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PRINCIPLES OF NATURAL GAS PRICING IN RUSSIA

Final Report

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EXECUTIVE SUMMARY

S.1 INTRODUCTION (see Chapter 1)

This report presents the results of work performed in natural gas pricing, as part of energy sector assistance provided to Russia by the U.S. Agency for International Development (A.I.D.). The report was prepared in support of the World Bank, for the use of the Bank in developing natural gas projects in Russia, and for use by A.I.D. to promote market reform in Russia. The report was prepared as part of the Energy Efficiency and Market Development Program, by RCG/Hagler, Bailly, Inc. and Merklein Associates. The report describes the situation existing in Russia in gas pricing as of early 1993, prepares estimates of the cost of exploration, production, and transmission, develops principles for pricing gas distribution, discusses taxation and subsidies, and develops conclusions and recommendations for gas price reform to ensure the financial viability of gas distribution companies and provide more efficient use of gas by end-users.

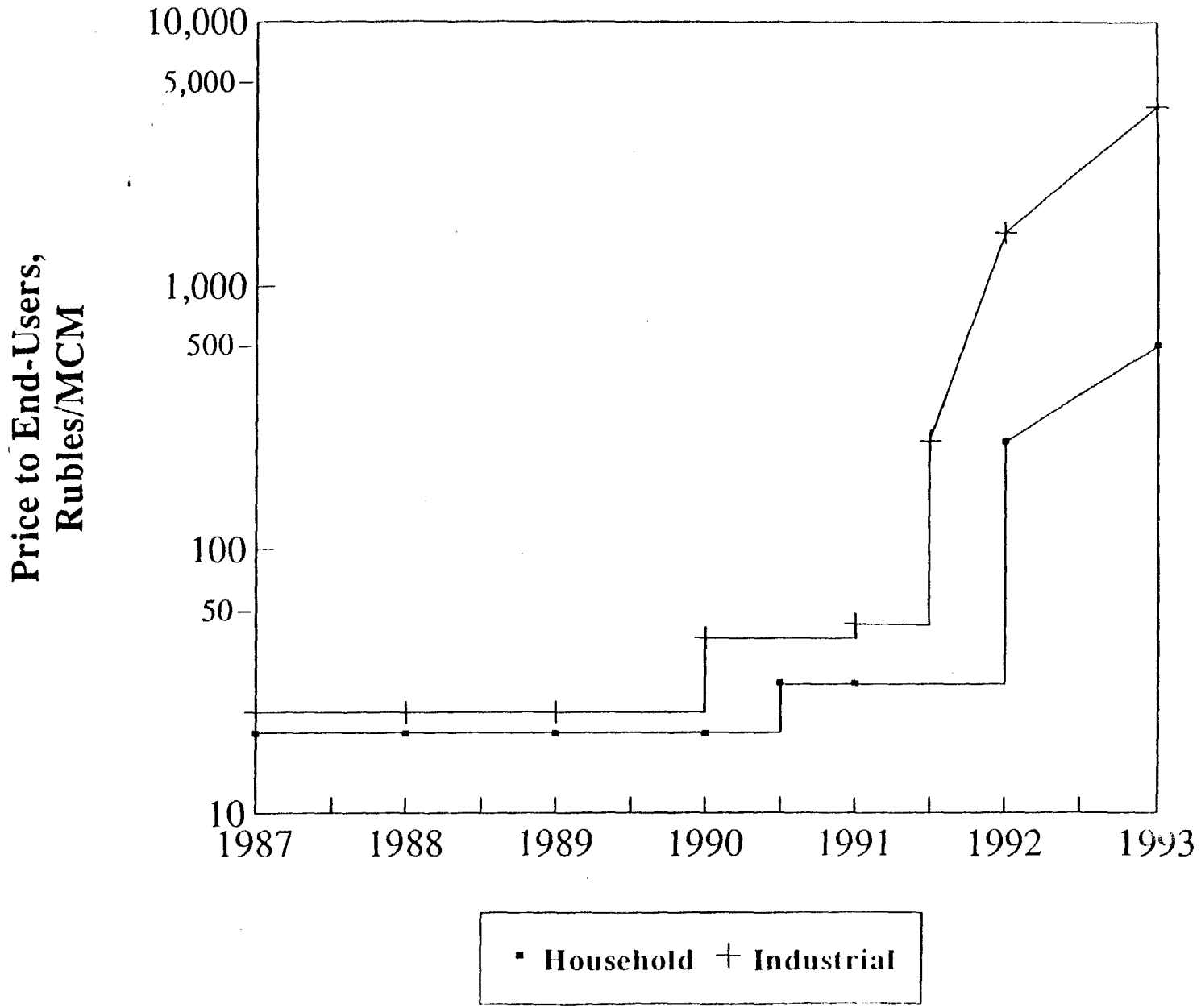
Existing Gas Pricing Conditions in Russia

The evolution of retail gas prices in Russia since 1982 is shown in Exhibit S-1. The structure of gas prices in Russia is based on a two-pronged system - for domestic uses or exports:

- *Domestic* The retail price to industrial customers, powerplants, and all final users except individuals and housing cooperatives was set at 4,000 rubles/thousand cubic meter (mcm) (equivalent to $0.20/MMBtu) effective February 1, 1993, and it is subject to a value added tax (VAT) of 20%. The retail price to individuals and housing cooperatives is set at 600 rubles/mcm ($0.03/MMBtu). The ccorresponding city gate prices are 3600 rubles/mcm and 300 rubles/mcm.

- *Exports* The price of gas sold by Gazprom to the government of the Russian Federation for resale in the export market is set at 6,000 rubles/mcm (equivalent to $0.30/MMBtu) as of February 1993, at an exchange rate of 1000 rubles/US$). This price applies to 55 percent of the

Exhibit S-1
Evolution of Natural Gas Prices in Russia



gas exported by Russia. For exports to CIS countries of the ruble zone that have bilateral agreements with Russia on mutual deliveries of basic goods, a minimum price level of 13,000 rubles/mcm (February 1993) plus VAT has been established (about $0.82/MMBtu). For other CIS countries, "world prices" are used although payments may be made in rubles. For exports to countries outside the CIS, "world prices" are used and payments should be made in hard currency.

Gas Industry Structure

The natural gas resources of Russia are the world's largest - estimated proved gas reserves alone of 64.5 trillion cubic meters (2,280 Tcf) are 17 times those of the USA. More than two thirds of the gas reserves of the former USSR are located in Western Siberia. The predominance of Russia as the world's largest owner of natural gas reserves can be seen from Exhibit S-2.

Russia's gas transportation network contains 220,000 km (130,000 miles) of pipeline. Although it is newer than the system in the U.S., the system is experiencing significant deterioration, with concomitant projected growth in capital requirements.

The natural gas sector in Russia is managed and owned largely by the following enterprises:

- Gazprom manages gas transmission, gas storage, non-associated gas production, and processing of non-associated gas. The company sells gas to distribution companies and exports gas under sales contracts. Gazprom consists of regional production and transmission enterprises.

- The natural gas distribution sector consists of more than 700 local distribution companies in 60 regions, each of which has a regional gas utility, plus the distribution companies of Moscow and St. Petersburg. Current plans call for the privatization of gas distribution enterprises.

- Rosneftegas and the oil enterprises manage associated gas production, as well as oil production. Associated gas represented 5.6 percent of the volume of Soviet gas production in 1990, and currently represents about 10 percent of the volume of Russian gas production.

Exhibit S-2
World Natural Gas Reserves

		RESERVES		
Rank	Country	TCF	TCM	Percent
1	Former USSR	2280	64.59	44.7%
2	Iran	600	17.00	11.8%
3	United Arab Emirates	196	5.55	3.8%
4	Saudi Arabia	185	5.24	3.6%
5	United States	167	4.73	3.3%
6	Qatar	162	4.59	3.2%
7	Venezuela	129	3.65	2.5%
8	Algeria	128	3.63	2.5%
9	Nigeria	120	3.40	2.4%
10	Iraq	109	3.09	2.1%
11	Indonesia	104	2.95	2.0%
12	Norway	97	2.75	1.9%
13	Canada	96	2.72	1.9%
14	Australia	75	2.12	1.5%
15	Mexico	71	2.01	1.4%
	Subtotal	4519	128.02	88.6%
	Rest of World	584	16.54	11.4%
	TOTAL	5103	144.56	100.0%

Note: Former USSR Reserves Include Reserves Classified as C2.

Source: International Energy Annual, 1991; US Dept. of Energy; DOE/EIA-0219(91); p 100.

- The State Committee on Geology manages oil and gas exploration.

Issues in Gas Pricing in Russia Today

The current system of gas pricing in Russia presents a number of critical issues:

The level of prices to all sectors is below economic costs.

- The price of gas in the household sector is substantially below the price to the industrial sector, although the cost of delivering gas to the household sector is higher.
- The city gate price of gas destined for the household sector is below the wellhead production cost of gas.
- There are no regional differences in gas prices within Russia.
- There is a large gap between domestic prices and export prices.

To provide a focus for this report, we have attempted to identify the aspects of price reform that appear to be most important and most needed:

- Transparency of wellhead prices.
- Availability of transmission service.
- Creation of city gate prices.
- Gradual introduction of transmission costs based on hard currency.
- Increase in distribution margins.
- Reversal of the disparity between industrial and household prices.
- Creation of additional customer classes.

We approximated the cost of gas transportation service on the Russian gas pipeline network using information from U.S. pipeline rate cases before the Federal Energy Regulatory Commission (FERC). We developed alternative approaches to estimating the cost of gas transportation service, based on different valuations of Gazprom assets and different assumptions about future capital expenditure requirements.

S.2 EXPLORATION AND PRODUCTION COSTS UNDER COMPETITIVE CONDITIONS (see Chapter 2)

Reserve to Production Ratios

In the United States, the reserve to production ratio is about nine, compared to a ratio of 22 in Canada. Russia's reserve to production ratio, by contrast, is 65 based on proved reserves, and perhaps as high as 80, depending on the analyst's treatment of "probable" reserves. In short, Russia has what the West would call "excess" gas reserves. One field alone, Urengoy, contains about 2.5 times the entire U.S. reserve base.

As can be seen from Exhibit S-3, precise information about the West Siberian fields is just now emerging. About 63% of the remaining West Siberian reserves (44.1 Tcm) appear to be contained in 15% of the 115-plus gas fields that have been identified in the four West Siberian Subregions. Also shown for comparison are equivalent U.S. data.

Exhibit S-3
Gas Reserves in Giant West Siberian Fields

Region	Remaining Reserves - BCM[1] -	Based on No. of Fields	Actual No. of Existing Gas Fields	1992 Product'n - BCM -
Taz Peninsula	19,580	12	80-plus	523
Yamal On-Shore	6,040	3	23-plus	-
Yamal Off-Shore	2,700	2	2	-
Gydan Peninsula	?	-	10-plus	-
TOTAL	28,320	17	115-plus	
U.S. Total	4,730	20,000	20,000	487

Source: Gazprom and Merklein & Associates estimates.

[1] Billion (10^9) cubic meter.

Russian estimates of 1990 natural gas production costs range from a low of 3 rubles per mcm[2] in the Tyumen-Urengoy-Yamburg Region to more than 12 rubles/mcm ($0.035/mcf[3]) in the Caucasus and Yakut Regions. To determine whether or not these extremely low costs are reasonable and, therefore, usable as a basis for a viable pricing regime, equivalent U.S. costs have been estimated by analyzing separately natural gas finding costs, development costs and field operating costs.

In relating the U.S. finding gas costs to those in Russia, and in particular in West Siberia which, by its very size, sets the standard for the Russian gas market in general, the one variable that cannot be ignored in this discussion is the size of the reserve that is likely to be discovered by a successful wildcat well. Given the giant gas accumulations in West Siberia, their finding costs are negligible. The wellhead price of natural gas required to achieve a competitive rate of return in developing a giant field is on the order of $0.20/mcf. Field operating costs for high-productivity West Siberian wells were estimated to be $0.012/mcf. This gives a total production cost under competitive conditions of about $0.21/mcf, assuming western pricing of inputs and labor.

S.3 GAS TRANSPORTATION COSTS UNDER COMPETITIVE CONDITIONS (see Chapter 3)

Gazprom Pipeline System

There is relatively little gas consumption in West Siberia, the dominant gas producing region in Russia. Total natural gas production, consumption and export data for Russia and selected countries of the former USSR are listed in Exhibit S-4.

[2] mcm is used to designate thousand cubic meters, Mmcm for million cubic meters.

[3] mcf = thousand cubic feet. 1 mcf = 0.028 mcm. 1 mcf = 1 GJ.

Exhibit S-4

Natural Gas Balances
Russia & Selected Republics of the Former Soviet Union
NON-ASSOCIATED GAS ONLY, BCM

	PRODUCTION		CONSUMPTION		NET EXPORTS	
	1990	1991	1990	1991	1990	1991
Ukraine	28.1	24.4	115.3	111.6	(87.2)	(87.2)
Belarus	0.3	0.3	14.9	14.9	(14.6)	(14.6)
Kazakhstan	7.1	7.9	13.0	13.8	(5.0)	(5.9)
Turkmenistan	87.8	84.3	15.9	14.3	71.9	70.0
Uzbekistan	40.8	41.9	37.9	39.0	2.9	2.9
Other Republics	9.9	8.6	18.3	17.0	(9.3)	(8.4)
Subtotal	**174.0**	**167.4**	**215.3**	**210.6**	**(41.3)**	**(43.2)**
Russia	640.6	642.9	461.0	466.0	179.6	177.0
Total Former USSR	**814.6**	**810.3**	**676.3**	**676.6**	**138.3**	**133.8**

Source: Plan Econ.

Three significant pipeline corridors connect the producing region of West Siberia with the consuming areas of the former USSR and with Russia's export markets to Western countries. Of these, the Central Corridor is by far the largest.

A direct estimation or verification of gas transportation costs in the former USSR from Gazprom cost data is practically impossible because of limited access to detailed cost accounting data and because of the many inconsistencies that seem to exist between the Russian and international oil and gas accounting systems.

An indirect way of determining Russian gas transportation costs is to estimate U.S. gas transportation costs under operating conditions approaching those in the former USSR. This can be done in one of two ways:

1. by simulating the construction of a representative pipeline, annualizing the costs incurred in the process, and adding them to operating costs.

2. by analyzing costs actually incurred by U.S. pipelines, as demonstrated in public rate hearings.

Using the rate hearings methodology, U.S. transportation costs have been derived for Panhandle Eastern Company, one of four major U.S. gas pipeline companies with rate data sufficiently developed for consideration.

Panhandle Eastern's transportation costs are $14.28/mcm/1000 km overall. This total includes gathering costs, field transportation costs, and an access fee (mostly overhead charges). Leaving out these upstream fees, Panhandle Eastern's straight trunk line transmission cost is $6.65/mcm/1000 km.

One can speculate how this might compare with the Russian gas situation. For West Siberian gas, one would expect the gathering and field transmission costs to be considerably less than what they are for Panhandle Eastern, given the enormous concentration of the resource. The access fee (overhead charge) is likely to be similar in size, whether explicitly listed or not. As regards the mileage charge, the huge pipeline capacities of the 1.4 m diameter lines draining gas from West Siberia are bound to offer significant economies of scale. Also, compressor fuel costs are likely to be lower, given the low production costs in Siberia, notwithstanding the relative fuel inefficiency of the Gazprom system compressor stations. On the other hand, there are operational problems peculiar to the Arctic, including the inhospitable climate in general and the need to cool the gas in the permafrost sections of the gas gathering and field transmission lines. These factors would tend to offset at least some of the savings. All in all, and without further study, we would be inclined to say that West Siberian gas can be shipped at a slightly lower expense per mile than similar gas can be in the United States.

That may, however, not be the case for gas produced in other parts of Russia. Gathering costs, field zone transmission costs, and access costs to the trunklines are likely to be as high in Russian gas operations as they are in the United States, perhaps higher, if maintenance has been neglected in the past and needs to be overcome with intensified repair costs. If it is assumed that mileage charges run about the same for all sources of Russian gas, non-Siberian gas sources with their higher up-stream costs have a restricted area in which they can successfully compete with West Siberian Gas.

S.4 CITY GATE DELIVERY COSTS UNDER COMPETITIVE CONDITIONS (see Chapter 4)

The results of estimates of city gate delivery costs for selected Russian cities are summarized in Exhibit S-5. The cities chosen for this report were Moscow, St. Petersburg, Nizhni-Novgorod, Chelyabinsk, Krasnodar, and Uzhgorod on the

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Exhibit S-5
Transmission Routes, Netback Prices, and Competitive City Gate Prices in Russia

	MILES	KM	WH Price $/MCF	CITY GATE PRICE $/MCF	$/MCM
MOSCOW:					
1 Urengoy - Punga - Ukhta - Gryazovets - Moscow	1744	2806	$0.178	$0.815	$28.76
2 Urengoy - Punga - Nizhnaya Tura - Perm - Nizhni Novgorod - Moscow	1860	2993	$0.178	$0.842	$29.72
3 Urengoy - Punga - Nizhnaya Tura - Perm - Yelets - Moscow	2160	3475	$0.178	$0.912	$32.18
4 Yamal - Ukhta - Gryazovets - Moscow	1594	2565	$0.655	$1.657	$58.50
5 Orenburg - Alexsandrov Gay - Petrovsk - Ryazan - Moscow	1000	1609	$0.286	$0.962	$33.95
6 Volga-Urals (Samara) - Petrovsk - Ryazan - Moscow	680	1094	$0.286	$0.883	$31.18
Netback: Uzhgorod - Yelets - Moscow	1070	1722		$1.951	$68.86
ST. PETERSBURG					
1 Urengoy - Punga - Ukhta - Gryazovets - St. Petersburg	1863	2998	$0.178	$0.843	$29.74
2 Shtokmanovskoye - St. Petersburg	1270	2043	$1.310	$2.381	$84.03
3 Yamal - Ukhta - Gryazovets - St. Petersburg	1713	2756	$0.655	$1.689	$59.61
Netback: Uzhgorod - Kobrin - Torzhok - St. Petersburg	1210	1947		$1.918	$67.71
NIZHNI NOVGOROD					
1 Urengoy - Punga - Niznnaya Tura - Perm - Nizhni Novgorod	1600	2574	$0.178	$0.781	$27.58
2 Orenburg - Alexsandrov Gay - Petrovsk - Nizhni Novgorod	705	1134	$0.286	$0.889	$31.40
3 Volga-Urals - Petrovsk - Nizhni Novgorod	540	869	$0.286	$0.849	$29.97
Netback: Uzhgorod - Yelets - Moscow - Nizhni Novgorod	1330	2140		$1.890	$66.72
CHELYABINSK					
1 Urengoy - Vingapur - Surgut - Chelyabinsk	1050	1689	$0.178	$0.653	$23.06
2 Vingapur - Surgut - Chelyabinsk	830	1335	$0.181	$0.809	$28.57
3 Urengoy - Punga - Nizhnaya Tura - Chelyabinsk	1150	1850	$0.178	$0.676	$23.88
Netback: Uzhgorod - Yelets - Perm - Nizhnaya Tura - Chelyabinsk	2180	3508		$1.692	$59.74
KRASNODAR					
1 North Caucasus - Rostov on Don - Krasnodar	500	805	$0.611	$1.178	$41.58
2 Orenburg - Alexsandrov Gay - Novopskov - Rostov on Don - Krasnodar	1210	1947	$0.286	$1.013	$35.76
3 Volga Urals - Alexsandrov Gay - Novopskov - Rostov on Don - Krasnod	1120	1802	$0.286	$0.991	$34.98
Netback: Uzhgorod - Yelets - Voronezh - Novopskov - Rostov on Don - Krasnoda	1500	2414		$1.851	$65.33
UZHGOROD					
1 Yamal - Ukhta - Gryazovets - Torzhok - Kobrin - Uzhgorod	2516	4048	$0.655	$1.902	$67.13
2 Shtokmanovskoye - St. Petersburg - Torzhok - Kobrin - Uzhgorod	2480	3990	$1.310	$2.738	$96.64
3 Urengoy - Punga - Nizhnaya-Tura - Perm - Yelets - Uzhgorod	2770	4457	$0.178	$1.054	$37.20

NOTE: Netback Prices are based on straight transmission rates, including fuel costs. Not included are Gathering Costs, Field Transmission Charges, Access Fees, Adjustments, or in-Field Fuel Allowances.
Used Urengoy costs, since that is the predominant export gas.
Average Rate: ((105.38-40.86)/2770)*100, Table C-3 - Urengoy-Uzhgorod = 2.329 cents/100 miles

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Ukraine/Slovac border, which is the main export station for Russian natural gas. Supply regions were the Taz Peninsula in Western Siberia ("Urengoy"), the Orenburg Region, the Volga-Urals, North Caucasus, Vingapur and two yet-undeveloped producing regions: the Yamal Peninsula in West Siberia and the Shtockmanovskoye Field in the Barents Sea. Depending on the transmission route chosen, the imputed city gate price of Urengoy gas in Moscow falls in the range of $0.81 to $0.91/mcf. As Exhibit S-5 shows, Urengoy gas can be delivered practically anywhere in Russia for a dollar or less per mcf. The imputed delivery cost to Uzhgorod is $1.05 per mcf.

The essential difference in transmission costs from Urengoy and other producing regions such as Orenburg is that the wellhead price differs from region to region, boosting the production cost component of the city gate price directly and indirectly raising fuel costs of the transmission activity in the field and on the movement of the gas to its destination.

Under the base conditions of this scenario, the Moscow city gate price for natural gas coming from Orenburg is higher than the prices of gas from Urengoy, $0.96/mcf for Orenburg gas vs. $0.81/mcf for the shortest-route Urengoy gas.

The Volga-Urals Region, some 1,100 km miles from Moscow, is barely competitive with Urengoy, and only on the longest Urengoy-Moscow transmission route. Volga-Urals gas arrives at the Moscow city gate at an overall cost of $0.88/mcf, just below the Urengoy-via-Yelets price of $0.91/mcf. Still, on the more direct route via Punga, Ukhta and Gryazovets, Urengoy gas can be delivered to the Moscow city gate at 92% of the Volga-Urals cost.

North Caucasus gas cannot compete with gas from the Urengoy Region anywhere in Russia, including the immediate vicinity of the North Caucasus Region itself.

The city gate prices for the 5 selected Russian cities and for delivery at Uzhgorod are listed, by cities, in Exhibit S-5, along with netback prices from Uzhgorod. The netback prices start from an Uzhgorod price of $2.20/mcf, minus straight transmission charges which include capital and operational costs (including fuel costs) of gas transmission.

S.5 ALTERNATIVE APPROACHES TO ESTIMATION OF TRANSMISSION COSTS (see Chapter 5)

There are several other approaches to transmission cost estimation that can be used, under different assumptions about the level of future investment and the way in which past capital investments are revalued and reflected in transmission charges. These approaches may be called "asset base" approaches because they all involve some sort of valuation of the asset base.

Transmission Cost for an Entirely New Asset Base

To estimate the value of an entirely new asset base we used data published by Gazprom on the physical characteristics of the system at the end of 1990. This was done by estimating the construction cost per mile on the basis of the pattern of pipeline construction cost per mile in other countries.

There are no 1.4 m (56-inch) pipelines in the United States, but on the basis of the cost trends for smaller diameter pipelines we estimate that the cost of a 1.4 m line would be about $1 million per km, excluding compressor stations, or $1.5 million per km, including compression. The figure of $1.5 million per km is consistent with Soviet costs when an official exchange rate is used for ruble-dollar conversion. Our assessment is that the U.S. data are roughly consistent with the data for other countries.

A linear relationship between pipeline diameter and cost per km was used to estimate the replacement cost of Gazprom pipelines. The replacement cost of Gazprom pipelines is therefore about $150 billion, excluding compressors, Exhibit S-6.

The average construction cost of compressors for which a FERC construction permit application was filed in the twelve-month period ending June 30, 1992 was $1,600 per kW. The compressor capacity of the Gazprom system at the end of 1990 was 46,579,000 kW. These figures suggest that the replacement cost of the compressor capacity is very large, approximately $75 billion, and therefore the cost of the transmission system is around $225 billion.

If this cost is recovered through levelized capital charges (including interest and principal, as in a standard 30-year mortgage), the cost of transmission in 1993 is $18.86 per mcm per 1000 km. This cost rises very gradually in nominal dollars but declines in real terms.

Exhibit S-6
Estimated Replacement Cost of Gazprom Pipelines

Dia. in mm	Diameter in inches	Gazprom trunk line distance in 1990, km	Gazprom trunk line distance in 1990, miles	Estimated replacement cost, 1990 $/mile	Estimated replacement cost, 1990 $billion	Annual delivery capacity of 1 pipe, bcm	Annual capacity utilization (assumed)	Cost per mcm per 1000 km (with level cap. cost), $/mcm
1420	55.9	55,440	34,428	1,749,718	60.240	28.10	80%	10.95
1220	48.0	35,447	22,013	1,477,389	32.521	20.74	80%	12.52
1020	40.2	30,158	18,728	1,205,060	22.568	14.50	80%	14.62
820	32.3	8,989	5,582	932,730	5.207	9.37	80%	17.50
720	28.3	22,332	13,868	796,565	11.047	7.22	80%	19.39
630	24.8	116	72	674,017	0.049	5.53	80%	21.43
529	20.8	26,696	16,578	536,491	8.894	3.90	80%	24.19
other		40,860	25,374	369,553	9.377			
Total		220,038	136,644		149.903			

Source: Trunk line distances are reported in Vniiegazprom, Gas Industry of the USSR 1990, p. 115. Replacement costs are estimated by fitting a straight line to data on U.S. average cost per mile over the 1984–1992 period

Transmission Cost for a Depreciated Asset Base, Based on Replacement Cost

Under this approach, the existing portion of the asset base is valued at $112.5 billion and is depreciated over 15 years (assuming that it is 15 years old and has an economic life of 30 years). New investment is depreciated over 30 years and is sustained at the level needed to hold the value of the asset base constant in real terms. The transmission charge therefore increases at about 3.5 percent per year.

The relationship between transmission cost estimates and the average age of the asset base is illustrated in Exhibit S-7. In one extreme case, the system is entirely new and the transmission cost is $22.60 per mcm per 1000 km. In the other extreme case, the assets are fully depreciated and the transmission charge consists only of operation and maintenance costs, which we estimate to be $2.19 per mcm per 1000 km.

Transmission Cost for a Depreciated Asset Base, Based on Book Value

If the Gazprom system has a replacement cost of $225 billion, an economic life of 30 years, and an age of 15 years, its asset value based on replacement cost less depreciation is $112.5 billion. This figure is close to the book value of Gazprom transmission system assets when the official exchange rate (effective September 5, 1990) is used to express the January 1, 1991 ruble value in 1990 dollars. When this valuation is used, the results are very similar to those for a depreciated asset base based on replacement cost

Transmission Cost Based on the Dollar Value of Investments Made in 1993 and Subsequent Years

Given the very high inflation that has occurred in 1991-93 in Russia, the book value of Gazprom investment will be far below replacement cost (net of depreciation) unless some sort of asset revaluation is implemented to offset inflation. One of the policy options available to the Russian government is to allow the book value of Gazprom assets to be practically wiped out by inflation. In such a scenario the level of transmission charges will depend on the dollar valuation of investments made in 1993 and subsequent years, but will be hardly affected by the valuation of investments made in 1992 and earlier years.

For the analysis of transmission cost based on future investments we selected two scenarios:

Exhibit S-7
Transmission Cost for a Depreciated Asset Base:
Relationship of Cost in 1993 to the Average Age of the System

Assumed condition of the transmission system	Assumed Average Age of the system at 1 Jan 93, years	Depreciated asset base at 1 Jan 93, $billion	Transmission cost per mcm per 1000km in 1993,* $/mcm/000 km	Moscow city gate price in 1993,* $/mcm
Entirely new	0	224.95	22.60	54.45
	5	187.46	19.90	49.73
	10	149.97	17.19	45.01
Actual condition (approx.)	15	112.48	14.48	40.29
	20	74.98	11.77	35.57
	25	37.49	9.07	30.84
	29	7.50	6.90	27.06
Fully depreciated	30	0.00	2.19	18.86

* These figures are based on the assumption that capital investments made in 1993 will enter the asset base for 1994 or later years, and therefore will not affect the level of transmission cost in 1993.

- a Most Likely Scenario involving $6 billion (in constant 1993 dollars) of annual investment, Exhibit S-8.

- a Low Cost Scenario involving $3 billion (in constant 1993 dollars) of annual investment.

In the Most Likely Scenario, the cost per mcm per 1000 km begins at a very low level in 1993 but grows rapidly, and the asset base grows rapidly. In 2021 the asset base (in constant dollars) reaches the level of replacement cost less depreciation that was estimated earlier for the 1990 asset base.

In the Low Cost Scenario, the cost per mcm per 1000 km begins at exactly the same level in 1993 but does not grow as rapidly. By 2021 the asset base is only half as large as the asset base in the Most Likely Scenario. The Low Cost Scenario yields a less expensive but less reliable transmission system.

S.6 PRICING PRINCIPLES FOR GAS DISTRIBUTION (see Chapter 6)

If distribution margins for each local gas distribution company are established on the basis of that company's cost of providing gas distribution service, it will be possible for end use prices to vary from company to company. This approach to pricing would be roughly comparable to the pricing system in place in the United States, where each gas distribution company calculates the rates needed to cover costs (including a fair return on capital invested).

One of the fundamental characteristics of the present system of Russian gas pricing is the low level of gas prices to the household sector, relative to prices to the industrial sector. The following pricing policy objectives and pricing methodologies might be considered:

1) ***Incentives for conservation.*** For each customer class, burner tip gas prices should be high enough to provide an incentive for the customer or consuming organization to make energy conservation investments that are consistent with economic efficiency objectives.

2) ***Payment of energy costs by energy-intensive industries.*** To promote an economically efficient pattern of production it is important that energy-intensive industries pay energy prices that cover the cost of producing and transporting energy.

Exhibit S-8
Transmission Cost Based on Dollar Valuation of Investments Made in 1993 and Subsequent Years*

Most Likely Scenario

Year	Growth rate of domestic demand	Domestic demand met by Gazprom, billion cm	Volume of gas transported, billion cm	Annual capital investment, $billion (nominal)	Asset base at Jan. 1, $billion (nominal)	Growth rate of asset base
1991	0.0%	584	695			
1992	−3.0%	566	677			
1993	−5.2%	537	648	6.01	0.15	
1994	−8.7%	490	602	6.39	6.15	4000.0%
1995	−7.1%	455	567	6.78	12.33	100.5%
1996	−6.4%	426	537	7.20	18.70	51.6%
1997	−2.7%	414	526	7.64	25.25	35.1%
1998	−1.4%	409	520	8.09	32.00	26.7%
1999	0.0%	409	520	8.57	38.96	21.7%
2000	1.4%	414	526	9.07	46.12	18.4%
2001	1.4%	420	532	9.60	53.50	16.0%
2002	1.4%	426	537	10.15	61.10	14.2%
2003	1.4%	432	543	10.72	68.93	12.8%
2004	1.4%	438	549	11.32	77.00	11.7%
2005	1.3%	444	555	11.94	85.30	10.8%
2006	1.3%	449	561	12.60	93.86	10.0%
2007	1.3%	455	567	13.28	102.67	9.4%
2008	1.3%	461	572	14.00	111.74	8.8%
2009	1.3%	467	578	14.75	121.09	8.4%
2010	1.3%	473	584	15.53	130.72	8.0%
2011	1.2%	479	590	16.34	140.64	7.6%
2012	1.2%	484	596	17.19	150.85	7.3%
2013	1.2%	490	602	18.08	161.37	7.0%
2014	1.2%	496	607	19.01	172.21	6.7%
2015	1.2%	502	613	19.98	183.37	6.5%
2016	1.2%	508	619	20.99	194.87	6.3%
2017	1.1%	514	625	22.04	206.71	6.1%
2018	1.1%	519	631	23.14	218.91	5.9%
2019	1.1%	525	637	24.29	231.47	5.7%
2020	1.1%	531	642	25.49	244.41	5.6%
2021	1.1%	537	648	26.74	257.74	5.5%
2022	1.1%	543	654	28.04	271.46	5.3%
2023	1.1%	549	660	29.40	285.60	5.2%

* These figures exclude transmission fuel and loss, which is a function of the value of gas at the transmission system receipt point.

Exhibit S-8 (cont.)
Transmission Cost Based on Dollar Valuation of Investments Made in 1993 and Subsequent Years*

Most Likely Scenario

Year	Annual return plus depreciation, $billion	Cost per mcm per 1000 km, $/mcm/000 km	Asset base measured in constant 1993 dollars, $billion	Growth rate of cost per mcm per 1000 km	Depreciation of 1992 and earlier assets, $billion	Inflation index
1991						
1992						
1993	0.02	2.36	0.15		0.01	1.000
1994	1.00	3.25	5.97	37.6%	0.01	1.030
1995	2.02	4.23	11.62	30.0%	0.01	1.061
1996	3.07	5.31	17.11	25.5%	0.01	1.093
1997	4.17	6.32	22.44	19.1%	0.01	1.126
1998	5.30	7.33	27.61	16.0%	0.01	1.159
1999	6.47	8.31	32.63	13.3%	0.01	1.194
2000	7.69	9.21	37.50	10.9%	0.01	1.230
2001	8.95	10.13	42.24	10.0%	0.01	1.267
2002	10.26	11.07	46.83	9.3%	0.01	1.305
2003	11.62	12.02	51.29	8.6%	0.01	1.344
2004	13.02	13.00	55.62	8.1%	0.01	1.384
2005	14.48	13.99	59.83	7.6%	0.01	1.426
2006	15.99	15.00	63.91	7.2%	0.01	1.469
2007	17.55	16.03	67.88	6.9%	0.01	1.513
2008	19.18	17.08	71.72	6.6%	0.01	1.558
2009	20.86	18.15	75.46	6.3%	0.01	1.605
2010	22.60	19.25	79.09	6.0%	0.01	1.653
2011	24.41	20.37	82.61	5.8%	0.01	1.702
2012	26.28	21.52	86.03	5.6%	0.01	1.754
2013	28.22	22.69	89.35	5.4%	0.01	1.806
2014	30.23	23.88	92.57	5.3%	0.01	1.860
2015	32.32	25.11	95.70	5.1%	0.01	1.916
2016	34.48	26.36	98.74	5.0%	0.01	1.974
2017	36.72	27.64	101.69	4.9%	0.01	2.033
2018	39.04	28.95	104.55	4.7%	0.01	2.094
2019	41.44	30.29	107.33	4.6%	0.01	2.157
2020	43.93	31.67	110.03	4.5%	0.01	2.221
2021	46.52	33.08	112.65	4.5%	0.01	2.288
2022	49.19	34.52	115.19	4.4%	0.01	2.357
2023	51.96	36.00	117.66	4.3%	0.00	2.427

3) ***Availability of capital.*** Gas distribution companies need to have the ability to obtain the capital required for reconstruction of older portions of the distribution network and for provision of gas service to new customers.

4) ***Access to private sector capital.*** At least a portion of the capital obtained by gas distribution companies should be obtained from the private sector, through the sale of stock or the issuance of debt by the distribution company.

5) ***Protection of vulnerable segments.*** Some sort of program will be needed to mitigate the adverse effects of gas price increases on vulnerable segments of the population.

6) ***Limitation of government subsidies.*** If any subsidies are provided to the distribution company by federal, regional, or municipal governments, these subsidies should be used only to mitigate the adverse effects of gas price increases on vulnerable segments of the population, and not maintained as a normal feature of gas service.

Retail Pricing Issues

Different sets of issues arising in the household and industrial two sectors arise. For the industrial sector it is important to provide "correct" price signals to ensure proper incentives for energy conservation and payment of energy costs by energy-intensive industries. For the household sector, the most difficult issue is the mitigation of the adverse effect of gas price increases on vulnerable segments of the population. This issue has two aspects: (1) prices for gas delivery where gas is used for cooking only, and (2) prices for gas delivery where gas is used for space heating and/or water heating as well as cooking.

The situation for space heating is complicated because of the extensive use of district heating in Russian cities. The gas distribution companies consider the combined heat and power stations and municipal boilerhouses as industrial loads, charging a high tariff. The price of heat sold by the district heating companies to the residential sector is regulated based on the residential gas cost. The difference (subsidy) is being made up by the heat/power company from electricity sales, from steam sales, from government contributions, or through financial manipulations of accounts.

The long-run marginal cost (LRMC) of distributing gas for cooking purposes only is so high that it is difficult to believe that gas can be competitive with electricity. The LRMC of distributing gas for space heating and water heating in the household sector (and in the commercial sector) is in the range of $4.00 - $4.50 per mcf, which is much higher than the present level of gas prices to the household sector (about $0.03/mcf).

There are three are particularly promising candidates for consideration in the development of gas pricing policies in the distribution sector:

1) ***Long run marginal cost (LRMC).*** In this approach prices are computed from economic analyses which estimate capital investment requirements and operation and maintenance expenses for incremental units of consumption.

2) ***Prices necessary to make gas sector enterprises self-financing.*** This financial approach requires the establishment of targets regarding the sources of capital for long-term investment (in particular, the percentage mix of capital from internally generated funds, issuance of new stock, and issuance of long-term debt).

3) ***Prices necessary to provide a fair rate of return on assets that are revalued on the basis of replacement cost.*** Under this financial approach, the concept of relating price to costs incurred is maintained while the accounts of the distribution enterprises are transformed through asset revaluation.

A Three-Stage Tariff Setting Methodology

A recommendation is presented to establish long run gas price targets on the basis of LRMC but to establish financial prices on the basis of the third option, a fair rate of return on assets that are revalued on the basis of replacement cost. As the asset base is transformed through new investment in reconstruction, the price level should gradually rise toward LRMC. If it is found after five years that prices lag behind LRMC, an investigation of the causes of this lag would be merited.

A three-stage electricity tariff-setting methodology has been used for several World Bank-funded power sector loans. This method should be appropriate to gas distribution tariffs as well. It uses marginal costs to establish the structure of tariffs, and financial revenue requirements to establish the level of tariffs, together with socioeconomic balancing considerations.

S.7 TAXATION AND SUBSIDIES (see Chapter 7)

Although the privatization of Gazprom and the gas distribution companies will facilitate the establishment of taxation policies in Russia that resemble gas industry taxation policies in OECD countries, there are two major obstacles remaining. First, the absence of gas sales transactions at the wellhead and the lack of transparency of wellhead prices (due to Gazprom's vertical integration) creates an obstacle to taxation of exploration and production according to western norms. Second, it is difficult to let the wellhead price of gas rise to an "international" level, because there is a need to mitigate the adverse effects of gas price increases on vulnerable segments of the population.

We assume that the Russian Federation will prohibit competition between domestic and export markets until the population can afford to pay "world prices" for natural gas, i.e., wellhead prices reflecting the value of gas in export markets plus transmission and distribution charges reflecting the economic cost of providing these services to domestic consumers. Furthermore, we assume that the Government of the Russian Federation will continue to use the present system of revenue collection associated with gas exports. This system is roughly comparable to a 48 percent royalty on the volume of gas exported.

To permit a transition to a competitive market in natural gas production, and to enable gas-on-gas competition to determine the level of wellhead prices, it will be necessary to make wellhead prices transparent and to separate production operations from gas gathering, gas processing, and transmission operations. Because we project gas demand in Russia and in other CIS republics to fall to 70 percent of the 1990 level, by 1998, we do not see a need to develop the Yamal fields and Barents Sea fields during the 1990s, and therefore the development of "high-cost" resources (high cost by Russian standards) may be deferred. Under these conditions the issue of taxation of wellhead prices of natural gas becomes relatively unimportant because the price level is so low, by international standards.

The appropriate forms of taxation of wellhead production would be a royalty of gas production; a system of lease bonus payments, with competitive bidding for new leases; and an income tax (i.e., a profit tax) for exploration and production enterprises having access to foreign equity investment. Over a transitional period of five years the profit tax may be extended to enterprises that do not have access to foreign equity investment.

For sociopolitical reasons, it may be necessary that the transmission and distribution charges for gas sold to households be increased very gradually over a transitional period

(for example, 1993-1998), so that end users pay a price sufficient to cover the cost of wellhead production plus a portion of the cost of transmission and distribution. Government tax revenue would not be needed to protect the household customer, if the necessary revenue is provided by industrial users of natural gas. This approach offers the benefit of allowing the gas transmission and distribution companies to operate more independently of government ministries. The government budgets are not affected by gas price subsidies, however, the competitiveness of the industrial sector is penalized by the cross-subsidy. Considering the relatively low values of non-energy costs of production (raw materials, labor), this cross-subsidy seems acceptable, during the transition period.

In current tax policy the VAT is applied to gas sales to industry but not sales to the population. This approach is entirely reasonable and we recommend that it be sustained. Although the VAT is applied to prices of petroleum products sold to households, there is no real "incentive" for households to switch from natural gas to oil, and most individual households have no control over the type of heating system they use. If natural gas can be delivered to the city gate for less than $1.00/mcf, it is unlikely that end use prices for gas used in space heating will be at the level of light fuel oil prices, on a heat content basis. Where gas is used for cooking, electricity is likely to be the lower-cost form of energy even when there is no VAT on household gas use. Thus fuel choice decisions in the household sector may be made by municipal governments or regional governments, and a VAT on household gas consumption is not necessary to protect oil or other energy sources from competition with natural gas.

S.8 CONCLUSIONS AND RECOMMENDATIONS (see Chapter 8)

Conclusions - Alternative Approaches to Determining Gas Price Levels

There are several alternative approaches to the calculation of gas price levels:

1. ***Prices necessary to cover operation and maintenance costs.*** This approach has been used by Gazprom, but is not consistent with the principle that the consumer should pay for the full cost (or LRMC) of providing a service or commodity, including a return on invested capital.

2. ***Prices necessary to make gas sector enterprises self-financing.*** This price level is the minimum needed to avoid government subsidization and recover the full cost of gas service. This requires a political determination of the value of the assets of the enterprise, including soft-currency assets. In an enterprise in which a portion of

new investment is made in hard currency, there are two approaches to making gas sector enterprises self-financing:

- Option 1: Sales in rubles only.
- Option 2: Sales in hard currency and in rubles.

3. ***Prices consistent with prices prevailing in North America or western Europe.*** In this approach, price targets are specified for some future year and prices are gradually raised to meet the price target. The targets are not related to current or historical costs of the Russian enterprise.

4. ***Netback pricing.*** In this approach, city gate gas prices are raised to the netback value of gas from the Russian border.

5. ***Long run marginal cost (LRMC).*** It is possible to estimate the LRMC of gas production, transmission, storage, and distribution and then establish gas prices at which the marginal price of gas service equals the marginal cost of gas. If properly implemented, this approach to pricing will yield an optimal level of economic efficiency.

6. ***Opportunity cost of gas as a substitute for alternative domestic fuels.*** For certain categories of natural gas consumption it is possible to identify an alternative fuel or fuels that can be used to displace gas. If the price of the alternative fuel is based upon international fuel markets, and if imports and exports of the alternative fuel are unrestricted, the border price of that fuel can be considered to be competitively determined. The price of gas can then be determined in a netback calculation.

7. ***Prices necessary to provide a fair rate of return on assets that are revalued on the basis of replacement cost.*** Another approach to pricing is to estimate the replacement cost of the infrastructure of a gas transmission enterprise or gas distribution enterprise, and estimate the prices necessary to provide a fair rate of return on the total capital invested.

In the present political climate in Russia, two of these approaches to gas pricing seem most worthy of serious consideration: (1) prices necessary to make gas enterprises self-financing, and (2) prices consistent with prices prevailing in North America or western Europe. The latter may be called "world prices" or "international prices." In determining the price of gas exported to CIS republics, the Russian government pays close

attention to "world prices." The idea that gas prices in Russia will eventually reach "world prices" is widely accepted.

In the long term the ideal solution is to have a competitive gas market whereby the gas price finds its own level. This price level may be approached through a regulatory framework in which the cost of service is derived from asset revaluation and establishment of a fair rate of return on total assets.

Recommended Principles of Gas Pricing

On the basis of our analysis of the cost of gas production and transmission, and the limited amount of information available on the ruble cost of gas distribution in Russia, we have developed a proposal for gas pricing policies for each of the different functions in the gas supply chain.

Gas production. The appropriate pricing policy for gas production is to ensure that prices are at levels necessary to make gas enterprises self-financing. Each enterprise created through privatization and restructuring should set prices sufficient to recover all costs including capital costs.

Given the present monopolistic ownership structure, non-associated gas production may be treated as a regulated industry. For example, production prices may be submitted by Gazprom to the Pricing Committee of the Russian Federation. The Pricing Committee may review the cost calculations used to show, for a particular production enterprise, that the price level is necessary to make the enterprise self-financing.

Unfortunately, an administrative procedure will be needed to determine production targets for each enterprise. Given a production target it should be possible to compute the necessary level of capital expenditures. Under competitive market pricing this administrative process could be eliminated.

Gas transmission. For this sector a pricing policy may be established to make transit fees consistent with transmission charges prevailing in North America or western Europe. Because Gazprom supplies both a domestic market and an export market, and capital is invested in hard currency, in barter arrangements, and in rubles, it is difficult to calculate the prices necessary to achieve self-financing. A much simpler and more direct approach to setting transmission charges is to estimate costs in dollars per mcm per 100 km, based on the physical characteristics of the system (for example, the age and diameter

of the pipelines, and the total compressor kW) and the construction cost per mile of pipe or cost per kW of compressor capacity in market economies.

Distribution. For this sector, a pricing policy may be developed on the basis of LRMC, calculated considering distribution system reconstruction costs in hard currency. Eventually, it should be possible to introduce pricing on the basis of financial criteria, such as a regulated return on asset base. A 3-stage tariff setting method is suggested, based on: 1) LRMC, 2) financial revenue requirements, 3) socioeconomic considerations.

Issues to Be Decided

The key policy question for gas pricing that must be decided by the Russians is how to optimize the hard currency gas earnings and at the same time sustain the standard of living and supply the basic energy needs of the Russian people. Questions include the following:

Where excess rent, subsidy, or other departure from market pricing of Russian gas seems warranted by conditions (such as exports versus domestic use, residential vs. industrial use), where should the differential be taken?

- Pipeline and distribution costs, requiring the bulk of financial infusion at this time, should be priced at service costs designed to produce the needed capital for system rebuild and expansion.

- Exploration and development costs, which are relatively less critical at this point in the Russian gas industry, can better withstand pricing consequences of policy choices.

- Social concerns dictate that departure from market prices is needed in distribution, because household prices have been historically a small fraction of industrial prices, and so must be phased upwards during a transition period.

Given the foregoing, what degree of price subsidy is needed, and for how long, in order to ensure continued gas service to major urban area gas customers?

- As of 1993, city-gate prices, in a market environment, would range from $0.81 to $0.91/mcf.

-- Wellhead price subsidies can probably be eliminated by 1994.

-- Transmission should be able to move to market pricing by 1995, at least for gas sales to industry.

Alternatively, can a tax policy be constructed that accomplishes the required distributional goals, while maintaining a single wellhead price, i.e., at market?

-- With transportation prices fixed on a basis of meeting future capitalization increments, positive taxation at the wellhead or point of delivery could gather available rents to meet other socioeconomic needs

-- Likewise, differing levels of taxation for city-gate gas could enable a single wellhead price.

What blend of organization of the Russian gas system, public and private, aggregated versus disaggregated, will be most conducive to capital formation?

-- Joint venture ownership of transmission legs may be an attractive option, e.g., foreign investment coupled with contributing ownership (and investment) by Gazprom

-- The need to clearly determine the costs of transportation by those newly independent countries located between Russia and key gas markets in western Europe may suggest unbundling, and operating the system on a transportation basis.

CHAPTER 1: INTRODUCTION

1.1 PROJECT OVERVIEW

1.1.1 Project Description

This report presents the results of work performed in natural gas pricing, as part of energy sector assistance provided to Russia by the U.S. Agency for International Development (A.I.D.). The report was prepared in support of the World Bank, for the use of the Bank in developing natural gas projects in Russia. The report was prepared as part of the Energy Efficiency and Market Development Program, by RCG/Hagler, Bailly, Inc. and Merklein Associates. The report describes the situation existing in Russia in gas pricing as of early 1993, prepares estimates of the cost of exploration, production, and transmission, develops principles for pricing gas distribution, discusses taxation and subsidies, and develops conclusions and recommendations.

Under A.I.D. funding from the same project, Hagler, Bailly is also carrying out two other tasks. In the first task, energy audits and energy management equipment is being provided to district heating systems to improve energy efficiency, focusing on gas-fired systems in Yekaterinburg and Kostroma. Energy audit instruments and training were also provided to engineers from four other cities - Moscow, St. Petersburg, Irkutsk, and Murmansk. In the second task, Hagler, Bailly is organizing a series of conferences and exhibitions to be held in June 1993 in four Russian cities, in an effort to disseminate the results of the district heating program, and expose energy professionals in Russia to energy saving technologies, and thereby establish a market for energy efficiency products and services.

The World Bank is developing a gas distribution project that would make funds available for reconstruction of gas distribution networks in selected cities and for conservation of natural gas by end users. The Bank may decide to specify conditions for gas price reform among the conditionalities attached to the gas sector loan to Russia. Gas price reform will be needed to ensure the financial viability of gas distribution companies and provide more efficient use of gas by end-users.

The purpose of this report is to present a proposed conceptual framework for gas price reform in Russia. We begin with a discussion of existing prices and price structure. We describe the rationale for price reform, present alternative approaches to price reform, and propose the use of certain gas pricing principles.

1.1.2 Roadmap to the Report

This report is organized as follows:

The remainder of Chapter 1 provides additional introductory information, such as:

- description of the existing conditions in the gas sector in Russia
- discussion of issues in gas pricing in Russia today
- discussion of the likely scope of price reforms
- discussion of the role of Government in gas price reform
- development of assumptions on restructuring in the gas sector

A series of three chapters follows, which present an analysis of costs in the gas sector in Russia, assuming the establishment of competitive conditions:

- Chapter 2 develops gas exploration and production costs
- Chapter 3 develops gas transportation costs
- Chapter 4 develops city gate delivery costs

Having identified that transportation costs are dominant, Chapter 5 presents alternative approaches for estimating gas transportation costs.

Chapter 6 presents a discussion of gas distribution costs, and a methodology for determining retail tariffs.

Chapter 7 is a discussion of taxation.

Chapter 8 presents conclusions and recommendations.

1.2 EXISTING CONDITIONS IN RUSSIA

1.2.1 Existing Prices and Price Structure

The evolution of retail gas prices in Russia since 1982 may be described in terms of three time periods (see Table 1 and Figure 1):

- 1982 - 1989 was a period in which prices were very stable, uniform throughout the Soviet Union, and nearly the same in the industrial and household sectors. The price of gas used in industrial facilities, power plants, and district heating plants was 24 rubles per thousand cubic meters (mcm). There were two price levels for gas sold to households: 20 rubles/mcm for space heating and 50 rubles/mcm for cooking. These household prices were not applied to gas used to produce district heat.

  Because it is difficult to define and measure the dollar value of the ruble in the 1982-1989 period, it is difficult to compare Russian domestic gas prices with international prices.[1] If the official exchange rate is considered an accurate measure of the value of the ruble, domestic gas prices in 1989 could be considered low - $39.42 per mcm for industrial use and $32.85 per mcm for residential space heating - but not low enough to indicate a need for major price increases.[2] If the official exchange rate is considered a gross overvaluation of the ruble, the level of Russian domestic gas prices in the 1980s must be considered very low relative to North American or western European price levels.

- January 1990 - May 1992 was a period in which prices were adjusted several times to keep pace with inflation and the structure of gas prices was modified. Gas prices were increased around 20 times during this period,

[1] During this period gas was exported to western Europe via Ukraine, so the Russian border price would have to be inferred from a Ukrainian border price. The "correct" level of transit fees is a controversial issue that has not yet been resolved. For 1991 the IEA reports a Russian export price of $50/MCM (see IEA, "Russian Energy Prices and Taxes," Note by the Secretariat, June 11, 1992, p. 16; the source is a "report by Mr. Chernomyrdin, chief of Gasprom").

[2] The official exchange rate in 1989 was 1 USD = 0.6088 ruble. See Eurostat, *Country Reports: Central and Eastern Europe 1991* (Luxembourg, 1991), p. 132.

Table 1
Domestic Prices of Natural Gas in Russia

Time period	Wholesale industrial prices: Price to resellers, R/MCM	Wholesale industrial prices: Distri-bution margin, R/MCM	Wholesale industrial prices: Price to end users, R/MCM	Household* prices: Price to resellers, R/MCM	Household* prices: Distri-bution margin, R/MCM	Household* prices: Price to end users, R/MCM
1989 a	21.4		24			Space heating:20 Cooking: 50
1990 b	42					
January 1991 c			51			31
1Q 1991 – 3Q 1991 d	Average: 42		Average: 52 Range: 45 to 61			
4Q 1991			[not reported]			
2 Jan 92 – 17 May 92 e			260			
18 May 92 – 31 Jan 93 f	Range: 940 to 1440	160	Range: 1100 to 1600 plus VAT	216	44	260
1 Feb 93 – g	3600	400	4000 plus VAT	300	300	600

* This customer category may be translated as "the population" or "the general public" and refers to gas sales for residential use, including sales to housing construction cooperatives. Most households do not have an individual gas meter, so these prices per MCM are used to develop prices per person or per square foot of living space.

a The price of 21.4 rubles/MCM includes turnover tax. Source: FT International Gas Report, 28 June 1991 p. 20; cited in IEA, "Russian Energy Prices and Taxes" (Note by the Secretariat), 11 June 92, p. 16.

b The price of 42 rubles/MCM includes turnover tax. Source: FT International Gas Report, 28 June 1991 p. 20; cited in IEA, "Russian Energy Prices and Taxes" (Note by the Secretariat), 11 June 92, p. 16.

c A single residential price for both cooking and space heating was set in January 1991.

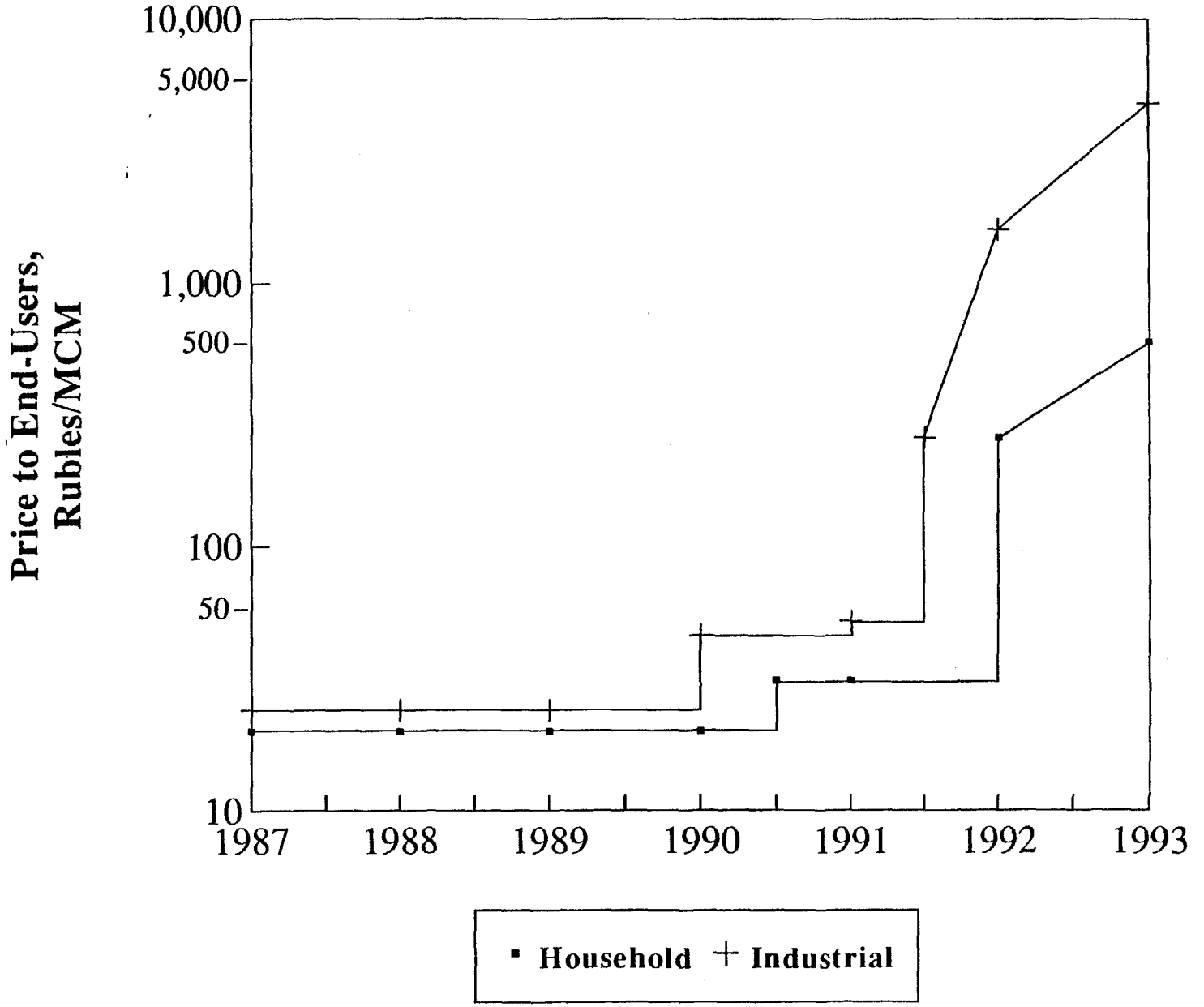
d Both prices (to resellers and to end users) include a state turnover tax.
The price to resellers is reported in Ekonomika y Zhisn, October 1991, and cited in IEA, "Russian Energy Prices and Taxes" (Note by the Secretariat), 11 June 92, p. 16.

e Source: The price level of 260 rubles/MCM is reported in Natural Gas Week International, 4 May 92, p. 1. The January 2, 1992 price level was set by Decree No. 55 of December 19, 1991 and the effective date (January 2, 1992) is cited in Decree No. 318, May 18, 1992, Appendix No.2.

f These figures exclude the value added tax, which is applied to wholesale industrial prices.
Source: Decree No. 318, May 18, 1992.

g These figures exclude the value added tax, which is applied to wholesale industrial prices.
Source: Decree No. 88, January 29, 1993.

Figure 1
Evolution of Natural Gas Prices in Russia



which encompasses the rise of Russia as an independent country. In January 1991 the two residential price levels were replaced by a single price level. During the first nine months of 1991, prices were regionally differentiated according to four geographical "cost zones." Following the dissolution of the Soviet Union in December 1991, the cost zone approach was abandoned and gas prices in Russia were geographically uniform. The government of the Russian Federation raised the prices of natural gas through Decree No. 55, issued on December 19, 1991, and Decree No. 318, issued on May 18, 1992 by President Boris Yeltsin.

During the January 1990 - May 1992 period the value of the ruble in international trade fell very sharply. By May 1992, domestic prices of gas in Russia were far below international levels.

- June 1992 - March 1993 was a period in which domestic prices were adjusted only once to keep pace with inflation, and the structure of gas prices was not modified. Given the turmoil in the Russian economy during this period, gas prices were remarkably stable. Through the process of privatization of both Gazprom and the gas distribution companies, the stage was set for future modifications of the structure of gas prices. Domestic prices of gas continued to be far below international levels.

The most recent price increase was enacted in Decree No. 88, issued on January 29, 1993 by Prime Minister Viktor Chernomyrdin. The primary reasons for the issuance of Decree No. 88 were to adjust domestic gas prices for cost increases driven by the inflation in the Russian economy, and to increase the price of gas supplied to CIS countries of the ruble zone. These measures were intended to enable Gazprom to continue operating without relying on the government budget for support, and to increase government revenues associated with natural gas exports.

Prices are currently specified in Decree No. 88. At present, the Russian Federation sets:

- city gate prices, at two different price levels: a price of gas for resale to households and a price of gas for resale to other consumers

- consumer prices, at two different price levels: a price for households and a price for other consumers. Among the largest consumers, there is no

difference between prices to consumers served by the high pressure network[3] and prices to consumers served by distribution enterprises.

- pipeline export prices, at various price levels. There is no difference between export prices of gas destined for resale to households and export prices of gas destined for resale to other consumers.

Decree No. 88 does not contain any mention of wellhead prices, field prices, or prices of gas purchased by Russian transmission enterprises. Prior to the breakup of the Soviet Union there were price levels for sales of gas by producing enterprises to transport enterprises; these "enterprise wholesale prices" varied geographically by "cost zone". In U.S. terminology, enterprise wholesale prices would be called delivered-to-pipeline prices or pipeline acquisition costs. When Russia established its own price control system this category of wholesale prices was dropped.

The structure of gas prices in Russia is extremely simple. Decree No. 88 set prices as follows, effective February 1, 1993:

- The retail price to industrial customers, powerplants, and all final users except individuals and housing cooperatives is set at 4000 rubles/mcm and is subject to a value added tax (VAT).[4] In Russia this retail price is called a "State regulated wholesale industrial price" although in North America it would not be considered a "wholesale" price.[5] The retail price to industrial customers is uniform throughout Russia and is the same for customers served

[3] In the United States, customers served directly by an interstate pipeline are called "main line industrial customers." These customers are able to "bypass" distribution companies that resell gas purchased from interstate pipeline companies. In Russia the high pressure network is the transmission grid; it is operated at pressures of at least 12 bar (176 psi), and it is roughly comparable to the U.S. interstate pipeline grid.

[4] In U.S. Energy Information Administration statistics, gas consumers are classified in five groups: residential, commercial, industrial, electric utility, and vehicle fuel. In Russia the "household" category includes sales that would be classified as residential plus a portion of the sales that would be classified as commercial (for example, sales of gas used in apartment buildings) but it does not include gas used by district heating enterprises.

[5] The use of the phrase "wholesale industrial price" to refer to a retail price is not an error in translation. In Russia, industrial enterprises are considered to be in the "wholesale" portion of the economy regardless of the way in which they purchase gas. In North America, enterprises that purchase gas directly from pipelines or producers might be labeled "wholesale" customers while enterprises that purchase gas from distribution companies might be labeled "retail" customers.

directly by the high pressure network (the transmission grid) and customers served by distribution companies. Gas consumed for power generation and district heat is sold at this price level. The level of the VAT is 20 percent, and is independent of gas prices. Decree No. 88 raised industrial gas prices by a factor of 3.6; under the previous decree the price level had been 1100 rubles/mcm (see Table 1).

- The retail price to individuals and housing cooperatives is set at 600 rubles/mcm. This price may also be described as the price to "households," "the population" or "the general public." The VAT is not added to this price.[6] Under Decree No. 318 this price level had been 260 rubles/mcm.

- For each of these two retail prices - for industrial use and for household use - there is a sort of city gate price that allows a distribution company to purchase gas at prices below the retail level:[7]

  - The price of gas sold for resale to all final users except individuals and housing cooperatives is set at 3600 rubles/mcm, creating a distribution margin of 400 rubles per mcm. Under Decree No. 318 this level had been 940 rubles/mcm, creating a distribution margin of 160 rubles/mcm.

  - The price of gas sold for resale to individuals and housing cooperatives is set at 300 rubles/mcm, creating a distribution margin of 300 rubles/mcm. Under Decree No. 318 this level had been 216 rubles/mcm, with a distribution margin of 44 rubles/mcm.

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[6] This tax policy favors natural gas over distillate fuel oil, because petroleum products are subject to VAT. In 1991 about 65 percent of the volume of gas sold to residential customers by Rosstroigazifikazia enterprises was for space heating, 24 percent was for cooking, and 11 percent was for water heating. These figures exclude gas sold to power plants and district heating enterprises.

[7] The concept of a city gate price is not part of the existing Russian system of pricing or the Soviet system of pricing. In North America the city gate price is important because prices are related to geographic location and because several cities have competitive spot markets for gas delivered to the city gate. In Russia there is no such competition or geographic variation, and the price of gas sold for resale to industry is higher than the price of gas sold for resale to households.

- The price of gas sold by Gazprom to the government of the Russian Federation for resale in the export market is set at 6,000 rubles/mcm. This price applies to 55 percent of the gas exported by Russia.[8] It is unrelated to export prices, i.e., the prices paid by the foreign gas companies. It is not subject to VAT.

- For exports to CIS countries of the ruble zone that have bilateral agreements with Russia on mutual deliveries of basic goods, Decree No. 318 established a minimum price level of 13,000 rubles/mcm plus VAT.

- For other CIS countries, "world prices" are used although payments may be made in rubles. For exports to countries outside the CIS, "world prices" are used and payments should be made in hard currency. (For the Baltic states, at least a portion of the payments have in fact been made in rubles.) In a February 1, 1993 press conference, a Gazprom representative stated that world prices varied between $76 and $83 per mcm and at then-current exchange rates were higher than 50,000 rubles/mcm.

The VAT was established on December 6, 1991 by President Yeltsin, and a VAT rate of 28 percent was established for all transactions subject to VAT.[9] On July 16, 1992 the Russian Parliament voted to lower the VAT on most goods (including natural gas) to 20 percent, effective January 1, 1993, and establish a separate VAT rate of 15 percent for certain foods (flour, cereals, dairy products, vegetable oil, goods for children, and macaroni).[10] Changes in the level of VAT are not timed to coincide with changes in the level of gas prices excluding VAT. The VAT is an important source of revenue for the Russian Federation and therefore it may be adjusted from time to time on the basis of macroeconomic policy. An increase in VAT may be favored as a measure to reduce the federal deficit and thereby stabilize the ruble. A reduction in VAT may be favored on the basis of the argument that an excessive VAT would hinder the development of a market

[8] This 55 percent fraction is decreed to be "the share meeting federal state needs." See Decree No. 951, December 10, 1992, paragraph 3, and Decree No. 88, January 29, 1993, paragraph 12.

[9] The decree signed by President Yeltsin was entitled "Law of the Russian Soviet Federated Socialist Republic On Value Added Tax," according to the translation by the U.S. Department of Commerce, Office of General Counsel. It might be more accurate to describe this document as an "Edict" or "Decree."

[10] "Parliament Lowers Value-Added Tax on Most Products, Starting Next Year," Bureau of National Affairs *Eastern Europe Reporter*, July 20, 1992, p. 586.

economy and perhaps lead to higher levels of tax evasion. The 20 percent VAT is still in effect, for natural gas and other energy commodities.

A discussion of gas price levels would not be complete without a consideration of wellhead prices. Because Gazprom is both a producer and a transmission company, most of the wellhead production of non-associated gas in Russia is not sold through transactions that are comparable to the sale of gas from Gazprom to a gas distribution company, or from a gas distribution company to an end user. Therefore the concept of a "wellhead price" is not clearly defined; it does not exist in the Russian government's gas price decrees (Decree No. 318 and Decree No. 88, cited above) and there are no wellhead price data in Gazprom's economic and statistical survey, *Gas Industry of the USSR 1990.*[11] However, gas extraction costs are measured by Gazprom, subject to the limitations of the Russian accounting methods used to measure this extraction cost. In the February 1, 1993, press conference there is a statement that the operating cost of field production of gas produced by Gazprom is 2,600 rubles per mcm, of which 1,900 rubles is the cost of gas extraction (excluding profit and capital investment) and 700 rubles is the cost of "maintenance of northern cities and villages."[12] This cost level is based on Gazprom's internal accounting system. It is far higher than 300 rubles/mcm, which is the price of gas sold by Gazprom to distribution companies for resale to the household sector.

Because the exchange rate between the ruble and the dollar is unstable, and because the exchange rate does not reflect purchasing power parity, it is difficult to compare domestic prices in rubles with foreign prices in dollars or other hard currency (see Table 2).

When a commercial exchange rate of 572 rubles per dollar (the February 8 rate) is used, and a heat content of 8000 kcal per mcm is assumed,[13] the burner tip price to households

[11] The IEA reports a "free" wellhead price of 1600 rubles/MCM in the second quarter of 1992, citing a Kommersant report on the Rossisky Gas Exchange. See IEA, "Russian Energy Prices and Taxes," Note by the Secretariat, June 11, 1992, p. 16. Without information about the ultimate disposition of this "free" priced gas or the volume of gas traded at this price, the significance of "free" prices is questionable. Our understanding is that "free" prices apply only to a small portion of the gas exported to CIS countries and eastern Europe.

[12] Like most industrial enterprises created by the Soviet Union, Gazprom provides many social services to its workers in many locations. These services include housing, food, medical care, and kindergarten. In 1990, 42 percent of the total capital invested by Gazprom was for social material development (see *Gas Industry of the USSR 1990*, page 186).

[13] In 1991, the retail price to industrial users was based on a lower calorific value of 7900 kcal/m^3, plus or minus 100 kcal/m^3.

Table 2
Retail Gas Prices in Russia

	Exchange rate or Purchasing Power Parity rate, rubles/$	Retail price to industry, before VAT	Retail price to industry, including VAT	Retail price to household sector, without VAT
Prices in December 1992				
in rubles/MCM		1100	1408	260
in $/MCM				
at the Dec. 1992 exchange rate	408	2.70	3.45	0.64
at Purchasing Power Parity	80	13.75	17.60	3.25
in cents/MMBtu				
at the Dec. 1992 exchange rate	408	8.5	10.9	2.0
at Purchasing Power Parity	80	43.3	55.4	10.2
Prices in February 1993				
in rubles/MCM		4000	4800	600
in $/MCM				
at the 8 Feb 93 exchange rate	5.72	6.99	8.39	1.05
at Purchasing Power Parity	112	35.71	42.86	5.36
in cents/MMBtu				
at the 8 Feb 93 exchange rate	572	22.0	26.4	3.3
at Purchasing Power Parity	112	112.5	135.0	16.9

Source: December 1992 gas prices before VAT are given in Decree No. 318. May 18, 1992. February 1993 gas prices before VAT are given in Decree No. 88, January 29, 1993. Purchasing Power Parity for December 1992 is a preliminary estimate by the World Bank; for February 1993 the December 1992 value is adjusted on the basis of the change in market exchange rates.

in early February 1993 may be expressed as 3.3 cents per MMBtu and the burner tip price to end users other than households may be expressed as 22.0 cents per MMBtu plus VAT (that is, 26.4 cents per MMBtu; see Table 2).

When Purchasing Power Parity is used, the prices expressed in dollars are about five times higher: 16.9 cents per MMBtu (household sector) and 112.5 cents per MMBtu plus VAT (industry sector).

1.2.2 Gas Industry Structure

The ownership and structure of the natural gas industry in Russia is becoming decentralized. The industry is in a transitional phase in which the autonomy of regional enterprises and local ownership of regional enterprises is increasing. The present structure of the industry may be summarized as follows:

- Gazprom manages gas transmission, gas storage, non-associated gas production, and processing of non-associated gas. Gazprom sells gas to distribution companies and exports gas under sales contracts. Gazprom consists of regional production and transmission enterprises; 34 are involved in production and 25 are involved in transmission and underground storage. Gazprom also sells directly to some large gas consumers.[14]

  On November 5, 1992 President Yeltsin signed Decree No. 1333, "Concerning the conversion of the State Gas Concern *Gazprom* into the Russian share-issuing company *Gazprom*" and on December 8, 1992 he signed Edict No. 1559, "Concerning the reorganization as joint stock companies and privatization of state enterprises, association and organizations of the Gas Industry of the Russian Federation." These decrees set in motion a process of privatization that is changing the ownership structure of the 79 regional production and transmission enterprises included in Gazprom.

[14] Vniiegazprom, *Gas Industry of the USSR, 1990: An Economic and Statistical Survey* (Moscow, 1991) contains data on annual Gazprom sales ("marketable gas") by transmission enterprise and by pipeline (for example, sales by Volgotransgaz on the Urengoy-Uzhgorod pipeline) but it does not contain a list of major customers or data on sales by customer.

- The natural gas distribution sector consists of 727 local distribution companies local in 60 regions, each of which has a regional gas utility, plus the distribution companies of Moscow and St. Petersburg. In the past the industry was under the central management of Rosstroigazifikazia. The cities of Moscow and St. Petersburg are not part of this association; they have their own gas distribution enterprises. Prior to the privatization program announced in December, Rosstroigazifikazia was comparable to a holding company which owned many municipal gas distribution enterprises but permitted cross-subsidization among cities. Under the privatization program defined in Edict No. 1559 dated December 8, 1992, gas distribution enterprises were to be reorganized as joint stock companies before March 31, 1993.

  Mosgaz manages gas distribution in Moscow. Gas is distributed by Mosgaz under sales tariffs, and some of this sales volume is not metered. Lengaz manages gas distribution in St. Petersburg, and is comparable to Mosgaz.

- Rosneftegas and the oil producing enterprises manage associated gas production, as well as oil production. Associated gas represented 5.6 percent of the volume of Soviet gas production in 1990, and currently represents about 10 percent of the volume of Russian gas production. Processing of associated gas is done by the producing associations and by Sibneftegaspererabotka (SNGP) in western Siberia.

- The Geological Committee of Russia (a successor to the USSR State Committee on Geology) manages oil and gas exploration. Because Russia's gas reserves are already very large, with a reserve/production ratio of about 65 years, the current need for gas exploration is modest, and therefore the Geological Committee does not need to allocate large amounts of capital expenditure to gas exploration.

In the Soviet era, the State Committee on Geology conducted all oil and gas exploration. If the transition to a market economy proceeds in the petroleum sector, a large portion of oil and gas exploration activity will be conducted by producing associations, foreign oil companies, and joint ventures between producing associations and oil companies. It is possible that the Geological Committee of Russia will evolve into an agency comparable to the U.S. Geological Survey (an agency that publishes maps and regional geological information and technical data) combined with the Minerals Management Service (an

agency that is responsible for scheduling oil and gas lease sales and regulating oil and gas operations on federal leases). To date, the Russian parliament has not passed an oil and gas law and therefore the future role of the Geological Committee of Russia is unclear.

Because most of the gas reserves in Russia are located in non-associated gas fields, the changes in the structure of the oil industry have had only a modest effect on the restructuring of the gas industry. It is quite possible that the restructuring of the gas exploration and production industry will move at a different pace in different categories of gas-bearing fields:

1. Oil fields with associated gas. As the oil producing sector becomes more competitive, the legal and contractual framework for associated gas production will increasingly resemble the legal and contractual framework found in market economies. Joint ventures and foreign oil companies will become more active in exploration and development of oil fields with associated gas.

2. New non-associated gas fields. As a result of the geological similarity between oil-bearing and gas-bearing formations, the various enterprises involved in oil exploration will discover non-associated gas fields as well as oil fields. Some of the newly discovered non-associated gas fields may be developed. In areas where non-associated gas is not found in giant fields, these enterprises may begin to compete with Gazprom affiliates for the sale of non-associated gas.

3. Existing non-associated gas fields. Following the privatization of Gazprom, the production enterprises will probably be restructured in a form that facilitates competition for ownership and management of the existing non-associated gas fields. The government of the Russian Federation is expected to relinquish its monopoly role as owner of non-associated gas production enterprises. Eventually the production enterprises may be able to purchase transmission services from transmission enterprises, thereby facilitating the development of competitive markets at the city gate.

The privatization of Gazprom will initially create regional monopolies in which ownership is shared by the Russian Federation and the regional or local government. At the regional level, a gas production monopoly will sell gas to a pipeline monopoly. This process will help to lay the groundwork for step 3 above.

1.2.3 Organizations Responsible for Gas Pricing Policy

One of the issues that must be resolved in the gas distribution sector is the question of who will establish gas pricing policies for distribution enterprises. Under the Soviet system decisions on gas pricing were strictly controlled by the central government in Moscow, and this tradition was essentially maintained when the Russian Federation was formed. End-use prices for gas were specified in Decree No. 318, issued on May 19, 1992, and Decree No. 88, issued on January 29, 1993; these decrees were issued by the Prime Minister. Paragraph 6 of Decree No. 88 contains a reference to "state price discipline:"

> Sales in the domestic market of the Russian Federation, of natural gas by enterprises and organizations irrespective of sectors they belong to and forms of ownership (including exchanges) at the prices which exceed the established ceiling of state regulating prices shall be a violation of state price discipline.

It is quite possible, however, that partial or total control over gas distribution margins and end use prices will eventually shift to autonomous republics, autonomous territories (*krai*), districts (*oblasts*), and local gas utility companies.[15] Many of the regional governments would like to assume more control over the enterprises within their borders, including gas distribution enterprises (and even gas transmission facilities), and some of the local gas distribution enterprises have declared that they have cut their ties with the regional utilities that have traditionally purchased gas from Gazprom and resold it to the local utilities.[16]

The issue of who will set gas prices is closely related to the issue of privatization. In December 1992 an edict concerning the privatization of state enterprises, associations, and organizations of the gas industry was issued by President Boris Yeltsin, representing the

[15] The distinction between an autonomous republic and an independent country is becoming blurred. In 1990 the parliament of Bashkiria (now Bashkortostan) adopted a Declaration of State Sovereignty, but the Republic of Bashkortostan was a signatory to the Russian Federal Treaty in March 1992. The Russian government has recognized special export rights for Bashkortostan, which is allowed to keep 75 percent of its hard currency exports. See *Eastern Europe Reporter*, July 5, 1993, pp. 510-512.

[16] To increase its autonomy, the parliament of Sverdlovsk voted in July 1993 to transform the Sverdlovsk oblast into a republic. Other oblasts might follow this example.

government of the Russian Federation.[17] The objective of this decree was to reorganize enterprises and associations involved in gas supply and operation, by transforming them into joint stock companies, and to reorganize selected industrial enterprises, construction enterprises, and start-up enterprises in a similar fashion, transforming them into joint stock companies. The decree established a March 31, 1993 deadline for the reorganization to be completed. Although this deadline was not met, the privatization program is proceeding rapidly.

Prior to the privatization program, all of the distribution companies except Mosgaz (serving Moscow) and Lengaz (serving St. Petersburg) were owned by Rosstroigazifikazia, a state enterprise with offices in Moscow. Within Rosstroigazifikazia there were 76 regional utilities (including 20 autonomous republics, 6 autonomous territories, and 50 districts) as well as 727 local utilities. Under the privatization program, Rosstroigazifikazia will become a joint stock company but it will not become the sole owner of the regional and local utilities. The ownership of the "enterprises involved in gas supply and the operation of the gas industry, which are part of associations" will be divided among the Russian Federation, regions, and towns according to the decisions of the State Committee of the Russian Federation for the Administration of State Property (GKI). After this allocation of ownership shares is established by GKI, shares may be sold to "members of the work collectives of joint stock companies."[18] Separate procedures are established for privatization of state enterprises which are not part of associations.

1.3 ISSUES IN GAS PRICING IN RUSSIA TODAY

The current system of gas pricing in Russia presents a number of critical issues:

- The price of gas in the household sector is substantially below the price to the industrial sector, although the cost of delivering gas to the household sector is higher. Because gas prices do not reflect costs, it is difficult to evaluate the cost-effectiveness of alternative investments in energy conservation or energy supply for the household sector. Higher gas prices

[17] Edict No. 1559 of the President of the Russian Federation of December 8, 1992, "Concerning the Re-Organization as Joint Stock Companies and Privatization of State Enterprises, Associations and Organization of the Gas Industry of the Russian Federation."

[18] Edict No. 1559, December 8, 1992.

may be needed to provide incentives (for household cooperatives, or for individual households) to use gas efficiently.

- The city gate price of gas destined for the household sector is below the wellhead production cost of gas. This pricing system creates a potential obstacle to deregulation of wellhead prices and to the creation of competitive markets at the wellhead or at the city gate.

- Because there are no regional differences in gas prices within Russia, there is a tendency for lower-cost producing areas to subsidize higher-cost producing areas, and a tendency for consumers in the cities closest to gas producing fields to subsidize consumers in the cities farthest from gas producing fields.

- There is a large gap between domestic prices and export prices. For example, there is an enormous difference between the price of gas sold to distribution companies for resale to the household sector (300 rubles per mcm) and the price of gas sold to countries outside the CIS (50,000 rubles per mcm). Therefore, there are financial incentives to separate the export sector from the domestic gas sector, although from the standpoint of operational efficiency it would be best to maintain an integrated gas production, transmission, and storage system.

  The disparity between domestic and export prices is an impediment to economically efficient trade between Russia and other CIS countries. Where gas prices are much higher on the non-Russian side of the border, trade is disrupted because gas-using Russian enterprises are given an artificial competitive advantage. Non-Russian industrial plants that were built to provide inputs and intermediate goods for Russian industry may be forced out of business, resulting in supply shortages for Russian industry. There is a possibility that this artificial competitive advantage is believed to provide a net economic benefit to Russia. The artificial nature of this competitive advantage, which is created by gas price controls, may not be recognized by Russian manufacturers.

1.4 LIKELY SCOPE OF PRICE REFORM

To fully describe the need for gas price reform in Russia one must examine the relationship of prices to costs, the way in which prices convey information, and the relationship between prices and the allocation of resources. Price reform involves many aspects:

- an adjustment in the level of prices
- the development of price variations (in line with cost variations) based upon geographic parameters, differences in the terms and conditions of service, and differences in the quality of gas delivered
- an increase in the number of products and services for which prices must be established (for example, different prices for firm and interruptible service)
- an increase in the frequency of adjustment of prices, to maintain a balance between supply and demand
- a shift from unmetered service to metered service, to permit pricing based on actual consumption
- a change in the way prices are used to guide economic decisions about production and consumption.

Our assessment is that the Russian gas industry has a need for price reform in every aspect. Household price levels are low; prices need to vary regionally (to reflect differences in transmission costs), and vary according to terms of service; products and services need to be identified and priced separately; prices need to be adjusted more frequently; metering needs to be implemented more widely; and prices need to be used to guide investment decisions and energy conservation initiatives.

To provide a focus for this report, we have attempted to identify the aspects of price reform that appear to be most important and most needed. The following elements could be considered the focus of price reform:

- ***Transparency of wellhead prices.*** At present, the functions of production and transmission of non-associated gas are both conducted by Gazprom subsidiaries. The transfer of natural gas to the transmission system is an

internal transaction. Information on wellhead prices is difficult to obtain. To promote the development of competitive markets for gas production, it is essential to make wellhead prices transparent.

- ***Availability of transmission service.*** In the past, local gas distribution companies in Russia purchased gas from regional utilities which in turn purchased gas from Gazprom. To promote the development of competitive markets for gas production it would be desirable to allow the distribution companies, or the regional utilities, to purchase gas from production enterprises and pay separately for gas transmission services from transmission enterprises.

- ***Creation of city gate prices.*** We may define a city gate price as the price of natural gas at the point of delivery from the high pressure transmission network to a particular gas distribution enterprise. Such a price is not a national average but a price at a particular location in the national transmission grid. To create an economically efficient system of pricing, city gate prices should vary from *oblast* to *oblast* (or from city to city), on the basis of the cost of gas production and transmission and storage.

  In the present price structure there are two price levels for gas sold for resale, neither of which varies from *oblast* to *oblast*. There is a price for gas sold for resale to households, and a price for gas sold for resale to other consumers; this pricing scheme is not related to costs and could not be sustained in competitive city gate markets.

- ***Gradual introduction of transmission costs based on hard currency.*** At present the transmission system is used to serve export markets and domestic markets, and capital investment is provided largely by export markets. Gazprom has demonstrated its ability obtain capital for pipeline capacity needed to serve export markets.[19] The domestic industrial sector can provide very little, if any, capital for Gazprom because the city gate price

[19] For example, in February 1993 the general director of Gazprom stated that western banks had already offered $3 billion in financing for a $10 billion project to build two pipelines to take gas from the Yamal Peninsula to Germany. Separately, $2 billion in financing was obtained in January 1993 from the government of Italy for the purchase of compressor station equipment to improve compression capacity on existing pipelines. See *Eastern Europe Reporter*, February 15, 1993, pp. 116-117.

(3600 rubles/MCM; see Table 1) is only 1000 rubles/MCM above the extraction cost of the gas. The domestic household sector provides absolutely no capital for Gazprom, because the city gate price (300 rubles/MCM) is below the extraction cost of the gas (2600 rubles/MCM). To enable domestic markets to attract capital investment and to facilitate open access to the transmission grid, it will be necessary to increase domestic transmission charges to a level based on transmission costs in hard currency.

- ***Increase in distribution margins.*** The present margins are 300 rubles/mcm for resale to households and 400 rubles/mcm for resale to other customers. At an exchange rate of 600 rubles per dollar these margins are equivalent to 1.6 cents/MMBtu and 2.1 cents/MMBtu. These margins are too low to support investment and appear to support only a minimum level of operation and maintenance. Construction of new distribution systems would require a margin of 4 to 5 cents/MMBtu for large industrial customers (including 3 cents/MMBtu for operation and maintenance) and $3.70/MMBtu for residential and commercial customers (including $3.00/MMBtu for operation and maintenance). The dramatic difference in margins is attributable to the fact that large industrial customers receive gas from large-diameter pipes at high load factor and higher pressure (6 to 8 bar, or 88 to 176 psi), while residential and commercial customers can be served by new, small-diameter pipes at medium pressure (3 bar or 44 psi).

  Without an increase in distribution margins, the gas distribution companies may not be able to generate the revenues necessary to attract the capital needed to sustain the industry's ability to provide service to Russian consumers. Higher margins are needed to make necessary investments economic over the long term.

- ***Reversal of the disparity between industrial and household prices.*** The cost of gas distribution (per mcm) is higher for household customers than the cost for industrial customers, because the household customers are served at lower pressure with smaller-diameter pipe. The cost of gas production and transmission for household customers is at least as high as the cost for industrial customers (who may obtain transmission discounts for interruptible service). In Russia, however, industrial customers pay a much higher price (including a much higher "city gate" price) than households. In the long

run, this price relationship should be reversed. Household prices should be brought up to industrial prices at the city gate, and up to a higher level at the burner tip.

- *Creation of additional customer classes.* For transmission companies there should be a price to consumers, other than gas distribution companies, that have a direct connection to the high pressure network.[20] For distribution companies there should be a customer classification system based on the different levels of delivery pressure; small commercial customers should pay a higher price than large industrial customers served by higher-pressure distribution mains.

  Without this price "signal," energy conservation opportunities will not be captured and the benefits of conservation will be lost. These benefits include an improvement in economic efficiency and an increase in the amount of gas available for export. The introduction of new and more efficient industrial equipment may be supported through energy efficiency programs.

Some of these policies would have the effect of raising prices. Through Decree No. 88, the Russian Federation demonstrated a willingness to raise prices to enable the gas industry to generate investment funds internally and avoid operating losses that would create a need for government subsidies. In this respect the Russian government accepted two of the primary objectives of gas price reform.

Fully meeting these objectives does not necessarily require an immediate increase in domestic prices to international levels. Gas price increases may exacerbate the loss of purchasing power that has been experienced by the majority of Russians in recent years. Gas price increases lead to increases in the prices of electricity and district heat, as well as increases in the price of products manufactured with natural gas.

Gas price reform does not necessarily mean that Russian domestic prices should rise to western European levels. The economic cost of gas in Russia is lower than in western Europe and many other countries, because Russian production is obtained from giant gas fields and transmission is accomplished with very large diameter pipelines. These economies of scale available to Russia are simply not available to most countries.

[20] In the simplest case, prices for all customers connected to the high pressure network in a given oblast would be identical. This uniform city gate price could be applied to all pipeline connections in the oblast.

1.5 NEED FOR GOVERNMENT CONTROL OVER GAS PRICE REFORM

To some extent one can find a need for price reform in almost any sector of the Russian economy. Where the conditions necessary to develop competitive markets already exist, however, the simplest way for the government to promote price reform is to encourage the creation of competitive enterprises and to remove price and allocation controls. In this respect price reform can develop from privatization, restructuring, deregulation and other activities that are not directly related to pricing. This approach to price reform may be called the competitive model.

For the near term and the medium term, the competitive model cannot be applied to natural gas transmission and distribution in Russia. The transmission system is controlled by Gazprom, a large, capital-intensive enterprise that plays a vital role in both the domestic economy and the export sector. These attributes are unavoidable, regardless of the pace of reform in the rest of the Russian economy, and they tend to slow the rate at which the gas industry can make a transition to a more competitive, decentralized industry.

Gas transmission and distribution are natural monopolies in Russia, as in most countries, because there are economies of scale in pipeline construction and operation. Gas transmission and distribution are capital-intensive because the construction and installation of gas pipelines represents a large share of the cost of transmission and distribution. Because the reliability of gas service depends on the continued operation of an interconnected grid, it would not be reasonable to try to privatize the industry by selling pieces of it to new and inexperienced companies. All of the pieces of the transmission grid are dependent on each other; Gazprom operates somewhat like a chain of transmission companies connected in series. Moreover, these sub-transmission enterprises currently lack the metering, accounting, and billing systems that would be needed to provide open access to the transmission grid. Under these conditions it is impossible for the gas transmission industry to be turned over to small, entrepreneurial firms having a small amount of capital; rather, transmission will continue to be controlled by a large enterprise for many years.

Gas production in Russia is also likely to be dominated by Gazprom for many years, because production is concentrated in a small number of giant fields under its control. For the major gas fields, production costs are so low that there is little incentive for new independent producers to try to compete in the same region with the existing enterprises that operate the major gas fields.

Gas plays a vital role in the domestic economy because it is the dominant fuel used to provide space heat, water heat, and electricity. Gas is the dominant fuel in Russia, accounting for over 40 percent of energy production.[21] Given the recent decline in oil and coal production, and the safety problems associated with nuclear power, the share of natural gas in total energy production is likely to increase. Given this vital role, the Russian government cannot afford to conduct "experiments" on the gas industry that might threaten the reliability of gas supply.

Gas also plays an important role in providing hard currency export earnings for Russia. We estimate that gas exports provide about 25 percent of total hard currency earnings. For 1992, exports to countries outside the former Soviet Union were planned to be 103.5 bcm,[22] which would be worth $8 billion at a price level of $80/mcm. The Russian government cannot afford to disrupt the industry in a way that would threaten the industry's ability to deliver a reliable gas supply to western Europe.

For these reasons, price reform in the natural gas industry will not develop through the competitive model. The attributes of a market economy will not arise in the gas industry through the creation of new companies and the bankruptcy of old, inefficient enterprises. Instead, price reform in the medium term must develop through the re-working of existing institutions.

1.6 ASSUMPTIONS ON PRICING AND STRUCTURAL ADJUSTMENT

To develop gas pricing principles, it is necessary to make some assumptions regarding the future structure of the gas industry. For the purposes of this study we have developed a set of assumptions to describe a gas industry structure that is similar to the present ownership and management structure, but which would be compatible with a transition to a more competitive gas industry. We assume that the gas industry will be organized in the future according to the following principles:

[21] A rough indication of the role of gas in Russian energy production is given by 1990 statistics for the Soviet Union. If 1990 Soviet energy production is measured in million tons of "standard fuel," the shares of various energy sources are gas, 40 percent; oil, 34.1 percent; coal, 18.1 percent; hydroelectric power, 3.1 percent; nuclear energy, 2.7 percent; wood, 0.8 percent, and peat and oil shale, 0.6 percent. A ton of standard fuel is 6.95 million kcal or 29.3 GJ.

[22] "Evaluating the FSU's Natural Gas Sector," *World Oil*, December 1992, Table 7.

1. Some power plants, district heating plants, and industrial and agricultural enterprises will continue to receive gas directly from the high pressure network, instead of receiving gas from a distribution enterprise. These enterprises may be defined as "HPN consumers." They will not sell gas to each other, to distribution enterprises, or to other consumers.

   All other ultimate consumers of gas in Russia will be served by distribution enterprises. An "ultimate consumer" may be defined as a household or enterprise that purchases gas and does not resell it. A "DE consumer" is an ultimate consumer served by a distribution enterprise.

2. Distribution enterprises will purchase and resell gas. They will purchase gas from transmission enterprises, production enterprises, or gas marketing companies, and they will sell gas to ultimate consumers. They will earn revenue by providing distribution and storage service. They will not act as common carriers or contract carriers (i.e., they will not transport gas owned by others) and will not sell gas to each other. They will own the gas moving through their distribution mains. Distribution enterprises may own gas storage facilities that are directly connected to the distribution system pipelines. Distribution enterprises may not profit by reselling gas at a markup above its purchase price.

3. Gas exported from Russia via Russian-owned pipelines will be delivered to export customers. An export customer may purchase gas at the Russian border or exchange gas at specific points within Russia for gas at the border. An export customer may not own any of the gas in the Russian high pressure network.[23] An "export customer" must be an enterprise owned by foreigners, not a Russian enterprise. It is possible for an export customer to be an ultimate consumer of gas, but the more likely case is that an export customer is an enterprise involved in purchasing gas for resale.

   Gas may also be exported from Russia via pipelines that are completely separate from the existing network and are owned by foreign enterprises.

[23] The intent of this provision is to avoid a two-tiered system of transmission charges, in which export customers pay a higher transmission charge than other customers. Such a system would be difficult to enforce, and might enable middlemen to earn excessive profits by transporting "export" gas at transmission charges intended for Russian consumers.

This situation may arise in the development of offshore fields, for example. The exporter in this situation is not a customer, because he is not served by the existing network; he may be called a "direct exporter." Natural gas produced at Shtokmanovoksoe (a currently undeveloped field in the Barents Sea), for example, might be exported to Finland through an offshore pipeline owned by foreigners.

In the long term it is possible that the Russian pipeline network could receive Russian offshore or onshore gas delivered to the network through pipelines owned by foreigners. If the Shtokmanovskoe field is developed, for example, and direct exporters build a pipeline to bring the gas onshore at either Finland or the Kola Peninsula, this offshore pipeline might also be used to deliver gas to a Russian onshore pipeline to St. Petersburg. In such a situation the transmission charges for the offshore pipeline would be negotiated with the pipeline owners. For the purposes of this study, however, we assume that all new pipeline construction linked to the Russian high pressure network is owned by Gazprom or other Russian enterprises and therefore subject to the same types of transmission charges as the existing high pressure network.

4. The high-pressure network (HPN) will be owned by one or more transmission enterprises which will either: (a) buy gas from producers or gas marketing companies and sell gas to distribution companies, HPN consumers and export customers; (b) transport gas owned by producers, gas marketing companies, distribution companies, and HPN consumers, or (c) conduct both of these activities. The HPN enterprises will earn revenues by providing transmission and storage service. Transmission enterprises may own gas storage facilities that are directly connected to the high-pressure network. Transmission enterprises may not own distribution lines or gas wells. Transmission enterprises may not profit by reselling gas at a markup above its purchase price.

5. The transmission enterprises will all accept and enforce a single set of gas quality specifications, so that gas streams from different sources of supply can be combined and exchanged without altering the quality of the gas delivered to the distribution company, HPN consumer, or export customer. Within the HPN, a cubic meter of gas will be a fungible commodity;

associated gas will be combined with and indistinguishable from non-associated gas.

6. Gas will be delivered to the high-pressure network by production enterprises. Each production enterprise will be responsible for delivering gas according to HPN quality specifications. A production enterprise will own gas wells from which non-associated gas is produced and/or oil wells from which associated gas is produced. A production enterprise may also own gas processing plants and gas gathering systems, or it may pay other enterprises for gathering and processing services. Some or all of the gas delivered by a production enterprise to the high-pressure network may be owned by gas marketing companies.

7. Gas marketing companies may exist. These companies will either buy and resell gas or charge a fee for bringing buyers and sellers together. Gas marketing companies may own gas processing plants and/or gas gathering systems, but any company which owns gas wells must be classified as a production enterprise. Gas marketing companies may not own transmission lines or distribution systems, and may not buy gas at the city gate; their activities must be upstream of the city gate.

Given these conditions, several types of gas prices will need to be set:

- ***Wellhead prices.*** These are prices of gas sold by producers to companies with gas gathering and processing operations.

- ***Gas purchase prices.*** These are prices of gas delivered to the HPN by producers or marketing companies. This gas stream must meet HPN quality specifications. These are wellhead prices plus a markup for gas gathering and processing.

- ***Transmission charges.*** These are prices for transmission services provided by transmission enterprises.

- ***City gate prices.*** These are prices of gas delivered to distribution enterprises. Each city gate price can be calculated from a sum of transmission charges and gas purchase costs (even if gas purchase prices are decontrolled).

- ***HPN consumer prices.*** These are prices of gas delivered to high pressure network consumers by transmission enterprises.

- ***DE consumer prices.*** These are prices of gas delivered to distribution enterprise consumers by distribution enterprises.

- ***Pipeline export prices.*** These are prices of gas delivered to export customers by Russian transmission enterprises.

- ***Direct export prices.*** These are prices of gas exported from Russia through pipelines owned by foreign enterprises.

The determination of pipeline export prices and direct export prices is outside the scope of this study. The other types of prices will be discussed in later chapters.

CHAPTER 2: EXPLORATION AND PRODUCTION COSTS UNDER COMPETITIVE CONDITIONS

CHAPTER SUMMARY: MAJOR CONCLUSIONS

A direct estimation or verification of gas production costs in the former USSR from Gazprom cost data is practically impossible because of limited access to detailed cost accounting data and because of the many inconsistencies that seem to exist between the Russian and U.S. oil and gas accounting systems.

An indirect way of determining Russian gas production costs is to estimate U.S. gas production costs under operating conditions approaching those in the former USSR.

Using this methodology, U.S. production costs (including exploration costs, field development costs, and field operating costs) in giant gas fields operating under conditions similar to those found in Russia have been calculated to be on the order of 21 to 22 cents per mcf. This estimate compares well with Gazprom's cost estimate of 18 cents per mcf in the Urengoy Field in West Siberia.

Overall, Gazprom's estimated range of natural gas production costs between 17 and 62 cents per mcf appears to be in line with Western cost experiences. Accordingly, we recommend that the Russian cost estimates in Table 5 be accepted as shown.

Russia's non-associated gas reserves are huge, both in absolute terms and relative to the rate at which they are produced. Russia's reserve to production ratio is on the order of 80 to 1, compared to an R/P ratio of 9.4 in the United States and 23.5 in Canada.

Many of Russia's non-associated gas accumulations are found in giant reservoirs, especially in Western Siberia, causing exploration, development and production costs on a per-unit basis to be very low by world standards.

2.1 THE DATA BASE

Russia's gas reserves are vast and geographically highly concentrated. Detailed information regarding field-by-field or even regional accumulations of non-associated gas is just now becoming available. Sources of this information are a Gazprom report entitled

Gas Industry of the USSR, 1990, statements by Russian government officials, sporadic press releases, professional contacts and working relations with representatives of Gazprom, and other statistical information of Russian origin that is increasingly being made available to Western observers. This kind of information, even though a vast improvement over the data that were available only a few years ago, nevertheless has two distinct qualitative drawbacks:

1. Given the variety of sources, the data that emerge are not always consistent; at times they are contradictory.

2. Some records, especially gas reserve records, are still being kept on a historical basis, for the former USSR as a whole or for Gazprom. Information such as gas reserves in Russia or in the other former Republics is not yet publicly available.

The data gap is a source of concern but, in the context of this report, it is not fatal. To the extent that aggregate data are used in this report, they will for the most part cover the former USSR, and they will be so labelled. Even then, the data will reflect interpretations and judgments of various Russian energy analysts, and as a result there might be inconsistencies in the adopted data base.

2.2 OVERALL GAS RESERVES

As of January 1991, the non-associated gas reserves of the former USSR were estimated to be 64.5 trillion cubic meters (Tcm), or 2.28 quadrillion cubic feet. By comparison, U.S. proved gas reserves were less than 5 Tcm (169 trillion cubic feet) at that date. More than two thirds of the gas reserves of the former USSR are located in Western Siberia. The predominance of the former USSR as the world's largest owner of natural gas reserves can be seen from Table 9.

2.2.1 Reserve Definitions

Unfortunately, there is no world-wide standard in defining oil and gas reserves. Even within the United States, a very mature oil-producing nation, efforts to standardize reserve definitions have not been successful. Accordingly, different U.S. government agencies (the U.S. Department of Energy, the U.S. Department of the Interior, the Securities and

Exchange Commission) and different private sector groups have different definitions. Hence, expressing Russian reserve data in non-Russian terms is potentially misleading.

The Russian gas reserve data listed above are based on what some U.S. oil and gas analysts would call proved and probable reserves, that is, reserves proved up by drilling, production testing and actual production (proved), plus reserves in new structures or in undeveloped portions of producing fields, where the commercial existence of gas has been proved generally by drilling and testing but where specific areal control of estimated reserves rests in part on geological and geophysical interpretations, and depth control is consistent with the lowest water-free production test to date or with the existing depth of the water table, if it has been found (probable reserves). This is a loose definition, even by U.S. standards, but it is the kind of data that the analyst has to work with. On the Russian scale of reserve definitions, this corresponds roughly to Class A, B, C1, and C2 reserves, where the C2 reserves correspond roughly to the internationally accepted concept of probable reserves. In Russian usage, C2 reserves are an early indication of the growth potential of a proved hydrocarbon accumulation. It is generally expected that C2 reserves will eventually be re-classified as C1 reserves, as new drilling and production data become available in the course of developing a field.

Actually, the C1/C2 distinction is mostly a regulatory one in Russian usage. A field may only be developed after a sufficient volume of its hydrocarbon content has been officially certified as Class C1 or higher, where the term "sufficient" generally has meant 80% of the expected overall in-place volume. For supergiant fields such as those in West Siberia, the implementation of a policy of withholding development until 80% of the field has been proved up would impose unacceptable delays. This has been recognized by Russian officials who have permitted earlier production operations in special cases. Given Russia's very cautious approach in certifying oil and gas reserves at the A, B, or C1 levels, hereafter referred to as "explored" reserves, and the history of repeated up-gradings of C2 reserves to C1 status, Class A through C2 reserves are listed here as "proved" reserves. However, C2 reserves will be shown separately whenever possible, so that the relative magnitudes involved will be known.

2.2.2 Reserve to Production Ratios

In an ideal world with predictable gas discoveries and consumption patterns, there exists an optimally sized reserve base to meet current and future demands. An inadequate reserve base leads to shortages and spiralling prices, an excessively large reserve base reflects a pattern of misallocated funds in developing reserves that may not be needed for decades. A

nation's funds are not being used efficiently if the development of its reserves deviates from the norm which is generally expressed in terms of its reserve to production ratio.

In the United States, the reserve to production ratio is about 9.4, compared to a ratio of 23.5 in Canada. Both countries possess reasonably efficient systems capable of providing a reliable supply opf gas with a minimum of premature exploration investments. Given the often considerable distance between producing areas and markets for natural gas, both systems are streamlined through the creation of storage sites near consumption centers. These sites derive their economic existence from seasonal price differentials which are unknown in Russia.

According to Gazprom, Russia's proven gas reserves on January 1, 1991 were 47.0 tcm and Russia's 1990 gas production was 640.23 bcm (including 44.5 bcm of associated gas).[1] These figures indicate a reserve to production (R/P) ratio of 73 to 1. According to British Petroleum, Russia's proven gas reserves at the end of 1992 were 47.6 tcm and Russia's 1992 production was 602.1 tcm, indicating an R/P ratio of 79 to 1.

These figures are roughly consistent with R/P ratios for the Soviet Union. The reserve base (including C2 reserves) of the USSR was approximately 64.5 Tcm (2,277 Tcf) in 1990, and the overall rate of non-associated gas production that year was on the order of 771 billion cubic meters (27.2 Tcf).[2] The R/P ratio, therefore, was somewhat above 80 to 1. If C2 reserves are left out, the former USSR reserves are reduced by 12.5 Tcm, down to 52.0 Tcm, for an adjusted R/P ratio of 67 to 1. If associated gas production is included in the reserve to production ratio, and the gas reserve is reduced by the existing C2 reserves (the worst-case scenario), the resulting reserve to production ratio would still be at the formidable level of 64 to 1. Associated gas is a by-product of oil production; it is actually gas that exists for the most part in liquid form under reservoir conditions, but comes out of solution as a result of the pressure reduction that oil undergoes as it approaches the well bore and is lifted to the surface (very much like the bubbles in mineral water that form when the pressure cap on the bottle is removed). However, associated gas

[1] Alexander Sedykh, "Existing and potential development projects in the former USSR," paper presented at a conference on *Natural Gas Policies and Technologies*, Vilamoura, Portugal, 2-3 April 1992, pp. 3-4.

[2] Gas Industry of the USSR, 1990; *An Economic and Statistical Survey; State Gas Concern Gazprom & All-Union Research Institute*; I. A. Zhuchenko, General Director; Moscow, 1991; p. 5.

production, generally under the jurisdiction of the Russian Ministry of Oil & Gas, represents only 5.4% of the total gas production of the former USSR.[3]

Most OECD countries with significant gas reserves have an R/P ratio below 30 to 1. Among OECD countries the Netherlands (28.1), Canada (23.5), Australia (22.0), New Zealand (20.5), and Germany (19.3) have relatively high R/P ratios while the United Kingdom (10.2) and the United States (9.4) have relatively low R/P ratios.[4] These figures suggest that in a country with a market economy and substantial domestic energy demand (or pipeline access to countries with substantial per capita energy demand) it should be possible to bring gas reserves into production so that the R/P ratio falls below 30. If the R/P ratio stays above 30, it is likely that either the "reserves" are high-cost resources that are marginally economic or the government has somehow created incentives to conduct more exploratory drilling than is necessary to satisfy market demand for gas.

We expect Norway's gas R/P ratio to fall below 30 as gas reserves are developed. Norway has an unusually high R/P ratio (72.1), but it has practically no domestic gas demand and its gas reserves were discovered only after western European countries had already made commitments to buy Algerian and Russian gas as well as other North Sea gas. Norway's gas is offshore (including fields off the northwestern Norwegian cost) and therefore relatively expensive to transport to major European cities.

In terms of the age of gas reserve additions and access to gas distribution systems, Russia may be compared with Canada rather than Norway. Russia is the world's largest gas producer and has an extensive transmission and distribution infrastructure. If the Russian gas industry had developed in a market economy, it might have brought the R/P ratio down to about 25. Because Russia's supergiant fields are so large and so far from population centers, however, it would take many years to bring the R/P ratio down to 25. The magnitude of Russia's gas reserve "excess" was in part unavoidable, given the size of the natural gas reservoirs in West Siberia. It is difficult not to overshoot a targeted R/P ratio, when the discovery of just one supergiant field, Urengoy, yields reserves that exceed the entire U.S. reserve base of 20,000 or so natural gas fields, by a factor of roughly 2.5. This

[3] Gas Industry of the USSR; op. cit.; p. 5. Actually, the total associated gas production in the former USSR is very low compared to other areas. Not all U.S. States keep track of separate associated and non-associated gas production, but Texas, for example does, and its associated gas-oil ratio is 2016 scf to 1 barrel of oil (1991), compared to a ratio of 375 to 1 in the former USSR. These numbers do raise questions about the efficiency of Russia's associated gas collection. One estimate puts the 1990 volume of wasted associated gas at 11.6 Bcm (409 Bcf).

[4] British Petroleum, *BP Statistical Review of World Energy*, June 1993, pp. 18-20.

is all the more true when one considers that another field neighboring Urengoy to the north, Yamburg, contains roughly the equivalent of the total U.S. natural gas reserves, and one to the east, Zapolyarnoye, contains half again of the U.S. reserve equivalent.

Taken by themselves, the Siberian natural gas reserves (through C2) have been estimated to be 44.1 Tcm (1,557 Tcf). Their withdrawal rate in 1990 was on the order of 542 Bcm (19.1 Tcf),[5] including production of Norilskgazprom, which does not feed into the pipeline corridors pointed toward the West or South, for an estimated West Siberian reserve to production ratio of 81. Thus, the West Siberian reserve to production ratio is of the same order of magnitude as that for the rest of the former USSR, not including West Siberia itself. This suggests one or all of the following three causes:

1. The production and reserve data underlying this discussion are inaccurate, or

2. Production operations outside Western Siberia are highly inefficient, perhaps involving flaring or other unrecorded production losses,[6] or

3. Reserve estimates in Western Siberia are low.

While almost surely all three factors play into this apparent anomaly, the third cause, low reserve estimates, warrants closer discussion.

2.3 WEST SIBERIAN RESERVES

Listed below in the order of increasing climatic hostility and development expense are four subregions of the overall West Siberian natural-gas bearing region:

Taz Peninsula, including the Urengoy, Yamburg, Zapolyarnoye and Medvezhye Fields, plus numerous other giant gas fields in the Region South of Taz,

[5] Gas Industry of the USSR, 1990; op.cit.; pp. 17-19.

[6] Estimates of West Siberian gas flaring are around 20 Bcm/year (706 Bcf/year).

Gydan Peninsula, including the Geofiziche, Gydan and Yubileynoye Fields, among others,

Yamal Peninsula, including the giant Bovanenkovskoye, Kharassavey, and Kruzenstern Fields, plus at least another 20-plus significant fields, and

Off-Shore Yamal, represented by Russanovskoye and Leningradskoye Fields.

We have been unable to find reserve data for the Gydan Peninsula and the Off-shore Yamal Subregions, possibly because no reserves (or not all of their reserves) have been certified. For example, the Off-Shore Russanovskoye and Leningradskoye Fields are estimated to jointly contain roughly the equivalent of 60% of the total U.S. reserves, or about 2700 Bcm. That is a first estimate, subject to revision, more than likely upward if past history on West Siberian gas fields is a guide. Yet, not having been certified, the reserves of these two giant fields are not included in the Western Siberian reserve base. To the extent that they are missing, the West Siberian reserve to production ratio has been underestimated. If those two fields were added into the reserve base, the reserve to production ratio would be increased by about five years. And that just covers two named fields. We do not know how many of the ten-plus gas fields on the Gydan Peninsula escape similar accounting or, for that matter, how many of the Yamal On-Shore and Taz Fields are not yet fully certified. The magnitude of the reserve data gap can be gleaned from Table 3, which shows that 63% of the remaining West Siberian reserves (44.1 Tcm) are contained in 15% of the 115-plus gas fields that have been identified in the four West Siberian Subregions. Also shown for comparison are equivalent U.S. data.

Table 3
Gas Reserves in Giant West Siberian Fields

Region	Remaining Reserves - Bcm -	Based on Nbr of Fields	Actual Nbr of Existing Gas Fields	1992 Product'n - Bcm -
Taz Peninsula	19,580	12	80-plus	525[7]
Yamnal On-Shore	6,040	3	23-plus	-
Yamal Off-Shore	2,700	2	2	-
Gydan Peninsula	?	-	10-plus	-
TOTAL	28,320	17	115-plus	
U.S. Total	4,730	20,000	20,000	487

The Taz Peninsula reserve to production ratio is nearly 40 to 1, or four times that of the United States, if only its 12 largest fields are taken into consideration. Using the 17 largest West Siberian gas fields as a basis, the reserve to production ratio rises to 54. As we have seen, the overall West Siberian reserve to production ratio is about 81 to 1, based on certified reserves. A significantly larger ratio is sure to exist for all of the region's known fields, including those where the reserves have not yet been, or have not been fully, certified.

The relevance of all this to the cost of natural gas in Russia's consuming areas is that the premature development of huge gas reserves in hostile climates and their connection with consuming regions is very expensive. We have pointed out earlier that, given the size and the regional concentration of the West Siberian natural gas reserves, the discovery of these giant reserves was inevitable once the West Siberian play got under way. Phasing in these giant fields in an orderly (that is cost-minimizing or profit maximizing) development plan, taking into consideration the time value of money, is a different matter. If a rational pricing system were in place, chances are that Off-shore Yamal, On-shore Yamal and even the Gydan Peninsula would not be developed until the investment in the Taz gas-producing infrastructure has been fully utilized, i.e., until the existing reserve base on the Taz Peninsula has been completely developed. (This does not even consider the much-talked-about Shtockmanov Field in the Barents Sea which is located in what might well be the

[7] Apparent discrepancy with West Siberian production rate of 542 Bcm/year probably due to inclusion of Norilskgazprom in the former figure.

roughest off-shore area in the world and which would require a 400-mile under-water pipeline connection to Murmansk).

Of course, Gazprom officials have studied the natural gas demand and supply situation in the former USSR, as well as current expectations regarding future export markets, and they have taken into consideration the lead times that are required to bring new West Siberian Fields or Subregions on line. These studies were not available to us, so we do not know whether Gazprom has considered the possibility of a 25% decline in domestic gas demand and other CIS gas demand due to economic restructuring, price increases and investments in energy efficiency. To re-estimate detailed future natural gas demand and supply patterns in Russia and elsewhere is far beyond the scope of this work. Hence, we will make our point with the limited information now at hand, based on three broadly defined projections of future West Siberian gas production plateaus: 550 Bcm; 700 Bcm, and 850 Bcm (19.4; 24.7; and 30 Tcf) per year. This spread of 300 Bcm (10.6 Tcf) per year roughly reflects Gazprom's own views concerning future increases in the overall natural gas production of the former USSR, which has been projected (optimistically, we believe) at 1100 to 1230 Bcm (38.8 - 43.4 Tcf) by the year 2010.

Table 4
Plateau Rates - West Siberia
12 Giant Fields, Taz Subregion, Bcm

Remaining Production	Plateau Rates	Required Reserve Base	Existing Reserve	Years at Plateau
19,580	550	4,580	15,000	27
	700	5,830	13,750	20
	850	7,080	12,500	15

Table 4 suggests that there is plenty of time, somewhere in the neighborhood of 20 years, before the decline from the targeted Taz regional plateau rate sets in. When that decline begins, the reduction in gas production will be gradual, in the sense that significant production will continue to be maintained for decades. This means that there is no particular hurry to move out of the Taz Peninsula and into the more hostile subregions to the North, even if the rather ambitious production targets of 850 Bcm (30 Tcf) per year from West Siberia are to be met. This is especially true if one considers that the lowermost

sedimentary horizon, the Jurassic, reportedly has hardly been touched by the drill bit and that the sedimentary basin has yet to be penetrated to the basement rock, which, in the Northern Tectonic Region, comes in as deep as 29,000 to 36,000 feet. A 26,000-foot superdeep stratigraphic test has reportedly been planned at the Urengoy Field.

Implicit in the plateau rates listed in Table 4 is the assumption that the Western-oriented natural gas production rates outside of Siberia will remain constant. Given the reserve potentials elsewhere throughout the former USSR, especially in the Southern regions of Russia and in Turkmenistan where the two giant fields of Dauletabad and Sovetabad await further expansion, this is not an unreasonable assumption. In fact, Gazprom's estimate concerning an 850 Bcm per year plateau rate in West Siberia seems high, especially if a rational pricing regime is introduced in Russia and if Western technology and investment are applied in other areas outside Siberia (for example, at the Karachaganak field in Kazakhstan).

Analyses on a broadly aggregate base fail to deal with the realities of the production problems that present themselves in the field. A detailed discussion of these problems goes beyond the scope of this study. Suffice it here to say that Gazprom is not dealing with one homogeneous reserve accumulation in West Siberia. To use the Urengoy Field as an example, gas production will be obtained from at least three geological formations (the Middle and Lower Cretaceous and the Jurassic), each with several strata, and each containing fluids with different compositions. These range from nearly pure methane in the main gas-bearing formation (the Cenomanian in the Middle Cretaceous) to natural gas with varying levels of condensate, to crude oil which exists in at least two strata of the Lower Cretaceous and, quite possibly, in some strata of the Jurassic. While some of the natural gas produced from the Cenomanian probably only requires dehydration and compression (and cooling in the permafrost sections of the gathering system), the deeper formations require more elaborate treatment at the surface.

2.4 PRODUCTION COSTS

As mentioned, Gazprom finds itself in the position of being a vertically integrated monopolist. The company produces, treats and transports natural gas to consumers which, in the case at hand, are either local distribution companies, major industrial users or foreign importers of Russian natural gas. In a market environment, such a situation confers extraordinary opportunities on the monopolist to charge prices above the competitive norm and, i.e., above production costs plus normal rates of return, and to extract considerable economic rents. These rents translate into greater-than-normal rates of return which, in

turn (in the competitive model) tend to attract competing capital into the industry. The entry of new capital eventually erodes the profit situation of the monopolist, or so goes the theory.

For several reasons, this self-liquidating monopoly process is not likely to take place in the Russian natural gas market. First among those reasons is the fact that the Russian Government has become, for the time being at least, the guarantor of Gazprom's monopoly position. Moreover, Gazprom's institutional objective over the past decades has been to meet production quotas, with little or no regard to profits. Management's ongoing preoccupation with production volumes, coupled with the Russian Government's continuing imposition of price controls, has deprived Gazprom of the opportunity to pursue pricing policies similar to those that would be found in market societies. Indeed, so harsh has been the pricing regime imposed upon Gazprom that the Russian Government had to step in in January of 1991 to rescue the company from bankruptcy through an emergency infusion of Government funds to cover the difference between allowable prices and subsidies, on the one hand, and development and production expenditures on the other.

There is another, non-institutional, reason that mitigates against the automatic dissolution of the Gazprom monopoly: the fact that most of the gas reserves are located a huge distance from markets to which the gas must be brought by pipelines. These pipelines constitute what has been called a natural monopoly: the enormity of the capital investments involved in building mammoth pipelines from Siberia to Russian consumption centers simply prohibits the building of duplicative or competing lines and, given the massive consumption rates of natural gas, there is no substitute fuel readily available to replace the gas.

In market-oriented societies, the policy response to the monopoly problem has been to set up regulatory bodies charged with administering prices that emulate those of the market, while at the same time splitting the services delivered by the monopolist into as many individually identifiable subservices as possible (unbundling of services) which are then sold under separate pricing regimes. We will deal in considerable detail with the subject in Chapter 3 on transport costs. Suffice it here to say that the procedure involves an attempt to estimate the costs involved in providing the many individual subservices that are needed to produce natural gas and to deliver it to the customer. In the case at hand, the relevant delivery costs are broken down into the broad categories of production costs, transport costs, and distribution costs. The estimation of Russian natural gas production costs is the focus of our discussion in this chapter.

Table 5 lists Russian estimates of their natural gas production costs.[8] These range from a low of 3.00-3.50 rubles per 1000 cubic meters in the Tyumen-Urengoy-Yamburg Region to more than 12.00 rubles in the Caucasus and Yakut Regions, column 2. The third and fourth columns in Table 5 reflect Gazprom's estimated natural gas production costs in rubles and in cents per mcf, based on an exchange rate (1990) of 0.5739 ruble per U.S. dollar. In terms of these units, the Urengoy and Gazprom overall natural gas production costs, according to Russian accounting methods, are 10 and 12 kopecks per mcf (or 17.9 and 20.2 cents/mcf), respectively.

As a general rule, high productivities tend to imply low production costs, but this is not necessarily always the case. The general rule is confirmed in Russia by wells located in the Urengoy, Yamburg, Nadym and Surgut regions, where new-well production rates range from 5 to 47 MMcf/d, with old-well production rates in excess of 12 MMcf/d. These regions are subject to production costs of 17-19 cents/mcf. Gas production costs in Norilsk, however, are nearly 40 cents/mcf at old-well/new-well productivities on the order of 7 MMcf/d. Similarly, Yakut old-well productivities of more than 9 MMcf/d are associated with some of the highest production costs in the former USSR.

To determine whether or not these costs are reasonable and, therefore, usable as a basis for a viable pricing regime, a comparison with competitive costs, as in the U.S. gas-producing industry, would be helpful. These costs will be broken down into finding costs, development costs and field operating costs.

2.4.1 Finding Costs

As mentioned earlier, the vertical integration of the Russian natural gas industry provides opportunities for the collection of monopolistic rents which are generally regarded as suboptimal in a nation's overall wealth generating activities. This and the fact that the industry's pricing policies deliberately aim for cross-subsidization, at the expense of industrial gas users and for the benefit of households, makes it highly desirable to establish an objective cost basis. One way of achieving this is by comparing Russian gas costs with those of an established and mature gas industry such as in the United States.

Most of the U.S. hydrocarbon cost analysis work in the past has focused on oil rather than natural gas. The one authoritative study on gas production costs was published by the

[8] Gas Industry of the USSR; op. cit.; pp. 35-39.

Table 5
1990 USSR Production Costs
Natural Gas and Condensate, and Gas Well Productivity

	NATURAL GAS			WELL PRODUCTIV.		CONDENS.	
	Rubles/ 1000CM	Rubles/ MCF	Cents/ MCF	Old Wells MMCF/D	New Well MMCF/D	Rubles/ Tonne	
Northern Gazprom	9.53	0.270	47.0	4.0	2.9	12.37	
Caucasus Gazprom	12.49	0.354	61.7	0.1	0.0	30.01	
Kuban Gazprom	9.75	0.276	48.1	0.3	1.2	10.51	
Southern Ugtransgaz	-	-	-	-	-	-	
Orenburg Gazprom	5.85	0.166	28.9	7.4	10.3	9.41	
Astrakhan Gazprom	5.80	0.164	28.6	12.4	9.7	5.80	-1988 Data
Urengoy Gazprom	3.63	0.103	17.9	22.6	16.7	5.11	
Yamburg Gazprom	3.50	0.099	17.3	40.6	47.5	52.42	
Nadym Gazprom	3.81	0.108	18.8	21.5	5.0	-	
Surgut Gazprom	3.71	0.105	18.3	14.1	14.2	-	
Tyumen	2.94	0.083	14.5	5.1	-	-	
Yamal Gazprom	13.39	0.379	66.1	-	-	-	
Yakut Gazprom	12.41	0.352	61.3	9.2	-	12.52	
Norilsk Gazprom	7.83	0.222	38.7	7.3	6.9	84.75	
Ukraine	6.06	0.172	29.9	1.5	8.9	17.79	
Central Asia	4.86	0.138	24.0	10.5	4.4	6.04	
Turkmenistan	4.30	0.122	21.2	11.8	24.1	15.24	
Ministry of Oil & Gas	12.01	0.340	59.3	1.3	3.0	-	
Gazprom Average	4.10	0.116	20.2	10.7	20.7	8.17	
USSR Average	4.27	0.121	21.1	8.9	15.6	-	

Note 1: This includes "Amortization" which, for Gazprom at large, averages 0.53 Rubles per 1000 CM, or 12.9% of Unit Cost.

Note 2: Used 1990 exchange rate of 0.5739 ruble/U.S. dollar in conversion to cents/MCF.

Source: Gas Industry of the USSR - 1990, op. cit.; p. 35 (Gas) & 39 (Condensate) for Production Costs and pp. 21-22 for Gas Well Productivities

Energy Information Administration (EIA) in 1986.[9] Using a discounted cash flow model and various historical and physical parameters descriptive of the period under investigation, the study focused on the 1972 to 1982 U.S. natural gas markets. In essence, the EIA study was an attempt to determine finding costs of natural gas and to estimate the gas prices that would be required to meet those costs with a 15% rate of return on exploration expenditures. Included in the finding costs were lease acquisition costs (held to an absolute minimum of 10% of the average historical U.S. acquisition costs for the period, an assumption that fits in well with current Russian valuation procedures), geologic and geophysical costs, and wildcat drilling costs, including the cost of dry holes. For the United States at large, that price turned out to be $2.15 per Mcf.[10]

In relating the U.S. required finding cost to Russia, and in particular to West Siberia which, by its very size, sets the standard for the Russian gas market in general, the one variable that cannot be ignored in this discussion is the size of the reserve that is likely to be discovered by a successful wildcat well. As it turns out, the mean size gas field discovered during that period in the United States was 8.9 Bcf (252 million CM). When the full reserve data for West Siberia are in, there are going to be at least 30 natural gas fields in that region with recoverable reserves in excess of 10 Tcf, or some one thousand times the size of the 1972-1982 average U.S. gas discovery. In addition, most of the West Siberian gas has been found at relatively shallow depths (about 4000 feet for the bulk of Urengoy's reserves), the average new-well production rate for West Siberia is in excess of 20 MMcf per day compared to 1 to 2 MMcf per day in the United States, and the geological failure risk of exploratory drilling in West Siberia is much lower than in the United States where the wildcat failure rate is on the order of 75-80%.[11] Hence, the U.S. finding cost of $2.15 per mcf will be diluted over several thousand times the average discovery volume in West Siberia. As a result, the West Siberian finding cost will become irrelevant (a fraction of a cent per mcf).

[9] *An Economic Analysis of Natural Gas Resources and Supply*; Energy Information Administration; October 1986; DOE/EIA-0481.

[10] *An Economic Analysis...*; op. cit.; Table 19, p. 65

[11] Independent Petroleum Association of America; *United States Petroleum Statistics*; Oct. 1992; Table 1.

2.4.2 Development Costs

Not all shows of oil or natural gas in exploratory wells prove up the existence of commercial reserves. Some shows are mere traces that do not warrant the completion of the exploration well. As mentioned, that happens in about four out of five U.S. exploration wells. In some exploration wells, however, electric logs, drilling mud analysis and drillstem tests reveal fair amounts of hydrocarbons, enough to complete the exploration well as a producer and to subject it to extensive production testing. Since a considerable portion of the well's overall expenditure has been incurred at that point in time, these sunk costs do not figure into the completion decision which in effect is governed by the cost of running the string of production casing and tubing (all of the tubing string and much of the casing can be recovered later), installing the wellhead and various minimum field facilities. The production tests that follow are designed to determine whether the drilling of additional development wells is economically justifiable. If the price of the natural gas to be produced is known with reasonable accuracy, the field's economic viability stands and falls with the development costs in that field. Alternatively, if the costs of developing the field can be estimated, it will be possible to determine the price that would be required at the wellhead to achieve a targeted rate of return. In the report cited earlier, the Energy Information Administration has studied this issue in considerable depth.

The Energy Information Administration study included annualized capital costs covering lease equipment (flow lines and connections, chiller/dehydrators, condensate storage tanks) and the drilling of development wells, as well as variable field operating costs (direct labor, fuel, chemicals and disposal, surface maintenance and well workovers). The study was structured to determine the price of natural gas that would be required to make the development of a proven gas field profitable at an after-tax 15% real rate of return. As it turns out, the price of natural gas required to achieve the targeted rate of return in developing a giant field in the United States (with exploration a sunk cost) was 19 cents per mcf in 1984, or roughly 20 cents per mcf today.[12]

At the extremely high production rates typical of West Siberian natural gas fields, where daily rates of production average more than 20 MMcf per well, gas field development costs per mcf are likely to be lower, assuming all costs are fully allowed for. Just precisely how much lower is difficult, if not impossible, to say without an exhaustive study of the Russians' accounting procedures. The difficulty of understanding Russian accounting

[12] *An Economic Analysis of Natural Gas Resources and Supply*; Energy Information Administration; DOE/EIA-0481; Table 25, p. 75 (West Coast; 7500 Feet; Field Size Class 9). Escalation based on costs of drilling development gas wells; API; Joint Association Survey.

methods is borne out by Table 6, which lists some of the major line items underlying Gazprom's cost data in Table 5.

The cost breakdown in Table 6 confirms the difference in Russian vs. non-Russian cost accounting. While the individual cost items tracked under the two systems are not the same, one thing that demands attention is the fact that about half of Gazprom's overall costs (65% at Urengoy) are labeled "Other Field Expenditures" in the Russian system. To a market -oriented cost-conscious company, and certainly to regulated industries in a general market environment, that is too large an item for such an ill-defined catch-all label.

2.4.3 Field Operating Costs

The cited EIA study of U.S. gas field development costs (19 cents per mcf in 1984) includes field operating costs. As was pointed out at the time, these costs reflect variable costs such as labor, fuel, chemicals and well workovers. They are, in short, the routine costs an operator incurs in maintaining production from an operating gas field.

While the EIA study of exploration and development costs was a one-time assessment that was done at a critical point in U.S. gas-price regulatory history, the Agency kept up its work in assessing natural gas lease operating costs on a regular basis. Their latest report, dated July 1990, updates and specifically identifies the variable field operating costs for natural gas production. These costs amounted to 1.24 cents per mcf in 1989, for wells producing 10 MMcf per day.[13]

There are no natural gas wells in the United States like those in West Siberia capable of producing 70-100 million cubic feet per day (open-flow potential), and averaging daily production rates of 20.7 million cubic feet, from 4000-foot depths.[14] Hence, a direct comparison with U.S production data is not possible. The only statistical information available in the United States of on-shore gas wells producing 10 MMcf/d is from 16,000-foot wells in North Louisiana. That is where the field operating costs of 1.24 cents per mcf were derived. These costs, which are listed in Table 7, are very rate sensitive.

[13] *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations, 1987 Through 1989*; Energy Information Administration; DOE/EIA-0185(89); Table 20; p. 27

[14] *New Gas Wells, Drilled in 1990.* Gas Industry of the USSR, 1990; op. cit.; p. 7.

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TABLE 6

BREAKDOWN OF 1990 NATURAL GAS PRODUCTION COSTS

	Rubles/1000 Cub. M.		Rubles/MCF		Cents/MCF	
	GAZPROM	URENGOY	GAZPROM	URENGOY	GAZPROM	URENGOY
Auxiliary Materials	0.07	0.04	0.0020	0.0011	0.35	0.20
Wages & Supplements	0.03	0.01	0.0008	0.0003	0.15	0.05
Preparation & Opening of Production (Well Completion Costs?)	0.01	0.00	0.0003	0.0000	0.05	0.00
Amortization	0.53	0.39	0.0150	0.0110	2.62	1.93
Operation & Maintenance - Field Equipm.	0.61	0.45	0.0173	0.0127	3.01	2.22
Formation Stimulation & Pressure Maintenance						
Gas Preparation (Dehydration & Compression?)	0.12	0.03	0.0034	0.0008	0.59	0.15
Shop Expenditures (Housing & Heating?)	0.22	0.19	0.0062	0.0054	1.09	0.94
General Field Expenditures	0.30	0.17	0.0085	0.0048	1.48	0.84
Other Field Expenditures	2.21	2.35	0.0626	0.0666	10.91	11.60
Total Field Costs	**4.10**	**3.63**	**0.1161**	**0.1028**	**20.24**	**17.92**

Note: Used 1990 exchange rate of 0.5739 ruble/U.S. dollar in conversion to cents per MCF.

Source: Gas Industry of the USSR - 1990; op. cot.; pp. 35 & 36

However, one has to be cautious in applying these derived rate sensitivities because they are simply different rate excursions in a given production environment where otherwise important cost parameters, such as differences in multi-phase behavior in a reservoir, unconsolidated sand problems, H_2S problems, etc., are ignored. We have pointed to deviations from the general productivity/cost rule in the former USSR in our discussion of development costs, Table 5.[15]

Table 7
U.S. Natural Gas Production Costs
- 1989 Field Operating Costs -

Rate of Production, mmcf/Day	Annual Cost, Dollars	Unit Cost, Cents/mcf
0.05	8,900	48.77
0.25	17,300	18.96
0.50	19,800	10.85
1.00	28,000	7.67
5.00	32,100	1.76
10.00	45,400	1.24

[15] Broad price indices fail to measure inflation (defined as erosion of the purchasing power of money) in a general price-control environment. Imagine what will happen in an environment of strict price controls when the money supply is doubled or tripled: the index will remain constant, yet the purchasing power of money will erode, at the extreme, to the point of a move toward a barter economy. And, of course, broad indices do not accurately measure price movements in specific (especially highly specialized) industries, which is why, for example, the Nelson refining index has been developed in the United States. This is also true of exchange rates in general. Rather than using the administered 1990 exchange rate of 0.5739, we could have calibrated the "actual" industry-specific exchange rate on the respective costs of gas production. Had we done this, the exchange rate would have been the ratio of total gas production costs in kopecks and cents per mcf, or 12/21 = 0.5714. We do not have sufficient faith in our cost calculations to seriously advance that case, but then, we have little faith in the ability of the various published inflation and exchange rate series to provide an accurate measure. From our calculation, it would appear that the exchange rate we used in this work is not unreasonable. What exchange rate one should use today or in the future is a different, and more difficult, question.

On the assumption that the greater well depths in North Louisiana tend to offset the climate-induced cost differentials in West Siberia (U.S. gas production costs double, and sometimes quadruple {at lower production rates} between 4,000 and 16,000 feet), and given the difference in production rates, the Russian production costs are not unreasonable if viewed in their historical perspective, i.e., at the 1990 exchange rate of 0.5739 ruble per U.S. dollar. At that rate, the Urengoy production cost of 10.3 kopecks per mcf translates into 17.9 cents per mcf.

2.4.4 Comparison with Overall U.S. Natural Gas Prices

There is yet another cost measure of natural gas that is of considerable analytical significance: the competitive wellhead price or, alternatively, the natural gas spot price. Neither of these two prices exist in Russia where all gas prices are set by Government fiat. Russian natural gas production is not competitive, by definition, and spot markets are nonexistent. In the United States, by contrast, the government no longer has any regulatory control over natural gas wellhead prices, and the market is extremely competitive: there are more than 4,200 oil and gas producers, most of them with access to contract carrier gas pipelines. This system allows producers, directly or through brokers, to negotiate gas prices with major gas consumers. There is, in short, an active spot market which tends to absorb gas at relatively low prices. Not surprisingly, spot prices exhibit greater seasonal volatilities than average wellhead prices, and they also reflect locational price differences, but over any given year they tend to average out at roughly the same levels as average U.S. wellhead prices.

Given its marginal role, the spot market price of natural gas reflects the lowest price U.S. producers can accept while remaining viable in the market. That price has been averaging about $1.60 per million Btu (or, roughly, per mcf) in 1992, with lows around $1.15 and seasonal highs of about $2.40. The difference between average gas prices charged at the wellhead ($1.60 per mcf) and the required price to profitably develop giant gas fields in the United States (20 cents per mcf) is considerable. But is it inconsistent? The answer is that there is no inconsistency, and for two reasons. First, not included in the EIA study of required development prices is the exploration risk. In the United States, that would have included lease acquisition costs, geological and geophysical work, and the drilling of 4 or 5 dry exploration wells for every successful wildcat. Moreover, the exploration wells that do find natural gas in this country tend to find the average size field as opposed to the Class 9 Field (10 Tcf) quoted from the EIA study. The average successful natural gas wildcat in the

United States, as it turns out, discovers about 16 billion cubic feet,[16] or one six-hundredth of the gas reserve discovery of 10 Tcf that was used as the basis of comparison with West Siberia's gas fields that often run in the hundreds of Tcf.

In retrospect, with current spot prices averaging $1.60 per mcf and 1984 required finding costs of $2.15 per mcf, one would expect that a 15% rate of return on fully risked exploration is not achievable and that, as a result, U.S. exploration activities would decline, or else that the minimum size gas field acceptable for development would have to become larger. Both suppositions have been borne out by history: Since publication of the EIA study, U.S. natural gas exploratory drilling has declined from 2,481 wells in 1982 to 581 wells in 1991.[17] In addition, the average size U.S. gas field required for development has risen from 8.9 Bcf in 1972-1982 to 16 Bcf in 1991. The model appears to have been accurate.

2.4.5 Production Costs - Summary

To test Russian claims that their cost of finding and producing natural gas is low, and to establish a base for subsequent valuation work, we have asked the question what those costs would be in the United States if we were to find and produce natural gas from fields of the size commonly found in West Siberia. This calculation of equivalent U.S. costs was based on extensive earlier analytical work and on historical U.S. data. Accordingly, the evolving equivalent U.S. cost data rest on a solid empirical foundation. These cost data are summarized in Table 8.

[16] *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1991 Annual Report*; Energy Information Administration; Fig. 10, p. 18

[17] Independent Petroleum Association of America; *United States Petroleum Statistics*, Oct. 1992; Table 1.

Table 8
Natural Gas Production Costs
in Giant Fields

Russia:	
Production Costs, 1990 Kopecks/mcf	12
Production Costs, Cents/mcf	21 (a)
United States:	
Finding Costs, Cents/mcf	<1
Field Development Costs, Cents/mcf	20
Field Operating Costs, Cents/mcf	1.2

Note (a): Based on a 1990 exchange rate of 0.5739 rubles/U.S dollar. Costs in cents/mcf vary with different assumptions regarding exchange rates (for example, costs are 6.7 cents/mcf at 1.8 rubles/U.S. dollar, and 1.0 cent/mcf at 20 rubles/U.S. dollar).

We offer two observations from Table 8. First, Russian production costs are indeed low, as they would be in the United States under similar circumstances. And second, we find no reason to reject the Russian cost estimates listed in Table 5. As mentioned, at the 1990 exchange rate of 0.5739 ruble per U.S. dollar, Russia's natural gas production costs were comparable to equivalent U.S. costs. Our recommendation, therefore, is to accept Russian cost data on natural gas production.

This rough estimate of production costs should not be used, however, to establish a system of wellhead price controls that would be maintained for several years and thereby prevent prices from moving lower (if the LRMC of gas production in a market economy turns out to be lower) or higher (if LRMC turns out to be higher). Unlike gas transmission, gas production does not have natural monopoly characteristics and the production sector can therefore support competitive market pricing if the industry is restructured in a legal and regulatory framework consistent with a market economy. Because many companies can have ownership shares of production from a single gas field, the size of Russia's supergiant gas fields need not be an impediment to the development of competitive markets for non-associated gas. Wellhead price controls may be needed only in a transitional situation in which industry structure is not conducive to competitive determination of wellhead prices.

If wellhead price controls were established but Gazprom were permitted to transfer cash flow from one production affiliate to another, it would be possible for low-cost producing areas such as Urengoy to subsidize high-cost producing areas such as the Yamal Peninsula. The high-cost areas might absorb capital that would be better invested in improving the energy efficiency of Russian gas consumption. Fortunately, Gazprom is structured so that gas production operations in different regions are organized in different enterprises. Under a privatization program these enterprises could be reorganized to become independent profit centers, without cross-subsidization. From an economic efficiency standpoint this reorganization of gas industry structure would be more important than the determination of the "correct" level of wellhead price controls.

Low production costs of natural gas do not necessarily make natural gas inexpensive. Given the remoteness of the bulk of Russian gas reserves from their markets, the cost of transporting the gas to market is a vital component of the overall cost structure. Indeed, the difference in transport costs establishes the competitive posture of non-Siberian gas which is certainly more expensive to find and produce, but cheaper to haul to market. Natural gas transport costs will be the topic of our discussion in Chapter 3.

2.4.6 Investment Needs in Gas Exploration

Given Russia's 80 to 1 reserve to production ratio, gas exploration in Russia could be limited to the measurement of reserves at known fields. We would not go so far as to recommend the total cessation of all natural gas exploratory activities, since it would make sense to attempt to determine and certify the size of Russia's reserves in known fields that are already producing or can easily be brought into production. But we would recommend that no new frontiers serving the European (Russian and non-Russian) markets be opened and that exploration capabilities be focused on oil exploration where the reserve and production situation appears to be critical.

Table 9
World Natural Gas Reserves

		RESERVES		
Rank	Country	TCF	TCM	Percent
1	Former USSR	2280	64.59	44.7%
2	Iran	600	17.00	11.8%
3	United Arab Emirates	196	5.55	3.8%
4	Saudi Arabia	185	5.24	3.6%
5	United States	167	4.73	3.3%
6	Qatar	162	4.59	3.2%
7	Venezuela	129	3.65	2.5%
8	Algeria	128	3.63	2.5%
9	Nigeria	120	3.40	2.4%
10	Iraq	109	3.09	2.1%
11	Indonesia	104	2.95	2.0%
12	Norway	97	2.75	1.9%
13	Canada	96	2.72	1.9%
14	Australia	75	2.12	1.5%
15	Mexico	71	2.01	1.4%
	Subtotal	4519	128.02	88.6%
	Rest of World	584	16.54	11.4%
	TOTAL	**5103**	**144.56**	**100.0%**

Note: Former USSR Reserves Include Reserves Classified as C2.

Source: International Energy Annual, 1991; US Dept. of Energy; DOE/EIA-0219(91); p 100.

CHAPTER 3: GAS TRANSPORTATION COSTS UNDER COMPETITIVE CONDITIONS

CHAPTER SUMMARY: MAJOR CONCLUSIONS

A direct estimation or verification of gas transportation costs in the former USSR from Gazprom cost data is practically impossible because of limited access to detailed cost accounting data and because of the many inconsistencies that seem to exist between the Russian and international oil and gas accounting systems.

An indirect way of determining Russian gas transportation costs is to estimate U.S. gas transportation costs under operating conditions approaching those in the former USSR. This can be done in one of two ways:

1. by simulating the construction of a representative pipeline, annualizing the costs incurred in the process, and adding them to operating costs.

2. by analyzing costs actually incurred by U.S. pipelines, as demonstrated in public rate hearings.

Using the rate hearings methodology, U.S. transportation costs have been derived for Panhandle Eastern Company, one of four major U.S. gas pipeline companies with rate data sufficiently developed for consideration.

Panhandle Eastern's rate structure, as shown in Table 14, will be used in Chapter 4, with appropriate adjustments, for the development of realistic city gate prices in various Russian cities.

To establish a range of transportation costs, three additional U.S. pipelines operating under different conditions have been analyzed.

Panhandle Eastern's transportation costs are $14.28/MCM/1000 km overall. This figure includes gathering costs, field transportation costs, and an access fee (mostly overhead charges). Leaving out these upstream fees, Panhandle Eastern's straight trunk line transmission cost is $6.65/MCM/1000 km.

3.1 BACKGROUND

The Russian natural gas trunk line system is one gigantic monopoly. Of the natural gas industry's essential functions, exploration and production, transmission, storage, and distribution, Gazprom's jurisdiction covers all of the production, transmission and storage activities, and part of exploration. Only the distribution function falls outside of Gazprom's jurisdiction. We have discussed the natural gas exploration and production operations in Chapter 2, with particular emphasis in the area where it is felt that an objective third-party review would be helpful: the pricing or costing of Russian production operations. This area needs attention since there is no sales activity at the point where Russian natural gas passes from the field to the pipeline that would establish an arms-length transaction price. Even if there were a formal sales transaction, the "price" at the point of transfer would have to be an imputed price reflective of a system that, in the recent past at least, was more concerned with meeting production quotas than with the bottom line profit objective that characterizes Western corporate organizations. The cost of producing natural gas, whether sold or not at the end of the first step on its journey to the consumer, is an important element that will certainly become one of the cornerstones of any rational regulatory gas pricing activity in Russia.

The gist of our preceding discussion on the cost of producing natural gas in Russia has been that Gazprom's claim that their cost of production is low, compared to Western standards, seems credible. That does not mean that one should, from here on out, accept Gazprom's suggested wellhead prices. To the contrary, the wellhead is a good place to impose a regulatory control point where Gazprom would have to account to some regulatory agency for its cost of production, unless of course, production operations are made truly competitive. If that were the case, a regulatory agency for wellhead price controls would become counterproductive.

Be this as it may, the second step in moving natural gas from often very remote regions to the consumer involves the pipeline industry. As mentioned, all non-associated natural gas in Russia is moved through lines belonging to Gazprom, a system that would ordinarily call for regulatory controls in the gas transportation sector. A brief descriptive digression of the Gazprom pipeline system will set the stage for our discussion of natural gas transport costs.

3.2 THE GAZPROM PIPELINE SYSTEM

3.2.1 Description

Unlike the United States, where the major gas producing areas are also major gas consumers (Texas is both the number one producing and consuming State by far), there is relatively little gas consumption in West Siberia, the dominant gas producing region in Russia. Ukraine is the largest consumption region serviced by Gazprom; that country depends on Russian gas imports for 75 percent of its consumption to meet the energy needs of its 51 million people and its broadly industrialized infrastructure. The Moscow region is the second largest consumption region, followed by the Volga-Urals region where heavy and energy-intensive industries predominate. As mentioned, non-associated gas is handled almost exclusively by Gazprom which produces and transmits some 97 percent of the total production of the former USSR, while the company has practically no associated gas production, Table 10.

Total natural gas production, consumption and export data for Russia and selected countries of the former USSR are listed in Table 11. One point of interest in Table 11, besides the sheer massiveness of their overall gas production which, in 1991, exceeded U.S. production by 50%, is the fact that Russian production has risen during the difficult 1990-1991 period, while gas production in the rest of the former USSR countries declined by about 4%.

Given Russia's regional disparity in gas production and consumption, it comes as no surprise that the Gazprom system of major transmission lines is generally oriented in an East-West direction. While the Gazprom pipeline network is fully integrated throughout the former USSR, and especially West of the Urals, Siberia is now, and will continue to be in the foreseeable future, the dominant source of natural gas. That is the area where within a circle of a 100-mile radius, centered in the Urengoy Field (an area less than one-thirtieth the size of Texas), total gas reserves are at least four times those of the entire United States, and sixteen times those of Texas.

Table 10
Selected 1990 Natural Gas Data
Former USSR and GAZPROM
Bcm

	FORMER USSR		GAZPROM		GAZPR/USSR
Non-Associated Gas	770.6	94.6%	747.7	100.0%	97.0%
Associated Gas	44.2	5.4%	0.3	0.0%	0.7%
Total Gas	814.8	100.0%	748.0	100.0%	91.8%

Source: Gas Industry of the USSR, 1990; *An Economic and Statistical Survey; State Gas Concern Gazprom & All-Union Research Institute*; General Director I. A. Zhuchenko; Moscow; p. 5.

Table 11
Natural Gas Balances
Russia and Selected Countries of the Former USSR
Bcm

	PRODUCTION		CONSUMPTION		NET EXPORTS	
	1990	**1991**	**1990**	**1991**	**1990**	**1991**
Ukraine	28.1	24.4	115.3	111.6	(87.2)	(87.2)
Belarus	0.3	0.3	14.9	14.9	(14.6)	(14.6)
Kazakhstan	7.1	7.9	13.0	13.8	(5.0)	(5.9)
Turkmenistan	87.8	84.3	15.9	14.3	71.9	70.0
Uzbekistan	40.8	41.9	37.9	39.0	2.9	2.9
Other Countries	9.9	8.6	18.3	17.0	(9.3)	(8.4)
Subtotal	**174.0**	**167.4**	**215.3**	**210.6**	**(41.3)**	**(43.2)**
Russia	640.6	642.9	461.0	466.0	179.6	177.0
Total Former USSR	**814.6**	**810.3**	**676.3**	**676.6**	**138.3**	**133.8**

Note: Non-Associated Gas only; Processed Associated Gas Delivered to Gazprom was 44.2 Bcm in 1990.

Source: PlanEcon Energy Report; April 1992; Vol. II, pp. 46-49.

Three significant pipeline corridors connect the producing region of West Siberia with the consuming areas of the former USSR and with Russia's export markets to Western countries. Of these, the Central Corridor is by far the largest. It consists of fifteen parallel lines, 56" in diameter, running in a generally Southwestern direction towards Punga where three lines branch off into the Western Corridor, to run through the Northern Urals towards Ukhta and on to Torzhok located some 150 miles North-West of Moscow. The Central Corridor lines continue on Southward from Punga, turning West and crossing the Urals in the vicinity of Nizhnaya Tura to move via Perm towards the main consumption areas. The Southern Corridor, consisting of two 56"-lines, runs in a Southerly direction from the Yamal/Urengoy region towards Chelyabinsk, where the lines turn West to cross the Southern Urals and move on to Ufa and the industrial Volga-Urals region. Parts of that system reach Uzhgorod, on the Ukraine/Slovak border, where the lines meet Gazprom's export lines from the Central Corridor and from other sources.

The world's largest pipeline is part of the Central Corridor. The line is 56" in diameter, the standard size for gas lines connecting West Siberia with the European part of Russia and the rest of the former USSR; it is 2770 miles long (roughly the distance from New York City to Los Angeles). Like most of the Russian 56"-diameter trunk lines, this line is designed to operate at 1070 Psi and it has an intake capacity of 32 Bcm (1.1 Tcf) per year. Current Gazprom plans call for several additional 56"-diameter lines to be built in the 1993-2000 period. All in all, the Gazprom trunk line system consists of 132,000 miles of lines, 60% of which are 48" or 56" in diameter. The latter size, 56", does not exist in the United States, and 48" is extremely rare.

Russian industry standards call for a pipeline write-off period of 33 years, even though U.S. and Canadian lines generally last much longer than that (the U.S. standard, 40 years, is evolving toward shorter write-off periods, to as little as 20 years, for reasons that have more to do with attracting investment capital than with the physical life cycle of the lines). Only 2.5 percent of Gazprom's lines exceed the 33-year standard; 60 percent of the lines are less than 15 years old. Couple this with some 300 gas treatment plants and over 500 compressor stations containing an average of about 10 turbine compressor units per station, and what you have is by far the largest integrated pipeline system in the world.

To facilitate a transition to a market economy in Russia's natural gas sector it is necessary to estimate the transmission tariffs that would enable a pipeline company operating in a competitive environment to earn a normal rate of return. In the United States and Canada, regulatory institutions attempt to prevent gas pipelines from charging excessive rates and earning monopoly profits. In Russia, Gazprom has a monopoly on gas exports and therefore these concerns are valid, but there is no history of rate-of-return regulation and it

is impossible to define a "normal" rate of return under the present economic conditions. Given public opposition to energy price increases, there is a real danger that gas prices and transmission tariffs will be set too low. If so, consumers would not have an incentive to use gas efficiently and the gas industry would not be able to generate or attract the capital needed to maintain a safe and reliable transmission and distribution infrastructure.

3.2.2 Transmission Costs

The only indication of Gazprom's transmission costs we have been able to find expresses transmission costs in terms of rubles/mcm rather than rubles/mcm/km. For Gazprom at large, 1990 gas transmission costs are thus claimed to be 7.714 rubles/Mcm.[1] The item immediately preceding these cost data reflects the average distance that gas is being shipped by Gazprom. That distance is 2590 kilometers, or 1610 miles. Assuming for a moment that Gazprom meant that the average cost of transporting natural gas is 7.714 rubles/Mcm over an average distance of 2590 km, the transmission costs would be about 3.0 rubles/Mcm/1000 km. Translated into U.S. terms, this is the equivalent of 13.5 kopecks/Mcf/1000 miles, or 23.5 cents/Mcf/1000 miles.

On the other hand, the number Gazprom put forward as their 1990 transmission cost could be interpreted to mean that Gazprom incurs an average cost of 77.14 rubles per 10,000 cubic meters delivered, regardless of the delivery point. That number corresponds to 7.714 rubles/Mcm of gas delivered, or 21.9 kopecks (38.2 cents) per Mcf.

Gazprom's reported city gate delivery price of 216 rubles/Mcm for residential use, and 940 rubles/Mcm for industrial and district heat use (October 1992), is inconsistent with either set of numbers. That month, the retail price inflation index, relative to the base year of 1990 (Table 12), was running at 2727, for an adjusted city gate delivery price (residential use) in constant 1990-currency of 7.9 kopecks/Mcm. The latest wholesale inflation index we have for the country is for July of 1992, when it was six times the retail index. If, therefore, the wholesale index had been used to deflate the reported industrial delivery price, that price, too, would have been unrealistically low.

In short, price discussions and comparisons get to be very confusing during periods of high inflation. That, and the ready availability of data for that year, are the main reasons we

[1] In the original data the cost is expressed in rubles per 10,000 cubic meters. See Vniiegazprom, *Gas Industry of the USSR 1990*, pp. 10 and 136.

TABLE 12

RUSSIAN INFLATION AND EXCHANGE RATES

		Retail Prices		Industr.Wholesale		Exchange	
		Monthly Change %	Price Index	Monthly Change %	Price Index	Rate Rub/US$	
1990		-	100	-	100	0.5739	Official Rate
1991	Jan	6.6	107	62.9	163	25	Market Rates
	Feb	4.8	112	18.9	194	34	
	Mar	6.4	119	7.1	207	36	
	Apr	54.4	184	8.2	224	33	
	May	2.3	188	3.8	233	38	
	Jun	0.0	188	2.8	240	41	
	Jul	-0.7	186	17.3	281	52	
	Aug	-0.2	186	15.2	324	52	
	Sep	1.3	188	6.6	345	55	
	Oct	3.9	196	5.8	365	62	
	Nov	9.0	213	9.4	399	106	
	Dec	12.6	240	11.3	444	170	
1992	Jan	221.0	772	382.0	2,142	204	
	Feb	24.0	957	75.0	3,749	176	
	Mar	21.0	1,158	28.0	4,799	153	
	Apr	14.0	1,320	16.5	5,590	153	
	May	11.2	1,467	23.0	6,876	122	
	Jun	15.0	1,688	36.0	9,351	125	
	Jul	7.5	1,814	17.0	10,941	143	
	Aug	10.0	1,996			170	
	Sep	12.0	2,235			225	
	Oct	22.0	2,727			353	
	Nov	25.0	3,408			427	
	Dec					408	
1993	Feb 8					572	
	Mar 8					648	
	Mar 18					667	
	Apr 17					779	

Source: Pre-1993 data furnished by World Bank Staff; Original Source: Goskomsat and IMF. 1993 data from Wall Street Journal quotations.

have opted to focus our discussion on the economically calm year of 1990. The artificial nature of Soviet government exchange rates is illustrated by the difference between the "official rate" and the "special rate" for ruble-dollar transactions in 1989-1990 (see Table 13).

Because domestic inflation in the Soviet Union was moderate throughout the 1980's (Table 13), 1990 is the most recent year for which amortization and depreciation are reasonably reflected in Soviet production cost estimates. In the 1991-1993 period, inflation severely eroded the book value of capital assets and reduced the purchasing power associated with depreciation charges. During a period of high inflation, the cash flow associated with depreciation fails to provide an enterprise with enough purchasing power to replace or reconstruct the physical assets that are worn down (unless capital assets are revalued). Book depreciation therefore understates the loss of asset value caused by physical depreciation, and production cost estimates are understated.

This is not to say that 1990 inflation and exchange rate data are free of controversy. Quite apart from the question just how relevant broad indices such as the retail price index, the wholesale price index, or the overall exchange rate are to specific and highly specialized industries, the pre-1991 rates in Russia reflect prices and exchange rates set by government fiat; they may not have been moving as fast then as they are today, Table 13, but they are suspect as to their ability to reflect the values they were supposed to measure. See Chapter 2 for a discussion of that issue.

If Gazprom were capitalized like a pipeline company in North America or western Europe, Gazprom would have to issue debt with corresponding interest costs. Depreciation charges would be used to perpetuate the original capital investment, and interest payments would be due and chargeable against operating revenues. Both interest and depreciation would be a reflection of the valuation of the company and they would be treated as a charge against transmission costs. Revenues would have to be sufficient to provide a rate of return on equity that would enable Gazprom to raise capital through new stock offerings. Gazprom does charge depreciation ("amortizatsia"), and in 1990 depreciation represented 64% of overall transmission expenses ("sebestoimost") under Soviet accounting principles.[2] That charge is high by Western standards where, in the United States, for example, depreciation

[2] See Vniiegazprom, *Gas Industry of the USSR 1990*, p. 136. In Soviet accounting, "amortizatsia" was equivalent to what western accountants call depreciation, and there was no distinction among depreciation, depletion, and amortization. There was no difference between book depreciation and tax depreciation. In most industries the annual accounts were designed to compare production cost ("sebestoimost") with revenue. These concepts have been carried over into Russian accounting.

charges, adjusted for equivalence with Gazprom data, have been running at about 18% of overall transmission expenses (see Table 26). Under Soviet accounting, Gazprom's estimate of "sebestoimost" contained no allowance for a rate of return on capital, either in the form of interest on debt or profit on equity, and therefore transmission costs were understated by Western standards.

Table 13
Inflation and Official Soviet Exchange Rates, 1989-1990

Year	Av. Monthly Earnings, Rubles	Cost-of Living Price Index	Official Exchange Rate, USD/Ruble	Special Exchange Rate, USD/Ruble
1980	169	100		
1985	190	105		
1986		107	0.6783	
1987	203	109	0.5843	
1988	220	109	0.6067	
1989	240		0.6088	6.088
1990	257			
Mar 1990			0.6120	6.120
From Sep 5, 1990			0.5739	5.739

Source: Eurostat, *Central and Eastern Europe 1991* (Luxembourg), pp. 132, 143, 145. To express 1990 USSR energy prices in dollars, the World Bank has used an exchange rate of 1 USD = 0.58 R. This is published in IMF-World Bank-OECD-EBRD, *The Economy of the USSR: Summary and Recommendations*, Table 5 on page 42.

Given the nature of the transfer of Gazprom's assets, we do not understand the underlying accounting principles. But then, we do not need to understand them in the present context.

In the discussion that follows, we will attempt to establish what the transportation costs (economic costs) would be in Russia on the existing system, if they had evolved in a competitive market structure, and what the transportation costs will be on new pipelines now on Gazprom's planning horizon, for which some loan mechanisms are likely to be invoked.

In short, we propose to provide a reality check by comparing Gazprom's cost data with free-market estimates of our own. We know what it would reasonably cost in a competitive environment to ship natural gas over long distances, since gas transmission monopolies are generally regulated in market societies and, therefore, subject to public rate hearings. In the United States, for example, the Federal Energy Regulatory Commission (FERC), which has jurisdiction in this area, follows a cost-plus pricing regime that requires gas pipeline transmission companies to publicly state and justify the prices they charge for their various services so that the resulting returns on invested capital, after appropriate risk adjustment, are comparable to those of companies engaged in more competitive industries.

3.3 REGULATORY POLICIES AND COMPETITIVE TRANSMISSION PRICES

The FERC divides overall transmission services into several subservices, including: gathering the gas, a service which is fairly substantial in the United States, where the marketable gas is collected from some 20,000 operating gas fields; providing field transportation and access facilities to trunk lines; gas transmission proper; and storage services designed to smooth out pipeline loads through seasonal and operational fluctuations. In addition, pipelines commit stated portions of their throughput capacities to customers on a non-interruptible basis, for a fee. Interruptible gas transport services, while subject to curtailment during peak demands, come at a discount that is attractive to large customers with dual-fired boiler capabilities, such as electric utilities and large manufacturing plants.

Over the last ten to fifteen years, the FERC has pursued a policy pattern of making gas transmission services ever more competitive. The most important feature of this evolving policy has been to get gas pipeline companies out of the transaction business, where the pipeline purchases the gas at the line inlet and sells it to its customers on the downstream side of the line. Today, most of the interstate natural gas in the United States is shipped on a service basis, where the pipeline acts as a contract carrier (very much like a motor freight carrier), providing access to its line to all comers (subject to physical and capacity constraints) on identical, and published, terms, without ever taking possession of the gas.

In effect, the line sells the services of transporting natural gas between designated points. Each subservice in this process is costed out separately.

This process of regulatory evolution that has made the pipeline transmission industry more competitive in the recent past has culminated, in 1992, in what is generally considered the final stepping stone in exposing the lines to the rigors of the market. FERC Order 636 now requires gas pipelines to cost out separately the one remaining service that had until then escaped regulatory scrutiny: the gathering of natural gas from the gas producing fields on the upstream side of the pipeline. The transition to the new cost accounting system is currently being phased in. The beginning of the 1993/1994 heating season is the deadline for the system to be in place for all interstate pipelines. The data of only four pipeline companies were conformant with the new system at the time of writing. (New-system cost data will be available in time for all major U.S. gas pipelines, though, for study and review, should a regulatory structure along these lines be considered as a model for Gazprom).

The idea behind this move towards "unbundling" of gas transport services is to charge the customers only for the services they need. For example, a broker may put together a spot market deal in which one or several gas producers agree to furnish natural gas on an interruptible basis to an electric utility with dual (natural gas/fuel oil) firing capability. In such a deal, the gas pipeline only furnishes, and charges for, gathering services, access to the line and transportation on an as-available basis. There is no storage service, no setting aside and holding of pipeline capacity, and there are no charges for these services. This is in contrast to the transaction days when the pipeline was regulated with regard to, and charged for, the overall delivery of natural gas without specific break-downs for individual services. In those days it was difficult for the pipeline customer to know whether, and to what extent, he was being asked to subsidize services that he himself did not require, a situation that is descriptive of gas transportation in Russia today.

We have reviewed a number of FERC rate cases under the new and old pricing regimes and have selected a representative company as an example of how the unbundling of services affects the consumer and makes the pipeline more competitive. The description of FERC's historic policy move to identify and eliminate cross-subsidies between users of different pipeline services may well serve as one of several possible examples for the establishment of pricing policies in Russia today. The company we chose to analyze is Panhandle Eastern Pipeline Corporation which transports natural gas from the Texas-Oklahoma Panhandle Region to Detroit and its surrounding area. Even though the proposed rate schedule here under discussion is public information, and preliminary rate discussions with FERC staff seem to indicate that the proposed rate schedule is likely to be approved, the rate hearings

themselves have not yet been held, so that minor variations are still possible. With this in mind, the current rate information of Panhandle Eastern is shown in Table 14. The rates listed in this table are for enhanced interruptible transportation service, a subcategory of interruptible service that allows for extremely narrow deviations from contracted hourly transportation volumes.

Panhandle Eastern, Table 14, gets most of its gas from old fields that deliver relatively low volumes per well. The company also collects associated gas. The resulting low-density gathering system is expensive to operate, and that is reflected in the gathering charge which runs at 26.85 cents per dekatherm, not counting fuel charges of 1.89 cents (a dekatherm "Dt" is for all practical purposes the equivalent of an Mcf; accordingly, the dekatherm and the Mcf will be treated as equivalent units in the discussion that follows). The pipeline itself is subdivided into a field zone which covers gas transportation through that portion of the line where gas gathering is the dominant activity. Movement in the pipe through the field zone is costed out at 16.67 cents/Mcf, plus 3.27 cents for fuel reimbursement. An access fee in the amount of 12.07 cents/Mcf basically reflects overhead expenses. For shipments within the market zone, mileage charges apply. These vary, depending on the distance the gas is being shipped. For a distance of 1000 miles, for example, the mileage charge is 21.70 cents without fuel costs and 30.31 cents/Mcf with fuel costs, for an overall transportation charge, including fuel costs, of 91.05 cents/Mcf. The reason fuel costs are dealt with separately is that they are an important factor in the overall costs (about 15% for a distance of 1000 miles) over which the pipeline has no control. Being a separate line item, sudden changes in fuel costs can be dealt with through cost adjustments that do not require extensive hearings before the FERC.[3]

All of these costs are for interruptible contracts (in fact "enhanced" interruptible contracts), the only contracts where billing takes place on a volume basis throughout. Firm contracts are more complex, since they involve a fixed cost component designed to set aside for the natural gas purchaser a stated portion of the pipeline's throughput capacity, plus a variable cost component per Mcf of gas actually transported. This is an important concept that deserves closer discussion if and when rate designs applicable to Russian gas transport are contemplated. However, for the purpose at hand, which is to review the reasonableness of Russian gas transport charges, the discussion based on interruptible contracts is sufficient. This is all the more true, since firm and interruptible rates converge (in variable terms) at a 100% load factor.

[3] In fact, many common-carrier contracts specify fuel costs in terms of in-kind credits, where designated percentages of the moving gas are used up as compressor fuel. This provision makes gas transport rates (but not city gate prices) completely independent of fuel costs.

Table 14
Panhandle Eastern Corp.
Rate Structure: Interruptible Rates

Function		
Assumed Wellhead Price	160.00	Cents/Mcf
Gathering	26.85	Cents/Mcf
Fuel Allowance	1.18	Volume Percent
Field Transmission	16.67	Cents/Mcf
Fuel Allowance	1.73	Volume Percent
Access Charge	12.07	Cents/Mcf
Fuel Allowance	0	Volume Percent
Market Area Transmission	2.17	Cents/100 miles
Fuel Allowance	0.39	Volume %/100 miles

Wellhead	------ Wellhead+Gathering ------			------ Field Transmission ------				
Price Assumed Cents/Mcf	Gathering Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Total WH & G Cents/Mcf	Transm. Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Trunkline Inlet Price Cents/Mcf	Access Fee Cents/Mcf	Trunk Line Inlet Price Cents/Mcf
160	26.85	1.89	188.74	16.67	3.27	208.67	12.07	220.74

	---------- Market Zone Transmission ----------					Overall Transportation		
Trunk Line Inlet Price Cents/Mcf	Distance Miles	Transm. Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Total Transm. Cents/Mcf	City Gate Price Cents/Mcf	---------- Charges ---------- No Fuel Cents/Mcf	Fuel All. Cents/Mcf	With Fuel Cents/Mcf
220.74	0	0	0.00	0.00	220.74	55.59	5.15	60.74
	500	10.85	4.30	15.15	235.90	66.44	9.46	75.90
	1000	21.70	8.61	30.31	251.05	77.29	13.76	91.05
	1500	32.55	12.91	45.46	266.21	88.14	18.07	106.21
	1744	37.84	15.01	52.86	273.60	93.43	20.17	113.60

Overall Transportation Charges (Gradients)
Cents/Mcf/100 Miles

Distance	--- Trunk Line Only ---		- Overall Charges -	
Miles	With Fuel	No Fuel	With Fuel	No Fuel
0	-	-	-	-
0-500	3.03	2.17	15.18	13.29
0-1000	3.03	2.17	9.11	7.73
0-1500	3.03	2.17	7.08	5.88
0-1744	3.03	2.17	6.51	5.36

The gas transportation charges of Panhandle Eastern, with and without fuel costs, have been plotted in Figure 2, as a function of distance. That figure shows the implication of the up-front charge for gathering and field zone transmission, as well as the treatment of overhead charges as a lump-sum fee (access fee). These one-time charges burden any given Mcf of natural gas with a fixed up-stream charge as a condition of entering the system. For Panhandle Eastern, that charge is 55.59 cents per Mcf, not counting a fuel allowance of 5.15 cents/Mcf. That is considerably more than the mileage charge itself (with fuel) that the gas is burdened with on a 1000-mile shipment down the pipeline.

Given the high up-stream cost of transporting natural gas, shipping it gets cheaper, on a per-mile basis, as distances grow. For example, if Panhandle Eastern had a pipeline twice as long and the variable transport cost over the second half were comparable to that of the first half, the total cost per Mcf would rise by 30.31 cents (the additional mileage charge of 21.70 cents, plus fuel charges of 8.61 cents), to 121.36 cents. The resulting overall charge per 1000 miles would be approximately 61 cents for the entire 2000-mile transmission, compared to 91 cents over the first 1000 miles.

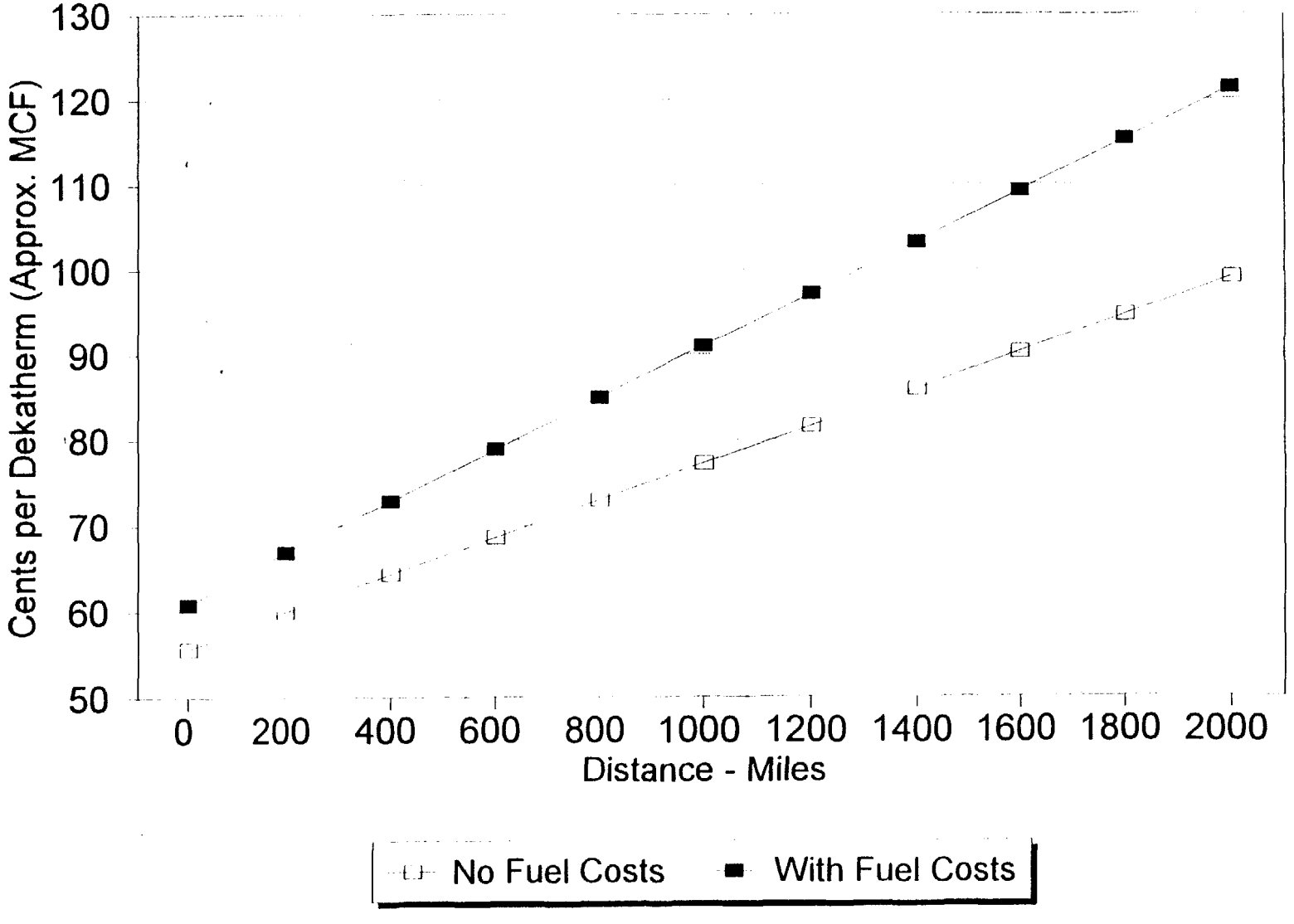
3.4 TRANSPORT RATE VARIATIONS

No two pipelines are exactly the same, and neither are their operating costs. We have analyzed three additional pipeline companies to establish a reasonable range in which transport rates might be expected to move under a competitive cost-plus pricing regime. The pipelines we have reviewed are the Transcontinental Gas Pipeline Company (Transco), which is engaged in moving natural gas from South Texas (including off-shore leases) as far North as New York City; the Tennessee Gas Pipeline Company (Tenneco) which transports gas from Southern Texas and Louisiana to New York State and to several New England States; and the Northern Border Pipeline Company (Northern Border) which is a pipeline-to-pipeline transfer agent for Canadian import gas which it moves over a 969-mile trunk line from Montana to Iowa.

The rate schedules for these lines are shown in Tables 16 through 18. For the discussion at hand, Table 15 summarizes our findings regarding the spread of transport costs. The only difference between Panels A and B in this table is the use of different units of measurement.

The term "trunkline only" in Table 15 refers to the rates charged for the service of moving natural gas, with and without fuel costs, through the main transmission system. The rates,

Figure 2
Gas Transportation Charges, Panhandle Eastern, Interruptible Service



therefore, do not include charges for gathering fees, field transmission fees and access fees (when specifically listed), nor do they include the fuel costs associated with these activities. The "overall system" rates include all activities from the wellhead to the city gate, with and without fuel costs. All rates were calculated to a standard distance which, for purposes of this report, was chosen to be the distance between Urengoy and Moscow.

As can be seen in Panel A of Table 15, the trunkline-only rates without fuel range from 1.89 cents per 100 miles (Transco) to 3.86 cents (Northern Border). Panhandle Eastern has relatively low rates at 2.17 cents per 100 miles. With fuel, the rates are a fraction of a penny higher.

The overall system rates, without fuel, are considerably higher than the trunkline-only rates in those cases where gathering and field transportation fees are high, as they are in the Panhandle Eastern case. In the Northern Border case which involves a pipeline-to-pipeline transfer of natural gas, there are no such charges. Consequently, the respective trunkline-only and overall system charges for Northern Border are identical. Again, Panhandle Eastern rates are high in the overall rate schedule, 6.51 cents/Mcf per 100 miles with fuel, compared to 5.36 cents without fuel.

Table 15
Competitive Gas Transport Rates
Selected U.S. Interstate Pipelines
Rates are Based on the Distance Urengoy-Moscow (1744 miles)

Panel A		**Trunkline Only**		**Overall System**	
Cents/Mcf/100 Miles		With Fuel	No Fuel	With Fuel	No Fuel
Table					
14	Panh. Eastern	3.03	2.17	6.51	5.36
16	Transco	2.32	1.89	3.08	2.65
17	Tenneco	4.45	3.69	4.45	3.69
18	Northern Bord	4.13	3.86	4.13	3.86

Panel B		**Trunkline Only**		**Overall System**	
$/Mcm/1000 km		With Fuel	No Fuel	With Fuel	No Fuel
Table					
14	Panh. Eastern	6.65	4.76	14.28	11.76
16	Transco	5.09	4.15	6.76	5.81
17	Tenneco	9.76	8.10	9.76	8.10
18	Northern Bord	9.06	8.47	9.06	8.47

One should not draw anything but broad conclusions from this analysis. A portion of the variation in pipeline rates can be attributed to differences in pipeline vintage. In the United States a pipeline rate in $/Mcm/1000 km is a function of the age of the pipeline, because pipelines are valued on the basis of depreciated historical capital cost. The older the pipeline, the lower the historical capital cost per mile and the lower the ratio of net (depreciated) assets to gross assets.

The wide divergence of "trunkline only" rates is not surprising, since those rates are highly dependent on the placement, within the overall transmission system, of the transfer point on the pipeline where field transportation stops and market zone (here, for brevity, but somewhat inaccurately labeled "trunkline-only") transmission begins. That is an arbitrary designation, as is the definition of gathering vs. field transportation. To the extent that arbitrary definitions still prevail in these subsystems, cross-subsidization continues to exist in the overall gas transportation systems. It always will, but it can be reduced to a minimum, and under FERC Order 636, it has been.

There is also the distinct possibility that some gathering and field transportation activities escape statistical capture under this system. For example, there has been considerable divestiture of intra-state pipeline transportation services such as gathering and field transportation, to give either local pipeline subsidiaries or independent gatherers (oftentimes the producers themselves) a better profit opportunity or more operational flexibility. To the extent that this happens, that particular service is not reflected in the pipeline rates, but it will show up on city gate prices, since the pipeline inlet price will be increased by the cost of these activities. There is a good chance that Transco's low overall rates are reflective of partially uncaptured activities of this kind, given the fact (Table 16) that Transco assesses no fees for gathering and field transportation in its rate schedule.

One can speculate how this might compare with the Russian gas situation. For West Siberian gas, one would expect the gathering and field transmission costs to be considerably less than what they are for Panhandle Eastern, given the enormous concentration of the resource. The access fee (overhead charge) is likely to be similar in size, whether explicitly listed or not. As regards the mileage charge, the huge pipeline capacities of the 56"-lines draining gas from West Siberia are bound to offer some economies of scale. Also, fuel costs are likely to be lower, given the low production costs in Siberia, their fuel wastage notwithstanding. On the other hand, there are operational problems peculiar to the Arctic, including the inhospitable climate in general and the need to cool the gas in the permafrost sections of the gas gathering and field transmission lines. These factors would tend to offset at least some of the savings. All in all, and without further study, we would

be inclined to say that if Gazprom had the same capital structure as a U.S. pipeline, West Siberian gas could be shipped at a slightly lower expense per mile than similar gas could be in the United States.

That may, however, not be the case for gas produced in other parts of Russia. Gathering costs, field zone transmission costs, and access costs to the trunklines are likely to be as high in non-Siberian Russian gas operations as they are in the United States, perhaps higher, if maintenance has been neglected in the past and needs to be overcome with intensified repair costs. If it is assumed for the moment that mileage charges run about the same for all sources of Russian gas, non-Siberian gas sources with their higher up-stream costs have a restricted area in which they can successfully compete with West Siberian Gas.

There are other factors that have considerable influence on the various service costs and charges of a gas trunkline. Perhaps the most important is capacity utilization. A pipeline operating at full capacity the year around will impose a lower charge per unit volume of gas throughput than one that is not used at capacity. We have not dealt with Gazprom's gas storage system, but it clearly is a vital factor in keeping the gas lines filled to capacity the year around. Given Gazprom's control over essentially all the gas moving within the former USSR, and its lack of competitive pressures, capacity utilization becomes essentially a matter of scheduling. Not so in a competitive environment, where competing gas lines continuously try to lure away customers and where other fuels are engaged in similar competitive maneuvers. In such an environment, keeping a pipeline running at or near capacity is immensely more complicated since this requires the line to keep up with, or better yet to anticipate, predatory pricing discounts by competing gas lines as well as by competing fuels.

The age of a pipeline is also an important factor in setting the line's service charges. In a generally inflationary environment, pipeline construction costs will be higher for recent constructions, compared to lines that have been in operation for many years or decades. In the U.S., depreciation charges reflect original construction costs rather than pipeline replacement costs. As a result, depreciation charges for older lines are lower (per mile or, for equal pipeline capacities, per Mcf) than those for new ones. And, of course, once a line has been written off, its depreciation charge vanishes.

Table 16
Transcontinental Gas Pipeline Co.
Rate Structure - Interruptible Rates

Function		
Assumed Wellhead Price	160.00	Cents/Mcf
Gathering	0	Cents/Mcf
Fuel Allowance	0	Volume Percent
Field Transmission	0	Cents/Mcf
Fuel Allowance	0	Volume Percent
Access Charge	13.31	Cents/Mcf
Fuel Allowance	0	Volume Percent
Market Area Transmission	1.891	Cents/100 miles
Fuel Allowance	0.245	Volume %/100 miles

Wellhead	------ Wellhead+Gathering ------			------ Field Transmission ------				
Price Assumed Cents/Mcf	Gathering Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Total WH & G Cents/Mcf	Transm. Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Trunkline Inlet Price Cents/Mcf	Access Fee Cents/Mcf	Trunk Line Inlet Price Cents/Mcf
160	0	0.00	160.00	0.00	0.00	160.00	13.31	173.31

	---------- Market Zone Transmission ----------					Overall Transportation		
Trunk Line Inlet Price Cents/Mcf	Distance Miles	Transm. Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Total Transm. Cents/Mcf	City Gate Price Cents/Mcf	---------- Charges ---------- No Fuel Cents/Mcf	Fuel All. Cents/Mcf	With Fuel Cents/Mcf
173.31	0	0	0.00	0.00	173.31	13.31	0.00	13.31
	500	9.46	2.12	11.58	184.89	22.77	2.12	24.89
	1000	18.91	4.25	23.16	196.47	32.22	4.25	36.47
	1500	28.37	6.37	34.73	208.04	41.68	6.37	48.04
	1744	32.98	7.41	40.38	213.69	46.29	7.41	53.69

Overall Transportation Charges (Gradients)
Cents/Mcf/100 Miles

Distance	--- Trunk Line Only ---		- Overall Charges -	
Miles	With Fuel	No Fuel	With Fuel	No Fuel
0	-	-	-	-
0-500	2.32	1.89	4.98	4.55
0-1000	2.32	1.89	3.65	3.22
0-1500	2.32	1.89	3.20	2.78
0-1744	2.32	1.89	3.08	2.65

Table 17
TENNECO
Rate Structure - Interruptible Rates

Function		
Assumed Wellhead Price	160.00	Cents/Mcf
Gathering	0	Cents/Mcf
Fuel Allowance	0	Volume Percent
Field Transmission	0	Cents/Mcf
Fuel Allowance	0	Volume Percent
Access Charge	0	Cents/Mcf
Fuel Allowance	0	Volume Percent
Market Area Transmission	See Table Below	
Fuel Allowance	See Table Below	

Wellhead	------ Wellhead+Gathering ------			------ Field Transmission ------				
Price Assumed Cents/Mcf	Gathering Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Total WH & G Cents/Mcf	Transm. Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Trunkline Inlet Price Cents/Mcf	Access Fee Cents/Mcf	Trunk Line Inlet Price Cents/Mcf
160	0	0.00	160.00	0.00	0.00	160.00	0	160.00

----------	Market	Zone	Transmission	----------		Overall Transportation		
	Transm.	Fuel	Fuel	Total	City Gate	----------	Charges	----------
Distance Miles	Charge Cents/Mcf	Allowance Vol. %	Allowance Cents/Mcf	Transm. Cents/Mcf	Price Cents/Mcf	No Fuel Cents/Mcf	Fuel All. Cents/Mcf	With Fuel Cents/Mcf
0	0.00	0.00	0.00	0.00	160.00	0.00	0.00	0.00
500	18.45	2.36	3.78	22.23	182.23	18.45	3.78	22.23
1000	36.90	4.72	7.56	44.46	204.46	36.90	7.56	44.46
1500	55.36	7.09	11.34	66.69	226.69	55.36	11.34	66.69
1844	68.05	8.71	13.94	81.99	241.99	68.05	13.94	81.99
1744	64.36	8.24	13.18	77.54	237.54	64.36	13.18	77.54

Overall Transportation Charges (Gradients)
Cents/Mcf/100 Miles

Distance	--- Trunk Line Only ---		- Overall Charges -	
Miles	With Fuel	No Fuel	With Fuel	No Fuel
0	-	-	-	-
0-500	4.45	3.69	4.45	3.69
0-1000	4.45	3.69	4.45	3.69
0-1500	4.45	3.69	4.45	3.69
0-1844	4.45	3.69	4.45	3.69
0-1744	4.45	3.69	4.45	3.69

Table 18
Northern Border Pipeline Co.
Rate Structure - Interruptible Rates

Function		
Assumed Wellhead Price	160.00	Cents/Mcf
Gathering	0	
Fuel Allowance	0	
Field Transmission	0	
Fuel Allowance	0	
Access Charge	0	
Fuel Allowance	0	
Market Area Transmission	3.863	Cents/Mcf/100 miles
Fuel Allowance	1.6	Volume % Overall

Wellhead	------ Wellhead+Gathering ------			------- Field Transmission -------				
Price Assumed Cents/Mcf	Gathering Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Total WH & G Cents/Mcf	Transm. Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Trunkline Inlet Price Cents/Mcf	Access Fee Cents/Mcf	Trunk Line Inlet Price Cents/Mcf
160	0	0.00	160.00	0.00	0.00	160.00	0	160.00

	---------- Market Zone Transmission ----------				
Trunk Line Inlet Price Cents/Mcf	Distance Miles	Transm. Charge Cents/Mcf	Fuel Allowance Cents/Mcf	Total Transm. Cents/Mcf	City Gate Price Cents/Mcf
160.00	969	37.43	2.56	39.99	199.99
	1744	67.37	4.61	71.98	231.98

Overall Transportation Charges (Gradients)
Cents/Mcf/100 Miles

Distance Miles	-- Trunk Line Only -- With Fuel	No Fuel
969	4.13	3.86
1744	4.13	3.86

CHAPTER 4: CITY GATE DELIVERY COSTS UNDER COMPETITIVE CONDITIONS

CHAPTER SUMMARY - MAJOR CONCLUSIONS

In a market environment, Moscow City Gate prices of natural gas from the Urengoy Area (Taz Peninsula) can be expected to range from about 81 to 91 cents per mcf, or $28.80 to $32.20 per mcm (1990 prices), depending on the transmission route.

At the former Soviet Union's main gas export station, in Uzhgorod (Ukraine), West Siberian gas from Urengoy and surrounding fields can be delivered at $1.05 per mcf, or $37.20 per mcm.

In those cities where Yamal and Shtockmanovskoye gas was priced alongside with Urengoy and other sources of gas, neither Yamal nor Shtockmanovskoye gas is expected to be able to compete.

Within Russia, gas from sources other than Urengoy will be able to compete with Urengoy gas over short distances only. North Caucasus gas is unable to compete with Urengoy gas even in the North Caucasus Region, given the high production cost of North Caucasus gas, as reported by Gazprom.

4.1 BACKGROUND

In a market economy, natural gas city gate prices reflect the cost of searching for, finding, developing, producing, processing and transporting natural gas from producing regions to the point of purchase by local distribution companies. The first portion of this process, up to the point where natural gas leaves the wellhead and enters the gathering system, has been covered in Chapter 1, where we have offered the conclusion that Gazprom's published production costs are in line with those of the Western World under equivalent production conditions. Gazprom's natural gas production costs, listed in Table 21, have been used as the upstream component of Russia's imputed city gate prices in this chapter. In those areas where published wellhead prices were missing, prices from nearby regions with similar production characteristics were used. For example, wellhead prices from the Orenburg Region were used in lieu of the missing wellhead prices from the Volga Urals Region.

Natural gas transport costs are a different matter. Since historical cost information from Gazprom is not based on western accounting, and costs were distorted by Soviet price controls, we estimated the economic cost of natural gas transportation in a market economy using data from U.S. gas pipeline rate hearings as our point of departure, Chapter 3. The individual cost components of natural gas transmission, as imposed by U.S. regulatory procedures, were accepted with modifications to reflect Russia's producing and transmission environments. These data were incorporated into a spreadsheet model which forms the core of Chapter 4.

4.2 RESULTS OF ANALYSIS

To estimate the cost of transporting gas from major producing areas to selected cities, we constructed a simplified diagram of the Russian natural gas grid (see Figure 3). The transmission corridors numbered and shown in Figure 3 are listed in Table 19. The city gate price model and its results for selected Russian cities are presented in Tables 19 through 25. The first two of these Tables (19 and 20) simply reflect pipeline segments and distances of major transmission routes in Russia. Published information was used wherever possible for the distances of the individual segments or overall transmission routes. When this information was not available, distances were estimated with the aid of large-scale maps. The model was built in such a way that entering corrected pipeline segments in the Mileage Column of Table 19 carries through for appropriate adjustments throughout the model. However, minor adjustments in the mileage of individual pipeline segments are not likely to produce significantly different city gate prices, since total distance-related natural gas transmission expenses generally range from 25 to 55% of the final city gate price. In Moscow, for example, distance-related transmission costs for Urengoy gas range from 50 to 55% of the city gate price, depending on the delivery route, compared to 25% for Orenburg gas, and about 26% for gas from the Yamal Peninsula.

Tables 21 through 25 provide basic data and interim results in calculating city gate prices. The cities chosen for this report were Moscow, St Petersburg, Nizhni-Novgorod, Chelyabinsk, Krasnodar, and Uzhgorod on the Ukraine/Slovac border, which is the main export station for Russian natural gas. Supply regions were the Taz Peninsula in Western Siberia ("Urengoy"), the Orenburg Region, the Volga-Urals, North Caucasus, Vingapur and two as of yet undeveloped producing regions: the Yamal Peninsula in West Siberia and the Shtockmanovskoye Field in the Barents Sea. Each producing region is listed separately in Tables 21 through 25. We will explain the data and calculations of Urengoy-origin gas in some detail (Table 25), and provide summary explanations for the other producing regions.

Table 19
Pipeline Segments in Russia

	Approximate Length	
WESTERN SIBERIA	**Miles**	**KM**
1 Urengoy - Punga	540	869
2 Punga - Nizhnaya Tura	330	531
3 Nizhnaya Tura - Chelyabinsk	280	451
4 Surgut - Chelyabinsk	660	1062
5 Vingapur - Surgut	170	274
6 Urengoy - Vingapur	220	354
URALS		
7 Punga - Ukhta	354	570
8 Nizhnay Tura - Perm	180	290
9 Nizhnay Tura - Ufa	360	579
10 Chelyabinsk - Ufa	220	354
EUROPEAN RUSSIA		
11 Nizhni Novgorod - Moscow	260	418
12 Perm - Nizhni Novgorod	550	885
13 Ukhta - Gryazovets	590	949
14 Gryazovets - Moscow	260	418
15 Ryazan - Moscow	120	193
16 Petrovsk - Ryazan	330	531
17 Perm - Yelets	880	1416
18 Yelets - Voronezh	90	145
19 Voronezh - Novopskov	130	209
20 Alexsandrov Gay - Novopskov	440	708
21 Orenburg - Alexsandrov Gay	330	531
22 Ufa - Orenburg	220	354
23 Ufa - Samara	280	451
24 Samara - Petrovsk	230	370
25 Samara - Alexandrov Gay	240	386
26 Alexsandrov Gay - Petrovsk	220	354
27 Petrovsk - Nizhni Novgorod	310	499
28 Gryazovets - Torzhok	242	389
29 Gryazovets - St. Petersburg	379	610
30 Torzhok - St Petersburg	270	434
31 Moscow - Torzhok	130	209
32 Yelets - Moscow	230	370
NORTH CAUCASUS		
33 Novopskov - Rostov-on Don	200	322
34 Rostov-on-Don - Krasnodar	240	386
35 Rostov-on-Don - Stavropol	220	354
36 Rostov-on-Don - North Caucasus	260	418
UKRAINE-BELARUS		
37 Yelets - Uzhgorod	840	1352
38 Kobrin - Uzhgorod	300	483
39 Torzhok - Kobrin	640	1030
NORTH WESTERN SIBERIA		
40 Yamal Peninsula - Ukhta	744	1197
41 Yamburg - Urengoy	70	113
KARELIA-BARENTS		
42 Shtokmanovskoe-St. Petersburg	870	1400 On Land
	400	644 In Water

Table 20
Transmission Routes in Russia

	MILES	KM
MOSCOW:		
1 Urengoy - Punga - Ukhta - Gryazovets - Moscow	1744	2806
2 Urengoy - Punga - Nizhnaya Tura - Perm - Nizhni Novgorod - Mosco	1860	2993
3 Urengoy - Punga - Nizhnaya Tura - Perm - Yelets - Moscow	2160	3475
4 Yamal - Ukhta - Gryazovets - Moscow	1594	2565
5 Orenburg - Alexsandrov Gay - Petrovsk - Ryazan - Moscow	1000	1609
6 Volga-Urals (Samara) - Petrovsk - Ryazan - Moscow	680	1094
Netback: Uzhgorod - Yelets - Moscow	1070	1722
ST. PETERSBURG		
1 Urengoy - Punga - Ukhta - Gryazovets - St. Petersburg	1863	2998
2 Shtokmanovskoye - St. Petersburg	1270	2043
3 Yamal - Ukhta - Gryazovets - St. Petersburg	1713	2756
Netback: Uzhgorod - Kobrin - Torzhok - St. Petersburg	1210	1947
NIZHNI NOVGOROD		
1 Urengoy - Punga - Niznnaya Tura - Perm - Nizhni Novgorod	1600	2574
2 Orenburg - Alexsandrov Gay - Petrovsk - Nizhni Novgorod	705	1134
3 Volga-Urals - Petrovsk - Nizhni Novgorod	540	869
Netback: Uzhgorod - Yelets - Moscow - Nizhni Novgorod	1330	2140
CHELYABINSK		
1 Urengoy - Vingapur - Surgut - Chelyabinsk	1050	1689
2 Vingapur - Surgut - Chelyabinsk	830	1335
3 Urengoy - Punga - Nizhnaya Tura - Chelyabinsk	1150	1850
Netback: Uzhgorod - Yelets - Perm - Nizhnaya Tura - Chelyabinsk	2180	3508
KRASNODAR		
1 North Caucasus - Rostov on Don - Krasnodar	500	805
2 Orenburg - Alexsandrov Gay - Novopskov - Rostov on Don - Krasno	1210	1947
3 Volga Urals - Alexsandrov Gay - Novopskov - Rostov on Don - Kras	1120	1802
Netback: Uzhgorod - Yelets - Voronezh - Novopskov - Rostov on Don - Krasn	1500	2414
UZHGOROD		
1 Yamal - Ukhta - Gryazovets - Torzhok - Kobrin - Uzhgorod	2516	4048
2 Shtokmanovskoye - St. Petersburg - Torzhok - Kobrin - Uzhgorod	2480	3990
3 Urengoy - Punga - Nizhnaya Tura - Perm - Yelets - Uzhgorod	2770	4457

The top panel of Table 26 lists the different categories for which cost data are available from U.S. regulatory procedures (Column 1), and the actual costs involved in our U.S. model pipeline company, Eastern Panhandle Pipeline Company (Column 2). These unbundled services, including gathering, field transmission and access to the high pressure network, cost 56.68 cents per mcf without fuel costs, and 61.84 cents with them.

The gathering function reflects the fact that natural gas has to be collected from a multitude of gas fields in the United States, with secondary lines reaching out into sometimes small gas fields in remote locations. The costs associated with that function are 26.85 cents/mcf for Panhandle Eastern. That is high by U.S. standards. As we explained in Chapter 2, the high Panhandle Eastern Gathering costs reflect the low density gathering system of the Texas Oklahoma Panhandle area where much of the gas comes from the old Hugoton Field. A review of the sporadic information on gathering costs in other producing regions of the United States suggests that the average for the nation may be as low as half of the Panhandle Eastern costs. Accordingly, we have reduced the gathering cost for Russia's conventional producing regions (Orenburg, Volga Urals, North Caucasus, and Vingapur) by 50%, to a level of reasonable equivalency with average U.S. gathering costs.

By contrast, the West Siberian gas fields are relatively close together, and the individual gas wells in West Siberia are essentially all giant producers (in excess of 20 Mmcf/day). Hence, the gathering function in the Taz Peninsula Area ("Urengoy") has been estimated to be half of the equivalent U.S. cost, (or 25% of the Panhandle Eastern cost), at 6.71 cents per mcf (Columns 3 & 4).

Field transmission refers to the fact that, following the gathering function from individual wells, the bulk of the gas is moved through secondary collection lines before entering the main transmission line proper. There is generally a specific compressor or transfer station at which, for regulatory and cost accounting purposes, the field transmission activity stops and trunkline transmission begins. Given the complexity and the regional spread of that activity, the field transmission cost of Panhandle Eastern is 16.67 cents/mcf.

Compared to the U.S. producing environment, field transmission is less expensive in West Siberia, where the natural gas is more highly concentrated than anywhere else in the world. Accordingly, we have derated the field transmission costs to 25% of the U.S. equivalent, for a total of 4.17 cents/mcf. We should note that, on the basis of distance alone, there is a case to be made for derating this cost even more. However, there are compensating expenses, notably the fact that all but the South Dome of the Urengoy Field and all fields to the North of Urengoy (including Yamburg) are located in areas of continuous permafrost.

The Southern part of Urengoy has discontinuous pockets free of permafrost. The digging of trenches for gas pipelines is very problematical, and expensive, in these areas, and the gas has to be cooled to prevent the lines from melting the frozen ground. In addition, there will be costs associated with dehydration, purification, and products extraction of the raw wellhead gas.

The conventional Russian gas production areas are likely to have field transmission costs similar to those of Panhandle Eastern. Accordingly, Panhandle's cost of 16.67 cents/mcf was accepted as a reasonable approximation to field transmission costs in Orenburg, Volga Urals, North Caucasus, and Vingapur.

Panhandles Eastern's access fee reflects a portion of the pipeline's overhead expense. It is based on administrative and general costs, supervision and engineering expenses, customer account and sales expenses, and the cost of storage for load balancing and systems management purposes. These are system-wide costs that do not vary with the location of gas receipt and delivery. In those cases where U.S. pipelines do not specifically list access fees, their overhead expenses are absorbed into the general rate structure.

Overhead expenses have been judged to be about the same for Panhandle Eastern and Russian pipelines, including those originating in West Siberia. These costs are 12.07 cents/mcf. The "Adjustments" to these costs in Tables 26 through 28 reflect purely institutional surcharges such as mandated pipeline contributions to the U.S. Gas Research Institute and others. These specifically U.S. charges have been deleted for all Russian gas costs.

The final upstream cost item, "Fuel Allowance", reflects the fuel usage during gathering and field transmission operations. In the Panhandle Eastern case, this item is expressed as a volume percentage of the entering fuel. The difference between the actual fuel costs incurred by Panhandle Eastern and the estimated costs in Western Siberia reflect different wellhead prices ($1.60 U.S. vs. $0.178 West Siberia) and different scales of the activities themselves. For example, since West Siberian gathering costs have been reduced by 75%, the volumetric assessment of the fuel allowance has been discounted by that same factor, from 1.18% in the Panhandle Eastern case to 0.30% in West Siberia.

Each transmission route in Tables 21 through 26 is represented by a separate panel showing, among other things, the distances involved (in miles and kilometers), our estimated wellhead price, trunkline inlet price, and the city gate price (in cents/mcf and $/mcm). Fuel consumption during the transmission phase is expressed as a volumetric percentage of the gas moving through the system, subject to the trunkline inlet price. To

estimate fuel consumption for transmission other than field transmission, we used the fuel allowance in the interruptible transportation tariff for Panhandle Eastern, i.e., 3.9 percent of the inlet volume per 1000 miles of distance.[1]

Depending on the transmission route chosen, the imputed city gate price of Urengoy gas in Moscow falls in the range of 81 to 91 cents/mcf. As Table 21 shows, Urengoy gas can be delivered practically anywhere in Russia for a dollar or less per mcf. The imputed delivery cost to Uzhgorod is $1.05 per mcf.

The essential difference in transmission costs from Urengoy and other producing regions such as Orenburg (Table 22) is attributable to two causes: first, the wellhead price differs from region to region (5.85 Rubles/mcm in Orenburg vs. 3.63 in Urengoy), boosting the production cost component of the city gate price directly and indirectly raising fuel costs of the transmission activity in the field and on the movement of the gas to its destination. Second, the producing environments in onshore areas outside West Siberia more nearly resemble those of the United States, so that the various unfueled cost items at the top panel of Table 22 and elsewhere are carried at U.S. equivalence. For gathering costs, that means 50% of Panhandle Eastern's regulatory allowance, and for field transmission it means full equivalence (100%) of Panhandle Eastern's costs.

The percentage equivalences of individual unfueled upstream activities are shown in Tables 21 through 26 to make the judgment process in this evaluation more transparent. Different producing environments can be simulated by changing the percentage numbers (expressed as fractions) of the Russian equivalences, and the impact of the stipulated conditions on city gate prices can then be traced through the model. Under the base conditions of this scenario, the Moscow city gate price for natural gas coming from Orenburg is higher than the prices of gas from Urengoy, 96 cents/mcf for Orenburg gas vs. 81 cents for the shortest-route Urengoy gas.

As mentioned, wellhead price data were not available for the Volga-Urals Region, so we chose the Orenburg price instead. The Volga-Urals Region, some 680 miles from Moscow, is barely competitive with Urengoy, and only on the longest Urengoy-Moscow transmission route. Volga-Urals gas arrives at the Moscow city gate at an overall cost of 88 cents/mcf, just below the Urengoy-via-Yelets price of 91 cents. Still, on the more direct

[1] Gazprom's reported fuel consumption for gas transmission is 8.2%, plus 1.2% of losses. It is not clear whether that includes fuel consumption and losses in gathering and field transmission. Gas Industry of the USSR - 1990; op. cit; p. 123.

Table 21
City Gates Prices From Urengoy Field

VARIOUS COSTS	PANH. c/Mcf	URENGOY c/Mcf	Adj. Fact.	WH Price Rub/MCM	Exchange Rate Ruble/$	WH Price $/MCM	WH Price $/MCF
Gathering	26.85	6.71	25.0%	3.63	0.5793	$6.27	$0.1775
Field Transm.	16.67	4.17	25.0%				
Access	12.07	12.07	100.0%	US WH Pr.	US WH Pr		
Adjustm. (GRI, etc.)	1.09	0.00	0.0%	$/MCF	$/MCM		
	56.68	22.95		$1.60	$56.48		
FUEL ALLOWANCE							
Gathering	1.18%	0.30%					
Field Transmission	1.73%	0.43%					
Trunkline/1000miles	3.90%	3.90%					

URENGOY RATES

URENGOY-MOSCOW, Via Punga, Ukhta, Gryazovets

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1744	17.75	40.86	81.48	2806	6.27	14.42	28.76

URENGOY-MOSCOW, Via Punga, Nizhnaya Tura, Perm, Nizhni Novgorod

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1860	17.75	40.86	84.19	2993	6.27	14.42	29.72

URENGOY-MOSCOW, Via Punga, Nizhnaya Tura, Yelets

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
2160	17.75	40.86	91.17	3475	6.27	14.42	32.18

URENGOY-ST. PETERSBURG, Via Punga, Ukhta, Gryazovets

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1863	17.75	40.86	84.26	2998	6.27	14.42	29.74

URENGOY- NIZHNI NOVGOROD, Via Punga, Nizhnaya Tura, Perm

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1600	17.75	40.86	78.13	2574	6.27	14.42	27.58

URENGOY- CHELYABINSK, Via Vingapur, Surgut

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1050	17.75	40.86	65.32	1689	6.27	14.42	23.06

URENGOY- CHELYABINSK, Via Punga, Nizhnaya Tura

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1150	17.75	40.86	67.65	1850	6.27	14.42	23.88

URENGOY- UZHGOROD, Via Punga, Nizhnaya Tura, Perm, Yelets

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
2770	17.75	40.86	105.38	4457	6.27	14.42	37.20

Table 22
City Gate Prices from Orenburg

VARIOUS COSTS	PANH. c/Mcf	ORENBURG c/Mcf	Adj. Fact.	WH Price Rub/MCM	Exchange Rate Ruble/$	WH Price $/MCM	WH Price $/MCF
Gathering	26.85	13.43	50.0%	5.85	0.5793	$10.10	$0.2861
Field Transm.	16.67	16.67	100.0%				
Access	12.07	12.07	100.0%	US WH Pr.	US WH Pr		
Adjustm. (GRI, etc.)	1.09	0.00	0.0%	$/MCF	$/MCM		
	56.68	42.17		$1.60	$56.48		
FUEL ALLOWANCE							
Gathering	1.18%	0.59%					
Field Transmission	1.73%	1.73%					
Trunkline/1000miles	3.90%	3.90%					

ORENBURG RATES

ORENBURG-MOSCOW, Via Alexandrov Gay, Petrovsk, Ryazan

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1000	28.61	71.67	96.17	1609	10.10	25.30	33.95

ORENBURG-NIZHNI NOVGOROD, Via Alexsandrov Gay, Petrovsk

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
705	28.61	71.67	88.94	1134	10.10	25.30	31.40

ORENBURG-KRASNODAR, Via Alexsandrov Gay, Novopskov, Rostov on Don

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1210	28.61	71.67	101.31	1947	10.10	25.30	35.76

FROM VOLGA URALS

VARIOUS COSTS	PANH. c/Mcf	VOLGA URALS c/Mcf	Adj. Fact.	WH Price Rub/MCM	Exchange Rate Ruble/$	WH Price $/MCM	WH Price $/MCF
Gathering	26.85	13.43	50.0%	5.85	0.5793	$10.10	$0.2861
Field Transm.	16.67	16.67	100.0%				
Access	12.07	12.07	100.0%	US WH Pr.	US WH Pr		
Adjustm. (GRI, etc.)	1.09	0.00	0.0%	$/MCF	$/MCM		
	56.68	42.17		$1.60	$56.48		
FUEL ALLOWANCE							
Gathering	1.18%	0.59%					
Field Transmission	1.73%	1.73%					
Trunkline/1000miles	3.90%	3.90%					

VOLGA URALS RATES

VOLGA URALS-MOSCOW, Via Petrovsk, Ryazan

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
680	28.61	71.67	88.33	1094	10.10	25.30	31.18

VOLGA URALS-NIZHNI NOVGOROD, Via Petrovsk

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
540	28.61	71.67	84.90	869	10.10	25.30	29.97

VOLGA URALS-KRASNODAR, Via Alexsandrov Gay, Novopskov, Rostov on Don

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1120	28.61	71.67	99.11	1802	10.10	25.30	34.98

route via Punga, Ukhta and Gryazovets, Urengoy gas can be delivered to the Moscow city gate at 92% of the Volga-Urals cost.

According to published Gazprom information, North Caucasus gas (Table 23) is very expensive to produce. Its wellhead price is 12.49 Rubles/mcm, or 61.1 cents/mcf. As a result, North Caucasus gas cannot compete with gas from the Urengoy Region anywhere in Russia, including the immediate vicinity of the North Caucasus Region itself. We have not done the calculations to pinpoint the difference in delivery costs of Urengoy gas in the North Caucasus Region, but we note that the delivered price of Urengoy gas at Uzhgorod, some 2770 miles from Urengoy (105.4 cents/mcf), is about the same as the North Caucasus wellhead price plus gas gathering and related costs (104.9 cents/mcf, from the wellhead price of 61.1 cents plus gas gathering and related costs of 43.8 cents).

Yamal production costs have been estimated by Gazprom to be 65.5 cents/mcf. We have not discounted gathering costs on the Yamal Peninsula from the Panhandle Eastern levels as we did on the Taz Peninsula, since the gas concentration, while extremely high by world standards, is nevertheless lower than at Urengoy. Moreover, all of the production and gas gathering activity at Yamal will be in a permafrost environment, with the result that any cost savings associated with reduced distances are likely to be offset by additional costs due to operational difficulties in an extremely harsh climatic environment. Field transmission costs, which we derated by 75% in Urengoy, were judged to be the same per volume of gas transmitted as equivalent U.S. costs, since the gas moving through every foot of the gas gathering and transmission lines will have to be cooled to temperatures just below the surrounding atmosphere, and buried in what amounts to nearly solid ice. In short, we do not dispute the Russians' claim that production costs in Yamal are going to be very high. We are, however, adding a cautionary note that the gas gathering and field transmission costs are also going to be high and that, between these two high costs, Yamal gas will not be able to compete with Urengoy for a long time to come. As long as Urengoy gas is available in volumes sufficiently in size to be the swing producer in meeting both Russian and foreign demands, the cost of producing Yamal gas appears to be prohibitive. Delivered at Moscow, Yamal gas will be about twice as expensive as Urengoy gas (166 cents/mcf vs. 81 cents for Urengoy gas).

The expense of developing Shtockmanovskoye gas from the Barents Sea is likely to be even higher. It is true that the Shtockmanovskoye Field, the largest by far of several gas and gas condensate fields that have been discovered in the Barents Sea, is a giant reservoir containing at least 120 Tcf of gas (more than twice the size of the Troll Field off-shore Norway), possibly much more. If developed, Shtockmanovskoye could well become the third or fourth largest gas field in Russia. However, the development and placement on

Table 23
City Gate Prices from North Caucasus

VARIOUS COSTS - -	PANH. c/Mcf	ORENBURG c/Mcf	Adj. Fact.	WH Price Rub/MCM	Exchange Rate Ruble/$	WH Price $/MCM	WH Price $/MCF
Gathering	26.85	13.43	50.0%	12.49	0.5793	$21.56	0.6108
Field Transm.	16.67	16.67	100.0%				
Access	12.07	12.07	100.0%	US WH Pr.	US WH Pr		
Adjustm. (GRI, etc.)	1.09	0.00	0.0%	$/MCF	$/MCM		
	56.68	42.17		$1.60	$56.48		
FUEL ALLOWANCE							
Gathering	1.18%	0.59%					
Field Transmission	1.73%	1.73%					
Trunkline/1000miles	3.90%	3.90%					

NORTH CAUCASUS RATES

NORTH CAUCASUS-KRASNODAR, Via Rostov on Don

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
500	61.08	104.90	117.79	805	21.56	37.03	41.58

FROM VINGAPUR

VARIOUS COSTS	PANH. c/Mcf	VINGAPUR c/Mcf		WH Price RUB/MCM	Exchange Rate Ruble/$	WH Price $/MCM	WH Price $/MCF
Gathering	26.85	13.43	50.0%	3.71	0.5793	$6.40	$0.181
Field Transm.	16.67	16.67	100.0%				
Access	12.07	12.07	100.0%	US WH Pr	US WH Pr		
Adjustm. (GRI etc.)	1.09	0.00	0.0%	$/MCF	$/MCM		
	56.68	42.17		$1.60	$56.48		
FUEL ALLOWANCE							
Gathering	1.18%	0.59%					
Field Transmission	1.73%	1.73%					
Trunkline/1000miles	3.90%	3.90%					

VINGAPUR (SURGUT) RATES

VINGAPUR-CHELYABINSK, Via Surgut

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
830	18.14	60.96	80.95	1335	6.40	21.52	28.57

FROM YAMAL

VARIOUS COSTS	PANH. c/Mcf	VINGAPUR c/Mcf		WH Price RUB/MCM	Exchange Rate Ruble/$	WH Price $/MCM	WH Price $/MCF
Gathering	26.85	26.85	100.0%	13.39	0.5793	$23.11	$0.655
Field Transm.	16.67	16.67	100.0%				
Access	12.07	12.07	100.0%	US WH Pr	US WH Pr		
Adjustm. (GRI etc.)	1.09	0.00	0.0%	$/MCF	$/MCM		
	56.68	55.59		$1.60	$56.48		
FUEL ALLOWANCE							
Gathering	1.18%	1.18%					
Field Transmission	1.73%	1.73%					
Trunkline/1000miles	3.90%	3.90%					

YAMAL RATES

YAMAL-MOSCOW, Via Ukhta, Gryazovets

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1594	65.48	123.45	165.72	2565	23.11	43.58	58.50

YAMAL-ST. PETERSBURG, Via Ukhta, Gryazovets

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1713	65.48	123.45	168.87	2756	23.11	43.58	59.61

YAMAL-UZHGOROD, Via Ukhta, Gryazovets, Torzhok, Kobrin, Uzhgorod

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
2516	65.48	123.45	190.16	4048	23.11	43.58	67.13

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Table 24
City Gate Prices from Shtockmanovskoye

VARIOUS COSTS	PANH. c/Mcf	SHTOCKMANOV c/Mcf		WH Price RUB/MCM	Exchange Rate Ruble/$	WH Price $/MCM	WH Price $/MCF
Gathering	26.85	26.85	100.0%	26.78	0.5793	$46.23	$1.310
Field Transm.	16.67	25.01	150.0%				
Access	12.07	12.07	100.0%	US WH Pr	US WH Pr		
Adjustm. (GRI etc.)	1.09	0.00	0.0%	$/MCF	$/MCM		
	56.68	63.93		$1.60	$56.48		
FUEL ALLOWANCE							
Gathering	1.18%	1.18%					
Field Transmission	1.73%	2.60%					
Trunkline/1000miles	3.90%	3.90%					

SHTOCKMANOVSKOYE RATES

SHTOCKMANOVSKOYE-ST. PETERSBURG

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
1270	130.96	200.56	238.06	2043	46.23	70.80	84.03

SHTOCKMANOVSKOYE-UZHGOROD, Via St. Petersburg, Torzhok, Kobrin

Distance Miles	Wellhead Price c/Mcf	Trunkline Inlet Price c/Mcf	City Gate Price c/Mcf	Distance KM	Wellhead Price $/MCM	Trunkline Inlet Price $/MCM	City Gate Price $/MCM
2480	130.96	200.56	273.78	3990	46.23	70.80	96.64

Note: Used two times Yamal price for Shtockmanovskoye wellhead price .

production of the field will be expensive. While the climate in the Barents Sea is relatively mild for the latitude, the development of pack ice, while rare, cannot be excluded, and drift ice will be a permanent operational hazard, so that ice-resistant deep-water platforms will be required. The water depth at Shtockmanovskoye has been estimated to be 200 to 300 meters (660- 980 feet). Moreover, a 400-mile under-water pipeline will have to be laid with at least one platform-mounted compressor station somewhere on route to maintain pressure in the line and to assure throughput at design capacity.

Of all the production costs, that of Shtockmanovskoye gas is the most uncertain. That may be the reason why Gazprom has not published as much information on the development cost and resulting wellhead price of this gas as it has on other fields. We have made a very tentative guess that the production cost of Shtockmanovskoye gas might well be twice the cost of Yamal gas, or $1.31/mcf. If correct, the delivered city gate price in St. Petersburg of Shtockmanovskoye gas will be nearly three times as much as the delivered price of Urengoy gas, or $2.38/mcf, compared to Urengoy's city gate price of 84 cents/mcf. If the Shtockmanovskoye gas could be produced at a cost equivalent to Yamal gas, it would be able to compete with Yamal gas, especially in the Eastern portion of Scandinavia, but neither Yamal nor Shtockmanovskoye gas could begin to compete anywhere inside or outside of Russia with West Siberian gas from the Taz Peninsula ("Urengoy gas").

The city gate prices for the 5 selected Russian cities and for delivery at Uzhgorod are listed, by cities, in Table 25, along with netback prices from Uzhgorod. The netback prices start from an Uzhgorod price of $2.20/mcf, minus straight transmission charges which include capital and operational costs (including fuel costs) of gas transmission. Not included are gathering costs, field transmission charges, access fees, adjustments, or in-field fuel allowances. The straight transmission costs, including fuel costs, amount to 23.29 cents per mcf per 1000 miles, or 14.5 cents per 1000 kilometers. These are in effect the revenue requirements for straight transmission, not including charges for gas production, gathering, field transmission, and access fees.

Listed in Table 26 are revenue requirements for straight transmission for all U.S. pipeline companies for 1991. As that table shows, returns on equity instruments and debt service amount to approximately 21 percent of revenue requirements; depreciation and amortization is 18%; and overall taxes are 15%, for a total of 54% of what loosely could be called financial charges. The rest is operating and maintenance expenses; these amount to approximately 46% of revenue requirements. Given the free-market framework that is simulated by the regulatory approach to costing out natural gas transmission services, Table 26 gives a rough idea of the cost structure that would realistically be considered in setting the pipeline transmission rate which, in Russia, is the primary determinant of city gate

Table 25
Transmission Routes, Netback Prices, and Competitive City Gate Prices in Russia

	MILES	KM	WH Price $/MCF	CITY GATE PRICE $/MCF	$/MCM
MOSCOW:					
1 Urengoy - Punga - Ukhta - Gryazovets - Moscow	1744	2806	$0.178	$0.815	$28.76
2 Urengoy - Punga - Nizhnaya Tura - Perm - Nizhni Novgorod - Moscow	1860	2993	$0.178	$0.842	$29.72
3 Urengoy - Punga - Nizhnaya Tura - Perm - Yelets - Moscow	2160	3475	$0.178	$0.912	$32.18
4 Yamal - Ukhta - Gryazovets - Moscow	1594	2565	$0.655	$1.657	$58.50
5 Orenburg - Alexsandrov Gay - Petrovsk - Ryazan - Moscow	1000	1609	$0.286	$0.962	$33.95
6 Volga-Urals (Samara) - Petrovsk - Ryazan - Moscow	680	1094	$0.286	$0.883	$31.18
Netback: Uzhgorod - Yelets - Moscow	1070	1722		$1.951	$68.86
ST. PETERSBURG					
1 Urengoy - Punga - Ukhta - Gryazovets - St. Petersburg	1863	2998	$0.178	$0.843	$29.74
2 Shtokmanovskoye - St. Petersburg	1270	2043	$1.310	$2.381	$84.03
3 Yamal - Ukhta - Gryazovets - St. Petersburg	1713	2756	$0.655	$1.689	$59.61
Netback: Uzhgorod - Kobrin - Torzhok - St. Petersburg	1210	1947		$1.918	$67.71
NIZHNI NOVGOROD					
1 Urengoy - Punga - Niznnaya Tura - Perm - Nizhni Novgorod	1600	2574	$0.178	$0.781	$27.58
2 Orenburg - Alexsandrov Gay - Petrovsk - Nizhni Novgorod	705	1134	$0.286	$0.889	$31.40
3 Volga-Urals - Petrovsk - Nizhni Novgorod	540	869	$0.286	$0.849	$29.97
Netback: Uzhgorod - Yelets - Moscow - Nizhni Novgorod	1330	2140		$1.890	$66.72
CHELYABINSK					
1 Urengoy - Vingapur - Surgut - Chelyabinsk	1050	1689	$0.178	$0.653	$23.06
2 Vingapur - Surgut - Chelyabinsk	830	1335	$0.181	$0.809	$28.57
3 Urengoy - Punga - Nizhnaya Tura - Chelyabinsk	1150	1850	$0.178	$0.676	$23.88
Netback: Uzhgorod - Yelets - Perm - Nizhnaya Tura - Chelyabinsk	2180	3508		$1.692	$59.74
KRASNODAR					
1 North Caucasus - Rostov on Don - Krasnodar	500	805	$0.611	$1.178	$41.58
2 Orenburg - Alexsandrov Gay - Novopskov - Rostov on Don - Krasnodar	1210	1947	$0.286	$1.013	$35.76
3 Volga Urals - Alexsandrov Gay - Novopskov - Rostov on Don - Krasnod	1120	1802	$0.286	$0.991	$34.98
Netback: Uzhgorod - Yelets - Voronezh - Novopskov - Rostov on Don - Krasnoda	1500	2414		$1.851	$65.33
UZHGOROD					
1 Yamal - Ukhta - Gryazovets - Torzhok - Kobrin - Uzhgorod	2516	4048	$0.655	$1.902	$67.13
2 Shtokmanovskoye - St. Petersburg - Torzhok - Kobrin - Uzhgorod	2480	3990	$1.310	$2.738	$96.64
3 Urengoy - Punga - Nizhnaya Tura - Perm - Yelets - Uzhgorod	2770	4457	$0.178	$1.054	$37.20

NOTE: Netback Prices are based on straight transmission rates, including fuel costs. Not included are Gathering Costs, Field Transmission Charges, Access Fees, Adjustments, or in-Field Fuel Allowances.
Used Urengoy costs, since that is the predominant export gas.
Average Rate: ((105.38-40.86)/2770)*100, Table C-3 - Urengoy-Uzhgorod = 2.329 cents/100 miles

Table 26
Cost of Service: Composite U.S. Pipeline
Transmission Only - 1991 Thousand Dollars

ITEM	Expense Item	Subtotals	Percent of Revenue Requirement	Percent of O&M Expenses
Return				
Preferred Stock	15,890			
Common Stock	279,430			
Long-term Debt	191,021	**486,341**	**20.9%**	**45.5%**
Depreciation & Amortization	413,600	**413,600**	**17.8%**	**38.7%**
Income Tax				
Federal	152,135			
State	22,373			
Other Taxes	185,165	**359,673**	**15.4%**	**33.7%**
Operating & Maintenance Exp.				
Administrative & General	563,285			
Customer Expense	712			
Supervision & Engineering	72,195			
Compressor Stations				
Labor	124,679			
Nonlabor	53,433			
Compr. Station Maintenance & Repair	66,960			
Other Operating & Maintenance	187,252	**1,068,516**	**45.9%**	
REVENUE REQUIREMENT		**2,328,130**	**100.0%**	

Source: Natural Gas 1992 - Issues and Trends; Energy Information Administration; March 1993; DOE/EIA-0560(92); p. 60

prices (on the order of 80% for Moscow city gate prices for Urengoy gas). The total tax burden of the system is 34% of O&M costs, or 15.4% of revenue requirements. Equity and debt service (dividends and interest) amount to 45.5% of O&M costs, or 21% of revenue requirements. These are reasonable indications of the relative size of these cost components in a gas transmission system in a market economy.

The simplest tariff structure for transmission service would be a "transit fee" measured in $/MCM/1000 km and charged to all customers. In U.S. ratemaking terminology this would be called a volumetric, distance-based rate. This type of rate may be applied to all firm gas transportation service and to the transportation component of firm pipeline sales service. Because Gazprom's customers do not have daily contract quantities or monthly contract quantities, and because customers are unable to make accurate demand projections in the present unstable economic situation, it would not make sense to try to establish two-part rates (with demand and commodity charges) for firm transportation service (or the transportation component of firm sales service).

For interruptible transportation service or interruptible sales service, it would be possible for Gazprom to charge a lower transportation tariff than that charged to firm customers. Because pipeline capacity does not have to be built to serve interruptible load, interruptible gas transportation service could be priced as low as short-run marginal cost (SRMC), which includes pipeline fuel and loss plus the metering and accounting costs associated with handling the interruptible customers' accounts in addition to firm gas customer accounts.

If Gazprom needs to create an economic incentive for its customers to select interruptible service instead of firm service, then Gazprom can offer discounted transportation rates for interruptible service. We doubt that such "incentive rates" are necessary, however. It is reasonable to assume that the delivered cost of gas in Russia will always be competitive with the delivered cost of light fuel oil. At present, gas in Russia is also competitive with heavy fuel oil. Although it is possible to envision a time when Gazprom would have to discounted interruptible rates to encourage customers to use gas as a boiler fuel, it may not be in Russia's interest to encourage consumers to use gas as a boiler fuel. From an energy policy standpoint it is important to consider the effect of heavy fuel oil displacement on Russia's export earnings. The residual fuel oil that is displaced by gas is not necessarily an exportable commodity, although it is obvious that gas is an exportable commodity. Because cost of transporting residual fuel is higher than the cost of transporting gas, the residual fuel "netback" value from a Russian export terminal is likely to be lower than the natural gas netback value from an export point. If a gas surplus develops, the appropriate energy strategy may be to use gas as a transportation fuel, or create new export markets (in India or Pakistan, for example), rather than use gas to displace residual fuel oil.

We therefore recommend that interruptible gas rates be the same as firm gas rates, for a transitional period. This policy would simplify the rate design process in two ways: it would prevent the development of a political controversy over which customers should have access to cheaper (interruptible) gas supplies, and it would defer the need to measure firm demand precisely, i.e. to specify daily contract quantities or monthly contract quantities.

On the basis of our review of reserve data, we concluded in Chapter 2 that Urengoy and Yamburg have the reserves required to deliver large volumes of gas for many years, thereby deferring the need to conduct exploration in frontier areas. In any production scenario, however, gas supplies from other gas producing regions will provide an important component of total gas supply, even if no new fields are discovered. It will be necessary for the government of the Russian Federation to estabish a method of setting city gate prices when each oblast or gas consuming region is supplied by two or more gas producing regions. The status quo may be described as a system of average cost pricing combined with cross-subsidization of the household sector by industry and other consuming sectors.

The selection of the optimal method of pricing gas purchase costs at the city gate depends upon the competitive structure of the gas industry and the extent to which the unbundling of gas services is considered to be desirable. Among the policy options available to Russia are the following:

- Average cost pricing. Distribution companies buy gas from pipeline companies at prices reflecting the average cost of gas purchased by each pipeline company, with costs averaged over the calendar year. This average cost of gas is reflected in the rates charged to the customers of the distribution companies. For each distribution company, all firm customers purchase the same mix of gas supplies.

- Open access. Distribution companies, power plants, district heating plants, and large industrial customers are given a choice between purchasing gas from pipeline companies (at average cost, as above) or purchasing gas directly from producing associations and gas marketing companies. Those who purchase gas directly from producing associations and gas marketing companies have the freedom to pursue different gas purchasing strategies and pay different prices for gas.

- Marginal cost pricing. Distribution companies buy gas from pipeline companies according to tariff schedules in which incremental supplies of gas are priced at marginal cost. Each pipeline calculates its marginal cost of gas

for winter and for summer, for peak periods and for off-peak periods, on the basis of the least-cost mix of gas supplies consistent with the pipeline's gas purchase contracts. The gas pipeline tariffs (and the distribution company tariffs) are designed so that correct "price signals" are sent to consumers - so that the marginal price of gas sold to a particular consumer on a particular day is equal to the marginal cost to the pipeline company (or the distribution company) of supplying gas to that consumer on that day.[2] Wellhead prices are determined competitively and are typically not based on marginal cost.

Although the city gate price of Urengoy is lower than the city gate price of Yamal and Shtockmanovskoye gas supplies, the competitive advantage of Urengoy relative to other regions is no more than 15 cents per mcf. Therefore, if the supplies from these regions could be protected from competition with Urengoy, through contracts or protectionist legislation, the worst possible outcome (for the cities selected in this analysis) would be an increase in the city gate price of 15 cents per mcf. By international standards, this differential is small. It is our belief that average cost pricing at each city gate, at least for an initial transition period, would not create any serious distortions in the gas market unless Yamal and Shtockmanovskoye fields are used to supply the domestic market. These are the only truly "high-cost" gas supplies, by North American or Western standards; practically everything else is below $1 per mcf at the city gate.

It might be well at this point to note again that these and other cost "estimates" in this paper are not our estimates of costs currently incurred in the Russian natural gas industry. They are, instead, reasonable cost standards based on the experience of Western gas producers and pipelines operating either in a free-market environment (producers) or in a regime of regulated monopolies (pipelines). These costs, in short, approximate those that the Russian gas industry might have been expected to incur if it had evolved in a market environment. Alternatively, these costs might be regarded as interim targets until such time when Russia's gas industry has developed its own market-based standards.

[2] This approach to pricing has been applied in the electric utility industry but it is generally not implemented in the natural gas industry in North America or western Europe. Therefore it may be considered experimental or untested.

CHAPTER 5: ALTERNATIVE APPROACHES TO ESTIMATING TRANSMISSION COSTS

CHAPTER SUMMARY

In the preceding discussion we have estimated costs per mcf and costs per mcf per 1000 miles for selected U.S. natural gas pipeline companies, using publicly available information about the transportation tariffs charged by these companies. The results can be expressed as costs per mcm and costs per mcm per 1000 km and then used to estimate Gazprom's transmission costs. Our assumption is that the prices charged by these U.S. pipelines are an accurate measure of costs (including the cost of providing equity shareholders with a reasonable rate of return on their investment). Many of the largest metropolitan areas of the United States are served by two or more interstate pipelines which compete with each other. Although this competition is constrained by regulatory procedures and by the small number of competitors in most end use markets, there is enough competitive pressure to give the interstate pipelines an incentive to minimize costs and to charge prices that accurately reflect costs. In those U.S. gas transmission markets where there is little or no competition, regulatory agencies are responsible for ensuring that prices accurately reflect costs.

There are several other approaches to transmission cost estimation that can be used to estimate Gazprom's cost per mcm per 1000 km under different assumptions about the level of future investment and the way in which past capital investments are revalued and reflected in transmission charges. These approaches may be called "asset base" approaches because they all involve some sort of valuation of the asset base. In each of these approaches the cost per mcm per 1000 km is measured in dollars rather than rubles, because we expect the dollar to be a much more stable currency. We expect the inflation rate for the dollar[1] to be far lower than the inflation rate for the ruble. We have developed very rough estimates of Gazprom's transmission cost in dollars per mcm per 1000 km using the following approaches:

1. ***Transmission cost for an entirely new asset base.*** This is the simplest of the four approaches described here. The physical characteristics of the Gazprom

[1] To simplify the analysis we assume a constant inflation rate for the dollar, at 3 percent per year over the next 30 years. In the context of Russian domestic prices for natural gas, this assumption means that the purchasing power of the dollar in Russia will decline at 3 percent per year. We do not make an assumption about the inflation rate for the ruble. It should be noted that the dollar is in fact a currency in use in Russia.

system (e.g., the total compressor capacity and the total length of pipelines in each size category) are used to estimate the replacement cost of the entire system. Then three very simple but unrealistic assumptions are introduced:

(a) it would be possible to construct an entirely new system, without a mix of older and newer pipelines and compressor stations

(b) that the system does not require expansion or modification to meet changes in supply and demand

(c) capacity utilization does not change as the system grows older.

The cost per mcm per 1000 km is estimated simply by dividing the annual revenue requirement by total system throughput (measured in mcm-km). Gazprom's assets are revalued at 100 percent of their replacement cost, and a ten percent real rate of return on total capital is used to estimate revenue requirements. This approach might be called the "green-fields" approach because the pipeline grid is analyzed as if it were a single construction project involving entirely new construction. The resulting cost figures place an upper bound on the reasonable range of transmission charges for the next fifteen years. If a depreciated asset base is used to calculate transmission charges, these charges decline in real terms and in nominal terms as the system grows older, and after fifteen years the transmission charges under the "green-fields" approach no longer represent an upper bound.

2. ***Transmission cost for a depreciated asset base based on replacement cost.*** This approach is slightly more realistic than the "entirely new asset base" approach. The following assumptions are used:

(a) the value of the asset base this year can be estimated from the average age and the replacement cost of the system

(b) future capital investments will be maintained at the level required to preserve the dollar value of the asset base in real (inflation-adjusted) terms

(c) capacity utilization does not change as the system grows older.

Under this approach Gazprom's assets are revalued on the basis of replacement cost less depreciation, and a ten percent real rate of return on total capital is used to estimate transmission costs. Annual capital investment is maintained at the level that would be required if reconstruction and new construction costs were raised to the North American level. It is assumed that there are no savings in the dollar cost per km of pipe (or the dollar cost per kW of compressor capacity) as a result of the use of Russian labor and Russian-manufactured equipment. Reconstruction is either performed by western firms with western equipment or performed by Russian firms meeting the same quality specifications and charging the same prices for goods and services.

Under this approach, gas customers are exposed to a dramatic rate increase in 1993 as a result of asset revaluation and a major capital expenditure program consistent with international price levels. In reality this sort of shock treatment is unlikely to occur, and therefore the resulting transmission charges may be considered an upper bound of the reasonable range of charges. Compared with the "green-fields" approach, the depreciated asset base approach provides a more sophisticated way of defining the upper bound for transmission charges, and the figures are not as high.

3. ***Transmission cost for a depreciated asset base based on book value.*** This approach is based on the assumption that the value of the asset base in 1993 is understated, but not completely wiped out by inflation. A revaluation of assets occurs, but the dollar equivalent of the book value (after revaluation) is low by western standards. Because the system requires reconstruction and new construction, it is impossible to sustain deliverability if this asset base is held constant in real terms. The level of annual investment must be high enough to allow the asset base (measured in dollars) to gradually increase to a level consistent with western standards, e.g., a depreciated asset base based on replacement cost. The following assumptions are used:

   (a) the asset base in 1993 is revalued on the basis of the dollar equivalent of the book value of the asset base in 1990

   (b) future capital investments will have a high growth rate, so that the asset base in real (inflation-adjusted) terms will grow steadily (e.g., at 2 percent per year)

(c) capacity utilization does not change as the system grows older.

Under this approach the level of transmission charges is moderated by the relatively low value of the asset base (per km of pipe or per kW of compressor capacity) and the use of low-cost Russian labor and low-cost Russian equipment. This approach may be considered more realistic than the use of a depreciated asset base based on replacement cost.

4. ***Transmission cost based on the dollar value of investments made in 1993 and subsequent years.*** This approach is based on the assumption that the book value of Gazprom assets is practically wiped out by inflation, and the level of transmission charges is therefore dictated by the level of future capital expenditure and the level of system throughput. If an asset revaluation takes place, the new valuation is so low that the effect on tariffs is trivial by western standards. The following assumptions are used:

(a) the book value of the asset base in 1993 is close to zero, when expressed in dollars, and assets are not revalued

(b) future capital investments will be large enough to permit the asset base to rise gradually over a 30-year period

(c) domestic demand decreases in the 1990's and remains flat thereafter, resulting in lower capacity utilization.

To analyze this approach we have developed two scenarios, a "most likely" scenario and a "low cost" scenario. The low cost scenario provides a lower bound to the projection of future transmission charges in dollars per mcm per 1000 km, based on the assumption of lower Russian equipment and labor costs.

In Decree No. 88 issued on January 29, 1993, the city gate price of gas for industrial users was set at 3600 rubles/mcm, and in the February 1 press conference the production cost of gas (excluding capital investment) was reported to be 2600 rubles/mcm. Assuming a transmission margin of 1000 rubles/mcm and an exchange rate of 600 rubles per dollar, the transmission charge was only $1.67/mcm. If we also assume that the average distance of gas transmission was 2590 km (the 1990 level), the transmission charge could be expressed as 64 cents per mcm per 1000 km. In our analysis of the four approaches discussed above, the estimate of the lower bound in 1993 turned out to be $2.62 per mcm per 1000 km. The

February 1993 level of transmission charges is so low that it does not appear to be viable unless domestic industrial customers are subsidized by export customers or by the Russian government. The February 1993 transmission margin for household customers is even lower than the margin for industrial customers, indicating the need for an even greater subsidy.

5.1 TRANSMISSION COST FOR AN ENTIRELY NEW ASSET BASE

To estimate the value of an entirely new asset base we used data published by Gazprom on the physical characteristics of the system at the end of 1990. Although it might be preferable to obtain more recent data to estimate replacement costs, the advantage of 1990 data is that financial as well as physical data are available and are meaningful (or at least, more meaningful than financial data for 1991 or 1992).

In estimating the replacement cost of the Gazprom system on the basis of 1990 data, we have not attempted to estimate costs for the Russian portion of the system as opposed to the whole of Gazprom. Although we have obtained disaggregated data on some indicators (for example, gas consumption), most of the data series used in our analysis are published for the entire Gazprom system or for Gazprom subsidiaries, not for the various republics. In 1990 Russia accounted for 78.6 percent of gas production and 63.9 percent of gas consumption in the Soviet Union.[2]

The most accurate method of estimating the replacement cost of the Gazprom system would be to develop engineering cost estimates for every major pipeline based on a detailed description of the route, the terrain, the compression requirements, and so forth. A much simpler approach is to estimate the construction cost per mile on the basis of the pattern of pipeline construction cost per mile in other countries. For the United States, cost information is submitted to regulatory authorities (the Federal Energy Regulatory Commission) and is available by year and by pipeline diameter. For the rest of the world cost estimates are available from trade journals, which provide a less reliable source of data. We decided to develop a methodology based on information for the U.S., after comparing U.S. construction cost with construction cost in other countries.

[2] Gas production data are from PlanEcon, Inc., PlanEcon Energy Report II,1 (April 1992), p. 48. Gas consumption data are from Vniiegazprom, *Gas Industry of the USSR 1990*, p. 143.

In a sample of 122 gas pipeline construction projects that are under construction, planned, or completed recently (in 1992 or 1993), we found that 84 percent of the projects have costs (including compressor costs) between 0.5 million dollars per mile and 5 million dollars per mile (see Table 27), with a weak correlation between pipeline diameter and cost per mile. There is a tendency for offshore projects to have higher costs per mile than onshore projects, but the data do not suggest that pipelines in northern latitudes (e.g. Canada and Norway) are more expensive than pipelines in southern latitudes (e.g. the Iran-Pakistan project or the TransMediterranean project). Canadian project costs are mostly between 1 and 2 million dollars per mile, but the Foothills pipeline, which would bring Arctic gas into the system, is projected to cost $4.2 million per mile. The high cost for the Foothills pipeline may be explained not only by the Arctic conditions but by the fact that this is the cost for a completely new pipeline rather than an incremental cost for modification of an existing pipeline. The Foothills pipeline would be roughly comparable to a pipeline from Yamal to Ukhta. The $3 billion cost estimate for the Shtockmanovskoye pipeline (375 miles undersea from Shtockmanovskoye to Murmansk, and 650 miles overland from Murmansk to St. Petersburg)[3] represents a cost of $2.8 million per mile. Historical costs of six 56-inch lines built in 1981-1985 (including compressor costs) averaged about 1.1 million rubles per mile, which would be $2.6 million per mile at the official 1986 exchange rate (see Table 28).

For the United States, average costs (excluding compressor costs) for large-diameter pipelines built in 1984-1992 range from 0.5 million dollars per mile for 20-inch pipe to 1.1 million dollars per mile for 36-inch pipe (see Table 29). Given the amount of compressor capacity in the Gazprom system, we have estimated that the replacement cost of compressor stations is 50 percent of the replacement cost of the pipelines (see the discussion below, and Table 32).

There are no 56-inch pipelines in the United States, but on the basis of the cost trends for smaller diameter pipelines we estimate that the cost of a 56-inch line would be about $1.75 million per mile, excluding compression, or $2.6 million per mile, including compression. This is higher than the cost per mile of recent TransCanada system expansion projects (shown in Table 27) but lower than the cost per mile for the Foothills pipeline. The figure of $2.6 million per mile is also consistent with Soviet costs when an official exchange rate is used for ruble-dollar conversion. Our assessment is that the U.S. data are roughly consistent with the data for other countries.

[3] "International Pipeline Forecast," *Pipelines & Utilities Construction*, September 1992, p. 27.

Because Alberta and British Columbia have gas pipelines in terrain and climate conditions that bear similarities with Russian conditions, the ideal country to use as a point of reference would probably be Canada rather than the United States. Canadian gas pipeline construction involves a smaller annual mileage, larger pipeline diameters, and higher cost per mile than U.S. gas pipeline construction. In 1992, Canadian gas transmission pipeline construction involved 817 miles at a cost of $1.55 billion, or $1.90 million (Canadian dollars) per mile, while U.S. gas transmission pipeline construction involved 4,098 miles at $3.78 billion, or $0.92 million (U.S. dollars) per mile.[4] A large portion of the difference in cost per mile must be explained by the larger pipeline diameters that are typical of Canadian transmission (see table B-10), as well as the lower value of the Canadian dollar. In the United States, there is very little 42-inch pipe construction but 36-inch pipe construction is approximately twice the cost per mile of 20-inch pipe construction (see Table 29). We have not been able to measure the effect of terrain and climate on the differences between U.S. and Canadian construction cost per mile, but a very rough estimate would be a 15 percent premium for Canadian conditions. The concept of replacement cost for the Gazprom system is a theoretical concept, however; a 15 percent cost reduction could be expected from the mass production possible in Russian construction and from the absence of right-of-way costs. To keep the analysis simple, we have estimated the replacement cost of the Gazprom system on the basis of trends in U.S. gas pipeline construction cost (excluding right-of-way costs) and compressor costs.

Our approach involved the following steps:

1. Analyze data on U.S. pipeline construction costs, to find a statistical relationship between cost per mile and pipeline diameter. Develop a linear equation for cost per mile as a function of pipe diameter.

2. Obtain data on the average construction cost per horsepower of U.S. gas pipeline compressor capacity.

3. Obtain data on the total length of pipelines owned by Gazprom in 1990, for 56-inch pipe, 48-inch pipe, and so forth. Estimate the replacement cost of each category using the linear equation for cost per mile (from Step 1).

[4] Robert Carpenter, "Pipeline Construction Forecast," *Pipeline & Utilities Construction*, January 1993, p. 24. At mid-July 1993 a Canadian dollar was equivalent to US $0.78.

4. Obtain data on the total compressor capacity of the Gazprom system in 1990 and estimate the replacement cost of this capacity, using U.S. cost data (from Step 2). Assume that the capital cost of the transmission system is simply the sum of the pipeline cost plus compressor cost.[5]

5. Using assumptions about the cost of capital, operation and maintenance cost, etc., compute the annual revenue requirement (excluding the value of pipeline fuel and loss[6]) associated with the capital cost derived in Step 4. Obtain data on the annual volume of gas transported in 1990 and average distance of gas transported in 1990, and calculate the cost per mcm per 1000 km.

Data on U.S. pipeline construction costs are publicly available in regulatory proceedings. In the United States, interstate natural gas pipelines are required to file an application for FERC approval before starting a pipeline construction project. The application must include a cost estimate for the project. Data from FERC construction-permit applications (combined with data on actual costs of completed pipeline construction projects) is summarized in tables published annually in the trade press. These tables show the average cost per mile for construction project applications filed in the twelve-month period ending June 30, 1992 and the average for applications filed in each of the preceding 12-month periods. We computed the average cost per mile, excluding right-of-way costs, and adjusted the figures for inflation (using the implicit price deflator for GDP). Next, we computed the simple average of the inflation-adjusted cost per mile figures for 1984 through 1992 (see Table 29).

A linear relationship between pipeline diameter and cost per mile can be seen when the data are shown graphically (see Figure 3). The regression line shown in Figure 3 was used to estimate the replacement cost of Gazprom pipelines, which have diameters that do not

[5] For major pipeline companies in the United States, the costs of transmission mains and compressor station equipment represented 90.3 percent of transmission plant in 1991. The other components (in order of importance, i.e., cost) were structures and improvements, measuring and regulating equipment, right-of-way, communication equipment, other transmission equipment, and land and land rights. See U.S. Department of Energy, *Statistics of Interstate Natural Gas Pipeline Companies 1991*, DOE/EIA-0145(91), p. 167.

[6] For the purposes of this discussion, "transmission charges" do not include pipeline fuel and loss. The value of pipeline fuel and losses can be measured by computing the volume of gas used as fuel or lost (based on a percentage of the volume of gas delivered to the transmission system), and multiplying this figure by the average value of gas at the point of receipt by the transmission system.

match the standard U.S. pipeline diameters (see Table 30). The replacement cost of Gazprom pipelines is therefore about $150 billion, excluding compressors (see Table 30).

The annual delivery capacity of a standard 1420 mm Soviet pipeline (approximately 56-inch diameter) is reported to be 28.1 Bcm.[7] This figure was used to estimate the capacity of smaller pipelines, based on the square of the diameter (see Table 30). The cost per mcm per 1000 km will depend on the annual capacity utilization of the pipeline. We assumed a relatively high utilization of 80 percent, despite the seasonal nature of gas demand for space heating, because we assume that a large volume of gas is consumed in the summer by electric power stations and industrial boilers that consume heavy fuel oil in the winter.[8]

Because pipeline capacity varies with the square of the diameter but cost per mile varies linearly with diameter (see Figure 3), the cost per mcm per 1000 km is lower for 1420 mm pipe than for 529 mm pipe. To illustrate this relationship we computed the annual revenue requirement that would be needed to repay the capital cost per km of a pipeline if this revenue requirement were levelized (in nominal dollars) over 30 years. The results are shown in the right-hand column of Table 30. If U.S. construction costs are applied to Gazprom pipeline diameters, a 1420 mm pipeline can transport gas for $10.95/mcm/1000 km and a 529 mm pipeline can transport gas for $24.19/mcm/1000 km. These figures include an allowance for compressor costs and operation and maintenance expense.

The average age of the Gazprom pipeline system may be estimated from data on the net change in the total length of trunklines over the 1940-1990 period (see Table 31). We estimate an average age of 14.8 years. If this is the age of the Gazprom pipeline system, a revaluation of assets should result in a book value of less than half the cost of a "green-field" system. With straight-line depreciation over 30 years, the asset value of a 15-year-old system would be 50 percent of the original cost, less the erosion of book value attributable to inflation. Because the larger-diameter pipelines are generally newer than the

[7] Nameplate throughput of a 56-inch pipeline is 32.0 Bcm/year at the head station and 28.1 Bcm/year at the end of a 3,000-km pipeline route. In our cost analysis we estimate a transmission cost per Bcm of gas delivered to the customer, and add a percentage allowance for fuel and loss.

[8] Among U.S. pipelines there is a great deal of variation in annual capacity utilization. In 1991 the average daily flow in pipelines delivering gas to the western region (California, Oregon, Washington, Arizona, Nevada, Idaho) was 85 percent of pipeline capacity available for such deliveries. For other regions, annual capacity utilization ranged from 33 percent to 71 percent. See U.S. Department of Energy, *Natural Gas 1992: Issues and Trends*, DOE/EIA-0560(92), p. 86.

smaller-diameter pipelines, however, the average age of the system is probably somewhat less than 15 years. In other words, the weighted average age would probably be lower if Table 31 were based on pipeline capacity instead of pipeline length.

The average construction cost of compressors for which a FERC construction permit application was filed in the twelve-month period ending June 30, 1992 was $1202 per horsepower.[9] The compressor capacity of the Gazprom system at the end of 1990 was 46,579,000 kW.[10] These figures suggest that the replacement cost of the compressor capacity is very large, approximately $75 billion, and therefore the cost of the transmission system is around $225 billion (see Table 32). If this cost is recovered through levelized capital charges (including interest and principal, as in a standard 30-year mortgage), the cost of transmission in 1993 is $18.86 per mcm per 1000 km. This cost rises very gradually in nominal dollars (shown in Table 33) but declines in real terms (assuming that the sum of fixed and variable operation and maintenance cost is constant in real terms, at 10 cents per mcf per 1000 miles).

If the capital cost of the "green-field" system is depreciated over 30 years on a straight-line basis, the transmission cost per mcm per 1000 km (in current dollars) is higher in the first seven years, compared with cost recovery through levelized capital charges. Over a fifteen-year period the asset base declines from $225 billion to $112.5 billion (see Table 33). This table is based on the simplifying assumption that no new investment is made; in reality, the average age of the system does not decline as rapidly as the age of the original pipeline because the system is subject to capital improvements such as compressor station rehabilitation.[11] If we assume that the Gazprom system has an average age of 15 years, its replacement cost less depreciation may be valued at $112.5 billion. This is the point of departure for the second approach to transmission cost estimation.

Just as it is unrealistic to expect an entire pipeline system to be constructed on a "green-field" basis, it is unrealistic to assume that no new investment would be made during the 30-year economic life of the system. The example illustrated in Table 33 would require a crash program to completely reconstruct the system, starting in 2023. The "green-field" approach may be viable for a pipeline segment or a compressor station, but it should not be

[9] See *Oil & Gas Journal*, November 23, 1992, pp. 52, 55.

[10] Vniiegazprom, *Gas Industry of the USSR 1990*, p. 10.

[11] The purpose of this exercise is to show the relationship between tariffs and average age of the system, not to develop a projection of the average age of the Gazprom system as it is rehabilitated and expanded.

applied to an entire pipeline system. A depreciated asset base is a more reasonable approach to pipeline system valuation.

In the United States, the asset base of natural gas pipeline companies is measured on the basis of original cost less depreciation, rather than replacement cost less depreciation. The original cost of transmission plant owned by major U.S. pipeline companies at the end of 1991 was $37.7 billion.[12] This figure is substantially below our estimate of the replacement cost of the Gazprom system, for several reasons:

1. Because the purchasing power of the dollar has been eroded by inflation, the original cost of the U.S. pipeline system (in current dollars) is much lower than the replacement cost of the U.S. pipeline system (in today's dollars).

2. Because the U.S. pipeline system is generally older than the Gazprom system, and because the value of the dollar has declined over the last 30 years, the original cost asset base for U.S. pipelines has been substantially eroded by inflation. Between 1970 and 1990, U.S. transmission pipeline mileage increased only 24 percent while Soviet gas transmission mileage increased 226 percent. U.S. gas production reached a peak in 1973, but Soviet gas production increased by 245 percent over the 1973-1990 period.[13] These statistics suggest that the average age of the U.S. transmission grid is greater than the average age of the Soviet grid.

3. The Gazprom system moves a larger quantity of gas. The volume of gas received by Gazprom for transmission in 1990 was 767.3 Bcm, while the volume of gas delivered to U.S. consumers in 1990 was 476.5 Bcm (16.819 Tcf).[14] One indication that larger volumes are moved over long distances in the Gazprom system is the fact that 56-inch, 48-inch, and 40-inch pipelines account for 55 percent of Gazprom's trunk line mileage (see Table 30).

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[12] U.S. Department of Energy, *Statistics of Interstate Natural Gas Pipeline Companies 1991*, DOE/EIA-0145(91), p. 167.

[13] American Gas Association, *Gas Facts: 1990 Data*, p. 26; *Gas Industry of the USSR 1990*, p. 16.

[14] *Gas Industry of the USSR 1990*, p. 16; U.S. Department of Energy, *Natural Gas Annual 1991*, DOE/EIA-0131(91), p. 4.

4. Because the major gas producing fields in the Gazprom system are in western Siberia, far from the major population centers of the former Soviet Union, a cubic meter of gas in the Gazprom system is transported over a larger distance, on average, than a cubic meter of gas in the U.S. pipeline system.[15] The average distance of gas transmission by Gazprom in 1990 was 2,590 km (1,608 miles); we estimate that the U.S. average is in the neighborhood of 400 miles, or one-fourth the Gazprom figure.

5. The compressor capacity of the Gazprom system is much larger than that of the U.S. transmission system. In 1990 Gazprom had 46,579,000 kW of capacity while the U.S. transmission system had 10,249,000 kW of compressor capacity (13,738,000 horsepower).[16]

For these reasons, the original cost of the transmission plant in the asset base of U.S. pipelines companies is smaller than the replacement cost of the asset base of Gazprom. Moreover, our estimates of replacement cost do not contain an adjustment to reflect the mountainous terrain or harsh climatic conditions associated with construction of Gazprom's pipeline grid. These factors might raise the average replacement cost per mile above the level prevailing in the United States.

5.2 TRANSMISSION COST FOR A DEPRECIATED ASSET BASE BASED ON REPLACEMENT COST

Under this approach, the existing portion of the asset base is valued at $112.5 billion and is depreciated over 15 years (assuming that it is 15 years old and has an economic life of 30 years). New investment is depreciated over 30 years and is sustained at the level needed to hold the value of the asset base constant in real terms (i.e. to maintain 3 percent growth, to offset a 3 percent annual decline in the purchasing power of the dollar). The transmission charge therefore increases at about 3.5 percent per year (except in 2008, the year in which depreciation charges for the January 1, 1993 assets are discontinued). The nominal growth

[15] A rough indication of gas transportation distances is shown in U.S. Department of Energy, *Natural Gas Annual 1991*, DOE/EIA-0131(91), p. 21, Figure 5. If the United States is divided into six regions, two of them (the Southwest and Central regions) have enough gas production to meet 100 percent of their needs; the other four depended on imports from other regions and from Canada to meet 61 percent of their needs in January 1992, the peak month of the 1991-92 winter. See U.S. Department of Energy, *Natural Gas 1992: Issues and Trends*, DOE/EIA-0560(92), p. 87.

[16] *Gas Industry of the USSR 1990*, p. 10; American Gas Association, *Gas Facts: 1990 Data*, p. 65.

rate of 3.5 percent per year indicates a real growth rate of 0.5 percent per year. The trends in asset value, annual investment, and transmission cost are shown in Table 34.

With a depreciated asset base based on replacement cost, transmission charges in 1993 are $14.48 per mcm per 1000 km. This might be considered a "world price" for transmission on the Gazprom system, based on its physical characteristics (the length of the pipelines, the diameters of the pipelines, and the amount of compressor capacity). If Gazprom were able to make a complete transition to a market economy, Gazprom would not only charge a "world price" for transmission service; Gazprom would also provide transmission services with the same degree of reliability, the same attention to safety and environmental standards, and the same quality of service offered by North American and European pipeline companies.

In the scenario illustrated in Table 34, annual capital requirements start at about $11 billion and increase at over 4 percent annually for the first 15 years. This projection provides a rough estimate of the level of investment that would be required for Gazprom to maintain the value of the asset base in real terms, assuming a very rapid transition to international cost levels and international standards for pipeline safety and reliability. Annual investment of $11 billion per year is roughly twice the level of investment in the U.S. transmission system over the 1991-1993 period. Gazprom also has large capital requirements associated with natural gas production, gathering and processing.

Given the need for reconstruction and maintenance of pipelines and compressors in Gazprom's transmission system, it may be argued that the effective "age" of the assets is more than 15 years, when North American pipelines are used as a standard for comparison. The figures in Table 34 are sensitive to the assumption made regarding the average age of the transmission system assets at January 1, 1993. If the physical assets are in very poor condition, they might be considered equivalent to 20-year old or 25-year old assets by western standards even if they are only 15 years old. When the assumed age of the assets is increased, the value of the asset base declines and therefore the transmission charge is lowered, given a policy of maintaining the real (inflation-adjusted) asset value at the January 1, 1993 level. The less valuable asset base will yield a relatively low requirement for annual investment (compared with the figures in Table 34) but if the asset base is not permitted to grow, the reliability and safety of gas supply will be lower than in a scenario where the value of the asset base rises to a "normal" level consistent with international standards. As the assumed age of the assets is increased, the need for a reconstruction program also increases and the investment criterion behind Table 34 - maintenance of the real asset value at the January 1, 1993 level - becomes unacceptable and unrealistic. An

alternative approach is described below, in the discussion of a depreciated asset base based on book value.

The relationship between transmission cost estimates and the average age of the asset base is illustrated in Table 35. In one extreme case, the system is entirely new and the transmission cost is $22.60 per mcm per 1000 km (as in Table 33); this case is not technically achievable. In the other extreme case, the assets are worthless (i.e., 30 years old, assuming an economic life of 30 years) and the first year transmission charge consists only of operation and maintenance costs (based on international standards), which we estimate to be $2.19 per mcm per 1000 km.

5.3 TRANSMISSION COST FOR A DEPRECIATED ASSET BASE BASED ON BOOK VALUE

If the Gazprom system has a replacement cost of $225 billion, an economic life of 30 years, and an age of 15 years, its asset value based on replacement cost less depreciation is $112.5 billion. This figure is close to the book value of Gazprom transmission system assets when the official exchange rate (effective September 5, 1990) is used to express the January 1, 1991 ruble value in 1990 dollars. This book value is $118.9 billion (see Table B-36). When this valuation is used, the results are very similar to those in Table 34.

It is well known, however, that the official Soviet exchange rate is not an accurate measure of the purchasing power of the ruble. If the purchasing power of the ruble in 1990 was somewhere between 1.2 rubles per dollar and 1.8 rubles per dollar, the value of Gazprom's assets at year-end may range from $37.9 billion to $56.9 billion (see Table 36). At the commercial exchange rate the assets were worth $40.2 billion, which is about one-third of replacement cost less depreciation.

Given the remarkable speed with which Soviet pipeline construction crews were able to install long-distance pipelines during the 1980's, it would not be surprising to find that the quality of the construction was below North American standards. Therefore the dollar valuation per kilometer of newly installed pipelines in the Soviet Union may be lower than the dollar valuation per kilometer of newly installed pipelines in North America. It may be argued that assets existing at January 1, 1993 should be depreciated over 15 years (i.e., the remainder of their economic life), but should be replaced with assets that raise the standards of quality, safety and reliability of the system. Therefore the use of a relatively low dollar figure to measure the value of the existing asset base should be accompanied by

a projection of a long-term increase in the value of the asset base, in real terms, to bring it up to international standards.

To illustrate this point we assume that a 5 percent annual growth rate in the asset base is needed, if January 1, 1993 assets are valued at $40.2 billion (based on the value of January 1, 1991 assets at the commercial exchange rate[17]). Transmission costs in 1993 are only $6.58 per mcm per 1000 km, under this scenario, but by 2023 they are nearly $32 per mcm per 1000 km (see Table 37), which is about the same level as transmission charges for a depreciated asset base based on replacement cost (Table 34). Over a 30-year period the value of the asset base rises to a level consistent with international standards.

Given reports that the Gazprom system suffers from pipeline corrosion, pipeline accidents, inadequate protection of pipelines at river crossings, and poor performance of compressor equipment, a valuation of $40 billion may be considered more realistic than $112.5 billion. However, the estimate of annual investment requirements ($4.7 billion in 1993) could be revised upward to meet the following objectives:

- to improve the safety and reliability of the pipeline system so that the real annual growth rate of the asset base exceeds 2 percent
- to extend the transmission system into Arctic regions with higher pipeline construction costs per mile
- to obtain supplies from more remote areas; to increase the average distance over which gas is transported
- to increase the volume of gas delivered.

Given Russia's high reserve/production ratio for natural gas, it should not be necessary to extend the transmission system into Arctic regions or obtain supplies from more remote areas. Given the potential decline in gas demand in the CIS due to the decline in industrial production and likely increases in gas prices, it should not be necessary to increase the volume of gas delivered.

[17] To be precise, some adjustment could be made to reflect the changes in the dollar value per kilometer of pipe or per kW of compressor capacity between January 1, 1991 and January 1, 1993. In improving the accuracy of the results, such an adjustment would probably not be worth the effort involved.

5.4 TRANSMISSION COST BASED ON THE DOLLAR VALUE OF INVESTMENTS MADE IN 1993 AND SUBSEQUENT YEARS

Given the very high inflation that has occurred in 1991-93 in Russia, the book value of Gazprom investment will be far below replacement cost (net of depreciation) unless some sort of asset revaluation is implemented to offset inflation. One of the policy options available to the Russian government is to allow the book value of Gazprom assets to be practically wiped out by inflation. In such a scenario the level of transmission charges will depend on the dollar valuation of investments made in 1993 and subsequent years, but will be hardly affected by the valuation of investments made in 1992 and earlier years. The level of annual investment would be unrelated to the book value of assets, but should be roughly comparable to the dollar equivalent of the level of annual investment made by Gazprom in 1990.

Capital investment in trunk lines in 1990 was reported to be 2.773 billion rubles, which would be equivalent to $4.83 billion at the official exchange rate effective September 5, 1990 (see Table 36). Given the size of the Gazprom system, we consider an investment requirement of about $3 billion to be the minimum needed to fund reconstruction programs, pay for deferred maintenance, and modify the system as needed to meet changes in the regional pattern of supply and demand. In the United States, which moves a smaller quantity of gas over a shorter average distance from producing field (or import point) to city gate, gas transmission construction expenditures were $2.9 billion in 1990 and about $5 billion in 1991.[18] For the analysis of transmission cost based on future investments we selected two scenarios:

- a Most Likely Scenario involving $6 billion (in constant 1993 dollars) of annual investment in addition to asset base depreciation
- a Low Cost Scenario involving $3 billion (in constant 1993 dollars) of annual investment in addition to asset base depreciation.

In these scenarios we also used different assumptions about the percentage decline in gas consumption in the former Soviet Union in the 1990's. These assumptions influenced our projections of the total volume of gas transported by Gazprom.

[18] American Gas Association, *Gas Facts: 1990 Data*, p. 183.

One of the weaknesses of the projections in Tables 33, 34, and 37 is that changes in the amount of gas transported by Gazprom were not considered. It is highly likely that structural changes in the economies of the republics of the former Soviet Union and increases in real prices of natural gas will result in a decline in gas consumption below the 1990 level, even if there is a recovery in real GDP and real incomes. Lower aggregate demand in the former Soviet Union will reduce transmission capacity utilization and therefore raise transmission costs per mcm per 1000 km.

Trends in aggregate gas demand (and supply) in the former Soviet Union are closely related to trends in the volume of gas transported by Gazprom. We estimate the portion of Soviet gas demand met by Gazprom to be 583.6 Bcm (see Table 38), or 92.3 percent of total domestic use. This estimate is based on the assumption that all gas exports from the Soviet Union in 1990 were transported by Gazprom. The volume of gas received for transmission by Gazprom in 1990 was 767.3 Bcm, or 93.8 percent of gas supply in the Soviet Union (see Table 38).

Russia, Turkmenistan and Uzbekistan were net exporters in 1990, and the other twelve republics were net importers.[19] Thus a portion of the gas transported in Russia is delivered to other republics and/or received from other republics (see Tables 39 and 40). In theory the costs of the Gazprom system could be allocated so that transmission charges for delivery of gas to Russian distribution systems and Russian enterprises connected to the high-pressure network would be based solely on the cost of building and operating gas transmission capacity required to serve these customers. From a political standpoint, however, the Russian Federation probably has an incentive to use export markets (particularly exports to western Europe) to subsidize domestic markets. Because the potential for cross-subsidization exists, a decline in Russian gas demand does not necessarily lead to an increase in gas prices to Russian customers of Gazprom.
In our analysis we have not attempted to allocate Gazprom costs among republics. To show the effect of a decline in demand we have used different assumptions about the volume of gas transported by Gazprom on the systemwide average cost per mcm per 1000 km. We assume that the relationship between demand and transmission costs in the overall system is a good indication of the relationship between Russian demand and the transmission costs allocated to Russian consumers.

In the Most Likely scenario (Table 41), the cost per mcm per 1000 km begins at a very low level in 1993 but grows rapidly, and the asset base grows rapidly. In 2021 the asset base

[19] PlanEcon Inc., *PlanEcon Energy Report II,1* (April 1992), p. 48.

(in constant dollars) reaches the level of replacement cost less depreciation that was estimated earlier for the 1990 asset base (Table 34).

In the Low Cost scenario (Table 40) the cost per mcm per 1000 km begins at exactly the same level in 1993 but does not grow as rapidly. By 2021 the asset base is only half as large as the asset base in the Most Likely Scenario (i.e., replacement cost of the 1990 asset base less depreciation). The Low Cost scenario yields a less expensive but less reliable and less safe transmission system.

5.5 COMPARISON AMONG ASSET BASE APPROACHES

The preceding analysis has focused on average costs for the Gazprom system as a whole. Some countries may have costs per mcm per 1000 km that are above the Gazprom system average, while other countries may have below-average costs. Given the limitations of the data, we must assume that Russian costs are equal to system average costs.

The objective of our analysis is to estimate the true economic costs of gas transmission, and suggest a price path that would permit a transition from current price levels to true economic costs. In our view the most realistic approach, among the asset-based alternatives, is a depreciated asset base based on a book value of about $40 billion, with a projection of a decline in throughput associated with a drop in demand (see Table 41). In this approach, the asset base and annual capital investment shown in Table 35 are spread over a smaller transportation volume (in 1998-2023), due to a drop in domestic gas demand as shown in Table 41. The result is that the cost per mcm per 1000 km is higher in Table 41 than in Table 37.

In the discussion of asset-based approaches to transmission cost estimation we have used data on the Gazprom system as it existed in 1990. Our primary interest is in the Russian portion of this system, however. The demand projection in Table 41 may be interpreted as a drop in the total volume of gas transported through Russia. This volume includes three components: gas transported for delivery to Russian consumers, gas transported for export to other countries of the former Soviet Union, and gas transported for export to the rest of Europe. Given the Russian government's pricing policy for gas exports, the largest percentage decline is likely to develop in gas transported for export to other countries of the former Soviet Union.

The transmission charges in Table 41 exclude an allowance for pipeline fuel and losses, and are roughly comparable to the Tenneco and Northern Border prices shown in Table 15.

These figures may be interpreted as evidence that the cost of transmission on Gazprom's system would be lower than the cost of transmission on Tenneco and Northern Border, if Gazprom's assets were revalued at $40 billion and throughput remained at the 1990 level. Given the larger diameter of Gazprom pipelines, one would expect Gazprom to have a cost advantage when the system is fully utilized. With a 25 percent reduction in throughput, Gazprom's cost advantage is eliminated.

These results may be interpreted as evidence that the revaluation of Gazprom assets to $40 billion (as opposed to $10 billion or $120 billion) will bring transmission charges up to a U.S. level. The level of transmission charges by U.S. pipelines is somewhat arbitrary, because it is based upon the original (book) cost of assets with no adjustment for inflation. If a policy of bringing transmission charges in Russia up to "international" levels is desired, there is a relatively simple solution - to revalue assets at $40 billion and apply a 2 percent real growth rate to the asset base. Of course, an immediate jump to this price level would create a shock to the Russian economy that would probably not be acceptable. The issue of determining the appropriate path of gas prices is outside the scope of this chapter.

If transmission tariffs were limited to volumetric rates and were calculated on the basis of economic costs, customer groups with a high load factor should enjoy lower tariffs than customer groups with a low load factor. However, the preceding analysis does not distinguish customer groups according to load factor and therefore all customer classes would be charged the same tariff. Although this tariff structure would be unacceptable in North America, due to its simplicity it may be a reasonable structure for Russia, given the enormous disparities among prices charged for gas resold to households, gas resold to industry, and gas sold to foreigners. A uniform volumetric and distance-based transportation tariff for all customer classes would create much less cross-subsidization than the present pricing system. The present system has three forms of cross-subsidization:

- The transportation of gas for domestic consumption is subsidized by the transportation of gas for export. This subsidy is difficult to measure because the majority of gas export contracts do not contain separate charges for gas production, transmission, and storage. The fact that export prices are higher than domestic city gate prices demonstrates that cross-subsidization exists, however.

- The transportation of gas for residential consumers is subsidized by the transportation of gas for industrial consumers, district heating, power plants, and commercial users.

- Because gas prices are the same throughout Russia, the transportation of gas over larger distances (from producing field to city gate) is subsidized by the transportation of gas over shorter distances. Cities and oblasts in or near producing areas provide a subsidy to cities and *oblasts* in the rest of the country.

A significant step toward rational pricing would be accomplished if these forms of cross-subsidization were eliminated.

Table 27
Gas Pipeline Construction Costs Outside the United States

Country	Company	Pipeline length, miles	Pipeline diameter, inches	Estimated cost, $million	Estimated cost per mile, $million	Offshore	Data source	
Bolivia to Brazil	Petrobras	1900	NA	296	0.16		PLInd	Sept92
Russia to Ukraine	Ukrgazprom, Ukrnaftogazbuf	70	NA	15	0.21		P&UC	Jan93
Spain	Repsol Petroleo	218	22	50	0.23		P&UC	Jan93
Brazil	Petrobas	1175	NA	400	0.34		P&UC	Jan93
Argentina to Peru	governments of Peru and Argentina	684	NA	260	0.38		PLInd	Jan92
Argentina to Brazil	Gas del Estado	774	30	300	0.39		P&UC	Jan93
Peru	PETROPERU	400	20,14	160	0.40		PLInd	Jan92
India	Gas Authority of India Ltd.	7500	large	3000	0.40		P&UC	Jan93
Colombia	Promigas	621	24	250	0.40		P&UC	Jan93
Turkey	Botas	520	NA	225	0.43		P&UC	Jan93
Spain	Empresa Nacional de Gas	112	20,26	50	0.45		P&UC	Jan93
Venezuela	Corpoven	209	NA	100	0.48		P&UC	Jan93
United Kingdom	Scottish Area Gas Evacuation System	150	24	75	0.50	yes	P&UC	Jan93
Tunisia	?	149	NA	75	0.50		P&UC	Jan93
Abu Dhabi	Abu Dhabi National Oil Co.	93	28	50	0.54		P&UC	Jan93
Malaysia to Indonesia	TransAsian Pipeline Co.	5000	large	3000	0.60	yes	P&UC	Jan93
Hungary	State Oil and Gas Trust	200	28,32	125	0.63		P&UC	Jan93
United Kingdom	Shell U.K. Exploration and Production	118	24	75	0.64	yes	P&UC	Jan93
Czechoslovakia to Germany	Czech government	1100	NA	700	0.64		PLInd	June92
Venezuela to Colombia	Carbocaol	310	24	200	0.65		P&UC	Jan93
United Kingdom	Total Oil Marine	110	22	75	0.68	yes	P&UC	Jan93
Belgium	Distrigaz	60	20	42	0.70	yes	PLInd	June92
Qatar to Dubai	Dubai Natural Gas	200	large	150	0.75		P&UC	Jan93
Bolivia to Brazil	Yacimiento Petroliferos	332	24	250	0.75		P&UC	Jan93
Mexico	TransMexico	1315	30	1000	0.76		P&UC	Jan93
Algeria to Morocco	Sonatrach	328	48	250	0.76		P&UC	Jan93
Sweden to Finland	government of Finland	250	20	200	0.80	yes	P&GJ	Aug92
Bolivia to Brazil	Yacimiento Petroliferos	350	20	294	0.84		P&GJ	Aug92
Brazil	National Petroleum Council	232	NA	200	0.86		PLInd	Jan92
United Kingdom	Amoco Exploration Co.	254	36	225	0.89	yes	P&UC	Jan93
Germany	Bayerngas Gm	18,	20	16	0.89		PLInd	Sept92

Table 27 (cont.)
Gas Pipeline Construction Costs Outside the United States

Country	Company	Pipeline length, miles	Pipeline diameter, inches	Estimated cost, $million	Estimated cost per mile, $million	Offshore	Data source	
Germany	VNG	10	24	9	0.90		PLInd	Sept92
Brazil	Petrobas	774	20,24	700	0.90		P&UC	Jan93
Germany	Bayerngas Gm	12	20	11	0.92		PLInd	Sept92
Thailand	Petroleum Authority of Thailand	208	24	200	0.96	yes	P&UC	Jan93
Libya	Liby.... government	896	30	880	0.98		P&UC	Jan93
Norway to Germany	Statoil	762	40	750	0.98	yes	P&UC	Jan93
Germany	STEGAL GmbH	30	32	30	1.[illegible]		PLInd	Jan92
Canada	Alberta Natural Gas Company Ltd.	50	42	50	1.00		P&UC	Jan93
Bangladesh	Bangladesh Oil & Gas Corp.	110	24	110	1.00		PLInd	Jan92
Norway	Midgard Field Partners	300	large	300	1.00	yes	P&UC	Jan93
Australia	Dept. of Resources and Energy	3000	large	3000	1.00		P&UC	Jan93
Germany	Midal Gas Line	398	32	400	1.01		P&GJ	Aug92
Canada to United States	Niagara Pipeline System	57	24	62	1.09		PLInd	Jan92
Indonesia	Trans Javagas Pipeline Co.	267	NA	300	1.12	yes	PLInd	Sept92
Venezuela to Colombia	PDVSA	950	NA	1100	1.16		PLInd	Sept92
Netherlands	Gasunie	34.5	24	40	1.16		PLInd	Sept92
Russia to Australia	National Pipeline Research Soc. of Japan	16800	NA	20000	1.19	yes	P&GJ	Aug92
Sweden to Finland	Ministry of Trade of Finland	250	20	300	1.20	yes	PLInd	Jan92
India	Oil and Natural Gas Commission	560	26,30,36	700	1.25	yes	PLInd	Sept92
Norway	Statoil	140	20	185	1.32	yes	PLInd	Jan92
Canada	TransCanada Pipelines Limited	120.12	48	162.35	1.35		PLInd	Sept92
Tunisia to Italy	Transmediterranean Pipeline Co. Ltd.	257.6	NA	350	1.36		P&UC	Jan93
Canada	TransCanada Pipelines Limited	290	42,48	400	1.38		P&UC	Jan93
China	Hong Kong and China Gas Company Ltd	65.45	23.6,29.5	92.69	1.42		P&UC	Jan93
Canada	TransCanada Pipelines Limited	100.23	48	142.12	1.42		PLInd	Sept92
Canada	TransCanada Pipelines Limited	76.43	42,48	109.73	1.44		PLInd	Sept92
Germany	Midal GmbH	62	32	90	1.45		PLInd	Sept92
Canada	TransCanada Pipelines Limited	69.91	42,48	103.02	1.47		PLInd	Sept92
Spain	Enagas S.A.	300	26	461	1.54		PLInd	Jan92
Denmark	Dansk Underground Consortium	50	NA	77	1.54		PLInd	June92
France to Spain	Gaz du Sud–Ouest	40.	26	63	1.58		P&UC	Jan93

Table 27 (cont.)
Gas Pipeline Construction Costs Outside the United States

Country	Company	Pipeline length, miles	Pipeline diameter, inches	Estimated cost, $million	Estimated cost per mile, $million	Offshore	Data source	
Canada	Nova Corporation of Alberta	190	24,42,48	300	1.58		P&UC	Jan93
Belgium	Distrigaz	91	40	145	1.59		PLInd	Sept92
Germany	Bayerngas Gm	53	28	85	1.60		PLInd	Sept92
Iran	National Iranian Gas Co.	224	30	360	1.61		PLInd	Sept92
Canada	Union Gas Ltd.	10.2	30,36	16.7	1.64		PLInd	Sept92
Canada	Westcoast Energy	20	36	33	1.65		PLInd	Sept92
Germany	Ruhrgas AG	48	48	80	1.67		PLInd	Sept92
Canada	TransCanada Pipelines Limited	31.19	42	56.1	1.80		PLInd	Sept92
Qatar to Pakistan	Cresent Petrol. Co. of Sharjah UAE	1100	NA	2000	1.82	yes	P&UC	Jan93
Canada	TransCanada Pipelines Limited	23.24	42	42.67	1.84		PLInd	Sept92
Canada	TransCanada Pipelines Limited	58.41	42	107.53	1.84		PLInd	Sept92
Chile	international consortium	640	36,40	1200	1.88		P&UC	Jan93
Algeria to Spain	Omegaz–Estudes (Algeria)	786	NA	1500	1.91		PLInd	Sept 92
Netherlands	Gasunie	11.5	42	22	1.91		PLInd	Sept92
Saudi Arabia to India	Chiyoda Corporation	3600	48	7000	1.94	yes	P&UC	Jan93
Canada	TransCanada Pipelines Limited	19.08	42	37.23	1.95		PLInd	Sept92
Canada	Westcoast Energy	48	36	94.2	1.96		PLInd	Jan92
Canada	TransCanada Pipelines Limited	52.07	36,42	102.77	1.97		PLInd	Sept92
Canada	TransCanada Pipelines Limited	87.4	42	174.17	1.99		PLInd	Sept92
Malaysia to Indonesia	TransAsian Pipeline Co.	5000	NA	10000	2.00	yes	PLInd	Sept 92
Canada	TransCanada Pipelines Limited	36.6	42	74.12	2.03		PLInd	Sept92
United Kingdom	Invermoray Hydrocarbon Utility Co. Ltd.	275	24	606	2.20	yes	PLInd	Jan92
Canada	TransCanada Pipelines Limited	35.61	42	79.05	2.22		PLInd	Sept92
Scotland to Ireland	Bord Gais Eireann	177	24	400	2.26		P&GJ	Aug92
Denmark	Statoil, Dansk Olie & Naturgas	118	NA	270	2.29		PLInd	Jan92
Peru	PETROPERU	350	26,22	845	2.41		PLInd	Jan92
Iran to Italy	governments of Iran & Turkey	4000	NA	10000	2.50		PLInd	Jan92
Nigeria to Ghana to Niger	Economic Community of West Africa	1100	NA	2800	2.55		PLInd	Jan92
South Korea	Korea Gas Corp.	825	large	2200	2.67		P&UC	Jan93
Bolivia to Brazil	government of Bolivia	373	NA	1000	2.68		PLInd	Sept92
Brazil	Ministry of Mines and Energy	1864	NA	5000	2.68		PLInd	Jan92

Table 27 (cont.)
Gas Pipeline Construction Costs Outside the United States

Country	Company	Pipeline length, miles	Pipeline diameter, inches	Estimated cost, $million	Estimated cost per mile, $million	Offshore	Data source	
Norway	Statoil	190	40	510	2.68	yes	PLInd	Sept92
Canada	Union Gas Ltd.	21.3	48	58.3	2.74		PLInd	Sept92
Russia	Gazprom	1075	NA	3000	2.79	yes	P&UC	Sept92
Portugal	PetroSuimicae Gas de Portugal	248	NA	700	2.82		PLInd	Jan92
Norway to Netherlands	Gasunie and Statoil	280	40	800	2.86	yes	PLInd	Jan92
Norway	Statoil	118	36	340	2.88	yes	PLInd	Sept92
Canada	B.C. Gas, Inc.	15	42	45	3.00		PLInd	Sept92
Qatar to Iran	General Petroleum Corp.	994	NA	3000	3.02	yes	P&UC	Jan93
Norway	Statoil	125	28	380	3.04	yes	PLInd	Jan92
Trinidad and Tobago	?	800	large	2500	3.13	yes	P&UC	Sept92
Canada	Alberta Natural Gas Company Ltd.	48	42	161	3.35		PLInd	Sept92
Germany	Wintershall AG	25	36	85	3.40		P&UC	Jan93
Norway to Belgium	Statoil – Den Norske Stats Ojeselskap A.S	500	40	1700	3.40	yes	PLInd	Jan92
Norway to Germany	Statoil	403	40	1500	3.72	yes	PLInd	Sept92
Norway	Statoil	25	30	100	4.00	yes	PLInd	Sept92
Viet Nam	Petrovietnam	75		300	4.00	yes	PLInd	Sept92
Canada	Foothills Pipe Lines Ltd.	820	42	3430	4.18		PLInd	Jan92
Iran	National Iranian Gas Co.	212	NA	1000	4.72		PLInd	Sept92
Canada to United States	Sable Gas Systems Ltd.	164	30	780	4.76	yes	PLInd	Jan92
Costa Rica	government of Costa Rica	94	NA	450	4.79		PLInd	Jan92
Germany	Statoil Deutschland GmbH	44	42	215	4.89	yes	PLInd	June92
Iran to Pakistan	governments of Iran & Pakistan	2050	NA	11750	5.73		PLInd	Jan92
United Kingdom	Amoco Exploration Co., Amerada Hess, G	254	36	1680	6.61	yes	PLInd	Sept92
Spain	Enagas	300	26	2000	6.67		P&UC	Jan93
Tunisia to Italy	Snam, Enel	912	48	7300	8.00	yes	P&UC	Jan93
Libya to Italy	Agip	350	large	3000	8.57	yes	P&UC	Jan93
Germany	Ruhrgas AG	15.5	24	150	9.68		P&UC	Jan93
Netherlands	Amoco Netherlands Petroleum Co.	26.3	NA	400	15.21	yes	PLInd	Jan92
Russia to Japan	?	143	NA	3800	26.57	yes	PLInd	Sept92

Table 27 (cont.)
Gas Pipeline Construction Costs Outside the United States

Data sources:

PLInd: Pipe Line Industry, "Worldwide Construction Scoreboard"
P&UC: Pipeline & Utilities Construction, "Pipeline Construction Forecast"
P&GJ: "World Pipeline Work Set For Rapid Growth," Pipeline & Gas Journal, August 1992, PP. 14–15.

Where there are major discrepancies in the costs reported by two of these sources, Table B–10 shows both estimates. For example, the cost of the TransAsian Pipeline Co. project is shown as $3 billion (P&UC, January 1993) and $10 billion (PLInd, September 1992).

These costs appear to include compressor costs for those projects requiring compressor construction. Cost data are not restricted to costs that have been independently verified or subjected to regulatory review.

The preceding list excludes (1) projects for which costs were not reported, (2) projects with pipeline diameters less than 20 inches, (3) projects with pipeline length less than 10 miles, (4) crude oil, product, and NGL pipelines.

On the following pages, project locations are shown to identify the projects for which cost estimates are shown on the preceding pages.

Table 27 (cont.)
Gas Pipeline Construction Costs Outside the United States

Country	Company	Location
Bolivia to Brazil	Petrobras	Campos Basin, Bolivia to southeast Brazil
Russia to Ukraine	Ukrgazprom, Ukrnaftogazbuf	Korosten to Rokytne
Spain	Repsol Petroleo	Cartagena to Puertoliano
Brazil	Petrobas	Urucu to Manaus
Argentina to Peru	governments of Peru and Argentina	Campo Duran field, Argentina to Tocopilla, Peru
Argentina to Brazil	Gas del Estado	Salta Province to Brazil
Peru	PETROPERU	Yangas to Pacasmayo
India	Gas Authority of India Ltd.	national gas grid
Colombia	Promigas	Dibulla to Ballenas
Turkey	Botas	Bursa to Karabuk
Spain	Empresa Nacional de Gas	?
Venezuela	Corpoven	Anaco to Porto Ordaz
United Kingdom	Scottish Area Gas Evacuation System	Beryl to St. Fergus
Tunisia	?	M'Saken to Gabes
Abu Dhabi	Abu Dhabi National Oil Co.	Maqta to Al Ain
Malaysia to Indonesia	TransAsian Pipeline Co.	Malaysia to Philippines
Hungary	State Oil and Gas Trust	Beegdoroc to Szeged
United Kingdom	Shell U.K. Exploration and Production	Bacton to Shell Haven refinery
Czechoslovakia to Germany	Czech government	Prague to Dresden to Berlin to Postak
Venezuela to Colombia	Carbocaol	San Cristobal to Bogota, Colombia
United Kingdom	Total Oil Marine	Caister field to Killingholme
Belgium	Distrigaz	Berneau to Bastogne
Qatar to Dubai	Dubai Natural Gas	North Field, Qatar to Jebel Ali, Dubai
Bolivia to Brazil	Yacimiento Petroliferos	Santa Cruz to Brazil
Mexico	TransMexico	Mexico–U.S. border
Algeria to Morocco	Sonatrach	Hassi R'Mel to Morocco
Sweden to Finland	government of Finland	Gaevie, Sweden to Rihimaki, Finland
Bolivia to Brazil	Yacimiento Petroliferos	Santa Cruz to Brazil
Brazil	National Petroleum Council	Rio de Janeiro and Sao Paulo
United Kingdom	Amoco Exploration Co.	Central Area Transmission System
Germany	Bayerngas Gm	Marktoberdorf to Kempten

Table 27 (cont.)
Gas Pipeline Construction Costs Outside the United States

Country	Company	Location
Germany	VNG	Hojerswerda to Boxberg
Brazil	Petrobas	Sao Borjato to Rio Grande do Dol
Germany	Bayerngas Gm	Bierwang to Gendorf
Thailand	Petroleum Authority of Thailand	Erawan field to shore
Libya	Libyan government	al Brika to Sirte Basin
Norway to Germany	Statoil	Europipe: North Sea to Emden
Germany	STEGAL GmbH	Sachsen–Thuringen to Erdgas–Leitung
Canada	Alberta Natural Gas Company Ltd.	mainline to Kingsgate, B.C.
Bangladesh	Bangladesh Oil & Gas Corp.	Kailashtilla field to Ashugani
Norway	Midgard Field Partners	Midgard field to Norwegian grid
Australia	Dept. of Resources and Energy	across Australia
Germany	Midal Gas Line	Emden to Ludwigshafen
Canada to United States	Niagara Pipeline System	Hamilton to Niagara Falls, Ontario
Indonesia	Trans Javagas Pipeline Co.	Pagerungan to Gresik, Sarabaya
Venezuela to Colombia	PDVSA	Maracaibo fields to Bogota, Medellin & Girardot, Colombia
Netherlands	Gasunie	Velzen to Oudelandertocht
Russia to Australia	National Pipeline Research Soc. of Japan	Sakhalin to Australia
Sweden to Finland	Ministry of Trade of Finland	Gaevie, Sweden to Rihimaki, Finland
India	Oil and Natural Gas Commission	offshore and onshore India
Norway	Statoil	Sleipner to Karmoy
Canada	TransCanada Pipelines Limited	Saskatchewan
Tunisia to Italy	Transmediterranean Pipeline Co. Ltd.	Cap Bon, Tunisia to Sicily
Canada	TransCanada Pipelines Limited	Manitoba to Quebec
China	Hong Kong and China Gas Company Ltd	various districts
Canada	TransCanada Pipelines Limited	Alberta & Saskatchewan
Canada	TransCanada Pipelines Limited	Saskatchewan & Manitoba
Germany	Midal GmbH	Emden to Kassel
Canada	TransCanada Pipelines Limited	Manitoba & Ontario
Spain	Enagas S.A.	Sevilla to Nadrud
Denmark	Dansk Underground Consortium	
France to Spain	Gaz du Sud–Ouest	Lacq to Spain

Table 27 (cont.)
Gas Pipeline Construction Costs Outside the United States

Country	Company	Location
Canada	Nova Corporation of Alberta	southeastern Alberta
Belgium	Distrigaz	Zeebrugge to Blaregnies
Germany	Bayerngas Gm	Nordumgehung von Muchen
Iran	National Iranian Gas Co.	Neka to Resht
Canada	Union Gas Ltd.	southwest Ontario
Canada	Westcoast Energy	central B.C.
Germany	Ruhrgas AG	Lauterbach to Wetter
Canada	TransCanada Pipelines Limited	Ontario
Qatar to Pakistan	Cresent Petrol. Co. of Sharjah UAE	Qatar to Karachi
Canada	TransCanada Pipelines Limited	Ontario
Canada	TransCanada Pipelines Limited	Ontario
Chile	international consortium	Neuquen Basin to Concepcion
Algeria to Spain	Omegaz–Estudes (Algeria)	Hassi R'Mel, Algeria to Seville, Spain
Netherlands	Gasunie	Ten Boer to Borgercompagnie
Saudi Arabia to India	Chiyoda Corporation	Saudi Arabia to India
Canada	TransCanada Pipelines Limited	Ontario
Canada	Westcoast Energy	north and south B.C.
Canada	TransCanada Pipelines Limited	Ontario
Canada	TransCanada Pipelines Limited	Ontario
Malaysia to Indonesia	TransAsian Pipeline Co.	Malaysia to Philippines
Canada	TransCanada Pipelines Limited	Ontario
United Kingdom	Invermoray Hydrocarbon Utility Co. Ltd.	Bruce field to Nigg Bay (NGL line)
Canada	TransCanada Pipelines Limited	Ontario
Scotland to Ireland	Bord Gais Eireann	Moffat, Scotland to Loughshinny, Ireland
Denmark	Statoil, Dansk Olie & Naturgas	Ekofisk field to Tyra field
Peru	PETROPERU	Camisea to Lima; cost includes LNG pipeline plus gas
Iran to Italy	governments of Iran & Turkey	Iran to Turkey to Greece to Italy
Nigeria to Ghana to Niger	Economic Community of West Africa	Nigeria, Ghana, Benin, Niger
South Korea	Korea Gas Corp.	?
Bolivia to Brazil	government of Bolivia	Santa Cruz, Bolivia to Matto Grosso State, Brazil
Brazil	Ministry of Mines and Energy	Carauan to Sao Paulo

Table 27 (cont.)
Gas Pipeline Construction Costs Outside the United States

Country	Company	Location
Norway	Statoil	Troll to Sleipner (Zeepipe, Phase 2A)
Canada	Union Gas Ltd.	southwest Ontario
Russia	Gazprom	Stokmanovskoye to St. Petersburg
Portugal	PetroSuimicae Gas de Portugal	Setubal to Braga
Norway to Netherlands	Gasunie and Statoil	Ekofisk area to Eemshaven, Netherlands
Norway	Statoil	Troll to Heimdal (Zeepipe, Phase 2B)
Canada	B.C. Gas, Inc.	Vancouver
Qatar to Iran	General Petroleum Corp.	Qatar to Iran
Norway	Statoil	Haltenbanken, Heidrun to shore
Trinidad and Tobago	?	Trinidad to Puerto Rico
Canada	Alberta Natural Gas Company Ltd.	southeast B.C.
Germany	Wintershall AG	Rysum to Rehden
Norway to Belgium	Statoil – Den Norske Stats Ojeselskap A.S.	Sleipner to Zeebrugge
Norway to Germany	Statoil	Europipe: Riser Plaform 16/11 to Germany
Norway	Statoil	Sleipner to 16/11–S
Viet Nam	Petrovietnam	Bach Ho field offshore
Canada	Foothills Pipe Lines Ltd.	MacKenzie Delta to Alberta–B.C. border
Iran	National Iranian Gas Co.	Dalan field to Khuzestan field
Canada to United States	Sable Gas Systems Ltd.	Sable Island to Nova Scotia to Maine
Costa Rica	government of Costa Rica	Rincon to Gandoca
Germany	Statoil Deutschland GmbH	Emden to Etzel
Iran to Pakistan	governments of Iran & Pakistan	Sarkham
United Kingdom	Amoco Exploration Co., Amerada Hess, Gas Council	Central Area Transmission System
Spain	Enagas	Seville to Madrid
Tunisia to Italy	Snam, Enel	Trans–Med: Cap Bon, Tunisia to Italy
Libya to Italy	Agip	Bourri field to Italy
Germany	Ruhrgas AG	Vinnhorst to Ahlten
Netherlands	Amoco Netherlands Petroleum Co.	Blocks P/15 to P/18, Dutch sector
Russia to Japan	?	Sakhalin Island to Sekasti

Figure 3
Gas Transmission Corridors

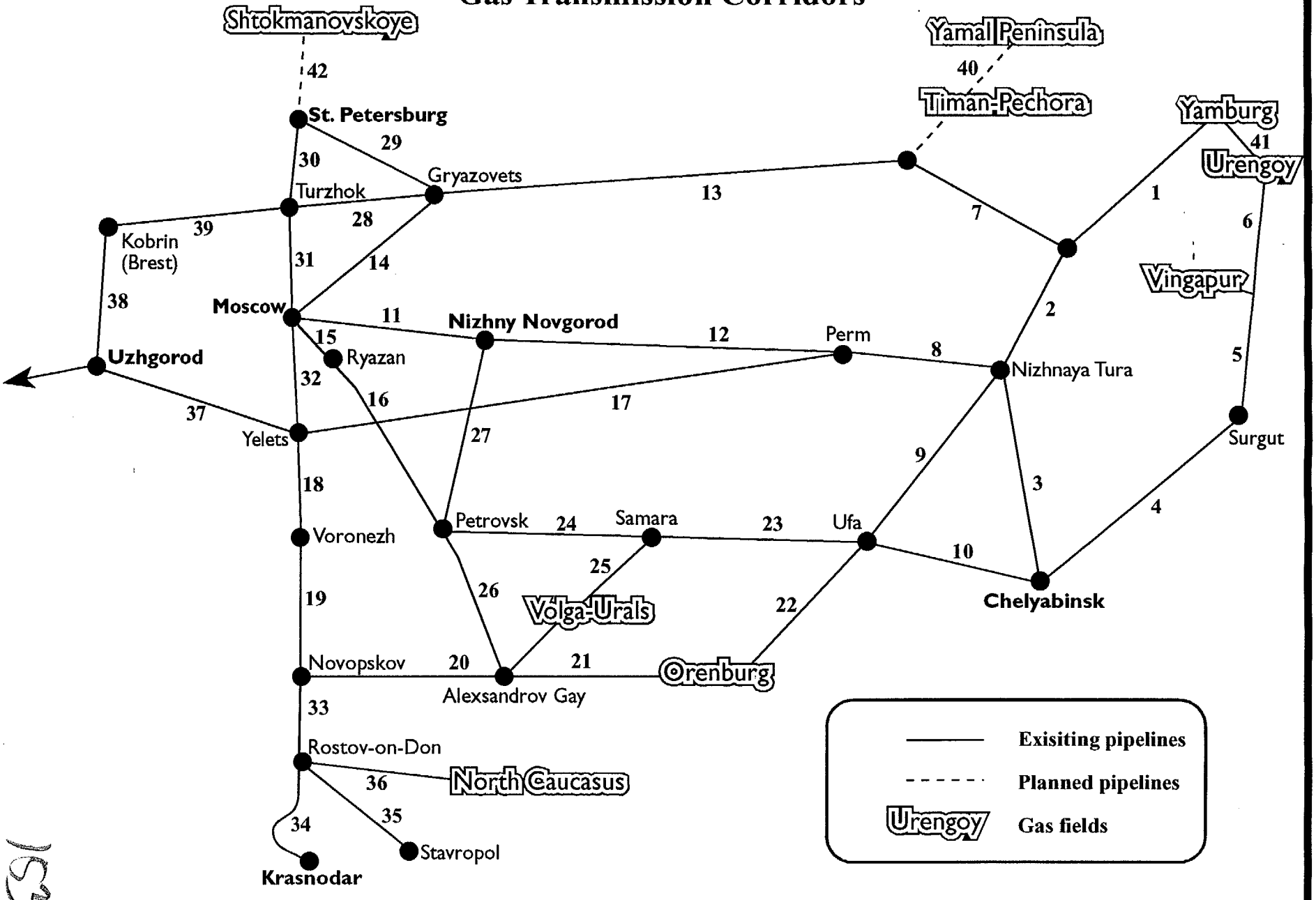

Table 28
Cost of Soviet Pipelines Supply Gas from Urengoy

Pipeline route	Length of route, km	Capital investment, million rubles	Official exchange rate, 1986 rubles per USD*	Purchasing Power Parity, rubles per USD**	Capital cost, dollars per mile***
Urengoy–Gryazovets	2238	2046.2		1.2	1,226,917
			0.6783		2,170,574
Gryazovets–Moscow	496	176.5		1.2	477,518
			0.6783		844,792
Urengoy–Petrovsk	2740	2418.7		1.2	1,184,564
			0.6783		2,095,646
Urengoy–Novopskov	3346	3078.9		1.2	1,234,801
			0.6783		2,184,521
Urengoy–Pomary–Uzhgorod	4451	7587.8		1.2	2,287,628
			0.6783		4,047,109
Urengoy–Center (I)	3022	3166.5		1.2	1,406,087
			0.6783		2,487,549
Urengoy–Center (II)	3035	2667.9		1.2	1,179,609
			0.6783		2,086,880
Total	19328	21142.5		1.8	978,600
				1.2	1,467,900
			0.6783		2,596,905

* This rate is published in Eurostat, Country reports: Central and Eastern Europe 1991, p. 132. We assume that the official exchange rate in 1980–86 was relatively stable.

** The Purchasing Power Parity rate in 1990 has been estimated by the World Bank to be between 1.2 rubles/USD and 1.8 rubles/USD.

*** These pipelines were built in 1981–85 and are all 56" in diameter. There are no 56" pipelines in the United States, but we estimate that costs would be about $1,750,000 per mile, given the cost trends for smaller diameter pipelines (see Figure B–2), and that compression would cost an additional $875,000 per mile.

Source: Distances and capital costs are reported by Oleg M. Ivantsov, Deputy Chairman, Council for Science, Engineering and Economics, Neftegazstroy, USSR, in "Historical Look: Soviet Union pipe line construction – Part 1," Pipe Line Industry, January 1992, p. 59, Table 2.

Table 29
U.S. Land Pipeline Construction Cost per Mile

		Average cost, current $ per mile						1990$/mile
	Year	Right of way	Material	Labor	Misc.	Total	Material, labor, & misc.	Material, labor, & misc.
12 in.	1983	5,135	91,492	73,042	20,754	190,423	185,288	
	1984	23,035	147,750	211,783	93,481	476,049	453,014	563,530
	1985	26,582	74,620	106,447	46,164	253,813	227,231	272,485
	1986	43,656	94,786	243,533	101,683	483,658	440,002	514,017
	1987	26,018	81,675	161,790	67,404	336,887	310,869	351,904
	1988	52,772	85,487	268,169	89,656	496,084	443,312	482,992
	1989	43,896	96,918	227,288	79,788	447,890	403,994	421,494
	1990	105,535	142,336	353,859	232,572	834,302	728,767	728,767
	1991	37,200	79,613	213,538	46,559	376,910	339,710	326,445
	1992	52,393	88,806	208,998	92,076	442,273	389,880	364,747
	1984–1992 average							447,376
16 in.	1983	31,542	337,088	929,969	278,159	1,576,758	1,545,216	
	1984	15,106	131,139	111,234	82,747	340,226	325,120	404,435
	1985	8,511	80,529	47,708	20,091	156,839	148,328	177,868
	1986	21,474	104,368	183,134	53,546	362,522	341,048	398,417
	1987	34,775	109,042	187,216	68,857	399,890	365,115	413,310
	1988	34,217	114,232	185,798	56,558	390,805	356,588	388,506
	1989	25,288	99,141	145,913	54,092	324,434	299,146	312,104
	1990	63,994	122,186	157,792	76,076	420,048	356,054	356,054
	1991	9,382	99,730	206,120	46,457	361,689	352,307	338,550
	1992	27,820	99,993	235,743	87,841	451,397	423,577	396,272
	1984–1992 average							353,946
20 in.	1983	12,682	147,354	154,811	46,073	360,920	348,238	
	1984	16,735	175,406	190,088	63,302	445,531	428,796	533,403
	1985	108,870	187,379	190,886	144,974	632,109	523,239	627,443
	1986	29,227	134,332	182,623	82,657	428,839	399,612	466,833
	1987	35,655	139,346	172,071	68,265	415,337	379,682	429,800
	1988	27,225	139,302	170,120	58,787	395,434	368,209	401,167
	1989	82,862	202,309	446,538	135,703	867,412	784,550	818,535
	1990	72,042	180,469	210,378	114,252	577,141	505,099	505,099
	1991	17,653	115,470	163,039	71,009	367,171	349,518	335,870
	1992	26,322	135,479	241,215	102,802	505,818	479,496	448,586
	1984–1992 average							507,415

Table 29 (cont.)
U.S. Land Pipeline Construction Cost per Mile

		Average cost, current $ per mile						1990$/mile
	Year	Right of way	Material	Labor	Misc.	Total	Material, labor, & misc.	Material, labor, & misc.
24 in.	1983	31,416	310,583	501,401	148,993	992,393	960,977	
	1984	29,133	289,487	298,521	128,390	745,531	716,398	891,168
	1985	26,648	296,486	305,437	151,657	780,228	753,580	903,657
	1986	43,746	245,807	378,917	170,094	838,564	794,818	928,518
	1987	34,785	254,677	271,319	110,959	671,740	636,955	721,033
	1988	49,494	231,264	360,603	145,358	786,719	737,225	803,213
	1989	26,328	165,032	193,096	75,348	459,804	433,476	452,253
	1990	54,631	193,527	277,460	123,844	649,462	594,831	594,831
	1991	19,013	158,756	220,900	55,916	454,585	435,572	418,563
	1992	20,905	151,227	321,542	107,278	600,952	580,047	542,656
	1984–1992 average							695,099
30 in.	1983	23,872	253,071	348,478	116,084	741,505	717,633	
	1984	20,885	336,043	376,631	183,034	916,593	895,708	1,114,221
	1985	60,408	320,219	314,878	152,035	847,540	787,132	943,891
	1986	34,035	268,922	253,838	120,603	677,398	643,363	751,586
	198[illegible]	25,506	257,158	308,383	161,008	752,055	726,549	822,453
	1988	47,502	260,549	322,973	137,019	768,043	720,541	785,036
	1989	26,090	294,249	285,222	116,421	721,982	695,892	726,037
	1990	33,430	303,009	226,208	160,097	722,744	689,314	689,314
	1991	31,703	252,331	252,064	173,554	709,652	677,949	651,476
	1992	32,802	347,224	317,424	190,524	887,974	855,172	800,045
	1984–1992 average							809,340
36 in.	1983	51,436	498,047	490,568	306,666	1,346,717	1,295,281	
	1984	36,063	358,876	362,667	152,787	910,393	874,330	1,087,628
	1985	21,967	389,751	296,742	157,536	865,996	844,029	1,012,120
	1986	36,058	428,572	468,960	151,769	1,085,359	1,049,301	1,225,809
	1987	45,461	415,118	637,294	144,784	1,242,657	1,197,196	1,355,226
	1988	59,395	385,007	449,650	204,591	1,098,643	1,039,248	1,132,270
	1989	35,408	417,820	529,578	180,613	1,163,419	1,128,011	1,176,874
	1990	28,792	391,256	354,475	149,048	923,571	894,779	894,779
	1991	37,274	366,217	297,010	184,782	885,283	848,009	814,895
	1992	39,107	405,194	372,047	245,283	1,061,631	1,022,524	956,609
	1984–1992 average							1,072,912

Source: Oil & Gas Journal, Nov. 23, 1992, p.51.

Table 30
Estimated Replacement Cost of Gazprom Pipelines

Dia. in mm	Diameter in inches	Gazprom trunk line distance in 1990, km	Gazprom trunk line distance in 1990, miles	Estimated replacement cost, 1990 $/mile	Estimated replacement cost, 1990 $billion	Annual delivery capacity of 1 pipe, bcm	Annual capacity utilization (assumed)	Cost per mcm per 1000 km (with level cap. cost), $/mcm
1420	55.9	55,440	34,428	1,749,718	60.240	28.10	80%	10.95
1220	48.0	35,447	22,013	1,477,389	32.521	20.74	80%	12.52
1020	40.2	30,158	18,728	1,205,060	22.568	14.50	80%	14.62
820	32.3	8,989	5,582	932,730	5.207	9.37	80%	17.50
720	28.3	22,332	13,868	796,565	11.047	7.22	80%	19.39
630	24:8	116	72	674,017	0.049	5.53	80%	21.43
529	20.8	26,696	16,578	536,491	8.894	3.90	80%	24.19
other		40,860	25,374	369,553	9.377			
Total		220,038	136,644		149.903			

Source: Trunk line distances are reported in Vniiegazprom, Gas Industry of the USSR 1990, p. 115. Replacement costs are estimated by fitting a straight line to data on U.S. average cost per mile over the 1984–1992 period

Table 31
Length of Gas Trunk Lines in the USSR

Year	Length of trunk lines at yearend, km	Net change in length, km	Age in 1990 of this increment, years	Cumulative percentage of 1990 total
1940	325	325	55.0	0.1%
1950	2,313	1,988	45.0	1.1%
1955	4,861	2,548	37.5	2.2%
1960	20,983	16,122	32.5	9.5%
1965	42,273	21,290	27.5	19.2%
1966	47,550	5,277	24.5	21.6%
1967	52,748	5,198	23.5	24.0%
1968	56,088	3,340	22.5	25.5%
1969	63,159	7,071	21.5	28.7%
1970	67,519	4,360	20.5	30.7%
1971	72,270	4,751	19.5	32.8%
1972	78,684	6,414	18.5	35.8%
1973	83,887	5,203	17.5	38.1%
1974	91,505	7,618	16.5	41.6%
1975	98,702	7,197	15.5	44.9%
1976	102,998	4,296	14.5	46.8%
1977	111,296	8,298	13.5	50.6%
1978	117,717	6,421	12.5	53.5%
1979	124,362	6,645	11.5	56.5%
1980	131,620	7,258	10.5	59.8%
1981	135,519	3,899	9.5	61.6%
1982	144,334	8,815	8.5	65.6%
1983	155,095	10,761	7.5	70.5%
1984	164,914	9,819	6.5	74.9%
1985	174,474	9,560	5.5	79.3%
1986	185,120	10,646	4.5	84.1%
1987	196,976	11,856	3.5	89.5%
1988	208,643	11,667	2.5	94.8%
1989	214,376	5,733	1.5	97.4%
1990	220,038	5,662	0.5	100.0%
Total		220,038		
Average			14.8	

Source: Vniiegazprom, Gas Industry of the USSR 1990, p. 115.

Table 32
Key Assumptions Used to Compute Transport Costs

DATA		
Volume of gas transported in 1990:	694.986	billion CM
Volume of gas transported for export:	110.048	billion CM
Average distance of gas transmission:	2,590	km
Compressor capacity:	46,579	000 kW
Source: Vnieegazprom, Gas Industry of the USSR 1990, pp. 10, 136.		
Compressor construction cost:	1,202	1990 $/horsepower
Source: Oil & Gas Journal, Nov. 23, 1992, p.52.		
ASSUMPTIONS		
Real after–tax cost of capital:	10.0%	
Projected inflation rate for the dollar:	3.0%	
Economic lifetime of pipelines:	30	years
Operation and maintenance cost:	0.10	1990 $/mcf/1000 miles
Pipeline fuel consumption and losses:	3.9%	per 1000 miles
Wellhead price from Urengoy field:	0.1775	1990 $/MCF
Gathering charges from Urengoy:	0.0671	1990 $/MCF
Field transmission charges at Urengoy:	0.0417	1990 $/MCF
Transmission access fee:	0.1207	1990 $/MCF
Fuel allowance for gathering:	0.30%	of wellhead volume
Fuel allowance for field transmission:	0.43%	of gathering volume
Urengoy–Moscow gas transport distance:	1744	miles
CONVERSION FACTORS		
1 horsepower =	0.746	kW
1000 CM = 1 MCM =	35.3	MCF
1 km =	0.621	mile
COMPUTED VALUES		
Transmission inlet price from Urengoy:	14.42	1990 $/MCM
Compressor construction cost:	75.05	1990 $billion
Asset base, at replacement cost:	224.95	1990 $billion
Pipeline component of asset base:	66.6%	
Nominal after–tax cost of capital:	13.0%	
System throughput in 1990:	1.80	million MCM–km

Table 33
Transmission Cost for an Entirely New Asset Base*

	Replacement cost with level capital charges and no new investment		Replacement cost with depreciation and no new investment			
Year	Level payment, 1990 $billion	Cost per mcm per 1000 km, $/mcm	Asset base at Jan. 1, $billion	Annual return plus depreciation, $billion	Cost per mcm per 1000 km, $/mcm/000 km	Depreciation of 1992 and earlier assets, $billion
1991						
1992						
1993	30.01	18.86	224.95	36.74	22.60	7.50
1994	30.01	18.93	217.46	35.77	22.13	7.50
1995	30.01	19.00	209.96	34.79	21.65	7.50
1996	30.01	19.07	202.46	33.82	21.18	7.50
1997	30.01	19.14	194.96	32.84	20.71	7.50
1998	30.01	19.21	187.46	31.87	20.25	7.50
1999	30.01	19.29	179.96	30.89	19.78	7.50
2000	30.01	19.37	172.46	29.92	19.32	7.50
2001	30.01	19.45	164.97	28.94	18.86	7.50
2002	30.01	19.53	157.47	27.97	18.40	7.50
2003	30.01	19.62	149.97	26.99	17.94	7.50
2004	30.01	19.71	142.47	26.02	17.49	7.50
2005	30.01	19.80	134.97	25.04	17.04	7.50
2006	30.01	19.89	127.47	24.07	16.59	7.50
2007	30.01	19.99	119.98	23.10	16.15	7.50
2008	30.01	20.09	112.48	22.12	15.70	7.50
2009	30.01	20.19	104.98	21.15	15.27	7.50
2010	30.01	20.30	97.48	20.17	14.83	7.50
2011	30.01	20.40	89.98	19.20	14.40	7.50
2012	30.01	20.52	82.48	18.22	13.97	7.50
2013	30.01	20.63	74.98	17.25	13.54	7.50
2014	30.01	20.75	67.49	16.27	13.12	7.50
2015	30.01	20.87	59.99	15.30	12.70	7.50
2016	30.01	21.00	52.49	14.32	12.28	7.50
2017	30.01	21.13	44.99	13.35	11.87	7.50
2018	30.01	21.26	37.49	12.37	11.46	7.50
2019	30.01	21.40	29.99	11.40	11.06	7.50
2020	30.01	21.54	22.50	10.42	10.66	7.50
2021	30.01	21.69	15.00	9.45	10.26	7.50
2022	30.01	21.84	7.50	8.47	9.87	7.50
2023					5.32	0.00
	NPV =225.0			NPV =225.0		

* These figures exclude transmission fuel and loss, which is a function of the value of gas at the transmission system receipt point.

Table 34
Transmission Cost for a Depreciated Asset Base Based on Replacement Cost*

Year	Annual capital investment, $billion	Asset base at Jan. 1, $billion	Nominal growth rate of asset base	Annual return plus depreciation, $billion	Cost per mcm per 1000 km, $/mcm/000 km	Nominal growth rate of cost per mcm per 1000 km
1991						
1992						
1993	10.87	112.48		22.12	14.48	
1994	11.34	115.85	3.0%	22.92	14.99	3.5%
1995	11.82	119.33	3.0%	23.75	15.52	3.5%
1996	12.32	122.91	3.0%	24.61	16.07	3.5%
1997	12.84	126.59	3.0%	25.50	16.63	3.5%
1998	13.38	130.39	3.0%	26.42	17.22	3.5%
1999	13.95	134.30	3.0%	27.38	17.83	3.5%
2000	14.53	138.33	3.0%	28.37	18.45	3.5%
2001	15.14	142.48	3.0%	29.39	19.10	3.5%
2002	15.77	146.76	3.0%	30.45	19.78	3.5%
2003	16.43	151.16	3.0%	31.55	20.47	3.5%
2004	17.12	155.69	3.0%	32.69	21.19	3.5%
2005	17.83	160.37	3.0%	33.86	21.94	3.5%
2006	18.57	165.18	3.0%	35.08	22.71	3.5%
2007	19.33	170.13	3.0%	36.35	23.51	3.5%
2008	12.63	175.24	3.0%	30.16	20.17	−14.2%
2009	13.21	180.49	3.0%	31.26	20.88	3.6%
2010	13.81	185.91	3.0%	32.40	21.63	3.5%
2011	14.44	191.48	3.0%	33.59	22.39	3.5%
2012	15.09	197.23	3.0%	34.82	23.19	3.5%
2013	15.78	203.15	3.0%	36.09	24.01	3.5%
2014	16.48	209.24	3.0%	37.41	24.86	3.5%
2015	17.22	215.52	3.0%	38.77	25.74	3.5%
2016	17.99	221.98	3.0%	40.19	26.65	3.5%
2017	18.79	228.64	3.0%	41.65	27.60	3.5%
2018	19.62	235.50	3.0%	43.17	28.57	3.5%
2019	20.49	242.57	3.0%	44.74	29.59	3.5%
2020	21.39	249.84	3.0%	46.37	30.63	3.5%
2021	22.33	257.34	3.0%	48.06	31.72	3.5%
2022	23.30	265.06	3.0%	49.81	32.84	3.5%
2023	24.32	273.01	3.0%	51.62	34.00	3.5%

Real growth rate of asset base: 0.0%

* These figures exclude transmission fuel and loss, which is a function of the value of gas at the transmission system receipt point.

Table 35
Transmission Cost for a Depreciated Asset Base: Relationship of Cost in 1993 to the Average Age of the System

Condition of the transmission system	Age of the system at 1 Jan 93, years	Depreciated asset base at 1 Jan 93, $billion	Transmission cost per mcm per 1000 km in 1993,* $/mcm/000 km	Moscow city gate price in 1993,* $/mcm
Entirely new	0	224.95	22.60	54.45
	5	187.46	19.90	49.73
	10	149.97	17.19	45.01
Actual condition (approx.)	15	112.48	14.48	40.29
	20	74.98	11.77	35.57
	25	37.49	9.07	30.84
	29	7.50	6.90	27.06
Fully depreciated	30	0.00	2.19	18.86

* These figures are based on the assumption that capital investments made in 1993 will enter the asset base for 1994 or later years, and therefore will not affect the level of transmission cost in 1993.

Table 36
Dollar Value of Gazprom's Transmission Assets Based Upon Book Value at Different Exchange Rates

Exchange rate basis	Exchange rate, rubles/$	Value of transmission assets at 1 Jan. 1991, $billion	Capital investment in trunk lines during 1990, $billion
Official rate effective Sept. 5, 1990	0.5739	118.94	4.83
Official rate, March 1990	0.6088	112.12	4.56
Purchasing Power Parity (lower figure)	1.2	56.88	2.31
Commercial rate	1.7	40.15	1.63
Purchasing Power Parity (higher figure)	1.8	37.92	1.54
Special rate effective Sept. 5, 1990	5.739	11.89	0.48
Special rate, March 1990	6.088	11.21	0.46
VEB Auction Market Rate	19.4	3.52	0.14
Market rate at 8 March 1993	648	0.105	
Book value of Gazprom pipeline transmission assets at 1 January 1991	68.258	billion rubles	
Capital investment in trunk lines, 1990	2.773	billion rubles	

Source: Book value is reported in Vniiegazprom, *Gas Industry of the USSR*, p. 212. Data on capital investment are shown at p. 184 of the same publication.
Official and special exchange rates are from Eurostat, *Central and Eastern Europe, 1991* (Luxembourg, 1991), p. 132.

Table 37
Transmission Cost for a Depreciated Asset Base Based on Book Value*

Year	Annual capital investment, $billion	Asset base at Jan. 1, $billion	Nominal growth rate of asset base	Annual return plus depreciation, $billion	Cost per mcm per 1000 km, $/mcm/000 km	Nominal growth rate of cost per mcm per 1000 km
1991						
1992						
1993	4.68	40.15		7.90	6.58	
1994	4.94	42.16	5.0%	8.31	6.88	4.5%
1995	5.21	44.27	5.0%	8.75	7.19	4.5%
1996	5.50	46.48	5.0%	9.21	7.51	4.5%
1997	5.79	48.80	5.0%	9.70	7.86	4.5%
1998	6.11	51.24	5.0%	10.21	8.21	4.6%
1999	6.44	53.81	5.0%	10.75	8.59	4.6%
2000	6.79	56.50	5.0%	11.31	8.98	4.6%
2001	7.16	59.32	5.0%	11.90	9.39	4.6%
2002	7.55	62.29	5.0%	12.53	9.82	4.6%
2003	7.95	65.40	5.0%	13.18	10.27	4.6%
2004	8.38	68.67	5.0%	13.88	10.74	4.6%
2005	8.83	72.11	5.0%	14.60	11.24	4.6%
2006	9.31	75.71	5.0%	15.36	11.75	4.6%
2007	9.81	79.50	5.0%	16.17	12.30	4.6%
2008	7.66	83.47	5.0%	14.33	11.38	−7.5%
2009	8.12	87.65	5.0%	15.13	11.92	4.8%
2010	8.61	92.03	5.0%	15.97	12.50	4.8%
2011	9.13	96.63	5.0%	16.86	13.10	4.8%
2012	9.67	101.46	5.0%	17.79	13.73	4.8%
2013	10.25	106.53	5.0%	18.77	14.39	4.8%
2014	10.86	111.86	5.0%	19.80	15.08	4.8%
2015	11.50	117.45	5.0%	20.89	15.81	4.8%
2016	12.17	123.33	5.0%	22.04	16.57	4.8%
2017	12.89	129.49	5.0%	23.25	17.37	4.8%
2018	13.64	135.97	5.0%	24.52	18.21	4.8%
2019	14.44	142.77	5.0%	25.86	19.09	4.8%
2020	15.27	149.90	5.0%	27.27	20.02	4.8%
2021	16.16	157.40	5.0%	28.75	20.99	4.8%
2022	17.09	165.27	5.0%	30.31	22.01	4.9%
2023	18.07	173.53	5.0%	31.96	23.07	4.9%

Real growth rate of asset base: 2.0%

* These figures exclude transmission fuel and loss, which is a function of the value of gas at the transmission system receipt point.

Table 38
Gas Balance of the USSR, 1990

		Gazprom, million m3	Ministry of Oil & Gas, etc., million m3	USSR total, million m3	Percent of USSR total
	Non–associated gas production	**747,697.4**	**22,915.4**	**770,612.8**	*94.6%*
Plus:	Associated gas production**	**261.6**	**43,906.0**	**44,167.6**	*5.4%*
Equals:	Non–assoc. & assoc. gas prod.**	**747,959.0**	**66,821.4**	**814,780.4**	**100.0%**
Plus:	Gas from condensate plants	*0.0*	*2,124.3*	**2,124.3**	
Plus:	Gas from other sources	*0.0*	*1,514.0*	**1,514.0**	
Plus:	Gas transferred to Gazprom	*19,355.3*	*(19,355.3)*		
Less:	Gas not transferred to Gazprom		*51,104.4*	*51,104.4*	
Equals:	Volume of gas received for transmission by Gazprom	**767,314.3**		**767,314.3**	
Less:	Pipeline fuel	**63,096.9**	*0.0*	**63,096.9**	
Less:	Pipeline losses	**9,231.3**	*0.0*	**9,231.3**	
Equals:	Volume of gas transported by Gazprom	**694,986.1**		**694,986.1**	
Plus:	Gas not transferred to Gazprom		*51,104.4*	*51,104.4*	
Less:	Storage injections	**53,645.9**	*2,650.9*	**56,296.8**	
Plus:	Storage withdrawals	**53,670.2**	*0.0*	**53,670.2**	
Less:	Net increase in line pack	**1,347.6**	*0.0*	**1,347.6**	
Equals:	Marketable gas	**693,662.8**	*48,453.5*	*742,116.3*	
Less:	Exports	*110,047.8*	*0.0*	**110,047.8**	
Equals:	Domestic use distributed by sector as follows:	*583,615.0*	*48,453.5*	**632,068.5**	**100.0%**
	Electric power			**268,209.0**	*42.4%*
	Industry			**259,470.4**	*41.1%*
	Residential			**86,584.9**	*13.7%*
	Agriculture			**13,947.5**	*2.2%*
	Construction			**5,209.6**	*0.8%*
	Transport			**2,922.6**	*0.5%*
	Losses in city networks			**5,724.5**	*0.9%*

* Figures in bold face were published by Gazprom. Figures in italics were inferred by RCG/Hagler, Bailly, Inc.

** These figures exclude associated gas that is flared or vented, as well as gas that is reinjected for the purpose of pressure maintenance.

Source: Vniiegazprom, Gas Industry of the USSR 1990, pp. 16, 17, 123, 142, 143.

Table 39
Transmission Cost Based on Dollar Valuation of Investments Made in 1993 and Subsequent Years*

Most Likely Scenario

Year	Growth rate of domestic demand	Domestic demand met by Gazprom, billion cm	Volume of gas transported, billion cm	Annual capital investment, $billion	Asset base at Jan. 1, $billion	Growth rate of asset base
1991	0.0%	584	695			
1992	−3.0%	566	677			
1993	−5.2%	537	648	6.01	0.15	
1994	−8.7%	490	602	6.39	6.15	4000.0%
1995	−7.1%	455	567	6.78	12.33	100.5%
1996	−6.4%	426	537	7.20	18.70	51.6%
1997	−2.7%	414	526	7.64	25.25	35.1%
1998	−1.4%	409	520	8.09	32.00	26.7%
1999	0.0%	409	520	8.57	38.96	21.7%
2000	1.4%	414	526	9.07	46.12	18.4%
2001	1.4%	420	532	9.60	53.50	16.0%
2002	1.4%	426	537	10.15	61.10	14.2%
2003	1.4%	432	543	10.72	68.93	12.8%
2004	1.4%	438	549	11.32	77.00	11.7%
2005	1.3%	444	555	11.94	85.30	10.8%
2006	1.3%	449	561	12.60	93.86	10.0%
2007	1.3%	455	567	13.28	102.67	9.4%
2008	1.3%	461	572	14.00	111.74	8.8%
2009	1.3%	467	578	14.75	121.09	8.4%
2010	1.3%	473	584	15.53	130.72	8.0%
2011	1.2%	479	590	16.34	140.64	7.6%
2012	1.2%	484	596	17.19	150.85	7.3%
2013	1.2%	490	602	18.08	161.37	7.0%
2014	1.2%	496	607	19.01	172.21	6.7%
2015	1.2%	502	613	19.98	183.37	6.5%
2016	1.2%	508	619	20.99	194.87	6.3%
2017	1.1%	514	625	22.04	206.71	6.1%
2018	1.1%	519	631	23.14	218.91	5.9%
2019	1.1%	525	637	24.29	231.47	5.7%
2020	1.1%	531	642	25.49	244.41	5.6%
2021	1.1%	537	648	26.74	257.74	5.5%
2022	1.1%	543	654	28.04	271.46	5.3%
2023	1.1%	549	660	29.40	285.60	5.2%

* These figures exclude transmission fuel and loss, which is a function of the value of gas at the transmission system receipt point.

Table 39 (cont.)
Transmission Cost Based on Dollar Valuation of Investments Made in 1993 and Subsequent Years*

Most Likely Scenario

Year	Annual return plus depreciation, $billion	Cost per mcm per 1000 km, $/mcm/000 km	Asset base measured in constant 1993 dollars, $billion	Growth rate of cost per mcm per 1000 km	Depreciation of 1992 and earlier assets, $billion	Inflation index
1991						
1992						
1993	0.02	2.36	0.15		0.01	1.000
1994	1.00	3.25	5.97	37.6%	0.01	1.030
1995	2.02	4.23	11.62	30.0%	0.01	1.061
1996	3.07	5.31	17.11	25.5%	0.01	1.093
1997	4.17	6.32	22.44	19.1%	0.01	1.126
1998	5.30	7.33	27.61	16.0%	0.01	1.159
1999	6.47	8.31	32.63	13.3%	0.01	1.194
2000	7.69	9.21	37.50	10.9%	0.01	1.230
2001	8.95	10.13	42.24	10.0%	0.01	1.267
2002	10.26	11.07	46.83	9.3%	0.01	1.305
2003	11.62	12.02	51.29	8.6%	0.01	1.344
2004	13.02	13.00	55.62	8.1%	0.01	1.384
2005	14.48	13.99	59.83	7.6%	0.01	1.426
2006	15.99	15.00	63.91	7.2%	0.01	1.469
2007	17.55	16.03	67.88	6.9%	0.01	1.513
2008	19.18	17.08	71.72	6.6%	0.01	1.558
2009	20.86	18.15	75.46	6.3%	0.01	1.605
2010	22.60	19.25	79.09	6.0%	0.01	1.653
2011	24.41	20.37	82.61	5.8%	0.01	1.702
2012	26.28	21.52	86.03	5.6%	0.01	1.754
2013	28.22	22.69	89.35	5.4%	0.01	1.806
2014	30.23	23.88	92.57	5.3%	0.01	1.860
2015	32.32	25.11	95.70	5.1%	0.01	1.916
2016	34.48	26.36	98.74	5.0%	0.01	1.974
2017	36.72	27.64	101.69	4.9%	0.01	2.033
2018	39.04	28.95	104.55	4.7%	0.01	2.094
2019	41.44	30.29	107.33	4.6%	0.01	2.157
2020	43.93	31.67	110.03	4.5%	0.01	2.221
2021	46.52	33.08	112.65	4.5%	0.01	2.288
2022	49.19	34.52	115.19	4.4%	0.01	2.357
2023	51.96	36.00	117.66	4.3%	0.00	2.427

Table 40
Transmission Cost Based on Dollar Valuation of Investments Made in 1993 and Subsequent Years*

Low Cost Scenario

Year	Growth rate of domestic demand	Domestic demand met by Gazprom, billion cm	Volume of gas transported, billion cm	Annual capital investment, $billion	Asset base at Jan. 1, $billion	Growth rate of asset base
1991	0.0%	584	695			
1992	−3.0%	566	677			
1993	−5.2%	537	648	3.01	0.15	
1994	−8.7%	490	602	3.20	3.15	2000.0%
1995	−7.1%	455	567	3.39	6.24	98.1%
1996	−6.4%	426	537	3.60	9.42	51.0%
1997	−2.7%	414	526	3.82	12.70	34.8%
1998	−1.4%	409	520	4.05	16.08	26.6%
1999	0.0%	409	520	4.29	19.56	21.6%
2000	1.4%	414	526	4.54	23.14	18.3%
2001	1.4%	420	532	4.80	26.83	15.9%
2002	1.4%	426	537	5.08	30.63	14.2%
2003	1.4%	432	543	5.36	34.54	12.8%
2004	1.4%	438	549	5.66	38.57	11.7%
2005	1.3%	444	555	5.98	42.73	10.8%
2006	1.3%	449	561	6.30	47.00	10.0%
2007	1.3%	455	567	6.65	51.41	9.4%
2008	1.3%	461	572	7.00	55.95	8.8%
2009	1.3%	467	578	7.38	60.62	8.4%
2010	1.3%	473	584	7.77	65.43	7.9%
2011	1.2%	479	590	8.17	70.39	7.6%
2012	1.2%	484	596	8.60	75.50	7.3%
2013	1.2%	490	602	9.04	80.76	7.0%
2014	1.2%	496	607	9.51	86.18	6.7%
2015	1.2%	502	613	9.99	91.76	6.5%
2016	1.2%	508	619	10.50	97.51	6.3%
2017	1.1%	514	625	11.03	103.43	6.1%
2018	1.1%	519	631	11.58	109.53	5.9%
2019	1.1%	525	637	12.15	115.81	5.7%
2020	1.1%	531	642	12.75	122.28	5.6%
2021	1.1%	537	648	13.38	128.94	5.4%
2022	1.1%	543	654	14.03	135.81	5.3%
2023	1.1%	549	660	14.70	142.88	5.2%

* These figures exclude transmission fuel and loss, which is a function of the value of gas at the transmission system receipt point.

Table 40 (cont.)
Transmission Cost Based on Dollar Valuation of Investments Made in 1993 and Subsequent Years*

Low Cost Scenario

Year	Annual return plus depreciation, $billion	Cost per mcm per 1000 km, $/mcm/000 km	Asset base measured in constant 1993 dollars, $billion	Growth rate of cost per mcm per 1000 km	Depreciation of 1992 and earlier assets, $billion	Inflation index
1991						
1992						
1993	0.02	2.36	0.15		0.01	1.000
1994	0.51	2.94	3.06	24.3%	0.01	1.030
1995	1.02	3.55	5.88	20.8%	0.01	1.061
1996	1.55	4.21	8.62	18.6%	0.01	1.093
1997	2.10	4.80	11.28	14.0%	0.01	1.126
1998	2.66	5.37	13.87	11.9%	0.01	1.159
1999	3.25	5.91	16.38	10.0%	0.01	1.194
2000	3.86	6.40	18.81	8.2%	0.01	1.230
2001	4.49	6.89	21.18	7.7%	0.01	1.267
2002	5.14	7.39	23.47	7.3%	0.01	1.305
2003	5.82	7.91	25.70	6.9%	0.01	1.344
2004	6.52	8.43	27.87	6.6%	0.01	1.384
2005	7.25	8.96	29.97	6.3%	0.01	1.426
2006	8.01	9.50	32.01	6.1%	0.01	1.469
2007	8.79	10.06	33.99	5.8%	0.01	1.513
2008	9.60	10.62	35.91	5.6%	0.01	1.558
2009	10.44	11.20	37.78	5.4%	0.01	1.605
2010	11.32	11.79	39.59	5.3%	0.01	1.653
2011	12.22	12.39	41.35	5.1%	0.01	1.702
2012	13.15	13.01	43.06	5.0%	0.01	1.754
2013	14.13	13.64	44.72	4.8%	0.01	1.806
2014	15.13	14.28	46.33	4.7%	0.01	1.860
2015	16.17	14.94	47.89	4.6%	0.01	1.916
2016	17.25	15.62	49.41	4.5%	0.01	1.974
2017	18.37	16.31	50.88	4.4%	0.01	2.033
2018	19.53	17.01	52.31	4.3%	0.01	2.094
2019	20.74	17.74	53.70	4.3%	0.01	2.157
2020	21.98	18.48	55.05	4.2%	0.01	2.221
2021	23.27	19.24	56.36	4.1%	0.01	2.288
2022	24.61	20.02	57.63	4.0%	0.01	2.357
2023	25.99	20.81	58.86	4.0%	0.00	2.427

Table 41
Transmission Cost for a Depreciated Asset Base Based on Book Value With Reduced Transportation Volumes*

Year	Annual capital investment, $billion	Asset base at Jan. 1, $billion	Nominal growth rate of asset base	Annual return plus depreciation, $billion	Cost per mcm per 1000 km, $/mcm/000 km	Nominal growth rate of cost per mcm per 1000 km
1991						
1992						
1993	4.68	40.15		7.90	7.05	
1994	4.94	42.16	5.0%	8.31	7.94	12.6%
1995	5.21	44.27	5.0%	8.75	8.82	11.0%
1996	5.50	46.48	5.0%	9.21	9.72	10.2%
1997	5.79	48.80	5.0%	9.70	10.38	6.9%
1998	6.11	51.24	5.0%	10.21	10.98	5.7%
1999	6.44	53.81	5.0%	10.75	11.48	4.6%
2000	6.79	56.50	5.0%	11.31	11.87	3.4%
2001	7.16	59.32	5.0%	11.90	12.28	3.4%
2002	7.55	62.29	5.0%	12.53	12.70	3.4%
2003	7.95	65.40	5.0%	13.18	13.14	3.5%
2004	8.38	68.67	5.0%	13.88	13.60	3.5%
2005	8.83	72.11	5.0%	14.60	14.07	3.5%
2006	9.31	75.71	5.0%	15.36	14.57	3.5%
2007	9.81	79.50	5.0%	16.17	15.08	3.5%
2008	7.66	83.47	5.0%	14.33	13.81	−8.4%
2009	8.12	87.65	5.0%	15.13	14.33	3.7%
2010	8.61	92.03	5.0%	15.97	14.87	3.8%
2011	9.13	96.63	5.0%	16.86	15.43	3.8%
2012	9.67	101.46	5.0%	17.79	16.01	3.8%
2013	10.25	106.53	5.0%	18.77	16.62	3.8%
2014	10.86	111.86	5.0%	19.80	17.25	3.8%
2015	11.50	117.45	5.0%	20.89	17.91	3.8%
2016	12.17	123.33	5.0%	22.04	18.60	3.8%
2017	12.89	129.49	5.0%	23.25	19.32	3.9%
2018	13.64	135.97	5.0%	24.52	20.06	3.9%
2019	14.44	142.77	5.0%	25.86	20.84	3.9%
2020	15.27	149.90	5.0%	27.27	21.65	3.9%
2021	16.16	157.40	5.0%	28.75	22.50	3.9%
2022	17.09	165.27	5.0%	30.31	23.38	3.9%
2023	18.07	173.53	5.0%	31.96	24.30	3.9%

Real growth rate of asset base: 2.0%

* These figures exclude transmission fuel and loss, which is a function of the value of gas at the transmission system receipt point.

CHAPTER 6: PRICING PRINCIPLES FOR GAS DISTRIBUTION

6.1 BACKGROUND

Gas distribution companies purchase gas for resale to industrial consumers, power plants, district heating boilerhouses, and residential consumers including housing cooperatives. Gas price reform will be needed to ensure the financial viability of gas distribution companies and promote more efficient use of gas by end users. The purpose of this chapter is to outline alternative pricing principles for gas distribution.

If distribution margins for each local gas distribution company are established on the basis of that company's cost of providing gas distribution service, it will be possible for end use prices to vary from company to company. This approach to pricing would be roughly comparable to the pricing system in place in the United States, where each gas distribution company calculates the rates needed to cover costs (including a fair return on capital invested). It is conceivable, however, that an autonomous republic, autonomous territory, or district will want to set a uniform schedule of gas prices for all of the local gas companies within the republic, territory, or district. Another option would be to have a pricing policy in which the structure of gas prices and the methodology used to set gas prices is specified by the republic, territory or district while the price calculations are performed by local gas distribution companies.

One of the fundamental characteristics of the present system of gas pricing in Russia is the low level of gas prices to the household sector, relative to prices to the industrial sector. This condition may well continue until the household sector can be charged higher prices without imposing an undue burden on the most vulnerable segments of the population. Some strategy for mitigating the effects of gas price increases on these vulnerable segments of the population will need to be developed for a transitional period that may last several years. Thus, the development of a gas pricing policy should ideally include an identification of the organizations that will be responsible for establishing and implementing the policy, over a period of five years or more. In the present political climate, however, it may be difficult to identify the organizations that will be involved in pricing policy over the next five years.

In the following discussion, pricing policy objectives and pricing methodologies are presented as issues to be addressed by whatever governments or joint stock companies are

involved in setting gas distribution margins. The problem of defining the future roles of federal, regional, and municipal governments as well as regional utilities and local utilities raises a number of political issues that may be distinguished from the issues that must be addressed in a comparison among alternative pricing methodologies.

6.2 PRICING POLICY OBJECTIVES

To guide the development of a gas pricing policy, it is useful to identify the policy objectives to be served. To define and evaluate alternative pricing methodologies, the following list of objectives is suggested:

1. ***Incentives for conservation.*** For each customer class, burner tip gas prices[1] should be high enough (up to the limit of LRMC) to provide an incentive for the customer or consuming organization to make energy conservation investments that are consistent with economic efficiency objectives. The price "signals" for energy conservation investments should be correct, to promote economically efficient patterns of investment by energy consumers.

2. ***Payment of energy costs by energy-intensive industries.*** In a market economy the prices of goods produced in the industrial sector should reflect production costs, so that the quantity of output in each sector is determined by the interaction of supply and demand. In some industries or manufacturing plants (for example, in petrochemical plants) the cost of the industrial product is related to the cost of gas. To promote an economically efficient pattern of production it is important that energy-intensive industries pay energy prices that cover the cost of producing and transporting energy. Energy subsidies in the industrial sector may lead to overproduction of energy-intensive goods.

3. ***Availability of capital.*** Gas distribution companies need to have sufficient revenue to obtain the capital required for reconstruction of older portions of the distribution network and for provision of gas service to new customers.

[1] A "burner tip" gas price is a price paid by a certain group of end users.

4. ***Access to private sector capital.*** At least a portion of the capital obtained by gas distribution companies should be obtained from the private sector, through the sale of stock or the issuance of debt by the distribution company.

5. ***Protection of vulnerable segments.*** Some sort of program will be needed to mitigate the adverse effects of gas price increases on vulnerable segments of the population.

6. ***Limitation of government subsidies.*** If any subsidies are provided to the distribution company by federal, regional, or municipal governments, these subsidies should be used only to mitigate the adverse effects of gas price increases on vulnerable segments of the population. The best policy is for these subsidies to pass directly to the population, not to the company.

6.3 RETAIL PRICING ISSUES

When these objectives are applied to pricing policies for the industrial sector and the household sector, different sets of issues arise in these two sectors. For the industrial sector it is important to provide "correct" price signals to ensure incentives for energy conservation and payment of energy costs by energy-intensive industries. Because industrial customers typically receive large annual volumes of gas at high pressure, the cost of gas distribution for these customers is relatively low. We estimate that the cost of constructing a new distribution system to serve these customers plus the cost of operating and maintaining such a system would be small relative to the city gate prices that would be required to produce and transport gas if the gas industry had evolved in a market economy. Therefore the principal focus of efforts at the federal level to obtain "correct" gas price levels in the industrial sector must be the development of city gate prices that reflect gas production and transmission costs. For gas distribution companies, the key issue in the industrial sector is to ensure that the distribution margin is high enough to enable the distribution company to obtain the capital required for reconstruction of older portions of the network. Because the percentage price increase needed to satisfy capital requirements is relatively small, it should not be very difficult to achieve rational pricing of gas sold to industry.

A key assumption in this review of price reform issues in the industrial sector is that programs to mitigate the adverse effect of district heat price increases on vulnerable segments of the population will involve district heat subsidies, rather than reductions in

the price of gas sold to district heat boilers and combined heat and power plants. Similarly, we assume that programs to mitigate the effect of electricity price increases on vulnerable segments of the population will involve cross-subsidization of households by industrial customers, rather than reductions in the price of gas sold to electric generating stations.

For the household sector, the most difficult issue is the mitigation of the adverse effect of gas price increases on vulnerable segments of the population. This issue has two aspects: (1) prices for gas delivery where gas is used for cooking only, and (2) prices for gas delivery where gas is used for space heating and/or water heating as well as cooking.

6.4 LONG-RUN MARGINAL COST (LRMC) OF SUPPLY

The LRMC of distributing gas for cooking purposes only is so high that it is difficult to believe that gas can be competitive with electricity. For cooking only, operation and maintenance costs are estimated as $3.00/GJ[2] and construction costs are $5.00/GJ (for a network with two levels of pressure) to $9.00/GJ (for a network with three levels of pressure). If household consumers could afford to pay such margins above the city gate price, it would be appropriate to raise distribution margins to at least $6.00/GJ (for apartments where gas is used for cooking only) so that housing cooperatives could accurately assess the cost-effectiveness of replacing gas cookers with electric cookers. However, the replacement of gas cookers with electric cookers might be implemented through planning at the municipal level, and through an investment program supported by the city, rather than through increases in the gas bills of household consumers. If the amount of capital available for gas-to-electric conversion is very limited, a gas price increase will not necessarily stimulate investment in such conversions.

The LRMC of distributing gas for space heating and water heating in the household sector (and in the commercial sector) is in the range of $4.00 - $4.50 per GJ, which is much higher than the present level of gas prices to the household sector (about 3 cents/GJ). However, this relatively high cost is spread over a small portion of total gas consumption. In 1991, gas sales to residential consumers in Russia were 15.06 BCM while sales to industry, district heat, and agriculture were 265.42 BCM and sales to municipal and commercial customers were 16.19 BCM. Therefore it is possible to develop gas price policies in which the industrial, district heat, and agricultural sectors bear a large portion

[2] We recommend GJ units for distribution and retail prices to reflect the fact that gas supplied at different locations may differ in calorific value (GJ/MCM).

of the cost of gas distribution to the residential sector. To accomplish a transition to rational pricing in the residential sector, it may be desirable to use cross-subsidies to raise residential margins very gradually and raise industrial margins sharply. For Russia as a whole, an increase (cross-subsidy) of 17 cents/GJ in the gas distribution margin for industry, district heat, and agriculture would provide enough revenue to cover operation and maintenance expenses for gas distribution to the residential sector.[3]

6.5 ALTERNATIVE APPROACHES TO DISTRIBUTION PRICING

There are three are particularly promising candidates for consideration in the development of gas pricing policies in the distribution sector. The potential advantages and disadvantages of these three options are discussed below.

1. ***Long run marginal cost (LRMC).*** In this approach prices are computed from (1) estimates of operation and maintenance expense in hard currency, based on the experience of France or other western countries, and (2) estimates of reconstruction costs based on assumptions about the percentage of the low and medium-pressure system subject to reconstruction, as well as estimates of the replacement cost of the high-pressure system.

   One of the advantages of this approach is that it does not require a reform of the financial system of each local distribution company. Because there are 729 local distribution companies in Russia (including Mosgaz and Lengaz), the reform of cost-based distribution pricing throughout the country would require the transformation of many accounting systems. The LRMC approach can be implemented relatively simply on the basis of cost calculations related to the physical characteristics of the system. A computer spreadsheet model for implementation of this approach has been developed by World Bank staff and sample calculations have been prepared for the distribution system of Ryazan, based on a methodology that can be applied to other cities.

   The principal problem with this approach is that it does not relate prices to actual costs incurred and therefore may be perceived by customers as a

[3] This simple calculation is based on 1991 consumption. Data for 1993 would probably show that more than 17 cents/GJ is needed because industry's share of gas consumption is lower than in 1991.

method of raising prices above the level needed to preserve the financial health of the distribution companies.

2. ***Prices necessary for gas sector enterprises to be self-financing.*** This approach requires the establishment of targets regarding the sources of capital for long-term investment (in particular, the percentage mix of capital from internally generated funds, issuance of new stock, and issuance of long-term debt).

   The advantage of this approach is that prices are related to book costs, and it is not necessary to address the potentially controversial issue of asset revaluation. The minimal transformation of accounting systems is required.

   A serious problem with this approach is that it fails to raise prices to offset the effect of inflation on the book value of assets. The effect of inflation, without asset revaluation, is to deprive the gas distribution enterprise of internally generated cash flow (through depreciation charges) that is vitally needed to modernize and reconstruct the distribution network.

3. ***Prices necessary to provide a fair rate of return on assets that are revalued on the basis of replacement cost.*** Under this approach, the concept of relating price to costs incurred is maintained while the accounts of the distribution enterprises are transformed through asset revaluation. The approach to measuring cost is changed through the introduction of replacement cost estimates. A real annual rate of return on total assets of 15 percent may be sufficient to attract private sector capital, if the financial health of the distribution company is backed by government policies that assure the company of an opportunity to earn a target rate of return on total capital.

   The advantage of this approach is that it can provide enough revenue to enable internally generated funds to cover the capital requirements of the distribution companies. A potential disadvantage is that the measurement of replacement cost is subjective and therefore potentially controversial. If replacement costs are estimated on the basis of hard currency costs in western Europe, for example, Russian gas consumers might argue that these figures are totally out of line with estimates based upon Russian labor and equipment costs. In some locations, when replacement costs are overestimated, large industrial consumers will be given an incentive to build

high pressure pipeline connections needed to bypass the distribution system. Therefore it is important that the estimate of replacement cost not be an overestimate.

6.6 TWO-STAGE TARIFF SETTING METHODOLOGY

Our recommendation would be to establish long run gas price targets on the basis of LRMC but to establish financial prices on the basis of the third option, a fair rate of return on assets that are revalued on the basis of replacement cost. As the asset base is transformed through new investment in reconstruction, the price level should gradually rise toward LRMC. If it is found after five years that prices lag behind LRMC, an investigation of the causes of this lag would be merited. The LRMC targets would have the advantage of giving the gas consumer a rational basis for developing gas price expectations for use in energy conservation planning and investment decisionmaking. The asset revaluation process, combined with a reconstruction program, would provide a mechanism for gradually raising prices to a level consistent with LRMC.

RCG/Hagler, Bailly has developed a two-stage electricity tariff-setting methodology for several World Bank-funded power sector loans. This methodology should be appropriate to gas distribution tariffs as well.

6.6.1 Introduction

Over the years, the World Bank, A.I.D., and other international development banks have developed a policy to encourage the establishment of efficient pricing systems by those state-owned utility companies that are borrowers (in this case, gas distribution companies). This policy recognizes that, in their current structure, these companies are monopolies which are not subject to competition. Further, the policy recognizes that these companies are subject to government manipulation, in the form of subsidies and control of management. Under this policy, engineering and economic studies are conducted by independent consultants to help establish efficient tariffs, based on marginal costs, and to ensure that capital development and expansion of the gas system proceeds at least economic cost.

The essence of an economic tariff setting methodology is based upon the recognition that an effective and acceptable set of tariffs can only be arrived at by a compromise among the following set of multiple objectives, some of which may be conflicting: encouraging

economic efficiency in resource utilization, ensuring financial viability of the gas distribution company including its ability to finance future resource mobilization; and recognizing the social welfare consequences of a tariff as well as other sociopolitical priorities of equity, fairness, sectoral and regional development.

A methodological framework has been employed by RCG/Hagler, Bailly to arrive at recommended electricity tariffs in several countries, using marginal costs to establish the structure of tariffs, and financial revenue requirements to establish the level of tariffs, together with balancing considerations.

The first step involves the estimation of the long-run marginal cost (LRMC) of supply for each tariff class. The marginal cost of gas is the opportunity cost of producing one more unit. Marginal cost pricing ensures that society's resources and needs are balanced in the most efficient manner. The financial analysis (step 2) estimates the average revenue requirement target, in $/GJ, to ensure the financial viability of the gas distribution company.

A bill frequency analysis (BFA) utilizes customer billing records to develop the profile of sales to customers under each tariff (step 3). The BFA provides estimates of the distribution of bills by consumption level (for example, the fraction of all bills rendered that had a billed consumption level of 5 GJ or less per month, 5-10 GJ, 10-15 GJ, etc). The BFA also estimates the distribution of sales, (for example, the fraction of all sales accounted for by customers who consumed 5 GJ per month or less, 5-10 GJ, 10-15 GJ, etc). This analysis is conducted for each tariff category.

Step 4 involves allocating the systemwide average revenue requirement target to each tariff class. As a first iteration this can be achieved by an assignment of class-specific revenue requirements that preserve the relative proportions as defined by the class-specific LRMC values obtained in step 1. Often, however, these "revenue neutral LRMCs" result in tariff charges by customer class that may deviate from sociopolitical or other objectives. In this manner, the final adjusted revenue responsibilities are determined for each tariff class. In short, the output of step 4 is tariff levels (i.e., average tariffs in $/GJ) for each customer class.

The purpose of step 5 is to develop a tariff design for each class that will generate the average tariff yield ($/GJ) required from that class. The tariff design (step 5) involves defining, for each tariff class, the block structure including block sizes and block rates, customer charges, optional features, etc. The bill frequency analysis provides valuable insights in this regard. The BFA also helps in simulating the revenue generated in each

tariff class for a given tariff design. Through an iterative process, tariff structures are necessarily fine-tuned to achieve the class average revenue yield, and at the same time the tariff design balances economic efficiency and other pricing objectives.

6.6.2 Long-Run Marginal Cost Analysis

Demand Forecast. The objective of this task is to specify a disaggregated demand forecast that will facilitate the marginal cost analysis over a ten-year horizon, and the financial analysis for the five-year horizon. The review begins with the gas distribution company's latest sales forecast and assesses whether certain aspects of the methodology, and/or changed circumstances as regards key exogenous variables that "drive" the forecast, are sufficient to warrant an adjustment to this forecast.

Next, the analysis concentrates on developing and implementing a procedure to disaggregate the forecasts by tariff class. This is accomplished for gas sales, as well as peak flow for each tariff class. In addition, the marginal cost analysis will require estimates of the coincident transit demand (mcm/hour) and the coincident peak demand (mcm/hour) at key points in the network. This analysis requires estimates of coincidence factors by customer class. Information used includes flow simulations, computer models, and customer consumption research data.

The demand forecasting environment for virtually all energy systems is characterized by uncertainty in key exogenous variables. Thus it may be appropriate to establish an interval of uncertainty around the expected value forecast. If it is judged that a range forecast best characterizes the future, then both the low and high forecasts can be employed in the study.

The sales forecast to be utilized in the study is one of the most important parameters that will impact the tariff development because of its effect on the financial revenue requirements (the other variable being city gate gas prices). Therefore, it is critical that this forecast be up to date and accurate as far as possible.

Least-Cost Capital Development Program. The objective of this task is to determine the least-cost system development and capital expenditure plan to meet the demand forecast identified in Task 1. Ideally, the work includes studies of technical options on both the supply side and the demand side. Such integrated (supply and

demand) studies are now required for gas and electric utilities by the majority of state regulatory agencies in the U.S.

The studies are based on engineering cost evaluations and computer simulations. These studies identify a number of options which can meet the requirements of the demand forecast for typical peak and off-peak days (or, ideally, for each day) in each year. These options include the use of existing equipment, as well as installation of new distribution capacity. Demand-side options (such as tariff design or metering changes, end-use efficiency improvements such as thermostatic radiator valves, and gas demand management controls) should be developed as candidates at this point. The capacity of each potential new technology (MCM/hour or GJ per year delivered) is taken to be a variable from year-to-year depending on an expected scenario of availability, as is the date of plant commissioning or retirement.

Capital cost estimates are prepared for each option. Fuel price forecasts (such as published by the World Bank) and operation and maintenance cost data (based on local experience) are used to estimate operating costs for each option.

Several computer models are available which can screen the options to reduce the number of candidates to a manageable set. In other cases, engineering judgement is used. Having identified the candidate options, each is subjected to simulation runs which dispatch the candidate system to meet the demand forecast at a given level of reliability, to determine system costs on a year-by-year basis.

The annual costs are normalized using discounted cashflow techniques, and the cost of serving the demand forecast under each option is thus brought to a single net present value. These values can be compared and the "least-cost" option can be selected. An output of this task will be a least-cost capital expenditure plan for the ten-year horizon, disaggregated by major geographic areas, customer groupings, and demand-side.

Analysis of Marginal Cost Structure. The objective of this task is to establish the economic (marginal) cost of supplying gas to different customer groups. The key objective of marginal cost pricing is to enhance economic efficiency. This objective implies that prices should signal the true economic cost of supply. This helps to ensure that gas demand and supply are efficiently balanced. In this context, economic theory suggests that the relevant opportunity cost of gas is its marginal cost, i.e., the cost of producing one more unit at a given point in time. Prices that are equal to marginal cost provide the correct signals to decision-makers -- producers and consumers -- and should

result in a market equilibrium at a level and pattern of consumption that reflect the best allocation of a nation's scarce resources.

It is important to differentiate the long-run marginal costs of supplying gas by:

- supply pipeline characteristics (pressure, diameter)
- customer segment
- time-of-day and if appropriate, by season.

The following four steps are undertaken to develop estimates of "strict LRMC":

Step 1: Marginal network capacity costs

Step 2: Marginal costs at points of delivery

Step 3: Sensitivity analysis

Step 4: Customer costs

Financial Analysis. The objective of this task is to determine the total revenue requirement ($) and average revenue requirement ($/GJ) that will enable the gas distribution company to function as an independent and viable commercial operation and hence, enable them to provide adequate, economic and reliable gas service.

Prudent financial practice requires that a well managed gas utility meet certain financial objectives that are aimed at ensuring adequate revenues to not only cover their operating costs -- fuel, administrative, salaries, operations and maintenance cost, etc. -- and debt service and obligations, but also to enable the utility to self-finance a substantial portion of the local costs of the investment program from internal cash generation. In addition, capital investment in the energy sector should earn a real rate of return that reflects the opportunity cost of capital to the nation. When all these costs are provided for in the tariff, then all consumption at these tariff levels meets the desired criterion that customers are willing-to-pay for such service; in other words, the perceived benefit of consuming gas is equal to or exceeds its cost to the consumers.

A central element in this task is the implementation of a gas utility financial model (FM). FM is an approach used to develop the utility's pro-forma income statement, balance sheet, and sources and uses of funds over a planning horizon of five years into the future.

This makes it possible to determine the total and average revenue requirements, $ and $/GJ, respectively.

Once data inputs are prepared and entered, FM is benchmarked to the historical financial performance. In particular, it estimates historical values for selected key financial performance ratios such as:

- rate of return on net fixed investment
- debt-service coverage
- net internal funding
- debt-to-equity ratio
- current ratio
- cash on hand
- any other major ratios or conditions in existing financial covenants and loans.

A backcast analysis helps to benchmark the model as well as to identify emerging trends as regards financial performance ratios. Once this is accomplished, the model is running in a forecasting mode. Average revenues per unit sales (i.e., average tariff yield in $/GJ) are iteratively varied until the minimum average tariff yield level is identified. Under this yield -- i.e., the revenue requirement -- the selected financial performance ratios achieve levels that are considered to represent minimum acceptable financial performance.

Tariff Design. The objective of this task is to evaluate existing tariffs in light of the LRMC structure developed in Task 3 and the financial revenue requirements developed in Task 4, and to restructure existing tariffs based upon these and other considerations.

An important overall approach to gas pricing is the recognition that the recommended tariffs should meet a set of potentially conflicting objectives. The heart of implementation in this task is the systematic adjustment of strict LRMCs at points of delivery to meet non-efficiency objectives.

This "three-stage tariff setting method" is depicted below.

<u>Stage I - strict LRMC, based on:</u>

Economic cost of service - efficiency pricing

Stage II - revenue-neutral LRMC, based on:

Strict LRMC, and

Financial viability of gas utility company

Stage III - adjusted LRMC, based on consideration of:

revenue-neutral LRMC, and

Basic social needs

Simplicity of comprehension, metering & billing

Price stability, gradualism

Other sociopolitical objectives

In reviewing the above goals, it is necessary to recognize in advance that these may be conflicting at a number of points. As a result, the output of this task will be the development of adjusted tariff structures which balance these goals. We use a process typified by following a multi-step procedure:

Step 1: Develop strict LRMC tariffs

Step 2: Evaluate existing tariffs against LRMC

Step 3: Adjust strict LRMC tariffs for financial revenue requirement, and other considerations

Step 4: Structure other tariff provisions, such as interruptible rates and inflation clause

Step 5: Develop implementation plan for phasing-in new tariffs

CHAPTER 7: TAXATION IN THE RUSSIAN NATURAL GAS INDUSTRY

The purpose of this chapter is to discuss the most important policy issues facing the Russian Federation in the area of taxation of the gas industry, and to present our policy recommendations.

To provide a complete picture of the role of tax policy in the Russian gas industry, it is important to define Russian taxation in broad terms, i.e., the methods through which federal, regional, and municipal governments can collect revenue from private enterprises and joint stock companies. Under this definition, royalties, lease bonus payments, and allocations of export volumes to the government may be considered elements of taxation. Because Gazprom, Rosstroigazifikazia, and all of the regional and local natural gas distribution companies are being reorganized as joint stock companies, this definition of taxation is broad enough to encompass most, if not all, of the production, transmission, and distribution enterprises in the natural gas industry.

7.1 TRANSITIONAL NATURE OF TAX REFORM

The western concept of taxation of industrial enterprises was not part of the centrally planned Soviet economic system, and the Russian gas industry is still making a transition away from the concepts used in the era of central planning. Under the Soviet economy of the early 1980s (and earlier), the flow of financial resources to and from the gas industry was a consequence of the construction programs and production targets established for the industry by the central planners (Gosplan). Operating "income" (revenue minus expenses) was either allocated to special funds, such as a fund to pay bonuses to workers, or transferred to the government so that the capital investment program of the entire government could receive a contribution from the gas sector. The industrial enterprises of the entire country contributed to a single "pot" of money available for capital spending programs. Funds available to the enterprise were considered to be funds available to the country as a whole, and therefore the enterprise accounts and government accounts were part of the same accounting system. To describe a transfer from the Soviet government to an enterprise as an equity investment, or a transfer from to the enterprise to the government as a tax payment, would be to create the misleading impression that enterprise accounts and government accounts were clearly distinguished.

Under the period of *perestroika*, selected enterprises in the Soviet economy were made "self-financing" in the Soviet sense, i.e., capable of meeting their capital investment requirements from internally generated funds (depreciation and operating income). In 1989, the transformation of the associated gas operations of the Ministry of Oil and Gas into an enterprise named Gazprom was intended to make the gas industry more independent of the state budget of the USSR (although Gazprom continued to transfer large sums to the state budget in 1990[1]). The privatization program for Gazprom and Rosstroigazifikazia that was initiated in December 1992 may be viewed as the next logical step in the process of separating enterprise accounts from state budget accounts.

Under Edict No. 1559 of December 8, 1992, a remnant of the Soviet approach to gas pricing remains in the form of authorization for the government to subsidize the price of gas. The concept reflected in this decree is that the gas distribution enterprises have a legitimate right to receive state subsidies because their prices are subject to price controls issued by the Russian Federation:

> [The President of the Russian Federation decrees] That the losses of joint stock companies which sell gas at regulated State prices shall be subsidized from the republican budget of the Russian Federation and the corresponding budgets of territories in proportion to their shares in the charter capital of those companies.[2]

In early January 1993 only fourteen local distribution companies received state subsidies to cover operating losses, and at that time none of these enterprises had yet been transformed in a joint stock company.[3] Given the need to reduce or eliminate the budget deficit at the federal level, it is reasonable to suppose that the Russian Federation intends to limit the price subsidy program to a minority of the gas distribution enterprises of the country.

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[1] In 1990 Gazprom paid 4.9 billion rubles to the state budget. By December 1990 Gazprom was unable to pay its debts and was effectively bankrupt although there was no bankruptcy law. On January 28, 1991 President Gorbachev and the Soviet Cabinet of Ministers decided to write off 2.9 billion rubles of Gazprom debt, reschedule 3.1 billion rubles of Gazprom debt, and reduce Gazprom's 1991 obligation for payments to the state budget. The Soviet government was abolished before the year was over.

[2] Edict No. 1559, December 8, 1992, "Concerning the Re-Organization as Joint Stock Companies and Privatization of State Enterprises, Associations and Organizations of the Gas Industry of the Russian Federation," paragraph 13.

[3] This information was provided by Rosstroigazifikazia at a meeting on January 14, 1993.

Although the privatization of Gazprom and the gas distribution companies will facilitate the establishment of taxation policies in Russia that resemble gas industry taxation policies in OECD countries, there are two major obstacles remaining. First, the absence of gas sales transactions at the wellhead and the lack of transparency of wellhead prices creates an obstacle to taxation of exploration and production activities and profits according to western norms. Second, it is difficult to let the wellhead price of gas rise to an "international" level, because there is a need to mitigate the adverse effects of gas price increases on vulnerable segments of the population. In market economies there is a set of taxation issues that are related to the extraction of subsurface resources, and there are certain issues that are uniquely related to exploration and production of oil and gas resources.[4] The structure of the gas industry in Russia still creates an impediment to "normal" treatment of these taxation issues. In this chapter we suggest a transitional approach to taxation based on the need to protect domestic consumers from price increases.

7.2 TAX POLICY OBJECTIVES

The development of tax policy in Russia's gas industry is guided by several policy objectives:

- creation of tax systems that are compatible with the development of a market economy and the privatization of gas enterprises
- government collection of revenue sufficient to reduce or eliminate the budget deficit at the federal level
- capture of economic rent associated with natural gas exports
- mitigation of the adverse effect of gas price increases on vulnerable segments of the population
- achievement of a balance between the revenue objectives of the Russian Federation and the regional governments

[4] For a theoretical discussion see Chapter 3, "The Problems of Volume, Price, and Rent" in Ann Davison, Chris Hurst, and Robert Mabro, *Natural Gas: Governments and Oil Companies in the Third World* (Oxford, England: Oxford University Press, 1988). The general principles discussed in this chapter are applicable to all countries with gas resources, not simply third world countries.

- creation of economic conditions that will attract foreign investment in oil production, including oil produced in association with natural gas

- consistent application of value-added tax, profit tax, property tax, and excise taxes to the natural gas industry and other industries, to ensure that tax policies neither favor nor dis-favor the gas industry.

The selection of a particular tax policy may require a compromise among these objectives.

7.3 DIFFICULTY OF DISTINGUISHING TAX PAYMENTS FROM ECONOMIC RENT PAYMENTS

In OECD countries the taxation of natural gas exploration and production is typically based on a royalty system, while the taxation of gas consumption is typically based on a value added tax (VAT) or sales tax (see Table 42). The royalty system is designed to permit the government (as owner of subsurface resources) to capture economic rent but is not intended to have an effect on end user prices of gas. Royalty rates rarely exceed 16 percent, and the lowest fixed royalty rate is 5 percent (Italy's rate). In the Netherlands, the royalty rate varies according to the annual output of the well, and there is no royalty on gas production from the less productive wells; this is an effective incentive system for extending the life of older wells. Several countries have no gas production and therefore the issue of production taxes is not applicable. The VAT and sales tax are intended to generate government revenue by raising end user prices of gas. High levels of VAT are found in Denmark (25 percent), Finland (22 percent), and Sweden (25 percent), while low tax rates on gas consumption are found in the United States (2 to 6 percent), Canada (7 percent), and Turkey (6 percent VAT).

In Russia there appears to be widespread support for the proposition that it is desirable for governments (at either the federal level or the regional level) to capture economic rent associated with gas exports, but it is best for consumers to capture economic rent associated with the volume of gas consumed domestically. Throughout the 1970s and 1980s, domestic natural gas prices were decoupled from export prices in hard currency, and the collapse of the ruble has only widened the gap between export prices and domestic prices. Thus there is political support for a separation of export markets from domestic markets, to keep domestic prices well below the export price level. As long as domestic gas prices in Russia are kept below the netback values associated with gas exports, a portion of the economic rent associated with domestic gas consumption will be captured by consumers.

Table 42
Tax Policies of OECD Countries Regarding VAT and Excise Taxes on Natural Gas

Country	Production	Consumption
Australia	Royalty or RRT (resource rent tax), no excise. (For NW Shelf, royalty 10-12.5% of wellhead value of petroleum production).	Some states impose taxes on natural gas sales. Victoria: levy on large gas users and payment to the State government from the gas supply utility of about ⅓ of revenue from gas sales.
Austria	Royalty of 8%.	Gas purchases subject to VAT of 20% (refundable on purchases for commercial purposes).
Belgium	Not applicable.	Gas purchases subject to VAT of 17% (refundable on purchases for commercial purposes).
Canada	Various provincial royalties; general corporate income tax. Companies are allowed a 25% resource allowance deduction from income, in lieu of royalty deductibility.	GST (Goods and Services Tax) currently 7% (refundable on business inputs).
Denmark	Royalties for first and second round 2-16%, no royalties for third round; corporate tax of 34%; very high profits from oil and gas production subject to hydrocarbon tax.	Gas supplied to households subject to general VAT of 25%. Otherwise gas is exempt from taxes, but customer prices are based on the substitution prices for taxed oil products.
Finland	Not applicable.	Subject to general VAT rate of 22%, refundable on sales for commercial purposes and to environmental tax.
France	Production over 300 bcm/year subject to royalty of 5% by value; corporate tax of 34% for retained revenues, 42% for distributed revenues; local taxes.	VAT of 18,6% (5.5%on the fixed charges of utility bills) refundable on purchases for commercial purposes, special tax of 0.59 cents/kWh, on consumption exceeding 5 GWh/year.

Table 42
Tax Policies of OECD Countries Regarding VAT and Excise Taxes on Natural Gas

Country	Production	Consumption
Germany	Royalties payable to the relevant Land Government; corporate tax of 50% for retained revenues, 36% for distributed revenues; municipal taxes (13% - 19.4%).	Special tax on gas of 0.36 DM per 100 kWh. Gas sales subject to VAT of 14%.
Ireland	No royalties. Standard corporate tax of 40%. Supplementary levy becomes payable at 0.6 tcf, increasing the State's net revenues to 60%.	General VAT of 12.5%, refundable on purchases for commercial value.
Italy	Royalty of 5% (9%) on offshore (onshore) gas; corporate tax 16.2%; local income tax 16.2%.	General VAT of 19%, refundable...; excise tax on gas sold to households (except region of Mezzogiorno).
Japan	Not applicable.	Subject to general consumption tax currently 3% and an excise tax of 720 yen/mt.
Luxembourg	Not applicable.	General VAT of 6%, refundable....
Netherlands	Royalties range from 0% (annual output up to 100 million cm) to 15% (annual output over 10 bcm); greater part of economic rent through State participation; and special tax on NAM's (the main producer) net profit from sales of domestic gas.	General VAT of 18.5%, refundable..; small environment tax.
New Zealand	Royalty of 12.5% and 11% carried interest to the Crown; energy resources levy of 45c/GJ on fields developed before 1987.	General turnover tax 12.5%, energy resources and gas technology levies paid to the government (if production began before 1988).

Table 42
Tax Policies of OECD Countries Regarding VAT and Excise Taxes on Natural Gas

Country	Production	Consumption
Norway	Royalty of 10% on pre-1972 and 8-16% on post 1972 licenses, no royalties on field development approved after January 1, 1986; state income taxes (rate of 8%) correspond to municipal tax and general corporate income tax plus a special tax; annual capital tax of 0.3% of the net worth of the undertaking; CO_2 tax from oil and gas activities of NKr 0.8 per cm.	Not applicable.
Portugal	Royalties range between 16.67% and 24%, corporate taxes range from 36% to 39%.	Not yet known.
Spain	Not applicable.	General VAT of 13%, refundable ...
Sweden	Not applicable.	General VAT of 25%, refundable; energy tax (SKr 175 per 1000 cm); CO_2 tax (SKr 535 per 1000 cm).
Switzerland	Not applicable.	Excise tax, but exempt from turnover tax.
Turkey	Royalty of 12½% based on volume as for crude oil.	VAT at a special rate of 6%.
United Kingdom	Petroleum revenue tax (PRT) of 75% and royalty of 12.5% on earlier fields; levy on gas supplied before PRT was introduced in 1975.	General VAT of 17.5%, refundable ...; exception of gas sold to residential customers (VAT is zero rated).
United States	Federal corporate income tax, special concessions to recognize depletable nature of resource. Royalties not less than 12.5% of the value of production and on Outer Continental Shelf, 12.5% in deep water and 16.5% elsewhere. Lease payments on Federal Lands, most states have severance taxes. Levy on gas produced for oil spill pollution fund.	Sales tax by the States vary between 2% and 6%.

Sources: *The Role of IEA Governments in Energy*, OECD/IEA, France 1992; *Guide to European Oil Taxation*, Arthur Andersen, 1992.

In exporting gas to other countries (particularly western European countries), Gazprom is able to sell gas at prices that exceed the cost of exploration, production, transmission, and distribution. In a competitive market economy, the excess of the border price over the economic cost of gas would be called economic rent. Because the border price of gas is determined by international markets, domestic price regulation can alter the distribution of economic rent but it cannot eliminate the economic rent associated with exports. The ability of production associations to capture economic rent in a competitive economy would depend upon the scope of price regulation:

- If the transmission system were not subject to price regulation, a portion of the economic rent from exports would be captured by transmission companies and the remainder would be captured by owners of subsurface resources of natural gas and/or gas production companies (including producers of associated gas).

- If the transmission system were subject to price regulation such that the profits of the transmission companies provided a rate of return consistent with the profit performance of competitive industries, and if the profits of gas production companies were constrained by market competition, all of the economic rent from exports would be captured by the owners of subsurface natural gas resources.[5] If the federal government or the regional governments were the owners of oil and gas resources, all economic rent would be captured by these governments.

In the Russian economy today, the non-associated gas exploration and production sector is not competitive and the method of price regulation does not relate the price of transmission service to the cost of transmission service (including a fair rate of return on capital invested). As a result, it is practically impossible to distinguish economic rent from other sources of government revenue. Moreover, the government's method of obtaining revenue from gas exports bears a resemblance to a royalty system, although it is applied to the export volumes rather than production volumes. The Russian Federation allows Gazprom to negotiate export contracts, subject to government approval, but requires Gazprom to give the Russian Federation 55 percent of export revenue by selling 55 percent of the export

[5] By "owner" we mean the entity that owns the gas resources prior to the issuance of a license, lease, or other document giving a gas production enterprise the right to extract resources during a certain time period. In the Soviet economy there were no leases or contracts between the owners of subsurface resources and the production enterprises, and therefore the concept of "owner" had to be clarified by legislation of the Russian Federation.

volume of gas at a price of 6,000 rubles/mcm.[6] This system is roughly comparable to a 48 percent royalty on the volume of gas exported. (Assuming an export price of 50,000 rubles/mcm, the Russian Federation collects 48.4 percent of export revenue under the present arrangement.)

This level of royalty is roughly consistent with the ratio of economic rent to export revenue that would be expected if the gas industry had developed in a market economy. In the second half of 1992, export prices at the Russian border were US $75-80/mcm for gas exported to western Europe (and priced at $80-90/mcm at the importing country's border). If the gas production and transmission system had developed in a market economy, the cost of producing gas at Urengoy and delivering it to Uzhgorod would be about $37/mcm, leaving a difference of $38-43 for payment of taxes plus economic rent.

In the domestic gas sector, price controls practically eliminate the possibility that non-associated gas production associations can capture economic rent.[7] In the first half of 1993, domestic gas prices were even below LRMC, and it is likely that all economic rent associated with domestic gas consumption was captured by consumers.

If the domestic gas market is allowed to become competitive, however, domestic consumers will not be able to capture all of the economic rent associated with their consumption. Even if the export market is fully separated from the domestic market, economic rent may be captured in the domestic market by the gas producers in fields which have relatively low production costs and are located in regions for which there are relatively low transmission costs. In a fully competitive but deregulated city gate market, the price of gas at each city gate will be determined by the highest-cost increment of supply needed to serve that city (i.e., the marginal cost of gas supply at the city gate). Suppliers that are able to deliver gas to the city gate at a price below the marginal cost of supply will either capture economic rent or allow the owners of subsurface resources to capture economic rent. Because we

[6] The government share, 55 percent, is specified in paragraph 3 of Decree No. 951, "On Procedures for the Use of Hard Currency Reserves Generated from the Export of Natural Gas in 1993," dated December 10, 1992. The price received by Gazprom is established in paragraph 12 of Decree No. 88, "On State Regulation of Prices for Natural Gas and Other Categories of Energy Resources," dated January 29, 1993.

[7] In early 1993 Gazprom executives stated in a press conference that Yamburg and Urengoy were receiving only 200 rubles/mcm. Alexander Margulow, general director of Yamburggazprom, stated that "As a minimum margin we need R1,000 and we need it now." See "Giant Gazprom steps on Russian gas," *FT International Gas Report*, 5 February 1993, 220/2. Our interpretation of this article is that the 200 ruble/mcm revenue level was in effect before the government's February 1 price increase.

project gas demand in Russia and in other CIS republics to fall to 70 percent of the 1990 level, by 1998, we do not see a need to develop the Yamal fields and Barents Sea fields during the 1990s, and therefore the development of "high-cost" resources (high cost by Russian standards) could be deferred. In the long run, however, high-cost resources will become the marginal source of supply under competitive market conditions, and may therefore drive city gate gas prices upward. In such a scenario the owners of low-cost resources would be able to capture very large amounts of economic rent.

In a market economy both domestic and foreign customers would have equal access to all sources of gas, and development of high-cost sources would be deferred until lower-cost sources could no longer meet total demand (the sum of domestic demand plus export demand). In Russia it appears that Gazprom is adopting a different strategy, by asking export customers to pay for the development cost associated with higher-cost sources of gas, i.e., Yamal gas and Shtokmanovskoye gas. In other words there is a limited amount of evidence indicating that Russia plans to rely on a production allocation system, rather than a tax system alone, to capture economic rent. Under the production allocation approach, high-cost sources of gas are allocated to the export market and lower-cost sources of gas are held as reserves for the domestic market; in addition, the initial cost (including research and development) needed to develop new gas fields is borne by the export market, so that incremental capacity can be added at a lower cost to serve the domestic market. If the higher-cost sources are developed prematurely, the LRMC of serving export customers will be higher than the true LRMC of Russian gas, and economic resources will be wasted through overinvestment in higher-cost production. If the higher-cost sources are developed according to the schedule that would have been used under market conditions, economic resources are not wasted.

Gazprom's monopoly over non-associated gas enables Gazprom to allocate higher-cost gas resources to the export market. It appears that the initial phase of Yamal gas development will be largely funded by contracts to export gas to Germany via Belarus and Poland. Gazprom has started construction of two pipelines needed to transport Yamal gas to Germany. On March 19, 1993 an agreement was signed with Poland for construction of the Polish segment (about 680 km of pipeline).[8] The Russian section may be completed as early as 1994.[9] To construct 8 pipelines across Baidaratskaya Bay (which separates the Yamal Peninsula from western Russia), Gazprom formed a joint venture with Heerema Oil

[8] Bureau of National Affairs, *Eastern Europe Reporter*, March 29, 1993, p. 258.

[9] "Giant Gazprom steps on Russian gas," *FT International Gas Report*, 5 February 1993, 220/2.

& Gas Development in 1992. The first two lines across Baidaratskaya Bay are scheduled to be in operation in 1996, and are estimated to cost $570 million.[10]

In the present political and economic environment, Gazprom must balance the following objectives:

(1) minimizing the cost of producing and transmitting gas for domestic use, to enable the government to set low prices for domestic gas consumers

(2) minimizing the cost of producing and transmitting gas for export, to maximize export profits and thereby generate revenues for the government of the Russian Federation.

Our impression is that the first objective is given higher priority. If Gazprom's future is ultimately tied to its ability to serve its customers, it is more important to provide gas at low prices than to generate revenues for the government of the Russian Federation. Even from a political perspective, it may be more important to provide cheap energy to domestic consumers than to reduce the federal government deficit. However, this policy may result in two kinds of economic efficiency losses: overinvestment in gas production from higher-cost sources, and underinvestment in domestic energy efficiency. In addition, the sacrifice of the second objective may exacerbate the macroeconomic problems associated with the high level of the federal budget deficit.

7.4 TAXATION OF GAS PRODUCTION

To permit a transition to a competitive market in natural gas production, and to enable gas-on-gas competition to determine the level of wellhead prices, it will be necessary to make wellhead prices transparent and to separate production operations from gas gathering, gas processing, and transmission operations. This step has not been accomplished by Russia and therefore the development of tax policies for non-associated natural gas is still in an early stage.

If producers of natural gas have unrestricted access to export markets, the normal tendency of a competitive wellhead market is to achieve the same level of wellhead prices for export

[10] "Russia plans ambitious arctic marine pipelines," *Oil & Gas Journal*, May 3, 1993, pp. 34-36.

and for domestic consumption, if there are comparable terms and conditions in producer contracts. For example, spot prices for export and for domestic consumption will tend to be the same, unless a government authority intervenes to depress prices of gas destined for domestic use.

From the standpoint of maximizing government revenue, it would be reasonable to allow wellhead prices to rise to the netback value of gas based on export markets, i.e., a Russian border price less transmission charges. The government could then use royalties and profit taxes to obtain revenue from the higher level of wellhead prices. However, because it is necessary to mitigate the impact of gas price increases on vulnerable segments of the population, this approach to wellhead pricing and taxation is not viable. We assume that the Russian Federation will prohibit competition between domestic and export markets until the population can afford to pay "world prices" for natural gas, i.e., wellhead prices reflecting the value of gas in export markets plus transmission and distribution charges reflecting the economic cost of providing these services to domestic consumers. Furthermore, we assume that the Russian Federation will continue to use the present system of revenue collection associated with gas exports.

Under these conditions, the issue of taxation of wellhead prices of natural gas becomes relatively unimportant because the price level is so low, by international standards (in the neighborhood of 20 cents/MMBtu). The appropriate forms of taxation of wellhead production would be a royalty of gas production; a system of lease bonus payments, with competitive bidding for new leases; and an income tax (i.e., a profit tax) for exploration and production enterprises having access to foreign equity investment. Over a transitional period of five years the profit tax may be extended to enterprises that do not have access to foreign equity investment.

If Yamal gas does not compete with Urengoy and other fields supplying the domestic market, the price of Yamal gas could be high enough to generate economic rent for the producer. If the cost of delivering this gas to Uzhgorod is $67/MCM, however (see Table 25), and export prices remain at current levels, the amount of economic rent per MCM will not be large.

Because crude oil production in Russia has been declining since 1989 and because crude oil exports have declined, the government of the Russian Federation has enacted laws and decrees designed to permit foreign investment in oil exploration and production. Associated gas production is subject to the same royalty and tax provisions as crude oil production. Although non-associated gas production is almost entirely controlled by

Gazprom, through its regional subsidiaries, the laws concerning exploration for sub-surface oil and gas resources and production from new gas fields are applicable to both non-associated and associated gas. One of the major issues in the taxation of sub-surface resources is the balance of power and sharing of tax revenues between the regional governments and the Russian Federation. The tax policies of the regional governments are now always consistent with the objectives of the Russian Federation.

7.5 TAXATION OF GAS TRANSMISSION AND DISTRIBUTION

In transmission and distribution the primary question of tax policy is the method of protecting vulnerable elements of the population from gas price increases. Because this objective can be achieved without imposing separate wellhead prices for industry and for households, we recommend that wellhead prices be the same for industry and for households. Two approaches to protection of households from price increases may be considered:

- The transmission and distribution charges for gas sold to households may be increased very gradually over a transitional period (for example, 1993-1998) so that end users pay a price sufficient to cover the cost of wellhead production plus a portion of the cost of transmission and distribution. The remainder of the transmission and distribution expenses may be recovered through higher prices charged to industrial customers. Government tax revenue is not needed to protect the household customer, because the necessary revenue is provided by industrial users of natural gas.

  This approach offers the benefit of allowing the gas transmission and distribution companies to operate more independently of government ministries. The government budgets are not affected by gas price subsidies.

- The transmission and distribution charges for gas sold to households may be increased very sharply to the level needed to pay the economic cost of transmission and distribution service to the household sector. Government subsidies may be provided in the form of negative income tax rates for the lowest-income segments of the population. The level of income subsidy may be selected so that it is sufficient to pay for the increase in the household's monthly gas bill, even when the household is unable or unwilling to make a change in gas consumption in response to higher gas prices.

> This approach offers the benefit of keeping gas prices to industry at a level no higher than the economic cost of gas. Energy-intensive industrial enterprises therefore would not suffer a competitive disadvantage associated with the need to provide a subsidy to household gas consumers. Moreover, this approach allows all consumers to make energy consumption decisions and investment decisions on the basis of proper energy price signals that reflect the economic cost of production, transmission, and distribution.

We recommend that the first of these approaches be used. The cross-subsidization of household gas prices by industrial prices can occur at the distribution level, without creating a distortion in city gate prices. In other words, the industrial sector may subsidize not only the cost of building and operating gas mains to distribute gas to households, it may also subsidize the cost of purchasing gas at the city gate for resale to households. Although this approach creates a distortion in industrial gas prices, the percentage difference in industrial prices is not large (probably less than 20 percent) because the volume of gas delivered to the household sector is relatively small. Thus, we recommend that no tax be imposed for the purpose of creating government revenues needed to subsidize gas prices in the household sector.

In Decree No. 88 issued on January 29, 1993, the provisions of Decree No. 318 pertaining to payments by gas enterprises to the "Price Regulation Fund" were repealed. This fund was intended to provide a source of funds for government subsidy of energy prices, by imposing a very high tax rate on marginal increases in industrial gas prices above the minimum price level. We recommend that the concept of a "Price Regulation Fund" for the gas industry be abandoned permanently.

In current tax policy the VAT is applied to gas sales to industry but not sales to the population. This approach is entirely reasonable and we recommend that it be sustained. Although the VAT is applied to prices of petroleum products sold to households, there is no real "incentive" for households to switch from natural gas to oil, and most individual households have no control over the type of heating system they use. If natural gas can be delivered to the city gate for less than $1/MMBtu, it is unlikely that end use prices for gas used in space heating will be at the level of light fuel oil prices, on a heat content basis. Where gas is used for cooking, electricity is likely to be the lower-cost form of energy even when there is no VAT on household gas use. Thus fuel choice decisions in the household sector may be made by municipal governments or regional governments, and a VAT on household gas consumption is not necessary to protect oil or other energy sources from competition with natural gas.

CHAPTER 8: CONCLUSIONS AND RECOMMENDATIONS

8.1 CONCLUSIONS - ALTERNATIVE APPROACHES TO DETERMINING GAS PRICE LEVELS

There are several alternative approaches to the calculation of gas price levels:

1. ***Prices necessary to cover operation and maintenance costs.*** This approach is not sustainable but has been used by Gazprom. Representing Gazprom, Yevgeniya Selikhova stated at a February 1, 1993 press conference that "the price which has been established for gas in no way provides the gas industry with the necessary capital investments." The price of gas delivered to distribution companies for resale to households was set at 300 rubles/mcm although the operation and maintenance (O&M) cost of gas production was 2600 rubles/mcm, "excluding profits and not paying a single kopeck of capital investment."[1]

   This approach is not consistent with the principle that the consumer should pay for the full cost of providing a service or commodity, including a return on invested capital.

2. ***Prices necessary to make gas sector enterprises self-financing.*** This price level is the minimum needed to avoid government subsidization and recover the full cost of gas service. This is perhaps the only politically and economically acceptable approach in a situation in which the government wants to keep gas prices at the minimum price level needed to sustain the viability of gas enterprises.

   Although prices based on self-financing represent a reasonable policy option, the application of this concept to monopolistic enterprises requires a political determination of the value of the assets of the enterprise, including soft-currency assets. The historical basis for these assets is out of line with current prices.

   In a monopolistic enterprise such as a transmission or distribution company, the assets may be revalued on the basis of the net present value of the revenue projected to be available to repay capital investment. This revenue stream will be determined by future price levels, which are established by government decree. Conversely, if

[1] Press conference on regulation of prices for natural gas and other natural resources, February 1, 1993, p. 2.

the value of the assets is established by government decree, the price level needed to provide a fair rate of return can be calculated. There is no objective basis for determining the value of the enterprise, except through the use of price indices. If the assets include shares to be given to the workers, it would be possible to estimate the asset value that would give the average worker an ownership interest comparable in value to the ownership interest provided to the average worker in other industries.

The high rate of inflation in the Russian economy tends to reduce the cost of depreciation of historical assets.[2] It is important that the full cost of hard currency investment is reflected in prices. In an enterprise in which a portion of new investment is made in hard currency, there are two approaches to making gas sector enterprises self-financing:

- *Option 1:* Sales in rubles only. The ruble equivalent of hard currency investment can be calculated and added to the ruble value of other investment. The gas sale price in rubles is established at a level needed to recover the total investment. In this situation the hard currency investment creates an increase in prices.

  Frequent price adjustments may be needed to recover cost through sales in rubles only. When the ruble inflation rate is high, the ruble cost of labor and materials needed to maintain gas industry operations will rise rapidly and therefore gas prices in rubles need to be raised to recover ruble-denominated costs. When the ruble falls sharply against other currencies or the ruble-dollar exchange rate fluctuates sharply, gas prices need to be adjusted to recover dollar-denominated or hard currency costs.

- *Option 2:* Sales in hard currency and in rubles. For an enterprise with export revenues, the cost of hard currency investment can be recovered through gas exports to countries capable of paying in hard currency. The cost of ruble investment can be recovered through other exports and through

[2] At 1 January 1991 the book value of Gazprom's "basic fund" assets was 98.363 billion rubles, of which pipeline transmission represented 68.258 billion rubles. See Vniiegazprom, *Gas Industry of the USSR 1990*, p. 212. In April 1993 the press agency ITAR-Tass reported that Gazprom would be converted into a joint stock company valued at 89.3 billion rubles. See "Russia to Privatize Gazprom," *Eastern European Energy Report*, April 1993, p. 5. Our understanding is that Gazprom estimated its yearend 1992 value on the basis of replacement cost. According to a report based on Gazprom's press conference in Moscow, "Gazprom's fixed assets were estimated at R1423.5 bn (1992 prices)." See "Giant Gazprom steps on Russian gas," *FT International Gas Report*, 5 February 1993, 220/2.

domestic sales at the city gate. In this arrangement it is possible that neither class of customer pays a price that is related to its cost of service.

A distribution enterprise could establish prices in hard currency for industrial customers earning hard currency, and prices in rubles for all other industrial customers. This approach has not been implemented in the gas sector, although the basic concept is applied in tourist services. This option may be considered when (1) the distribution enterprise has hard-currency investment, (2) the ruble inflation rate is high, and (3) the distribution enterprise has large industrial gas consumers who are able to earn hard currency. However, it would be difficult to monitor the ability of different customers to earn hard currency and it would be politically difficult to implement hard-currency tariffs that are substantially higher than ruble-denominated tariffs.

3. ***Prices consistent with prices prevailing in North America or western Europe.*** In this approach, price targets are specified for some future year and prices are gradually raised to meet the price target. The targets are not related to historical costs of the Russian enterprise.

One way to implement this approach is to revalue the assets of the enterprise so that the price needed to earn a fair rate of return is raised to the "world" price level. If the assets are revalued in this manner, the cash flow of the enterprise will be sufficient to cover a large debt service obligation or provide substantial profits to the owners of the enterprise. To avoid creating excessive profits for the enterprise the government would have to combine an asset revaluation with the creation of a fixed obligation return on capital, e.g., a long-term debt payable to the government of the Russian Federation.

This concept is unlikely to be accepted by the Russian government because the "costs" created through asset revaluation are unrelated to historical costs and result in a rapid increase in gas prices. The effect of a combination of asset revaluation and creation of a debt service obligation payable to the Russian government would be similar to the effect of a specially designed tax. Through the debt obligation, gas customers are in effect being asked to "repay" the federal government for gas industry assets that were already "paid for" through the system of central planning and budgeting of the Soviet Union. Such a price increase would probably be perceived as an arbitrary scheme to raise government revenue.

4. ***Netback pricing.*** In this approach, city gate gas prices are raised to the netback value of gas from the Russian border, i.e., the border price less an allowance for the difference in transmission costs between (a) transmission from the producing area to the city, and (b) transmission from the producing area to the export point along the border (e.g., the Russian-Ukrainian border). The theory behind netback pricing is that gas used in the domestic market should be valued at its opportunity cost, which is the value the gas would have if it were exported. If a distribution company is considered the owner of a certain volume of gas and is given the right to have a portion of this gas exported instead of delivered to the distribution company, the opportunity cost of gas is measured by its value as an export.

   A problem with this approach is the separate nature of domestic demand and export demand. Given the very large reserves of Russian gas, the high reserve-to-production ratio, and Gazprom's ability to obtain hard-currency financing for transmission system improvements, Russian exports do not appear to be constrained by domestic demand for gas. Exports are only constrained by Gazprom's production and transmission capacity and the ability of the export market to absorb additional volumes. The marginal mcm of gas freed up by a drop in domestic demand does not necessarily lead to an increase in exports, and the marginal increase in demand would not necessarily require a decrease in exports. For these reasons the domestic market and the export market may be considered distinct markets.

   The Russian government has raised export prices to other countries of the CIS while maintaining a relatively low level of prices to domestic households. This policy reveals an unwillingness to raise domestic prices to the level of export prices. The opportunity cost concept would create a linkage between domestic prices and export prices that is contrary to the government's current gas pricing policy.

5. ***Long run marginal cost (LRMC).*** In theory it is possible to define and measure the long run marginal cost of gas production, transmission, storage, and distribution and then establish gas prices at which the marginal price of gas service equals the marginal cost of gas. If properly implemented, this approach to pricing will yield an optimal level of economic efficiency. The measurement of LRMC is dependent upon the selection of a base case scenario for gas industry development plus a scenario in which a "marginal" increase or decrease in demand results in a different level of costs. The selection of these scenarios and the accompanying assumptions about the future can raise a number of controversial issues.

Transmission/distribution system reconstruction and development programs based on Russian manufacturing and Russian labor will result in a ruble-denominated LRMC. One of the issues facing Gazprom and the gas distribution companies is the ability of Russian joint ventures or enterprises to manufacture the goods that are now imported by Gazprom. If foreign technology can be used to manufacture compressor station equipment, valves, and fittings in Russian establishments, it will not be necessary to rely on foreign labor for the manufacture of these goods. Given the current low level of wages in Russia, gas industry enterprises have an incentive to purchase from domestic suppliers where possible. This issue is particularly important to gas distribution companies because they have no hard currency revenue.

Reconstruction and development programs based on equipment imported from hard currency countries will result in a dollar-denominated LRMC or some sort of hard currency-denominated LRMC. This option is less attractive to Russian enterprises, although it is easier to estimate LRMC based on dollar costs than LRMC based on ruble costs.

6. ***Opportunity cost of gas as a substitute for alternative domestic fuels.*** For certain categories of natural gas consumption it is possible to identify an alternative fuel or fuels that can be used to displace gas. If the price of the alternative fuel is based upon international fuel markets, and if imports and exports of the alternative fuel are unrestricted, the border price of that fuel can be considered to be competitively determined.

Under this approach to gas pricing, the burnertip price of gas can be equated to the burnertip price of the alternative fuel where gas is a substitute for that fuel. If plentiful supplies of the alternative fuel are available to displace gas at a particular location, the alternative fuel price becomes the maximum price that the consumer in a particular market segment is willing to pay for gas. In the absence of gas-on-gas competition the price of gas may rise to this maximum level.

There are several difficulties with the application of this approach to gas pricing in Russia. First, the validity of the alternative fuel price as a competitive benchmark is limited only to the border price. The cost of transporting heavy fuel oil or coal to an export terminal will be a significant component of the total cost of producing and transporting the fuel. For locations within Russia, fuel prices may be very different from border prices. For many refineries, the cost of transporting heavy fuel oil to the border may be prohibitive. Second, prices of heavy fuel oil and coal may be

subject to price controls. Third, even in a competitive market economy there are regions in which one fuel is dominant. The price of gas is related to the cost of gas production, transmission and distribution, which need not be linked to the prices of petroleum products. A detailed analysis of supply and demand for each fuel would be necessary to identify the locations in Russia in which natural gas should not totally displace other boiler fuels and should not be totally displaced by other boiler fuels.

7. ***Prices necessary to provide a fair rate of return on assets that are revalued on the basis of replacement cost.*** Another approach to pricing is to estimate the replacement cost of the infrastructure of a gas transmission enterprise or gas distribution enterprise, and estimate the prices necessary to provide a fair rate of return on the total capital invested. If replacement cost is derived from costs estimated in hard currency, this approach may be used to avoid the valuation problems associated with measurement of the historical cost of assets purchased in rubles. An obvious problem with the use of ruble values is the effect of past inflation, which has practically wiped out depreciation charges based on costs incurred before 1991. After replacement cost is estimated, net book value can be estimated after cumulative depreciation is calculated.

A problem with this approach is that it lacks a strong theoretical basis for its use. In a market economy the assets of an enterprise will be valued on the basis of the amount an investor is willing to pay. This amount may be revealed through an acquisition of the enterprise by a competitive auction in which investors are invited to participate. This amount may also be calculated from the net present value of discounted cash flows, which in turn are a function of prices of goods and services sold. The result of such an acquisition, auction, or present value calculation may be higher or lower than an asset value based upon replacement cost.

If the infrastructure of a gas distribution enterprise is technologically obsolete, this infrastructure would not be worth replacing and therefore replacement cost would not be a correct measure of value. Similarly, if the infrastructure is not suited to a market economy, it would not be worth replacing. An example is the gas distribution infrastructure used to supply gas for cooking (and only cooking) to households. In a market economy this portion of the distribution system might never have been built. For this reason, replacement cost is not always a correct measure of economic value. LRMC-based pricing can address the problem of technological obsolescence by focusing on the least-cost technology currently needed to meet demand.

> If a distribution system is actually undergoing reconstruction, it will make sense to value the system on the basis of the cost of this reconstruction. In the reconstruction program, possibly only a portion of the system will be replaced. Thus the prices necessary to make a distribution system self-financing may include an allowance for a return on capital invested to replace portions of the distribution system. The self-financing approach must be distinguished from the replacement-cost approach.

In the present political climate in Russia, only the first three of these approaches to gas pricing are viable. The first approach - prices necessary to cover operation and maintenance costs - is not acceptable because it makes no allowance for capital investment. Therefore the only two approaches worth serious consideration are (1) prices necessary to make gas enterprises self-financing, and (2) prices consistent with prices prevailing in North America or western Europe. The latter may be called "world prices" or "international prices." In determining the price of gas exported to CIS republics, the Russian government pays close attention to "world prices." The idea that gas prices in Russia will eventually reach "world prices" is widely accepted.

The concept that prices must first reach the level needed to make enterprises self-financing, and later reach the level of world prices, is reflected in a February 1, 1993, statement by the chairman of the price committee:

> What we want today is the resources for the development of the gas industry, for construction of its production assets and this is the task the industry must handle on its own with the help of a new price. As far as world prices go, we will apply them when everything increases, including wages.[3]

In the long term the ideal solution is to have a competitive gas market whereby the gas price finds its own level. This price level may be approached through a regulatory framework in which the cost of service is derived from asset revaluation and establishment of a fair rate of return on total assets.

8.2 RECOMMENDED PRINCIPLES OF GAS PRICING

On the basis of our analysis of the cost of gas production and transmission, and the limited amount of information available on the ruble cost of gas distribution in Russia, we have

[3] Press conference on regulation of prices for natural gas and other natural resources, February 1, 1993, p. 4.

developed a proposal for gas pricing policies for each of the different functions in the gas supply chain.

Gas production. The appropriate pricing policy for gas production is to ensure that prices are at levels necessary to make gas enterprises self-financing. Each enterprise created through privatization and restructuring should set prices sufficient to recover all costs including capital costs. Recovery of operation and maintenance cost alone is inadequate. The important concept to stress is not the method of recovering costs (e.g. recovery of capital costs through calculation of a rate of return on an asset base) but the concept that capital costs must be recovered and regular capital outlays must be made to maintain system integrity. A second important concept is that wellhead price should be allowed to vary by region if costs vary by region.

In the long run, it would be desirable to encourage competitive bidding among several gas producing firms located in a gas field. At present the structure of gas reserve ownership does not support competitive bidding because Gazprom's production subsidiaries are organized along regional lines. Within each region there is a monopoly on non-associated gas production.

Given the present monopolistic ownership structure, non-associated gas production may be treated as a regulated industry. For example, production prices may be submitted by Gazprom to the Pricing Committee of the Russian Federation. The Pricing Committee may review the cost calculations used to show, for a particular production enterprise, that the price level is necessary to make the enterprise self-financing.

We assume that in the privatization of Gazprom, the non-associated gas production enterprises will become joint stock companies with 100 percent equity financing. From a lender's perspective the transmission and storage operations of Gazprom are more attractive as borrowers than the production operations, most of which would become risky ventures in a competitive gas market. If production is projected to be stable or declining, it should not be necessary for an enterprise to issue debt. Prices can be set so that the cash flow of the enterprise is sufficient to provide the capital needed to sustain production at existing levels. If the enterprise is expected to increase production substantially (for example, Yamalgazprom) some form of external financing will be needed.

Unfortunately, an administrative procedure will be needed to determine production targets for each enterprise for which the self-financing price level is to be determined. Given a production target it should be possible to compute the necessary level of capital

expenditures. Under competitive market pricing this administrative process could be eliminated.

To simplify the administrative process it would be possible to estimate the self-financing price level for only a small group of enterprises, which might be selected on a regional basis. The Russian gas producing industry could be divided into five or six regions, with a single price level in each region based on the projected gas production costs of a single enterprise. The U.S. experience with this sort of approach to wellhead prices is unsuccessful, however. In the 1960s the Federal Power Commission tried to establish "area rates" for natural gas producers. The impossibility of making a precise calculation of capital investment requirements (given uncertainty about the future relationship between reserve additions and drilling expenditures) led to regulatory delays that caused price increases to lag cost increases.[4] The gas producers did not have enough capital for investment and gas shortages ensued in the 1970s, in the interstate natural gas market.

We estimate that about a doubling of wellhead revenue per mcm will be necessary to raise revenue per mcm to the self-financing level. At present, production enterprises are not receiving revenues sufficient to cover their requirements for capital expenditures.

Because most of the non-associated gas in Russia is produced from very large gas fields, it is not possible to compare Russian and North American gas production costs without taking field size into consideration. On the basis of data for North America we estimate that costs from the giant fields should be in the neighborhood of 21 cents per mcf.[5] According to Gazprom statistics the average production cost of gas in 1990 was 4.27 rubles per mcm, which is equivalent to 21 cents per mcf when measured on the basis of the official exchange rate implemented in September 1990.[6] Although there are many problems associated with the choice of exchange rate and the differences between western accounting and CIS accounting, we conclude that wellhead production costs are between 20 and 30 cents per mcf.

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[4] See Chapter 5, "Regulating Producers," in M. Elizabeth Sanders, *The Regulation of Natural Gas: Policy and Politics, 1938-1978* (Philadelphia: Temple University Press, 1981).

[5] The basis for this estimate is presented in Chapter 2 together with a review of gas reserve data.

[6] A February 1993 article by Enron Corporation staff cites a June 1991 *Financial Times* report, "An Insider's Account," which shows a production cost of 24 cents per mcf in 1989. Margaret Carson and Bruce Stram, "Gas-export potential will grow until domestic economies hike local demand," *Oil & Gas Journal*, February 8, 1993. The ruble cost is not reported, but this dollar cost is roughly consistent with our figure of 21 cents per mcf.

The figure of 2600 rubles per mcm reported by Gazprom in the February 1, 1993 press conference does not include capital costs. At an exchange rate of 600 rubles per dollar, the operation and maintenance cost would be 12 cents per mcf. This is roughly consistent with a total cost of 20 to 30 cents per mcf.

Gas transmission. For this sector a pricing policy may be established to make transit fees consistent with transmission charges prevailing in North America or western Europe. Because Gazprom supplies both a domestic market and an export market, and capital is invested in hard currency, in barter arrangements, and in rubles, it is difficult to calculate the prices necessary to achieve self-financing. A much simpler and more direct approach to setting transmission charges is to estimate costs in dollars per mcm per 100 km, based on the physical characteristics of the system (for example, the age and diameter of the pipelines, and the total compressor horsepower) and the construction cost per mile of pipe or cost per horsepower of compressor capacity in market economies.[7]

This approach may be needed to set the level of transit fees to be charged for delivery of gas to Ukraine or to other republics. Because the Russian government has already proposed the use of "world prices" for the sale of gas to other republics, it is natural to have "world prices" for transportation of gas on behalf of other republics. A logical sequel to this development would be the use of "world prices" to set transit fees and transportation charges within Russia.

In the long run, it may be possible for the ruble to become fully convertible and for barter arrangements to be eliminated from Gazprom financing. Under these conditions the level of transmission charges could be established through a regulated return on an asset base, as in North America. This approach may not be required unless Gazprom's cost of transmission rises to a point at which it is higher than the level considered to be representative of North American costs. Given the large diameter of Russian transmission lines, this situation appears unlikely to develop.

In February 1993 Ukraine quoted a transit fee of $2.2 per mcm and Russia claimed that this level was far higher than the world average.[8] Thus the determination of the "world price" level of transit fees will be an outcome of the negotiations between Russia and the Ukraine.

[7] A review of gas transmission costs is presented in Chapter 5.

[8] "Ukrainians in Moscow to seek gas row solution," *Financial Times*, February 26, 1993, p. 36.

It may be possible to use these negotiations as a basis for setting long-run transmission charge targets in Russia.

Distribution. For this sector a pricing policy may be developed on the basis of long-run price targets based on distribution system reconstruction costs in hard currency. Because the World Bank is developing a program to lend funds for the reconstruction of gas distribution systems in selected cities, estimates of reconstruction costs are already being developed for these cities. For a long-run gas price target it would be suitable to use estimates of the cost in hard currency of 100 percent reconstruction of the gas distribution system for a particular city. For the purposes of this report we will use Ryazan because the best available information consists of estimates for Ryazan.
In the long run it may be possible to introduce pricing on the basis of a regulated return on asset base. Given the natural monopoly character of gas distribution networks, this will be a reasonable basis for setting prices when the ruble becomes fully convertible. During a transitional period in which ruble expenditures and hard currency expenditures are mixed, the development of a return on an asset base will be very difficult to implement unless a single currency is used to compute the asset base. It will be much simpler to apply a set of long-run price targets based on hard currency costs associated with reconstruction.

8.3 INTERRUPTIBLE SERVICE AND FIRM SERVICE

Because natural gas storage by the consumer is difficult, expensive, and potentially hazardous, the delivery of natural gas to the consumer may be viewed as a service rather than the sale of a commodity. In a market economy, different levels of service quality (for example, service reliability) are offered at different price levels. The price of gas in a gas supply contract is related to the terms and conditions of delivery, and to the reliability of supply. Prices for firm and interruptible supply, for example, are different.

One of the unfortunate aspects of centrally planned economies, in practice, is that productive activities tend to be viewed in terms of the supply of commodities rather than services. Quotas are established for the supply of commodities. Gas supply contracts are not needed, because supplies are distributed according to plan and usually according to the producer's requirements. Prices are not used to distinguish high-quality, reliable service from lower-quality, less reliable service. Although Russia is undergoing a transition to a market economy, these aspects of a centrally planned economy may remain for many years.

A relationship between price and quality of service may be an unfamiliar concept to gas industry officials as well as gas consumers. Given the urgent need to develop economically rational and meaningful prices in the gas sector, the development of different prices for different levels of service quality may have to be postponed to a later phase of gas price reform.

As we have discussed in Chapter 4, we do not see a need for Gazprom to provide lower rates for interruptible gas service, as an incentive to attract interruptible customers and interruptible load. Although the actual cost of interruptible service is lower than the cost of firm service, interruptible load would probably not increase significantly if lower rates were offered. There are very large political and logistical problems associated with quantifying the level of firm gas load and offering lower-cost gas supplies to interruptible customers. We therefore recommend that interruptible gas rates be the same as firm gas rates, for a transitional period. This policy would simplify the rate design process in two ways: it would prevent the development of a political controversy over which customers should have access to cheaper (interruptible) gas supplies, and it would defer the need to measure firm demand precisely, i.e. to specify daily contract quantities or monthly contract quantities.

An important exception is the export market to CIS countries, the Baltics, and formerly socialist European countries. For all of these export customers it would be reasonable for Gazprom to offer firm transportation service and interruptible transportation service as well as sales service. In international negotiations the political issues associated with gas supply interruption are unavoidable. From a Ukrainian or Lithuanian point of view the sales service presently provided by Gazprom is not "firm" and there needs to be a clarification of the distinction between firm and interruptible service.

At all levels - production, transmission, and distribution - gas purchasers should pay only for gas received. There are no contractual obligations between buyers and sellers that could be used to define minimum takes, take-or-pay obligations, or minimum bills. The quota system may be used for demand forecasting purposes but it should have no relationship to the reliability or firmness of service and no relationship to the price of gas. In every gas sales transaction, therefore, the seller should bear the risk that the level of demand he anticipated does not materialize. To the extent that this raises the required rate of return on total capital for gas producing associations or gas transmission enterprises, it may be necessary for the consumer to pay a higher price for gas than he would pay in a more stable and predictable economic system. Our recommendation is that risk associated with the uncertainty of gas demand be borne by seller rather than the purchaser, for a period of at least five years. After gas prices in Russia have stabilized and the transition to

a market economy is largely completed, it will be appropriate for gas customers to establish contractual obligations to pay for gas not taken. In the short term, however, payments for gas not taken tend to discourage efficient use of gas and thereby encourage wasteful gas consumption. Until customers are more familiar with energy efficiency alternatives and the future level of fuel prices associated with fuel-switching alternatives, it is not reasonable to negotiate daily contract quantities or to penalize a customer for failing to meet his "quota" of gas consumption.

8.4 IMPLEMENTATION CONSIDERATIONS

As mentioned earlier, the most realistic approach to pricing gas transmission services is likely to be on the basis of revenue requirements using a depreciated asset base based on book value. This happens to be the regulatory practice in North America, so that the two procedures, the regulatory analysis and the asset base valuation using book value, should produce comparable results. As it turns out, the first-year transmission rate at current through-put volumes has a calculated transmission cost of $6.58/MCM per 1000 km, compared to the estimated Urengoy-Moscow rate of $6.64/MCM (after adjustment for access fees). At reduced throughput volumes, that rate rises to $7.83/MCM per 1000 km. Considering the disparity of the sources of information and the difference in methodologies, this is a surprisingly good agreement suggesting that our year-by-year projections are acceptable, depending on the user's view concerning future through-put volumes. Since substantial increases in natural gas prices are inevitable to keep the pipeline viable in the long run, the reduced through-put volume scenario appears to be more relevant at the moment.

Using either scenario, the city gate prices developed appear to be reasonable. However, they are extremely high by Russian standards and in terms of Russian purchasing power in the household sector. Given the admittedly precarious exchange rate of 886 rubles per dollar (May, 14, 1993), the Moscow city gate price of about $30/MCM translates into 26,600 rubles/MCM, about seven times the current industrial wholesale price and forty-four times the current retail price to households. Given the current income levels in the household sector, this makes the continued subsidization of household retail prices inevitable. However, regardless of the subsidy arrangement to be chosen, Gazprom's overall revenue requirement must be met over a relatively short time interval.

Our suggestion would be that industrial wholesale prices be raised at a predetermined rate of 20% per quarter, plus any further increase in the ruble-dollar exchange rate. That would close the industrial wholesale price gap in about three years (2.75 years, to be exact). The

setting of export prices to the Baltic States and CIS countries is a matter of negotiation among the exporter, the importer and transit countries. To the extent that some of the importing countries have contributed financially or otherwise to the building of the pipeline system, credits may have to be negotiated. Nevertheless, as a minimum, a benchmark rate should be established immediately corresponding to the Uzhgorod city gate price of $37.20/MCM (or 33,000 rubles per MCM), nearly double the current CIS export price, plus any Ukrainian transit fees. That price should subsequently be subject to systematic increases in accordance with rising exchange rates, plus a surplus to capture part (and eventually all) of the border price rent. The latter adjustment may have to be approached gradually. For example, given the current international border price of $77.66/MCM ($2.20/MCF), or 68,800 rubles/MCM and the Uzhgorod city gate price, net of transit fees, of $37.20/MCM (33,000 rubles/MCM), a quarterly ramp-up by 10 percent will establish world-price parity, from full-cost recovery, in about 8 years.

Exports to Western European countries are easier to price. Russian natural gas will have to compete with natural gas from other sources (The Netherlands, Norway, Libya, for example) and with other types of fuels on the European market. At the moment, this is assumed to be the equivalent of $2.20/MCF at Uzhgorod, or 68,800 rubles per MCM, except that the transaction would have to be denominated in hard currency. That price should be established immediately, with recurring quarterly forward adjustments in new prices and settlements for past quarterly currency fluctuations.

That leaves the local distribution sector where our work has been less extensive. Decree No. 88, mentioned earlier, set the distribution margin for industrial consumers at 400 rubles/MCM, while the margin for households has been set at 300 rubles/MCM, i.e., lower than the industrial margin. That is contrary to the principle of LRMC pricing, since the high-pressure (6-12 bar or 88-176 psi), high-volume delivery of gas to industrial users is considerably less expensive than the delivery to households, especially in Russia where a three-pressure system is used for household deliveries. Estimates by other analysts have set the LRMC of industrial deliveries at $0.05/MMBtu, or roughly 1560 rubles/MCM at current exchange rates, about four times the allowable margin. By contrast, the LRMC of household deliveries, not including cooking, has been estimated to be around $4.00/MMBtu, or 125,000 rubles per MCM, i.e., 400 times the margin set by Decree No. 88. The LRMC of gas delivered for the sole purpose of cooking is roughly four times that of general household usage (space heating and hot water supply) and, for that reason, out of reach in terms of an ultimate adjustment to the LRMC.

It is generally recognized that natural gas deliveries even to households eventually need to be priced at or near the LRMC so that the gas will be used in accordance with its marginal

value. That would imply the re-design of the delivery system to include, at a minimum, metering devices and thermostatic controls, neither of which are in general use in households since their installation at current prices is not encouraged.

We would suggest that the industrial distribution margin be raised immediately to reflect the LRMC of 1560 rubles per/MCM, and be raised quarterly to track inflation. The household sector is a different matter. For example, adding to the city gate price in Moscow of 26,600 rubles/MCM the long-run marginal delivery cost to households (125,000 rubles) would imply raising the price to the household sector from its current level of 600 rubles/MCM ($0.019/MCF) to 151,600 rubles/MCM or $4.85/MCF, not unreasonable by Western standards but unthinkable in current-day Russia.

The household sector in Russia only consumes about four percent of Russia's overall domestic gas demand. Hence, a subsidy mechanism that keeps the industry at large self-sufficient will involve a 96% base supporting a 4% component, not counting exports. Given the household sector's consumption rate (1990) of 16 BCM, the overall subsidy will be on the order of 2.4 trillion rubles per year, if no price increase is introduced in the household sector. Spread over the other domestic consumers, such a subsidy would cost about 6,230 rubles/MCM, or about $0.20/MCF. Because the household share of gas demand varies regionally, the level of subsidy required from other consumers may vary regionally while averaging $0.20/MCF for the Russian Federation as a whole.

Another potential source for the subsidies would be Gazprom's exports, if an acceptable formula can be designed as to the respective sharing of the subsidy expense by Gazprom and the Government.

It is not economically efficient to maintain the household sector subsidy forever. However, setting the level and the rate of increase of household gas prices is more a political than an economic issue. We simply recommend a substantial one-time increase of natural gas prices for the household sector, followed by a steady upward adjustment over a long time span, perhaps as long as ten years, with the ultimate goal of dispensing with the subsidy altogether. In the meantime, the population could be slowly habituated to the ever-rising price of natural gas by noting on their bills both the amount billed to them and the subsidy that is carried by the gas industry at large.

8.5 ISSUES STILL TO BE DECIDED

The key policy question for gas pricing that must be decided by the Russians is how to optimize the hard currency gas earnings and at the same time sustain the standard of living and supply the basic energy needs of the Russian people. Questions include the following.

Where excess rent, subsidy, or other departure from market pricing of Russian gas seems warranted by conditions (such as exports versus domestic use, residential vs. industrial use), where should the differential be taken?

- Pipeline and distribution costs, requiring the bulk of financial infusion at this time, should be priced at service costs designed to produce the needed capital for system rebuild and expansion.

- Exploration and development costs, which are relatively less critical at this point in the Russian gas industry, can better withstand pricing consequences of policy goals.

- Departure from market prices is mainly needed in distribution, because household prices have been historically below industrial prices.

Given the foregoing, what degree of price subsidy is needed, and for how long, in order to ensure continued gas service to major urban area gas customers?

- As of 1993, city-gate prices, in a market environment, would range from $0.81 to $0.91/Mcf

- Wellhead price subsidies can probably be eliminated by 1994.

- Transmission should be able to move to market pricing by 1995, at least for gas sales to industry.

Alternatively, can a tax policy be constructed that accomplishes the required distributional goals, while maintaining a single wellhead price, i.e., at market?

- With transportation fixed on a basis of meeting future capitalization increments, positive taxation at the wellhead or point of delivery could gather available rents to meet other socioeconomic needs

-- Likewise, different levels of taxation for city-gate gas could enable a single wellhead price.

What blend of organization of the Russian gas system, public and private, aggregated versus disaggregated, will be most conducive to capital formation?

-- Joint venture ownership of transmission legs may be an attractive option, e.g., foreign investment coupled with contributing ownership (and investment) by Gazprom

-- The need to clearly determine the costs of transportation by those newly independent countries located between Russia and key gas markets in western Europe may suggest unbundling, and operating the system on a transportation basis.

APPENDIX A

THE RUSSIAN NATURAL GAS INDUSTRY
SELECTED STATISTICAL DATA

TABLE A-1

RUSSIAN - U.S. 1990 ENERGY STATISTICS

NUMBER OF GAS WELLS:	FORMER USSR	GAZ-PROM	% GAZPR.	U.S.
In Operation -	8,656	7,058	81.5%	272,541
Total -	9,722	7,844		

TOTAL GAS PRODUCTION:	FORMER USSR			GAZPROM			U.S.		
	Non-Assoc.	Asso-ciated	Total	Non-Assoc.	Asso-ciated	Total	Non-Assoc.	Asso-ciated	Total
Billion Cubic Meters	770.6	44.2	814.8	747.7	0.3	748.0	376.7	130.0	506.7
Trillion Cubic Feet	27.2	1.6	28.8	26.4	-	26.4	13.3	4.6	17.9

AVERAGE DAILY GAS PRODUCTION PER WELL:	F. USSR	GAZPROM		U.S.
	All Wells	All Wells	New Wells	All Wells
1000 Cub.M./D	256	307	587	3.79
MMCF/D	9.0	10.9	20.7	0.13

NATURAL GAS PRODUCTION COST:	FORMER USSR	GAZPROM
Rubels/1000 Cub.M.	4.27	4.10
Kopeks/MCF	12.1	11.6

CONDENSATE EXTRACTION COST	GAZPROM
Rubels/Tonne	8.17

CAPITAL INVESTMENT/ADDITIONAL GAS PRODUCTION	GAZPROM
Rubel/1000 Cub.M.	87.02

NATURAL GAS PROCESSING	GAZPROM
Volume of Processed Gas - Million Cub.M.	70.6
Products: Sulfur - 1000 Tons	2,510
Condensate - 1000 Tons	9,919
Helium - 1000 Cub.M.	9,460

NATURAL GAS TRANSMISSION - END-OF-YEAR	GAZPROM	
	Km	Miles
Existing Trunk Lines	211,515	131,457
1990 Annual Construction	5,016	3,117

COMPRESSOR CAPACITY - END-OF-YEAR	GAZPROM
1000 Kilowatts	46,597

AVERAGE TRUNK LINE DIAMETER	GAZPROM
Millimeters	1074
Inches	42.3

VOLUMES TRANSMITTED THROUGH TRUNK LINES	GAZPROM	
	BCM	TCF
Inlet Volume	767.3	27.1
Transmitted Volume	695.0	24.5
Marketable Volume	693.7	24.5

AVERAGE DISTANCE OF GAS TRANSMISSION	GAZPROM	
Kilometers - Miles	2,590	1,610

GAS TRANSMISSION COST	GAZPROM
Rubels/10,000 Cub.Meters	77.14

TABLE A-2

1990 REGIONAL GAS, CONDENSATE AND CRUDE OIL PRODUCTION

	NATURAL GAS Millions of Cubic Meters				CONDENSATE & CRUDE OIL Thousands of Tonnes		
	Non-Asso	Associated	Total		Condens.	Crude	Liquids
Northern Gazprom	7,334	-	7,334		516	-	516
Caucasus Gazpr.	482	-	482		4	8	12
Kuban Gazprom	2,092	-	2,092		23	-	23
Southern Ugtransgaz	6	-	6		-	-	-
Orenburg Gazpr.	44,745	27	44,772		5,686	157	5843
Astrakhan Gazpr.	2,094	-	2,094		733	-	733
Urengoy Gazprom	287,920	168	288,088	West Sib	6,868	451	7319
Yamburg Gazprom	158,757	-	158,757	West Sib	25	-	25
Nadym Gazprom	72,086	-	72,086	West Sib	-	-	-
Surgut Gazprom	17,581	-	17,581	West Sib	-	-	-
Tyumen	240	-	240	West Sib	-	-	-
Yamal Gazprom	-	-	0	West Sib	-	-	-
Yakut Gazprom	1,402	-	1,402		67	41	108
Norilsk Gazprom	5,093	-	5,093	West Sib	39	-	39
Ukraine	24,402	1	24,403		880	6	886
Central Asia	40,376	65	40,441	Total	1,525	243	1768
Turkmenistan	83,087	-	83,087	West Sib:	508	-	508
TOTAL GAZPROM:	**747,697**	**261**	**747,958**	**541,845**	**16,874**	**906**	**17780**
Ministry of Oil & Gas	22,915	43,906	66,821		1,339		
TOTAL USSR:	**770,612**	**44,167**	**814,779**		**18,213**		

Source: Gas Industry of the USSR, 1990; An Economic & Statistical Survey; State Gas Concern Gazprom and All-Union All-Union Research Institute; General Director I. A. Zhuchenko; Moscow; pp.17-19

TABLE A-3

MAJOR WEST SIBERIAN GAS FIELDS

TAZ PENINSULA & SOUTH	Initial Reserves - Billion Cub.Met.			Expected	Product'n to Date	Remaining Product'n
	A+B+C1	C2	A - C2	Ult. Recov.	End 1990	End 1990
Urengoy	12,518	285	12,803	11,500		
Yamburg	4,095	660	4,755	4,280		
Zapolyarnoye	2,631	39	2,670	2,430		
Medvezhye	1,548	-	1,548	1,470		
Severo-Urengoy	438	420	858	750		
Yuzhno-Russkoye	535	216	751	670		
Zapad.Tarkosalinsko	272	311	583	520		
Komsolmoskoye	458	-	458	410		
Yamsovey	436	35	471	400		
Vost. Tarkolasinskoe	267	104	371	330		
Gubkinskoye	352	-	352	320		
Yubileynoye (?)	324	19	343	300		
Total Taz	23,874	2,089	25,963	23,380	3,800	19,580
Total U.S Proved						4,730

YAMAL ON-SHORE	Initial Reserves - Billion Cub.Met.			Expected Ultimate	Product'n to Date	Remaining Product'n
	A+B+C1	C2	A - C2	Recovery	End 1990	End 1990
Bovanenkovskoye	2,239	1,912	4,151	3,740		
Kharassavey	861	404	1,265	1,300		
Krusenstern	363	758	1,121	1,000		
Total Yamal On-Shor	3,463	3,074	6,537	6,040	-	6,040
Total U.S. Proved						4,730

YAMAL OFF-SHORE	Initial Reserves - Billion Cub.Met.			Expected Ultimate	Product'n to Date	Remaining Product'n
	A+B+C1	C2	A - C2	Recovery	End 1990	End 1990
Russanovskoye	-	-	-	1,800		
Leningradskoye	-	-	-	900		
Total Yamal Off-shor	-	-	-	2,700	-	2,700
Total U.S. Proved						4,730

Note: Does not include reserves on Gydan Peninsula, for which data are not available.

Source: PetroStudies Co; Soviet Natural Gas Outlook; Vol. II; Organization, Economics, Exploration, Production; August 1991; p.24.

TABLE A-4

1990 - AVERAGE WELL DEPTH, Meters

	Develop. Wells	Explor. Wells
Northern Gazprom	2332	4625
Caucasus Gazpr.	854	2895
Kuban Gazprom	1958	2288
Southern Ugtransgaz		
Orenburg Gazpr.	3164	1950
Astrakhan Gazpr.	3885	
Urengoy Gazprom		
Yamburg Gazprom		
Nadym Gazprom		
Surgut Gazprom		
Tyumen	1764	
Yamal Gazprom		
Yakut Gazprom	2264	
Norilsk Gazprom	2400	
Ukraine	2204	3824
Central Asia	1825	2902
Turkmenistan	3015	3455
Gazprom Average	1959	2723

Source: Gas Industry of the USSR - 1990; op. cit.; p. 89

TABLE A-5

1990 DRILLING COSTS - BY COMPANY

Rubles per Meter

DEVELOPMENT WELLS

	Well Site Prepar'n	Move,Erect Derrick	Actual Drilling	Tests	Overh.	Break-downs	DEV.WEL TOTAL
Northern Gazprom	163.39	217.28	589.07	29.71	173.79	-	1173.24
Caucasus Gazpr.	1.74	14.55	115.60	10.83	13.62	0.02	156.36
Kuban Gazprom	45.17	40.55	315.56	71.41	46.76	0.16	519.61
Southern Ugtransgaz							
Orenburg Gazpr.	5.18	32.50	459.52	34.67	40.51	0.55	572.93
Astrakhan Gazpr.	15.97	21.96	564.41	52.68	110.66	-	765.68
Urengoy Gazprom							
Yamburg Gazprom							
Nadym Gazprom							
Surgut Gazprom							
Tyumen	52.15	22.14	352.90	19.67	64.73	1.18	512.77
Yamal Gazprom							
Yakut Gazprom	79.44	63.24	439.35	88.90	145.65	-	816.58
Norilsk Gazprom	19.29	39.18	309.24	28.02	57.28	-	453.01
Ukraine	29.31	19.35	203.30	25.49	30.69	0.32	308.46
Central Asia	18.89	20.89	360.80	31.11	48.46	-	480.15
Turkmenistan	7.04	38.08	287.80	17.17	56.99	-	407.08
Gazprom Average	**31.49**	**29.56**	**308.43**	**31.67**	**49.77**	**0.38**	**451.30**

EXPLORATION WELLS

	Well Site Prepar'n	Move,Erect Derrick	Actual Drilling	Tests	Overh.	Break-downs	EXPL.W. TOTAL
Northern Gazprom	92.94	27.96	805.09	149.63	154.77	-	1230.39
Caucasus Gazpr.	0.98	14.30	237.10	132.31	51.20	0.25	436.14
Kuban Gazprom	99.45	38.29	315.34	39.15	72.68	0.36	565.27
Southern Ugtransgaz							
Orenburg Gazpr.	5.80	31.93	3236.57	448.48	278.67	-	4001.45
Astrakhan Gazpr.							
Urengoy Gazprom							
Yamburg Gazprom							
Nadym Gazprom							
Surgut Gazprom							
Tyumen							
Yamal Gazprom							
Yakut Gazprom	299.89	229.41	209.12	105.32	189.20	-	1032.94
Norilsk Gazprom							
Ukraine	7.54	22.37	297.91	32.63	38.46	0.87	399.78
Central Asia	8.01	13.97	320.19	47.08	43.96	-	433.21
Turkmenistan	24.52	58.38	478.44	100.25	96.54	0.23	758.36
Gazprom Average	**41.57**	**43.63**	**423.00**	**81.63**	**82.70**	**0.33**	**672.86**

Source: Gas Industry of the USSR, 1990; An Economic & Statistical Survey; State Gas Concern Gazprom and All-Union Research Institute; General Director I. A. Zhuchenko; Moscow; pp.98-102

TABLE A-6

1990 GAS TRANSMISSION COSTS - Rubles /10,000 Cub.M.

	Wages & Supplem.	Social Insurance	Purchased El. Power	Internal Gas Use	Transm.& Stor. Loss	Materials	Amortiz'n of Capit.	Other Expendit.	Adjustm.	TOTAL COST
Average Gazprom	3.58	0.65	6.11	9.42	1.54	1.16	49.59	5.64	-0.55	77.14
Moscowtransgas	0.57	0.10	1.00	1.15	0.50	0.19	6.16	0.45	-0.12	10.00
Petersburgtransgas	0.59	0.11	3.79	0.91	0.16	0.18	6.90	0.62	-0.11	13.15
Western Transgas	1.43	0.26	6.18	0.57	0.16	0.53	11.01	1.53	-0.47	21.20
Georgia Transgas	3.25	0.71	0.13	1.54	3.04	0.46	18.05	2.01	-	29.19
Azerbaijan Transgas	2.55	0.46	2.93	2.98	9.06	0.54	17.17	2.14	-	37.83
Caucasus Transgas	1.81	0.33	0.87	2.87	1.04	0.59	15.40	1.68	-0.09	24.50
Volga Transgas	0.68	0.12	2.57	3.25	0.42	0.16	13.33	1.06	-0.04	21.55
Urals Transgas	1.01	0.18	0.49	2.15	0.32	0.38	9.47	1.31	-0.15	15.16
Southern Transgas	1.84	0.36	3.58	5.67	0.94	0.63	21.09	2.48	-0.60	35.99
Kuban Gazprom	3.44	0.62	0.45	1.81	0.31	1.18	15.55	6.58	-0.21	29.73
Yakut Gazprom	5.86	1.06	0.28	0.85	0.46	1.93	67.38	32.85	-	110.67
Norilsk Gazprom	6.24	1.16	0.02	0.62	0.43	1.15	24.91	3.71	-0.29	37.95
Turkmenistan Gazpr.	1.07	0.19	0.21	0.16	0.06	0.20	5.27	3.49	-	10.65
Orenburg Gazprom	0.68	0.12	0.42	1.92	0.28	0.24	11.38	1.35	-0.11	16.28
Tomsk Transgas	4.33	0.79	11.6	0.44	0.73	1.82	18.6	5.04	-	43.35
Ukraine Gazprom	1.22	0.22	1.85	3.28	0.46	0.39	17.94	2.38	-0.11	27.63
Tyumen Transgas	0.96	0.18	0.32	3.96	0.26	0.31	23.71	2.24	-0.05	31.89
Surgut Gazprom	2.19	0.40	8.00	2.92	0.26	0.97	29.32	3.79	-0.09	47.76
Central Asia Gazpro	2.16	0.39	3.69	1.42	0.38	0.91	18.88	3.92	-0.49	31.26
Astrakhan Gazprom	14.32	2.61	1.19	1.88	4.61	3.76	48.29	42.11	-31.48	87.29
Armenia Gazprom	4.14	0.79	0.25	0.78	2.36	1.09	14.31	3.92	-	27.64
Northern Gasprom	1.97	0.36	1.36	5.56	0.27	0.44	18.46	2.17	-0.40	30.19

Source: Gas Industry of the USSR, 1990; An Economic & Statistical Survey; State Gas Concern Gazprom and All-Union Research Institute; General Director: I. A. Zhuchenko; Moscow; pp. 136-140.