very expensive find its use uneconomical for small consumers. For a cluster of them a single such system is put on line upstream. But in case of dedicated small consumers on an isolated field, this system may be totally uneconomical. In such cases a weekly sampling may be more practical.

From the above it may kindly be noted that there is no metering facility which gives on line transfer of gas in energy terms. The energy terms are deduction of the average calorific value and the volume of gas passing through the terminal. This also would create some complications as to the reconciliation between the producer and the transmission company on the difference between energy units purchased , sold and in the line pack due to derived computations.

There is yet another issue related to measurement of calorific value periodically. In case of a process plant, the residual NGL is spiked back into the lean gas in bursts and is not a uniform injection. As such it may give erroneous quantum of energy units transferred to the consumer. The concept of payment by consumer for the energy units taken can probably be achieved by simplifying the existing rebate/premium formula related to a band to a direct linear relation. Further, the transmission companies normally charge on capacities of the system used, irrespective of the heat content of gas, which is beyond its control. As such there may be problems in computing transportation tarriffs in areas where the gas is having substatntial inert gas.

2 The price will be referred with reference to as specified pressure.

Para 7.29 on Page 50 covers the issue amicably. We have no further comments to offer.

3 The minimum guarantee offt-take of the consumers shall be with reference to monthly out-take.

The present contracts with major consumers have the minimum guarantee offtake clause on monthly basis only. We find the same is operating very well. Since in India we do not have any storage facility except for marginal line pack, it would not be possible to permit the consumer to make up on the shortfalls over a longer period. As such we find MGO on monthly basis is more practicable. Further in our contracts we have provided scheduled shutdown period up to 1 month for each party (Seller and Buyer) when no MGO is applicable. Similarly if drawal is effected due to Force Majeure reasons, again MGO is not available. As such present system of MGO which is also 80% on monthly basis, may be continued. Existing contracts with consumers with these provisions run upto 2007.

4. The GAIL would have to pay some damages in case they are not able to supply as per the contract with the consumers.

The possible defaults of GAIL in Gas Supply Contract could be one of the following :-

a) Non supply of contracted quantity.
b) Gas Supply at a pressure different from than contracted
c) The supply gas has higher sulpher and/or water content.

The issue of non supply of contracted quantity has been discussed in para 7.26 of the report and we have no further comments to offer. As regards (b) and (c), the consumer may be given an option to refuse the gas and not pay for it and also take exemption from the MGO. The issue has also been discussed in Para 7.29 and 7.30 of the report. The issue of payment of either i) compensating loss of profit on stoppage of production or (ii) reimbursement of cost of alternative fuel is dealt with in para 7.26, which we find is the realistic assessment.

Thanking you.

Yours faithfully

(R.P. SHARMA)
Executive Director (M&P)

आयल एण्ड नेचुरल गैस कारपोरेशन लिमिटेड
तेल भवन, देहरादून-248003
Oil & Natural Gas Corporation Ltd.
Tel Bhavan
Dehra Dun-248003

इन्द्र नाथ चटर्जी
निदेशक (वित्त)
INDRA NATH CHATTERJEE
DIRECTOR (FINANCE)

DO No.HQ/CA/Cost/GP/96
Dated: September 17, 1996

Dear Shri Sen,

Kindly refer to your DO letter No.L-12015/3/94-GP dated July 25, 1996 addressed to our CMD seeking our views on certain points which are being considered by the Gas Pricing Committee.

Our views are furnished pointwise in the enclosed note. We hope that this would meet your requirements.

With regards,

Yours sincerely,

(I.N. Chatterjee)

Shri A.Sen,
Director(NG),
Ministry of P&NG,
Shastri Bhawan,
New Delhi.

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Pointwise Comments on the Issues under consideration by the Natural Gas Pricing Committee

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1. Quantity of production and sale of gas for the purpose of pricing should be referred to in calorific value and not in cubic meters.

Comments:

Internationally the gas price is denominated in terms of thermal content. Likewise, the price of gas to be sold in the domestic market from the fields operated by Joint Ventures is also being considered for denomination in terms of calorific value. If the move to import gas from neighbouring countries to augment supplies materialises, then the country would be buying gas based on the principle of energy content.

Presently gas is sold in the domestic market on volumetric basis and price is linked to a broad based calorific value. The existing basic producer price of gas of Rs.1500 per 1000 SCM is applicable for a calorific value range of 9000-9500 KCal per cu.mtr. If the calorific value lies beyond this range, there is a premium/discount proportionate to the difference in the calorific value from the mean of the above range i.e. 9250 K.Cal per cu. mtr. Thus even at present there is a linkage of the gas price to the thermal content except that there is no change in the gas price between the calorific values of 9000 to 9500 K.Cal per cu.mtr.

While it would be desirable to switch over from the present pricing regime based on volumetric basis to the one based on calorific value in line with international practices, the following points merit consideration:

(a) The switch-over would need revamping/modification of the present system. The new system would call for installation of online calorific value meters at all the custody transfer points. This would require an engineering study to ascertain feasibility of installation of meters at the respective points, time frame for change over and the cost implications. In the event of a decision to switch over to the calorific value pricing regime, the time frame for installation of meters needs to be fixed. In case the producer is required to bear the metering costs, the same needs to be worked out and built into the gas price payable to the producer.

(b) As the supplies and billing have so far been made only on volumetric basis, data on unit cost of production of gas has been supplied by ONGC to various agencies on per 1000 SCM basis for working out the fair price of gas. As the calculations would be made on volumetric basis, it is very important to determine the base calorific value for converting and fixing the price in terms of thermal value. In this context it may be mentioned that with low calorific value gas being supplied in places like Krishna Godavari basin, Rajasthan etc, and a significant portion of gas produced by ONGC being supplied after extraction of LPG, NGL and C2-C3 the average calorific value for ONGC as a whole tends to be less than even the lower limit of the existing band i.e. 9000 K.Cal per cu.mtr. Hence it is proposed that the base calorific value for price fixation on thermal basis should be that of methane only (i.e. about 8500 K.Cal per cu.mtr.).

2. The price will be referred with reference to a specified pressure

Comments:

With the ageing of fields, pressure at which gas (both associated and free) is available at the surface changes with time. While associated gas is usually available at medium or low pressure, the free gas is available at a relatively higher pressure during early life of a producing field. However, both tend to taper off with time unless matching compression facilities are created at additional cost. The cost of compression could be substantial depending upon the gas quantities and the extent of boosting required. As such, it would be desirable to relate price of gas to a particular base pressure. In this context, the most important aspect is to fix the base pressure to which the price of gas can be related. Earlier gas used to be supplied to and accepted by consumers in the onshore areas at a specified pressure of 1 (one) kg/cm². This could be fixed as the base pressure and any additional boosting over this base pressure should be to the consumer account.

3. Minimum Guaranteed Offtake shall be with reference to monthly offtake.

Comments:

Minimum Guaranteed Offtake (MGO) charges is presently being levied only on monthly basis. For this purpose, in most cases the MGO has been fixed at 80% of the daily committed quantity multiplied by the number of days in the month.

While this has been found to be quite satisfactory in respect of fertiliser industry, base load power stations, sponge iron plants etc., there are some difficulties with respect to some typical consumers like tea industry which are seasonal in nature (offtake with extreme variation in the rate of consumption of gas between day and night), power plants in certain areas with load variation between day and night and also in different seasons. In such a situation, the erratic drawal leads to flaring of associated gas.

To overcome such situations as brought out above, either there should be MGO on daily basis or some other suitable alternate mechanism needs to be devised. For instance the maximum "swing" in the demand can be pegged at say 110% of the daily or hourly contracted quantity. Supplies above this maximum swing can be on a best efforts basis at say 15 to 20 per cent higher than the normal price.

4. GAIL would have to pay some damages in case they are not able to supply as per the contract with the consumers.

Comments:

Since MGO is imposed on the consumers, it is quite logical that there is a reciprocal demand from them to protect their interest against short/non-supply of gas. Since GAIL is the transporter of gas, the guarantee would ultimately be sought from ONGC. Stoppage of supply or short supply can happen in the following cases:

(a) Force Majeure including unexpected reservoir behaviour

(b) Planned maintenance shutdown at the producer's end or the consumer's end including that of GAIL with mutual consent of the parties concerned.

(c) Compressor breakdown at the producer's end or GAIL's end.

While no MGO is attracted under items (a) and (b) above, stoppage or shortfall in gas supply due to the reasons at (c) above needs further examination from the standpoint of reciprocal obligation under MGO. It is understood that while in some major international gas contracts there are some examples of treating (c) under force majeure, in other cases, consumers are compensated. But in the latter case, cost implications for extra precautions required in the maintenance for uninterrupted operation of compressors are built in the price of gas by the producer and alternatively by the transporter in the form of transportation cost of gas. In addition, certain operational tolerance limits as a percentage of daily committed quantity is usually allowed in international gas contracts while determining the shortfall in gas supply.

In the Indian context, with the tendency towards over-commitment of gas and the gas prices being kept artificially low, levy of damages which would necessarily be linked to the price of alternative fuels would place an unduly high risk on the producer and transporter. Therefore, suitable alternative mechanism has to be evolved for taking care of this aspect.