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PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run by the World Bank's Industry and Energy Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and 15 bilateral official donors in 1983, it focuses on policy and institutional reforms designed to promote increased private investment in energy and supply and end-use energy efficiency; natural gas development; and renewable, rural, and household energy.

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tWh

Abbreviations and Acronyms

ARCE	Romanian Energy Conservation Agency
b	billion (10^9)
bbl	barrel of oil
bcm	billion cubic meters
bcmd	billion cubic meters per day
bcmy	bcmy
BTU	British thermal unit
CCGT	combined-cycle-gas turbine power plant
cf	cubic foot
DH	district heating
ESMAP	Energy Sector Management Assistance Programme
GJ	gigajoule
GT	gas-turbine (power plant)
HSFO	high-sulfur heavy fuel oil
kcal	kilocalorie
km	kilometer
kPA	kilo Pascal
kWh	kilowatt hour
LFO	light fuel oil
LHV,HHV	low/high heating value
LCCD	least cost capacity development study
LPG	liquified petroleum gas
LSFO	low-sulfur heavy fuel oil
m	thousand (10^3)
cm^3	cubic meter
mcf	thousand cubic feet
MMcmy	MMcmy
MMcmd	million cubic meters per day
MMty	million tons per year
MM	million (10^6)
MMBTU	million BTU
MAOP	maximum allowable operating pressure
NAMR	National Agency for Mineral Resources
RADET	Bucharest district heating utility
RENEL	Romanian electric utility
ROMGAZ	Romanian gas utility

SH	space heating
t	trillion (10^{12})
tce	ton of coal
tcf	trillion cubic feet
TJ	terajoule
toe	ton of oil equivalent
WH	water heating

Conversions

1 cm	=	1,000 liters = 35.314 cf = 6.29 bbl
1 tcf	=	30 bcm
1 MMBTU	=	1 GJ = 1 mcf natural gas (energy content)
1 MMBTU	=	253 Mcal = 293 kWh = 1.059 GJ
1 GJ	=	239 Mcal = 277 kWh = 0.945/MMBTU
1 tce	=	7 x 10^6 kcal
1 toe	=	10 x 10^6 kcal
1 cm (natural gas)	=	8,000 kcal = 33,440 kJ = 0.00317/MMBTU
1 kcal	=	4.18 kJ
MMBTU	=	1,055 GJ
kWh	=	860 kcal
1 bar	=	14.5 pounds per square inch (psi)
1 psi	=	6.895 kPa

Currency Equivalents

Currency unit	=	Leu (plural = Lei)
3,000 Lei	=	1 U.S. dollar
1 Leu	=	.0003 U.S. dollar

All dollar values are U.S. dollars of 1996 unless otherwise noted.

Executive Summary

1 In 1993 the government of Romania formulated a comprehensive policy for the development of the oil and gas sector with the cooperation of the World Bank. This policy was aimed at addressing key issues in the sector, which included (a) the critical need for capital investment to arrest the decline in the domestic production of oil and gas as well as to rehabilitate the oil and gas infrastructure; (b) the high level of inefficiency of the entities within the sector caused by a lack of autonomy and commercial orientation; and (c) the serious obstacles to private sector participation caused by the absence of an appropriate legislative framework and pricing policies.

2 Since then, the government of Romania has embarked on a series of reforms that include the formulation of a new Petroleum Law, approved by Parliament in December 1995; creation of the National Agency for Mineral Resources (NAMR), which is the independent regulatory agency responsible for granting concessions and enforcing oil and gas pricing policies; restructuring of the main entities of the sector; and development of a policy for rationalization of producer and consumer prices for oil and gas.

3 The World Bank is assisting the government in the implementation of these reforms through its Petroleum Sector Rehabilitation Loan (August 1994). Components of this project include supporting institutional reforms such as the corporate restructuring of ROMGAZ and PETROM, encouraging environmental abatement and the increase of oil and gas production, and replacing of the most corroded sections of gas distribution and transmission lines. In order to lend further support to the reform process, ROMGAZ requested the assistance of ESMAP in 1994 to prepare the Gas Development Strategy, which would identify investments for an infrastructure development plan, including transmission, distribution, and storage, and which would be in line with the prospects for the supply and demand of natural gas over a medium-to long-term time frame.

4 This study formulates the Gas Development Strategy (GDS) by analyzing (a) the declining level of domestic gas production and the uncertainties surrounding the future availability and supply of domestic and imported gas; (b) the size of the future market for natural gas in relation to the cost of gas supplies and the economic value of gas to the consumer; and (c) the level and prioritization of investments needed in gas sector infrastructure. The study also makes recommendations concerning the ongoing restructuring of the industry and the formulation and implementation of a gas pricing policy, which will ultimately lead to a self-financing gas industry and encourage gas supplies to be used in their highest value applications.

Major Findings and Recommendations

Domestic Supply and Demand

5 Romania's domestic gas production will decline from 19 bcmy in 1995 to 12 bcmy by 2010. The economic demand is expected to increase to 27 bcmy by 2010, causing a gap between the demand and domestic supply of 15 bcmy by 2010. Although some of the supply shortfall may be met from the development of new domestic discoveries, the major part will need to come from increased levels of gas imports, which will thereby greatly increase Romania's dependence on external sources of gas.

Tail Gas Reserves

6 As the producing reservoirs become exhausted, a higher proportion of domestic production will be in the form of low-pressure tail gas produced at less than 10 bar. By the year 2010, a total of 85 percent of domestic production will be low-pressure tail gas. The unusually low operating pressures and excess capacity in the Romanian transmission system present an opportunity to use the tail gas without excessive investments in compression. Failure to exploit the tail gas will further increase the supply shortfall from 15 bcmy to 24 bcmy by 2010, and this, in turn, will increase the cost of gas imports, because the missing volumes of gas will need to be imported at international prices (see below). A high priority needs to be given to the exploitation of the tail gas either by inviting private sector participation in the form of joint ventures with ROMGAZ or by offering concessions to the domestic and foreign private sector. With respect to new discoveries, the NAMR is engaged in program to promote exploration that has attracted high international interest. However, attention needs to be focused on streamlining the follow-up bid evaluations and timely contract negotiations so that work can begin quickly.

Gas Sector Investments

7 With full exploitation of domestic tail gas reserves, the required investments in rehabilitation and expansion of the gas sector infrastructure are estimated at $3 billion (present value) up to the year 2010, and the bill for gas imports will be $5 billion. Failure to exploit the tail gas will increase the gas import bill to $9 billion. In either case, ROMGAZ does not have the financial resources to meet the investment requirements and pay for gas imports. It is therefore necessary for the gas sector to reduce fixed costs and improve the tariff structure to increase revenues. It must also attract private investment with an industry structure and regulatory system that encourages international competition in upstream and downstream activities. The sector reform process is already under way with the establishment of the NAMR to oversee the implementation of third-party open access (TPA) to the national transmission system and to approve tariffs for captive consumers (in conjunction with the Ministry of Finance). However, the prospects to increase private participation in the production and distribution of natural gas in Romania are critically dependent on raising producer and consumer gas prices to economic levels.

Gas Pricing

8 The current gas consumption in Romania is 25 bcmy. This is higher than the economic demand, because although the prices of competing fuels are close to their international levels, gas prices[1] are lower than economic cost and are at a uniform level of $1.7 per million BTU (MMBTU) for industrial consumers, and $0.6 per million BTU for residential and commercial consumers. This has brought about the use of gas in applications where it is uneconomical (such as for cement production, which should switch to coal) and has discouraged energy conservation. In view of Romania's diminishing gas resource, the objective should be to divert gas supplies from low to high-value uses (such as for future combined-cycle power generation plants and existing residential consumers), but these high-value consumers should pay a higher price for gas to reflect its true economic value. A fundamental reform of the gas pricing policy will eliminate the noneconomic demand, create incentives for investment in energy-efficient technologies (potential energy savings are 20 to 30 percent), reduce the bill for gas imports, and provide the basis for a financially self-sustaining gas industry without the need for direct or indirect subsidies from the government.

9 The pricing policy can be implemented in two stages. The first will need an increase in the price of gas to cover depreciation of ROMGAZ fixed assets and its five-year investment plan, and will require price increases[2] from $1.7 to about $3.2/MMBTU for industrial consumers, and $0.6 to about $4/MMBTU for residential consumers. This represents a sevenfold increase in the price of gas for residential consumers; thus, a defined program of phased price increases is needed to take account of the income constraints of the population. The second stage would involve freeing up consumer gas prices to allow market parity with competing fuels. This would be needed to cover the longer-term investments needed by the sector and to encourage interfuel substitution in the most efficient way.

Gas Transactions

10 To facilitate transactions within the sector and to fully realize the government of Romania's objective to introduce TPA on the national transmission systems, the government needs to (a) adopt a two-part billing system (commodity and capacity charge) for industrial customers with adequate metering; (b) implement transparent transaction prices between gas production, transmission, and distribution subsidiaries based on a two-part system of fixed and variable costs; and (c) implement a system of distance-based transmission tariffs for large industrial consumers operating off the transmission system, consistent with open access. These requirements can be implemented in the short-term and offer a transparency consistent with the requirements for eventual accession of Romania to the European Union.

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1. Prices are as of June 1996, excluding VAT.

2. Assumes domestic producer price is referenced to the import price of Russian gas or fuel oil, using 1994 international prices. International prices vary over time.

11 This transaction framework is consistent with a strategy to supply the *basic market* (for example residential and commercial consumers) that would—at least temporarily—be within the scope of traditional regulated public utilities. At the same time, this framework could be the basis for establishing conditions by which the *alternative market* (large industrial users) could be supplied by independent suppliers (both domestic and foreign) through the use of third-party open access to the national transmission system.

Gas Imports

12 Russian gas is received as payment for (a) gas transit services provided for Turkey and Bulgaria, (b) for hard-currency transactions between the government of Romania and GAZPROM, and (c) for gas volumes brought in by independent importers for fertilizer production. Apart from transit supplies for Turkey, gas imports from Russia are not underpinned by modern long-term contracts with the government of Romania, which would contain internationally accepted clauses, including take-or-pay penalties, minimum-load-factor conditions, or gas price indexation. Romania has suffered as a result—for example, in having no flexibility in imports to meet peak winter demand. Romania will become more dependent on imported gas, and the mission recommends that future contracts involving the government of Romania and foreign suppliers should be based on these modern long-term contracts, which are accepted practice in the international gas industry.

13 The proposals for a gas pipeline from Iran to Europe via Romania, or the Black Sea LNG terminal, can only be seen as long-term options because of their complexity and cost. The proposed interconnection between Ukraine and northwestern Romania would provide a second source of Russian gas, the major benefit being to achieve a better-balanced transmission system through direct supply to western Romania, which currently suffers supply constraints. The implementation of this project would need to be underpinned by a long-term supply contract. The proposed pipeline connection with Hungary would put Romania in a good position to achieve commercial diversification of supplies through swap deals with Western European gas companies, some of which may be eager to sell excess gas supplies. This scheme is an important step toward securing future gas supplies from outside sources and should be supported, again providing the investments can be underpinned by modern long-term supply and transportation contracts negotiated at economic price levels.

Key Recommendations

14 The mission proposes the following key recommendations, which are detailed fully in the main report:

- The government should implement a program of consumer gas price increases with target levels of approximately \$3.2/MMBTU for industrial and \$4/MMBTU for residential consumers, to cover the cost of gas supply to ROMGAZ, as well as its current investment program. Reduce the impact of price increases on the poorest residential consumers through lifeline rates or staged increases. The target tariff levels need to be achieved in line with an accelerated program for privatization and they need to cover the true costs of supply. Ultimately, consumer gas prices to non-captive consumers should be freed to reach market levels.

- Romania should implement (a) two-part billing (commodity and capacity charge) for industrial customers with adequate metering; (b) transparent transaction prices between gas production, transmission, and distribution subsidiaries based on a two-part system, (c) a system of distance-based transmission tariffs for large industrial consumers operating off the transmission system consistent with open access; and (d) interruptibles gas pricing.
- Until consumer prices reach market levels, the government to ensure the priority of supplies of natural gas to residential and commercial consumers who already have a direct supply of piped gas as well as to other highest-value consumers. The acquisition of new residential consumers who will not use gas for cooking, water heating, and space heating should be discouraged.
- Development of tail gas reserves should be afforded high priority. The conditions (legal, financial and contractual) for private participation in the production of tail gas (including increased recovery) and in the local distribution of low-pressure tail gas should be detailed in a policy document to be prepared for dissemination to potential investors.
- The government of Romania should seek future gas supply agreements with foreign suppliers based on modern long-term contracts, which are accepted practice in the international gas industry. The proposed pipeline connection with Hungary should be given high priority because it will facilitate diversification through access to potential Western European suppliers.

Gas Reserves and Supply Potential

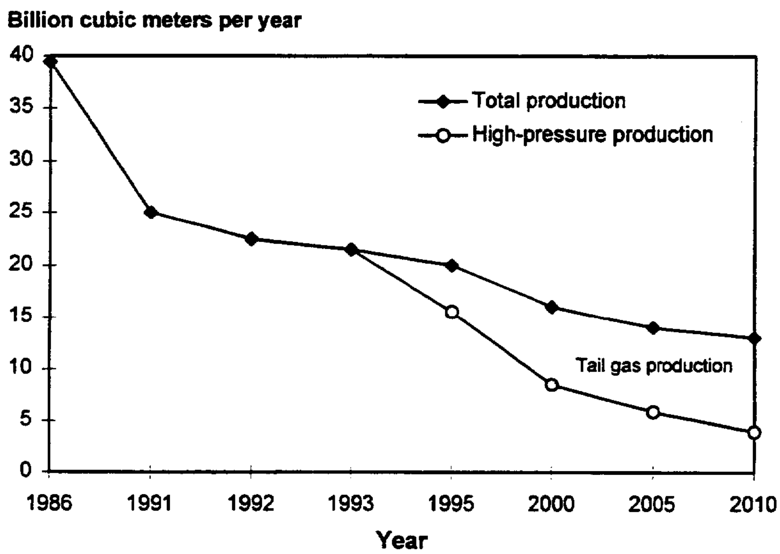
15 Romania's domestic supply of natural gas derives from 120 nonassociated gas fields located mostly in the Transylvania basin and operated by ROMGAZ (the national gas company), as well as more than 100 associated and nonassociated fields operated by PETROM (the national oil company) and located outside Transylvania. Aggregate production from these reservoirs has declined from a peak of 39 bcmy in 1986 to 19.1 bcmy in 1995, and will continue to decline to about 12 bcmy by 2010, as shown in Figure 1.

16 This decline represents an aggregate production of 235 bcm between 1996 and 2010. Roughly 132 bcm can be produced at pressures above 10 to 15 bar at a cost competitive with gas imports, and the remaining 103 bcm is mostly made up of tail gas production, which could be produced down to approximately 3 bar. These volumes do not take future discoveries into consideration, and foreign companies are now actively exploring for oil and gas in Romania with some early signs of success.

17 Unlike in other countries, where typical economic cutoff pressures are 10 to 30 bar, tail gas has an unusual significance for Romania, because the national transmission system is presently underutilized due to declining domestic production and is typically operated at pressures of 25 to 30 bar. This presents an opportunity to use the tail gas

without excessive investments in compression and transportation capacity, and in some cases it will be possible to supply the tail gas directly to local distribution networks. If valued at current import prices, the tail gas is worth $3 to $4 billion to Romania. The investments necessary to recover volumes of tail gas are likely to be less than the value of the recovered gas based on import parity. The efficient recovery and exploitation of this gas is a major issue for the Romanian gas industry, and international experience shows this to be of interest for private sector participation.

Figure 1 Romania: Natural Gas Production 1986–2010



External Supply Sources

18 The demand projections prepared for this study (see below) indicate that the supply–demand deficit will increase to 15.0 bcmy by the year 2010, but failure to exploit the tail gas reserves would increase this deficit to 24.0 bcmy. In any event, Romania will become increasingly dependent on gas imports, and the deficit will need to be made up, mostly from gas imports, although domestic production from new discoveries in Romania could make an important contribution to supply. With respect to the latter, the NAMR is engaged in an energetic exploration promotion program that has attracted high international interest. Although the volumes of gas to be discovered are inherently uncertain, the recent offshore discovery by Enterprise Oil demonstrates a real potential for reducing the import requirements through the exploitation of new discoveries. With respect to external supplies, several sources of imports are envisaged, as noted below.

Russia

19 Russian gas is imported from the transit line at Isaccea. An interconnection project between Ukraine and Satu Mare (in northwest Romania) is foreseen as providing a

second access to Russian gas, but its major benefit would be to achieve a better-balanced transmission system through a direct supply to western Romania, which currently suffers supply constraints. ROMGAZ is also considering a third source of Russian gas from a pipeline link through Moldova. Currently, Russian gas is received in payment for gas transit services provided for Turkey and Bulgaria, for hard-currency transactions between the government of Romania and GAZPROM, and as volumes brought in by independent importers for fertilizer production. Apart from transit supplies for Turkey, gas imports from Russia are not underpinned by modern long-term contracts, which contain internationally accepted clauses including take-or-pay penalties, minimum-load-factor conditions or gas price indexation. Romania has suffered as a result—for example, in lacking flexibility in imports to meet peak winter demand. Since Romania will become more dependent on imported gas, future contracts involving the country's government and foreign suppliers need to be based on these modern long-term contracts, which are accepted practice for the international gas industry.

Western Supplies

20 ROMGAZ is evaluating a short pipeline connection with Hungary, with the goal of securing volumes from West European suppliers. This connection would give Romania the best prospects for achieving commercial diversification of supplies through swap deals with West European gas companies, some of which are eager to sell excess gas supplies. This scheme is an important step for Romania toward securing gas supplies from diversified sources and should be supported, again provided that the investments can be underpinned by modern long-term supply and transportation contracts negotiated at economic price levels.

Middle East (Iran)

21 A new supply route bringing gas from Iran to Europe is under study by European gas companies. A gas pipeline running from Turkey through Central Europe is one of the proposed transportation options, in which case Romania would become a transit country and receive a new source of diversified gas supplies. The number of countries involved in this project, the evolution of European gas markets, the large investment required, and the geopolitical uncertainties are likely to require a long maturation period. This new supply route can be envisaged in the period from 2005 to 2010 at the earliest, and several alternative routes remain in competition with this scheme.

22 The Black Sea LNG terminal option has not been considered to be realistic. Mediterranean LNG supplies are almost entirely committed for the period from 2000 to 2010; the crossing of the Bosphorus strait by LNG tankers has raised hazard-related issues; and the cost of new LNG (Middle-East) is likely to be in the \$3.5 to \$4 /MMBTU (c.i.f.) range.

Potential Gas Markets

23 The present consumption of natural gas (domestic production plus imports) in Romania is 25 bcmy, accounting for about half of Romania's primary energy supply. This

represents at least twice the average share of gas in primary energy compared with that of OECD countries. The energy intensity for Romania is also roughly double the OECD average and reflects the past development of highly energy-intensive industries as well as pricing policies that have not encouraged investment in energy-efficient technologies.

24 The forecasts of economic demand for natural gas prepared for this study were based on a comparison between the economic value of gas in the various end-user categories (the netback value) and the cost of gas supplied to each of these categories. Actual demand for natural gas will depend on the gas pricing policies the government of Romania ultimately chooses to adopt.

Residential and Commercial Markets

25 The assessment of the economic demand for natural gas in the residential and commercial sector requires an analysis of the conditions under which gas could replace alternative fuels for cooking, water heating, and space heating. In Romania, the situation is complicated by the existence of district heating systems, which provide heat and hot water to residential apartment blocks and commercial enterprises. These consumers sometimes have a direct supply of piped gas, used mainly for cooking. District heating and direct piped gas account for more than 75 percent of the energy consumption in the residential and commercial sector, with gas being the main source of fuel for district heating plants.

26 *Existing Consumers of Natural Gas.* Where residential and commercial consumers already have a direct supply of piped gas (whether they are connected to district heating systems or not), the gas netback values at the point of ex-transmission are high ($4 to $8/MMBTU). These high values demonstrate that in an environment where all consuming sectors are competing for scarce gas supplies, a policy that gives priority of supplies of natural gas to consumers in the residential and commercial sector who are already connected is of high economic benefit to Romania.

27 Where gas is used as a fuel for an existing district heating system, the value of gas at the inlet to the district heating plant (ex-transmission) is about $3.9/MMBTU. If the plant and the heat network were to be closed down, and instead a new gas distribution system were constructed to provide a direct supply of gas to the apartment blocks, the value of gas at the inlet of gas distribution systems (ex-transmission) would also be around $3.5 to $3.9/MMBTU. This implies that from an economic standpoint, continuing to supply gas to the district heating plant is equivalent to closing down the plant and to constructing a new gas distribution network to supply gas directly to end users. This equivalence assumes that the cost of refurbishment of the heat distribution network is consistent with a district heating system in reasonably good physical shape, and it implies that the economic decision of how to proceed needs to be taken on a case-by-case basis.

28 *New Consumers of Natural Gas.* The construction of gas distribution systems to connect new consumers is economically viable when these consumers use gas for combined cooking, water heating, and space heating. In this case, the gas value ex-transmission is estimated at $3.5/MMBTU, which includes the cost of expanding existing networks or of building new ones. The gas value is greater than the cost of supplying gas ex-transmission (approximately $3.2/MMBTU); therefore the construction of new distribution networks

appears economically viable. In practical terms, the new gas distribution networks should only be constructed where there is no existing heat distribution system that is in reasonably good condition and that could be used instead of gas to supply heat for space and water heating.

29 The financial viability of constructing new gas distribution systems should be analyzed based on pricing criteria that reflect true economic costs. This may not currently be the case because urban communities are encouraged to use gas because its price is far below that of all alternative supply options. This creates a noneconomic demand for gas.

30 *Gas Demand in the Residential and Commercial Sector.* Table 1 shows the economic demand for gas in the residential and commercial sector through the year 2010, as estimated in this study.

Table 1 Economic Gas Demand in the Residential and Commercial Sector 1995–2010 (bcmy)

	1995	*2000*	*2005*	*2010*
Total demand	4.0	4.0	4.4	5.1

31 Economic demand is forecast to increase to about 5 bcmy in the year 2010. This represents an economic demand forecast where the value of gas ex-transmission is equal to or greater than the cost of supplying gas to ex-transmission and assumes a cost of gas (domestic production or imports) of about $2.6/MMBTU and transmission costs of roughly $0.4 to $0.6/MMBTU. It also assumes a progressive increase in the price of gas to residential consumers to eventually reach levels similar to those of market economies and assumes that programs will be developed and implemented to improve insulation of buildings and promote energy conservation.

Industrial Markets

32 Direct use of gas by the industrial sector is currently approximately 12 bcmy, which represents nearly 40 percent of the total energy and feedstock consumed in the sector. In addition, most of the heat consumed but not generated by the industrial sector is supplied by RENEL and other heat-generating plants, most of which are gas based. Thus, gas is by far the most important source of energy in the Romanian industrial sector.

33 Gas demand has been dominated by the fertilizer, chemical, iron and steel, heavy machinery, and construction material industries, which have accounted for about 80 percent of total gas consumption in the industrial sector. These industries are facing difficult restructuring issues caused by the loss of markets, obsolescence of plants, and shortages of raw materials. Their future is uncertain. It is therefore only possible to make broad estimates of future demand for gas. The balance of gas consumption includes the more diversified and smaller nonspecified industries (NSI), which are less vulnerable.

34 *The Fertilizer and Petrochemicals Industries.* At the end of the 1980s, ammonia production in Romania was about 4.5 million tons per year, produced in eight industrial

complexes with three generations of plants (early 1960s, late 1960s, and early 1970s). During this period, Romania exported much of its fertilizer production. Today, the third-generation plants are operating, the second-generation plants are on standby, and the first-generation plants are shut down. Actual production has declined from 2.2 million tons per year in 1990 to 1.8 million tons per year (MMTy) in 1993, of which 1.4 MMTy were produced by the five modern complexes.

35 The five modern complexes could supply the domestic market, estimated at about 1 to 1.3 million tons of ammonia, in the period from 2000 to 2010, and any excess production from these plants could be exported. The gas netback would be of about $4 to $4.5/MMBTU from these plants, assuming a domestic fertilizer price of $130 per ton. The netback values, however, are sensitive to the international price of fertilizers. The construction of new nitrogenous fertilizer plants at this time clearly would be uneconomical.

36 The strategy of the industry should be to run the plants on a marginal cost basis when international market prices are high, which would imply that these plants can secure gas supplies at prices compatible with conditions in the fertilizer market. Such gas supplies can be negotiated directly between the Romanian fertilizer industry and foreign gas suppliers such as the former Soviet republics, or with foreign marketing ventures, which could enter into gas supply agreements (that include buy-back agreements for the products) with the Romanian fertilizer industry. Such arrangements are already in place in Romania, where imported gas supplies contracted directly by the fertilizer industry are transported through the ROMGAZ transmission system with payment of a transport fee. The gas volume required for supplying the domestic market and for exports would be about 2.3 bcmy.

37 The gas market for other petrochemical industries would be limited to the production of methanol on an intermittent basis (0.3 bcmy), depending on the international price of methanol.

38 *The Iron and Steel and Cement Industries.* Both the iron and steel and the cement industries are undergoing restructuring, which should result in lower gas consumption in the medium term. This is due in part to different manufacturing processes (iron and steel) or to the use of alternative sources of energy (cement). The gas demand in the iron and steel sector for the period from 2000 to 2001 will be roughly 0.3 bcmy for process heating, where the gas netback value is about $4/MMBTU. This compares with a gas consumption of 1 bcmy in 1993.

39 Gas consumption in the cement industry was 0.3 bcmy in 1993, which represented 39 percent of the total consumption of the sector, the remainder being heavy fuel oil. From a technical viewpoint, there is no advantage in using gas instead of coal for making cement. Based on the cost of coal ($2.2/MMBTU) and the cost of converting the cement kilns from gas to coal ($0.8/MMBTU), the resulting gas netback value at the plant is $3/MMBTU, which is too low to justify using gas for making cement in an environment of constrained gas supplies. For these reasons, cement kilns should be converted to burn coal. The remaining gas consumption not displaced by coal (ancillary uses) is estimated at

0.2 bcmy, with a netback value of $3.9/MMBTU, and this represents the long-term economic demand for gas in cement production. Like the fertilizer industry, these industries should be encouraged to look for their own sources of gas inside or outside Romania.

40 *Nonspecified Industries.* The nonspecified industries (NSIs) consist of small and medium industries supplied by the gas network, with demand divided almost equally between plants supplied directly from the transmission system and those supplied from distribution systems.

41 Energy consumption of NSIs dropped significantly in 1988 and has been recovering slowly. The decline was primarily due to the slowdown in the industrial activity and to the introduction of energy conservation measures. Comparison of specific consumption with Western standards indicates that some plants are close to Western standards, whereas others are quite inefficient, and it is reckoned that the potential for energy savings is high (30 percent or more). Potential for energy savings exists in boiler plants, processes, and space heating of industrial premises.

42 *Boiler Plants.* A large number of plants are used to run centralized boilers serving processes, utilities, and providing heat to households and community buildings. These facilities are likely to be replaced progressively with more efficient decentralized boilers with efficiencies of 85 percent and improved distribution systems, thus resulting in energy savings of 20 to 30 percent.

43 *Processes.* Experience in other East European countries indicates that savings of 20 to 30 percent in gas consumption are possible with the acquisition of modern equipment geared toward improving the quality of products and making them competitive with imports. Similar levels of savings should be possible in Romania.

44 *Space Heating of Industrial Premises.* Industrial premises in Romania are often vast, ventilated, and noninsulated, and are heated with steam convectors. These could be replaced by radiant systems, which provide greater comfort and offer an energy savings of around 30 percent.

45 In terms of total energy demand it is likely that the level reached in the period from 1992 to 1993 will be maintained over the period from 1995 to 2010. This would imply that a recovery of energy demand can be offset by energy savings, by the restructuring of the sector toward light industries, and by modernization of equipment. For energy savings to be realized, gas prices will have to be at least adjusted to cover the true cost of supplies and ultimately to take account of the costs of competing fuels. Programs will have to be implemented to support energy efficiency and modernization. The economic value of gas in the NSIs will be in the range between $3.2 and $5.7/MMBTU (ex-transmission), depending on the type and location of the industry.

46 *Aggregate Gas Demand for Industry.* The forecast of the economic demand for natural gas in the industrial sector is summarized in Table 2.

Table 2 Economic Demand for Gas by Industrial Sector, 1993 and 2010 (bcmy)

Sector	*1993*	*2010*
Fertilizer and methanol	3.5	2.6
Iron and steel	1.1	0.25
Cement	0.3	0.15
NSIs	6.9	7.6
TOTAL	11.8	10.6

Power Generation

47 RENEL is responsible for about 96 percent of Romania's power generation and the associated production of heat, and it is currently the largest consumer of natural gas in the country. Over the last few years, the demand for power by industry has fallen sharply due to falling industrial output, whereas demand in the residential and commercial sectors has increased. The main fuel used by RENEL is natural gas, which accounted for 46 percent of the total fuel consumption in 1991.

48 The power sector development plan *up to the year 2000* is largely based on the modernization of existing plants and the completion of plants under construction. The least efficient units should be retired, the more efficient units should be refurbished, and the partially constructed units should be completed. The plan requires capacity additions that include (a) the refurbishment of 1,800 megawatts (MW) of existing coal and lignite capacity, (b) the completion of the existing Cernavoda 700 MW nuclear plant and the Turceni 300 MW lignite plant, (c) the retirement of 1,300 MW of existing capacity, and (d) the refurbishment and completion of hydroelectric capacity totaling 820 MW. The total available capacity planned for the year 2000 is 17 GW, of which 2.6 GW would be oil-, and 1.4 GW gas-fired. This represents a potential gas demand of about 2 bcmy for gas-fired plants, and an additional 4 bcmy if the oil- and gas-fired plants are converted to burn gas only. Currently, approximately 1 bcmy of natural gas is used as complementary fuel in lignite and coal-fired plants, and continuation of this practice could further increase the potential demand for gas. Therefore, the total potential consumption of gas for power generation and associated cogenerated heat by the year 2000 is estimated at between 6 and 7 bcmy.

49 The fuel options for plants to be built *after the year 2000* are still open and will depend on the relative cost of alternative generation modes. Beyond the year 2000, the candidate power plant options are (a) the refurbishment of existing oil and gas burning plants; (b) completion options including six cogeneration plants under construction, four nuclear units that remain to be completed, and hydroelectric capacity; and (c) the construction of plants that would include a combination of gas-fired combined-cycle plants (300 and 660 MW), and conventional coal-, lignite-, and fuel-oil-based power plants.

50 The power sector capacity and peak-load balance indicate that in 2010, the gap to be covered by new capacities should be around 2,000 MW and 4,500 MW, for the low and high-power demand scenarios, respectively. Whether this gap can be entirely covered by new gas-fired units depends on the price of gas. Assuming that the whole gap is covered by gas-fired units, the maximum potential gas demand corresponding to the 2010 gap would be 4 bcmy (low case) or 7 bcmy (high case). For the existing power stations remaining in operation in 2010, the potential gas demand should be about 2.6 bcm in gas-fired plants and another 1.6 bcm in plants converted to gas, with the potential consumption of gas as a complementary fuel at existing lignite and coal-fired plants at about 1 bcm. This results in a potential gas demand for power generation and associated cogenerated heat of 8 bcmy (low scenario) and 12 bcmy (high scenario) in the year 2010.

51 The value of gas (ex-transmission) when used in existing oil and gas plants is estimated at about $3.9 to $4.6/MMBTU, whereas the value of gas when used as a supplementary fuel in coal- and fuel-oil-based generating plants is $3.6 to $3.9/MMBTU. The netback analyses show that the least-cost option for base-load plants would be gas combined-cycle generating plants, where gas would have a value of $4.1 to $5.2/MMBTU, depending on the location of the plant, with the higher values applying to plants in the western part of Romania. Although the maximum potential demand for gas for the power sector in 2010 is about 12 bcmy, this includes plants where the value of gas is low ($2.5/MMBTU). If gas is restricted to power plants in which gas has a value of $3.4/MMBTU or above, the total economic gas demand is about 11.2 bcmy.

52 The economic demand for gas in power generation is summarized in Table 3. This shows that the gas supply to existing plants will decline as some oil- and gas-fired plants are retired, as plants are modernized and once the consumption of gas as a supplementary fuel is eliminated. After the year 2000, new combined-cycle plants will be introduced, and there will be a rapid increase in gas demand. This projection assumes that *all* new capacity will be gas based, but it is likely that part of the new power capacity will be coal based or other in order to increase the security of the fuel supply to the power sector.

Table 3 Economic Demand for Gas in Power Generation, 2000–2010 (bcmy)

	2000		*2005*		*2010*	
Plant type	*Low*	*High*	*Low*	*High*	*Low*	*High*
Existing	5.7	5.7	5.3	5.3	4.1	4.5
New	0	0	0	1.0	3.5	6.8
TOTAL	5.7	5.7	5.3	6.3	7.6	11.2

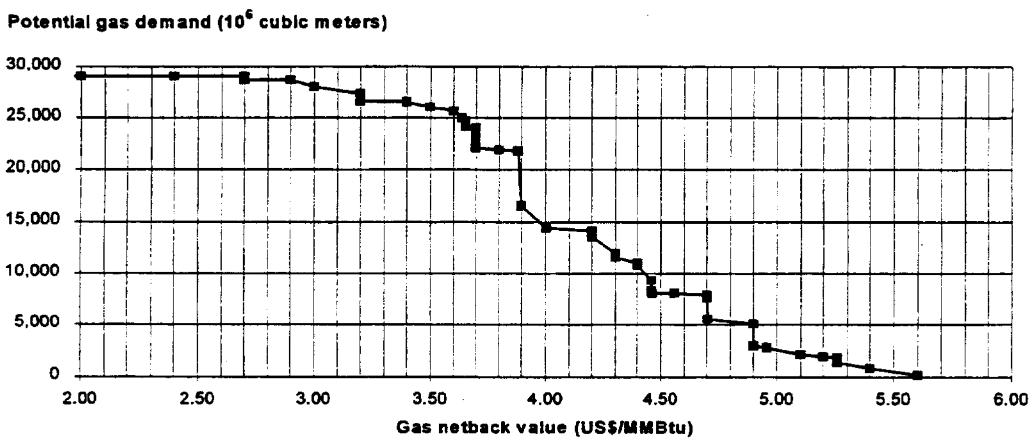
53 A key issue for the power sector is to secure adequate supplies of natural gas. RENEL currently depends on gas supplies from ROMGAZ and PETROM, but since gas reserves are declining, it is unlikely that these companies will be able to continue to supply

RENEL's existing plant. The policy of the government of Romania is to introduce independent power producers to the sector, and this could be coupled with alternative gas supplies arranged in cooperation between the new operators, RENEL, and the government. In such cases the ROMGAZ transmission system could provide third party access services and underground storage.

The Aggregate Economic Demand for Gas

54 Figure 2 shows the aggregate demand for natural gas in 2010 for all consuming sectors, against the netback value of gas in the various end uses calculated at the point of ex-transmission. The figure shows the spread of economic netback values of natural gas over the whole range of uses.

Figure 2 Romania: Total Potential Natural Gas Demand in 2010



55 The economic netback values (ex-transmission system) for natural gas in its end uses are shown in Table 4. A high netback value in an application, coupled with the use of gas in that application, would represent a high value to Romania's economy. Conversely, where gas has a value that is lower than the economic cost of supplying gas to that specific application, this would represent a net loss to the economy. As long as natural gas continues to be allocated to consuming subsectors by the government, the gas policy should allocate natural gas to its highest-value uses, as indicated in Table 4.

Table 4 Netback Values of Gas Ex-Transmission

End-use sectors	*Netback values $/MMBTU*	*Gas demand Bcmy*
Power		8.2 - 11.2
Existing plants—gas fired	3.9–4.6	2.6
Existing plants—gas used as complementary fuel	3.6–3.9	1.6
New gas-fired power plants	4.1-5.5	4 – 7
Combined-cycle gas turbines, gas turbines		
Industry		9 - 10.6
Fertilizers		
Retrofitted plants—domestic market	4.4	2.0
Retrofitted plants—export market	3.9	0.3
Standby plants	3.3	0.0
Case of a new fertilizer plant	1.0	0.0
Methanol	3.0	0.3
Iron and steel	3.9	0.3
Cement		
Gas for cement kilns	3.1	0.0
Gas for ancillary uses	3.9	0.2
Other industries		6 – 7.6
Boilers (replacing HSFO)	3.2	0.7
Boilers	4.1	3.9
Furnaces (nonmetallic industries)	4.4	0.6
Food industries (ovens, dryers)	4.6	0.2
Furnaces (metallurgy, mechanical)	4.9	0.2
Boilers (replacing LFO)	5.7	0.7
Residential and commercial		4.3 - 5.2
Existing gas consumers		
cooking—apartment blocks	8.3	0.03
cooking—single houses	4.3	0.03
space heating—apartment blocks	4.8	0.4
space heating—single houses	4.5	0.7
commercial	4.9	0.56
New gas consumers (conversion)		equivalent
conversion from DH to gas (in gas area)	3.7	to supply gas
conversion from DH to gas (out gas area)	3.5	to district heating
Gas for district heating (DH) systems	3.9	1.7[a]
New gas consumers (C, WH, & SH)		
new housing in DH area	3.6	1.2
new housing outside DH area	3.6	0.6

[a] Assuming the nonreplacement of RENEL cogeneration power plants. If RENEL maintains its heat output, 1.7 becomes 0.8 bcm, and there is an additional 0.4 bcm gas consumption in the power sector for heat generation.

Note: c=cooking; WH=water heating; SH=space heating. DH=district heating. HFSO=high-sulfur fuel oil. LFO=Light fuel oil

The Supply and Demand Balance of Natural Gas

56 The balance of the economic demand and supply of gas (excluding future discoveries) for Romania is shown in Table 5. At current and projected prices for gas at the border, the potential market for gas could reach roughly 27 bcmy by 2010. This assumes that market-based pricing policies will be introduced in the energy sector to ensure that interfuel competition will progressively replace the previous allocation system. The supply deficit will increase to 15.0 bcmy by 2010 or to 24.0 bcmy if tail gas remains unexploited.

Table 5 Supply–Demand Balance, 2000–2010 (bcmy)

Component	*2000*	*2005*	*2010*
Economic demand	20.2	21.2	26.9
Domestic supply	15.8	13.4	12.0
Supply deficit	4.4	7.8	15.0

Gas Infrastructure Development

57 The formulation of a gas infrastructure development plan is largely driven by the need to exploit the declining regional gas production efficiently, and to develop new infrastructure to support future gas imports.

Regional Production and Declining Field Pressures

58 The production prospects from ROMGAZ and PETROM fields that are already producing are shown in Table 6.

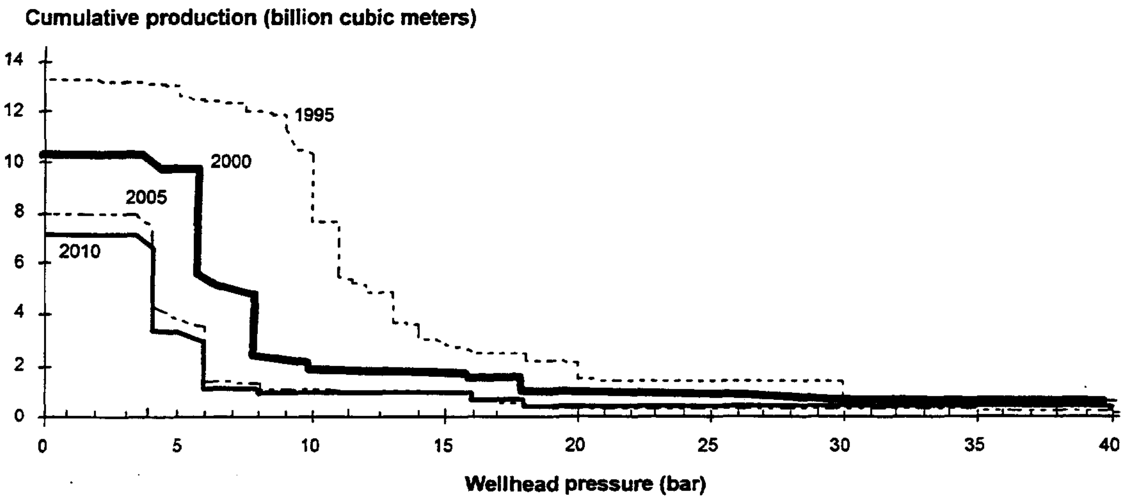
Table 6 Production Prospects from Producing Fields, 1995–2010 (bcmy)

Utility	*1995*	*2000*	*2005*	*2010*
ROMGAZ	13.3	10.1	8.0	7.0
PETROM	6.0	5.3	5.0	4.8
TOTAL	19.3	15.4	13.0	11.8

Source: ROMGAZ.

59 The declining production profiles and wellhead pressures from ROMGAZ fields are shown in Figure 3.

Figure 3: ROMGAZ: Cumulative Natural Gas Production versus Wellhead Pressure



60 By the year 2000, approximately 51 percent of ROMGAZ production (5.1 bcm) will be produced with a wellhead pressure equal to or less than 6 bar. By the year 2010, 50 percent (3.5 bcm) will be produced with a pressure equal to or less than only 4 bar, with only small volumes produced with pressures above 20 bar. The production from PETROM fields may be assumed to follow the same broad decline pattern as that of the ROMGAZ production, although in general PETROM fields operate at higher pressures than those of ROMGAZ.

61 ROMGAZ production from fields in the Transylvania region will be about 6 bcmy in 2010. This is equivalent to the expected gas demand in the region, with about 80 percent of the gas supply needed for power generation. Most of the gas produced in the region can therefore be consumed within the region. Its pressure, however, must be raised to the pipeline pressures (20 to 35 bar) for regional transmission and when used for power generation. Where fields are used to supply nearby distribution networks, additional compression and transmission will not be needed.

62 PETROM's main gas production is based in the Oltenia region, and a large share of this production will have to be transported from the production area to Bucharest. The gas pressure must therefore be raised to 30 bar for injection into the national transmission system, and capacity will be required for this additional compression. This additional capacity will have to be financed by PETROM through revenues gained from gas sales; thus, the sales price of gas will ultimately need to be increased to parity with imported natural gas or fuel oil.

The Domestic Production Infrastructure

63 *Gas Dehydration.* The existing gas dehydration plants (located upstream the production compressor stations) were designed for high-pressure operation, but because of declining field pressures they are now operating out of their design range. As field pressures decrease further, water loading of gas will increase, and new dehydration units

will be needed. It would be appropriate to install three new tri-ethelene-glycol (TEG) units downstream of the main production compressor stations.

64 *Production Compressor Stations.* More than 100 MW of compression power was installed in the 1980s, but the compressors are becoming less suitable due to the declining field pressures and flows. Assuming field pressures need to be raised to range of 20 to 35 bar for transmission, the future requirement for compressor power will not exceed the existing installed power. However, the compressor units must be revamped or changed to accommodate the new conditions. Broad estimates indicate that necessary investments could reach 50 percent of the current replacement cost of the installed power—namely, $140 million.

Natural Gas Transmission and Underground Storage

65 *Transmission Pipelines.* The ROMGAZ transmission network comprises 9,200 km of high-pressure pipelines (design pressure 30 to 60 bar), 1,800 km of low-pressure lines (design pressure 15 to 45 bar) in the central region, 370 km of transit lines transporting Russian gas to Bulgaria and Turkey, and five transmission compressor stations. In the past, the system transported 40 bcmy with a peak flow of 140 million cubic meters per day (MMcmd).

66 About half of the transmission lines were laid before 1970, and pressure derating has been necessary because of the age and poor physical condition of some of the pipelines. Typical levels of pipeline derating are about 25 percent, with a wide spread of maximum-allowable operating pressures (MAOPs). Transmission network simulations show that the system is capable of transporting the future gas demand while keeping the present levels of MAOP. External corrosion is a major problem and a pipeline replacement program of 200 km per year is planned. Although most of the network is cathodically protected, the facilities need to be revamped, and the monitoring of corrosion needs to be improved.

67 The primary objective for the existing transmission system is to maintain the integrity of the pipelines and thus avoid further reductions in MAOP. ROMGAZ will have to maintain a detailed computerized data base incorporating all information on the conditions of the lines, and it must also implement an extensive program of cathodic protection surveys. A dedicated quality assurance and supervision system covering pipeline repair and replacement work is also needed.

68 *Transmission Compressor Stations.* The main issue is the low pressure level now prevailing in the transmission network, because the transmission system compressors have been designed for higher suction pressures and flow rates, and the available installed power cannot be used efficiently to raise the pressure to required levels. The second issue is the age of the units, with 65 percent of the units more than 20 years old and having reached the end of their normal operating lives. Even if the supply pressure could be brought back to normal values, most of the stations would not work as designed, because the pipeline pressures have been strongly derated.

69 Two types of investments are needed in compressor stations: (a) investments to improve the short-term operation of stations in line with the present transportation

directions, from the center of the country to the periphery; and (b) longer-term investments, which will result directly from future transit schemes that will gradually allow imported gas to replace domestic gas.

70 Short-term investments will be for the provision of spare parts (most of the units are of foreign origin) and for compressor revamping in accordance with the present flow and pressure regime. The network simulations show that if gas is imported only from Russia (from Isaccea and Satu Mare), several existing stations will not be needed in 2010, such as Sinca and Batani. The decision to replace the older units depends on future transit schemes, both for the medium and long-term.

71 *Exploitation of Tail gas.* In the scenario where tail gas production is exploited, field pressure decline is significant in the period from 1995 to 2000. Gas pressure must be raised prior to injection in the pipelines. The priority is therefore to invest in production compressor stations. With starting pressures back to normal levels, existing compressor stations will be able to operate in better flow and pressure regimes. Domestic production can supply most of the demand within each producing region. After the year 2000, high-pressure gas imports will be available in the central region and the peak-day simulation shows that no compression will be needed in 2010, when the proposed locations and availability of new underground storages are taken into account. Therefore, no additional compression power is required in this case, and the issue is to maintain the most recent units in good working condition for the period 1995 to 2000.

72 *Alternative Scenario.* In the alternative scenario, where tail gas remains unexploited, gas imports must be increased rapidly (connection with Ukraine and increase of the capacity through Isaccea). The small amount of domestic production means that gas has to flow over longer distances than in the preceding scenario. The network simulations for 2010 show a need for increased compression power for Silistea and that Vintu and Onesti have to remain in operation and must therefore be reconstructed.

Future Evolution of the Transmission System

73 *Supply Sources.* The evolution of the national transmission system depends on the new supply locations for gas imports, and on the future levels of domestic production, which will reach 12 bcmy with tail gas production and 2.7 bcmy without it.

74 *Transmission System Requirements.* A simulation of the national transmission network for the year 2010 was carried out for this study, taking account of the peak-day demand at a regional level throughout Romania. Russian imports were assumed to come from the existing entry location in northwestern Romania and from the proposed interconnection between the Ukrainian system entering at Satu Mare (with connection to the central node of the Romanian network in order to replace the declining production). Natural gas imports from these two directions represents the most severe impact on the transmission system. Projects resulting in imports from the other directions noted earlier would result in a more balanced transmission system and therefore a less severe impact. The location and characteristics of new storage facilities were defined on the basis of the potential locations for depleted-field conversion, and current pipeline MAOP levels were

used. The domestic production consumed locally was assumed to be transported by local pipelines. The results of the analysis are sensitive to the exploitation of tail gas reserves.

75 In the case of full exploitation of tail gas, the simulations show that the existing network is capable of handling the peak flows without requiring major network reinforcements. This is due to the large capacity of the existing network, combined with a better geographical distribution of imports. The required investments for the interconnection with Ukraine, pipeline loops, and compression power are estimated at $265 million. Where tail gas remains unexploited, roughly 190 km of transmission loops are needed, and a big increase of compression power is required to transport gas imports to the western part of Romania. In this case the necessary investments increase to $475 million.

76 The Romanian transmission system will ultimately include transmission lines operating at several broad pressure levels. These include very high-pressure pipelines (75 bar or more) for interconnection and transit, the main national network (35 bar) transporting mostly imported gas, regional pipelines (20 to 35 bar) transporting domestic production and injected imports, and local low-pressure transmission lines (20 to 20 bar).

77 *Natural Gas Storage.* ROMGAZ operates three depleted fields as storage facilities near Bucharest, with a total storage capacity of 0.7 bcm and a peak send-out capacity of 7.1 MMcmd. These fields are not sufficient to deal with the fluctuations in demand in the Bucharest area, and ROMGAZ is expanding these facilities in order to reach a capacity of 1.4 bcm and 11 MMcmd in 2000. In addition, ROMGAZ is planning to convert three depleted fields to storage use after the year 2000, one in Transyslvania and two in Moldavia.

78 Taking all these projects into consideration would provide a total storage capacity of 3.2 bcm with a peak send-out capacity of 26 MMcmd in the year 2010. Based on the gas demand forecasts and load management needs developed for this study, however, there is a need for an additional storage capacity of 0.55 bcm and a peak send-out capacity of 31 MMcmd in 2010. The gap between the peak demand (138 MMcmd in 2010) and the available supply is significant and is mainly caused by the lack of flexibility of both domestic production and imports.

79 The possible solutions to reducing the supply and demand imbalance in winter peak days are (a) increase the peak deliverability of the existing and planned storages, (b) develop additional storage capacity with high peak send-out, (c) act on the demand side by creating a portfolio of interruptible customers, (d) install peak shaving facilities near the high peak demand areas (Bucharest and other large cities), and (e) negotiate additional import flexibility.

80 Given the large potential for converting depleted fields throughout Romania, underground storage will be the best likely option for additional storage, but could also include LPG peak shaving plants and possibly even salt domes. A broad estimate for the investments required to implement a comprehensive program of underground storage up to the year 2010 is about $430 million.

81 The existing storage facilities are operated by the ROMGAZ production division. It is recommended that the storage function, which plays an important role in load management and in the operation of the transmission system, be operated by the transmission division.

Natural Gas Distribution

82 The two ROMGAZ distribution subsidiaries (Bucharest and Tirgu Mures) operate distribution networks comprising more than 10,000 km of steel distribution lines. They supplied approximately 20 bcm to 375,500 customers in 1993. The larger share of the consumption goes to the industrial sector. Gas is also supplied for district heating through municipal district heating companies, industries supplying heat to nearby housing, and the power company RENEL.

83 The standard distribution pressure is 2 bar. Network design standards are comparable with those used in Western Europe, and Romanian standards for the installation of polyethylene pipes is under completion. Among the problems facing the distribution subsidiaries are (a) the available pressures in the distribution networks are very low because of low pressure delivered from the transmission system; (b) only 25 percent of the distribution lines are cathodically protected, and their efficiency is often because of stray currents; (c) the steel distribution pipes are generally in poor shape; and (d) about 25 percent of consumers are not equipped with meters.

84 The ROMGAZ distribution networks are virtually all steel construction with only 25 percent equipped with cathodic protection. The networks are in relatively poor condition, and their rehabilitation is a major task facing ROMGAZ. Installation of an extensive cathodic protection system is not deemed feasible because too many networks are old, and the network routing and CP system design should be carried out simultaneously and from day one to avoid interference by other infrastructure in an urban environment. The solution lies with the development of PE networks. Given the condition of the existing steel distribution networks, it is reasonable to assume that in the next 15 or 20 years most of these networks will need to be replaced by steel pipes (for the larger diameters) or by PE pipes (for the smaller diameters). The same can be assumed for service lines and meters.

85 After an analysis of the future gas demand, it is estimated that in the year 2010, distribution networks will supply 3 million housing units, with 30,000 commercial and industrial users. Assuming that most of the existing distribution networks will have to be replaced in the next 15 or 20 years, the estimated investment costs for rehabilitation, reinforcement, and expansion amounts to $1.5 billion including the service lines.

Summary of Investments

86 Table 7 lists the infrastructures (with the quantities of gas handled) and their associated investments. The investments in subsurface production facilities for the scenario assuming exploitation of tail gas are not included. Computation of the future quantities of gas that will be delivered by the distribution networks takes into account the fact that future power plants are likely to be supplied by the high-pressure pipelines.

Table 7 Projected Gas Production/Deliveries and Investment Requirements, 1995–2010

Gas Quantities	*1995*	*2000*	*2005*	*2010*
ROMGAZ gas production (bcm)				
Scenario—tail gas exploitation	13.3	10.1	8.0	7.0
Scenario—no tail gas exploitation	11.1	6	3.7	2.1
Gas transported (bcmy)	23.0	20.2	23.6	26.9
Gas delivered through distribution networks (bcm), of which:	18.0	16.0	15.0	14.0
Residential and commercial	3.6	4.0	4.4	5.1
Industry and others	14.4	12.0	10.6	8.9

Investments (million $)	*1995–2000*	*2000–2005*	*2005–2010*
Production facilities (Scenario—tail gas exploitation)			
Subsurface	n.a.	n.a.	n.a.
Dehydration	30		
Compression	100	40	
Transmission			
Scenario—tail gas exploitation	483	640	335
Scenario—no tail gas exploitation	823	508	335
Storages			
Scenario—tail gas exploitation	134	125	170
Scenario—no tail gas exploitation	134	145	150
Distribution			
Network	333	333	333
Service lines	173	173	173

Gas Pricing and Industry Restructuring

Industry Restructuring

87 The Romanian gas industry is vertically integrated, with ROMGAZ in charge of the production from its own fields, of transportation of gas through the national transmission system, and of the low-pressure distribution of gas to final consumers. PETROM is also a major gas producer and sells gas to ROMGAZ at the inlet of the national transmission system (NTS). Ownership of these enterprises is entirely within the public sector.

88 Reform of the hydrocarbons sector is now under way under the new Petroleum Law, which was approved by parliament in December 1995 (it will allow ROMGAZ to make gas transportation services available to third parties in return for a transmission tariff), the creation of the National Agency for Mineral Resources (NAMR) as the independent regulatory agency for the sector, and the restructuring of ROMGAZ.

89 ROMGAZ is already undergoing the first stages of restructuring. The objective of this first stage is the divestiture and privatization of the drilling units and the establishment of four strategic business units (SBUs) as separate, accountable profit centers: one for exploration and production, one for transmission, and two for distribution. It is intended that the exploration and production SBU will contract sales of gas directly with end users or with distribution companies. The transmission SBU will become a rate-regulated common carrier, and the distribution SBUs will become one or more rate-regulated utilities.

90 An ultimate objective of the government of Romania is to privatize the gas distribution activities. The Petroleum Law implies that the NTS will remain within majority public ownership, but the introduction of third-party open access (TPA) is expected to further stimulate international companies to invest in exploration and production in Romania. This law is also expected to remove institutional barriers for gas importers to supply gas directly to large consumers (industries and distribution companies) in Romania. The structural features of the industry—including the degree of vertical integration, level of competition possible at each stage, and ultimate objectives with respect to privatization—will have an impact on how the industry can be regulated, and some observations concerning this can be made.

91 This report does not deal with the details of the regulatory framework of the gas sector, which is already in an active stage of development. However, it is observed that under the current restructuring model, the NTS could be operated in one of two modes, which, in turn, will affect the ability of the NAMR to regulate the industry effectively. First, as an open-access pipeline, the transmission company would transport gas for third parties only, without being involved in buying and selling gas as a commodity. Second, as a hybrid pipeline, the company would transport gas for third parties *and* for itself. The characteristics of these two options are detailed in the report. The hybrid pipeline would be more difficult to regulate than the open-access pipeline, because of the need to ensure that third parties are able to use pipeline capacity on a truly nondiscriminatory basis. On the other hand, the hybrid pipeline would allow the transmission company to perform an important role in aggregating a substantial proportion of the supply contracts, to ensure that supply-demand matching and storage requirements are met.

92 For the transportation company operating under a full open-access regime, the distribution companies and suppliers (domestic and foreign) bear the volume risk and must ensure that all the gas they contract is sold into the market. The take-or-pay risks are therefore transferred away from the transport company, which will accrue its revenues on the basis of ship-or-pay contracts, where it will agree to provide a specific transport capacity to gas merchants and should be paid a regulated transport fee whether or not gas is actually transported.

93 In designing the regulatory framework, it is necessary for the government of Romania to decide on this important structural feature. In any case, the regulation need be only the minimum necessary to ensure (a) the protection of captive consumers, (b) the competitiveness of the market for natural gas and competing fuels, (c) the prevention of the abuse of monopoly power at the natural monopoly stages, and (d) the sector's attractiveness for private sector investors. In delineating this issue, the primary objective should be to encourage imports of gas to Romania to replace the rapidly decreasing domestic production.

Gas Pricing Policies

94 In Romania, natural gas is supplied to the residential sector (including district heating) at US$0.6/MMBTU, and to industry (including RENEL) at US$1.7/MMBTU. Both price levels exclude VAT and are uniform throughout the country. The estimates of the economic demand for natural gas are based on the economic costs natural gas and competing fuels. Table 8 shows that the current prices of competing fuels are close to their economic costs in Romania, but the prices for natural gas are substantially below the costs of supply needed to cover the net fixed assets of ROMGAZ and their five-year investment plan.

Table 8 End-User Prices and Costs of Natural Gas and Competing Fuels
(US$/MMBTU)

	LPG						*Gas*	
	Indus.	*Res.*	*Kerosene*	*Diesel*	*LSFO*	*HSFO*	*Indus.*	*Res.*
Price	5.8	n.a.	4.4	6.1	3.0	2.4	1.7	0.6
Economic cost	5.8	10.0	4.9	4.9	3.3	3.0	3.2[a]	4[a]

[a] Includes the cost of ROMGAZ fixed assets and investment program, assuming producer prices at international levels.

95 As a gas-importing country, Romania's ultimate goal should be to set end-user gas prices at parity with competing fuels in the market, taking account of the netback value of gas in its specific end uses, because this will encourage the most efficient use of gas and of competing fuels. Just to cover ROMGAZ costs and five-year investment plan, however, would require price increases of almost 700 percent to residential and 60 percent to industrial consumers, with residential prices needing to be even higher if priced at opportunity cost. Although the government of Romania is fully aware of the difficulties of establishing such price increases, especially in view of the income constraints of the general population, these gas price increases are unavoidable if the Romanian gas industry is to become self-sustaining and able to finance its own investment program.

96 As a first major step in gas prices rationalizing, the government of Romania has pegged the price of gas to industrial consumers to the price of HSFO (3.5 percent f.o.b. Med.), on the basis that during shortages of natural gas, HSFO is imported at the margin for RENEL power plants. If the government of Romania's hydrocarbon sector reforms ultimately result in multiple gas producers and importers in Romania with end-user prices

reaching international market levels, domestic producer prices could be left to find their own levels in a competitive market. It is noted that for new gas fields, the Concession Agreement already links the producer price to the international price of fuel oil.

97 In addition to the program of price increases, a number of measures can be taken to improve transactions within the sector. These are in fact necessary to implement the open-access policy on the national transmission systems. They include (a) the implementation of two-part billing system (commodity and capacity charge) for industrial customers with adequate metering; (b) implementation of transparent transaction prices between gas production, transmission, and distribution subsidiaries based on a two-part system of fixed and variable costs; and (c) implementation of a system of distance-based transmission tariffs for large industrial consumers operating off the transmission system, consistent with open access; and (d) implementation of interruptibles gas pricing.

98 This pricing framework would be consistent with a strategy to supply the *basic market* (for example, residential and commercial consumers), and to set up the conditions by which gas could be supplied to the *alternative market* (large industrial users normally operating directly off the transmission system) through the use of third-party open-access to the national transmission system. The supply of the basic market would, at least for some time, be within the scope of traditional public utilities, while the supply of the alternative markets could be largely deregulated. Many large industrial consumers can procure gas directly from suppliers other than ROMGAZ and PETROM and can transport that gas through the ROMGAZ system, which has spare capacity. The amount of gas traded under these procedures is still comparatively small but could become larger if RENEL and future electricity producers follow the same pattern.

99 During 1995, gas was sold by PETROM (both free and associated) to ROMGAZ at \$42.2/'000cm^3. This compares with free gas supplied from ROMGAZ own-production subsidiaries the transmission subsidiary at an internal transfer price of \$9.1/'000cm^3. Gas was supplied to the residential sector (including district heating) at \$20.6/'000cm^3 and to industry (including Renel and fertilizers) at \$ 71.7/'000cm^3, both price levels being uniform throughout the country. The price of gas to industrial consumers was pegged to the price of HSFO (3.5%S FOB Med), because during shortages of natural gas, HSFO is imported at the margin for Renel's power plants.

100 The taxation system for natural gas is governed by Law 42, which came into effect in 1993. This requires that ROMGAZ pay a gas tax (currently about \$15/'000cm^3) to the treasury on delivered volumes of natural gas, irrespective of the individual volumes and sources of gas (ROMGAZ, PETROM or imports) supplied to the transmission system. In addition, the price of associated gas supplied from PETROM to ROMGAZ is about 5 times the cost of ROMGAZ's own free gas production, even though much of the PETROM supply is associated gas. This system appears to be deficient in that it does not allow the government to capture the economic rent on gas production in an efficient manner.

101 As a gas-importing country, Romania should have as its ultimate goal the setting of prices at parity with competing fuels in the market, taking account of the netback value of gas in its specific end uses. The producer price would then be set by subtracting distribution, transmission, and storage costs. The excess profit would be taken by

government as tax. A transition to this system will be needed if the Romanian gas industry is to become self-sustaining and able to finance its own investment program.

102 In the meantime, a number of measures could be taken to improve the transactions within the sector, in view of the governments objective of introducing competition to the sector by attracting independent producers in the upstream sector and introducing full open access to the national transmission systems. These include (a) the implementation of two-part billing system (commodity and capacity charge) for industrial customers with adequate metering; (b) implementation of transparent transaction prices between gas production, transmission and distribution subsidiaries based on a two-part system; and (c) implementation of a system of distance-based transmission tariffs for large industrial consumers operating off the transmission system, consistent with open access. These questions are being addressed in separate studies for the government of Romania.

103 This pricing framework would be consistent with a strategy to the supply the basic market (for example residential and commercial consumers), and to set up the conditions by which gas could be supplied to the alternative market (large industrial users). The supply of the basic market would, at least for some time, be within the scope of traditional regulated public utilities, while the supply of the alternative markets could be largely deregulated. However a number of large industrial consumers can procure volumes of gas direct from suppliers other than ROMGAZ and PETROM and transport that gas through ROMGAZ system, which has spare capacity. The amount of gas traded under these procedures is still comparatively small (5 bcm) but could become significantly higher if RENEL (the largest gas consumer) and future electricity producers would follow the same pattern.

104 Since it is likely that part of the future power generation will be contracted to independent power producers (IPPs), these could be required to secure their own energy and gas supply. ROMGAZ having the responsibility to guarantee that transmission capacity would be available for a regulated transport fee. Alternatively, the power company could build its own, or purchase from ROMGAZ the required gas transmission and storage capacity.

LPG Imports

105 ROMGAZ is examining with an international consortium the feasibility to implement a liquefied petroleum gas (LPG) terminal at Constanta on the Black Sea. The terminal would have sufficient capacity to allow up to 700,000 tonnes of propane, together with air, to be injected into the Bucharest system during the 150 day winter period. Studies on the economic viability of the scheme were not available at the time of this study, but potential advantages include: (i) imported LPG would add allow both commercial and physical diversification of gas supplies; (ii) propane-air systems use simple technology which would be compatible with and make full use of the existing natural gas infrastructure. These system can be a very flexible solution to meet peak demand since they can be located close to the centers of demand and provide response times faster than delpeted field storage. In addition, an increased availability of LPG could allow more efficient use of the existing (and currently underutilized) LPG storage and distribution infrastructure in Romania, to supply residential and industrial consumers in those areas where it is uneconomic to extend the gas distribution.

1

Natural Gas Supply and Demand

1.1 The present consumption of natural gas in Romania is 25 bcmy (bcmy), accounting for about half of Romania's primary energy supply. About 19 bcmy are derived from domestic production; the balance is imported from Russia. The share of gas in Romania's primary energy consumption is at least twice that of the average for OECD countries. Romania's energy intensity is also about double the OECD average and reflects the earlier development of highly energy intensive industries as well as pricing policies that have not encouraged investment in energy efficient technologies.

1.2 This chapter examines the prospects for domestic gas production and imports and presents forecasts of economic demand based on an analysis of the economic value of gas in the various categories of end use. The economic values of gas (netback values) presented below have been calculated from the value of the alternative fuels replaced by natural gas, taking into account differences in thermal efficiency and the comparative cost of the equipment for gas and for the alternative fuels. The netback values are normally presented at the point of ex-transmission. In the case of large industrial consumers, this is close to the netback value at the industrial plant gate, because the cost of the supply line to the plant gate is usually quite small. For consumers operating off low-pressure distribution systems, the netback values take account of the cost of the low-pressure distribution systems, since they are also quoted at the point of ex-transmission. By comparing the netback value of gas ex-transmission for each end use with the cost of supplying gas to the point of ex-transmission for each end use, it is possible to estimate the economic demand for gas for each end use. These economic demand forecasts are presented below for each consuming sector, including power generation, residential and commercial, and industry.

Natural Gas Supply

The Declining Domestic Production

1.3 Romania's domestic supply of natural gas derives from 120 nonassociated gas fields located mostly in the Transylvania basin and operated by ROMGAZ, as well as more than 100 associated and nonassociated fields operated by PETROM outside Transylvania. The past trends in Romanian gas production are shown in Table 1.1, which shows that gas production has decreased rapidly since 1986, when production reached about 39 bcm.

Table 1.1 Romania's Domestic Gas Production, 1986–1994 (bcmy)

Producing entity	*1986*	*1987*	*1988*	*1989*	*1990*	*1991*	*1992*	*1993*	*1994*
ROMGAZ	26.8	25.3	25.2	22.2	19.2	17.2	15.1	14.8	—
PETROM	12.5	12.1	11.7	10.5	8.9	7.5	6.9	6.6	—
of which Assoc. Gas	(4.3)	(3.1)	(3.5)	(2.9)	(2.3)	(1.8)	(1.7)	—	—
TOTAL	39.3	37.4	36.9	32.7	28.1	24.7	22.0	21.4	19.6

Source: ROMGAZ. —not available.

1.4 The prospects for future domestic production are summarized in Table 1.2 and shown in Figure 1.1. These show that production will continue to fall from reservoirs currently in production to about 12 bcmy by 2010. These figures exclude production from new discoveries. The profile represents an aggregate production of 235 bcm from 1996 to 2010 from PETROM and ROMGAZ fields and includes incremental production gained from operations including sand control and fracturing in some 80 reservoirs. About 130 bcm of this gas can be produced at pressures above 10 to 15 bar at a cost that is competitive with gas imports. The remaining 103 bcm consists largely of tail gas production, which could be produced down to about 3 bar. Unlike in other countries, where typical economic cutoff pressures are 10 to 30 bar, tail gas has an unusual significance for Romania. This is because the national transmission system is presently underutilized due to the declining domestic production, and the system is therefore operated at pressures of typically 25 to 30 bar. This presents an opportunity to use the tail gas without excessive investments in compression and transportation capacity, and in some cases it will be possible to supply the tail gas directly to local distribution networks. If valued at current import prices of US$2.8/MMBTU, the tail gas has a value of $3 to $4 billion (present value) to Romania. However, the investments necessary to recover volumes of tail gas are likely to be less than the value of the recovered gas based on import parity. It is therefore clearly beneficial for Romania to produce these tail gas reserves where technically and economically viable. The potential for economic tail gas production can be more clearly defined by a detailed review of the characteristics of the major reservoirs.

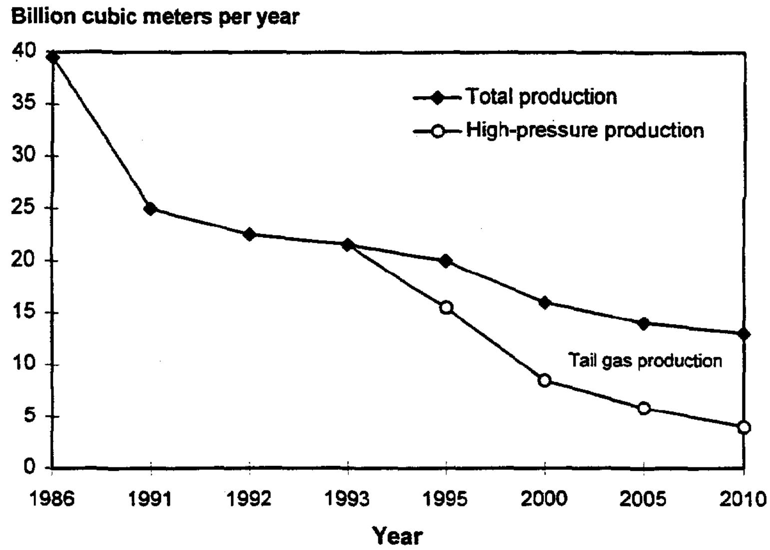
Table 1.2 Romania's: Domestic Natural Gas Production, 1995–2010 (bcmy)

Producing entity	*1995*	*2000*	*2005*	*2010*
ROMGAZ	13.3	10.1	8.0	7.0
Others (mainly PETROM)	6.0	5.7	5.4	5.0
TOTAL	19.3	15.8	13.4	12.0

Source: ROMGAZ.

Note: Excludes future discoveries.

Figure 1.1 Romania: Natural Gas Production to 2010



1.5 The demand projections prepared for this study (see below) indicate that the supply demand deficit will increase to 15.0 bcmy by 2010. Failure to exploit the tail gas reserves would increase Romania's supply deficit to 24.0 bcmy by 2010. This shows that in any event Romania will become increasingly dependent on gas imports. The deficit will need to be made up both from gas imports and from production of new discoveries within Romania. It should be noted Romania's National Agency for Mineral Resources (NAMR) is in the middle of an energetic exploration promotion program that has attracted international interest. Although the volumes of gas to be discovered are largely speculative, the recent offshore discovery by Enterprise Oil demonstrates a real potential for reducing the import requirements through the exploitation of new discoveries.

Potential External Suppliers

Russia

1.6 Russia is the traditional supplier of gas to Romania, with gas imported from the transit line at Isaccea. An interconnection project between Ukraine and Satu Mare (in northwest Romania) is planned and will provide a second access to Russian gas, but its major benefit would be to achieve a better-balanced transmission system through a direct supply to western Romania, an area that currently suffers supply constraints. ROMGAZ is also considering a third source of Russian gas from a pipeline link through Moldova. Currently, Russian gas is received as payment (a) for gas transit services provided for Turkey and Bulgaria, (b) for hard-currency transactions between the government of Romania and GAZPROM, and (c) for gas brought in by independent importers for fertilizer production. Apart from transit supplies for Turkey, gas imports from Russia are not underpinned by modern long-term contracts with the governments, which would contain internationally accepted clauses including take-or-pay penalties, minimum-load-factor conditions, or gas price indexation. Romania has suffered as a result of this—for example, in lacking flexibility in imports to meet peak winter demand. Since Romania will become more dependent on imported gas, future contracts involving the Romanian government and foreign suppliers should be based on such modern long-term contracts, which are accepted practice in the international gas industry.

Western Supplies

1.7 ROMGAZ is evaluating a short pipeline connection with Hungary, with the objective of securing volumes from Western European suppliers. This connection would put Romania in a good position to diversify its supply sources through swap deals with Western European gas companies, some of which are eager to sell excess natural gas. This scheme is an important step toward energy security for Romania and should be supported, again provided that the investments can be underpinned by modern long-term supply and transportation contracts negotiated at economic price levels.

Middle East (Iran)

1.8 A new supply route bringing gas from Iran (and possibly other countries) to Europe is under active consideration by European gas companies, and feasibility studies commenced in 1995. A gas pipeline running from Turkey through Central Europe is one of the proposed transportation options. In that case Romania would become a transit country and would receive a new source of gas supplies.

1.9 The number of countries involved in this project, the evolution of European gas markets, the large investments required, and the geopolitical uncertainties are likely to impose a long maturation period. This new supply route can be envisaged in the period from 2005 to 2010 at the earliest. Several routes are competitive in this scheme, including liquefied natural gas (LNG) or transit across the former Soviet republics. For these reasons, the scheme has not been considered in network simulations, which would assume the most severe case for the transmission system—that is, all imports from Russia.

1.10 The Black Sea LNG terminal option has not been considered realistic. Mediterranean LNG supplies are almost entirely committed for the period of 2000–2010, the crossing of the Bosphorus strait by LNG tankers has raised hazard-related concerns, and the cost of new LNG (Middle East) is likely to be in the \$3.5 to \$4/MMBTU range (cost insurance freight; c.i.f.).

Natural Gas Demand

Gas Demand for Power Generation

1.11 ***Past Trends in Gas Consumption for Power Generation.*** Annual demand for electricity in Romania decreased progressively from 71.4 terawatt hours (TWh) in 1989 to 58.3 TWh in 1992. However, peak demand increased over the same period from 8.8 gigawatts (GW) in 1989 to 9.5 GW in 1992. This was attributable to a 50 percent decrease in industrial demand, combined with an increase in residential demand for power.

1.12 Power generation and the production of heat for district heating are the main users of natural gas in Romania, as shown in Table 1.3. Since 1989, the Romanian electric utility's (RENEL) gas consumption for power generation and heat and power plants has decreased. Although recovery started in 1993, gas consumption for power generation has not yet reached the 1989 level.

Table 1.3 Romania: Trends in Gas Consumption for Power and Heat Production, 1989–1993 (MMcmy)

Consuming entity	*1989*	*1991*	*1992*	*1993*
RENEL	10,710	9,560	9,250	9,566
Power	6,820	5,360	6,300	—
Heat and power	3,890	4,200	—	—
Autoproducers	520	400	—	—
District heating	1,040	1,100	1,120	1,200

Source: ROMGAZ and ESMAP study estimates.

1.13 Power generation in Romania is dominated by RENEL. Natural gas is the main fuel used in Renel's thermal power generation plants, and it accounted for 46 percent of the total fuel consumption in 1991 to provide 40 percent of the power generated. The other fuels used were lignite, coal, and fuel oil.

Existing Power Generation Facilities

1.14 Table 1.4 shows the installed capacity of the Romanian power generation system in 1993. This capacity was 21,230 megawatts (MW), of which 20,300 MW was operated by RENEL.

Table 1.4 Installed Power Generation Capacity in Romania (Megawatts)

Fuel	*Capacity (Megawatts)*	*Capacity Percent*
Lignite and coal fired steam plants	8,500	40
Oil and gas fired steam plants	6,100	29
Hydroelectric plants	5,700	27
Autoproduction	930	3
TOTAL	21,230	100

1.15 Romania's available generation capacity in 1993 was only 15,200 MW, as shown in Table 1.5. This was caused by constraints imposed by poor fuel quality (high ash and sulfur content), as well as by old and inefficient equipment.

Table 1.5 Available Power Generation Capacity (MW)

Fuel	*Capacity*
Hydroelectric	4,960
Thermal (conventional)	6,700
Thermal (cogeneration)	3,500
TOTAL	15,200

1.16 The global efficiency of the RENEL power plants is about 65 percent for cogeneration plants and 33 percent for conventional thermal plants. Some units, however—generally the lignite-fired plants—have very low efficiencies. Global annual capacity factors are approximately 27.7 percent and 38.9 percent for conventional thermal and cogeneration plants, respectively, with some plants achieving capacity factors of less than 20 percent.

1.17 The Romanian power system does not have specific plants (such as gas turbines) to meet peak-load requirements. As a result, some thermal power stations that were designed for base load are run at a low capacity factor, and hydroelectric plants are used to meet peak capacity and to complement or substitute for thermal capacity in an emergency.

Power System Development Plans

1.18 The power development analysis considered in this report takes into consideration the current condition of the thermal units, scheduled plant retirements, RENEL's commitments to projects already under construction, and the results of the Least Cost Capacity Development (LCCD) Study for Romania, which was prepared in 1993.

Fuel Price Assumptions

1.19 Fuel price assumptions are a major factor in the choice of generation options when considering power system development plans. Fuel costs are expressed in economic costs. Romania will remain a net importer of energy in the future, and the opportunity costs of fuels delivered to power plants in Romania will reflect the costs of imported coal, crude oil, and fuel oil, plus delivery costs. Table 1.6 shows the basis for the fuel costs delivered to the power plants for various regions throughout Romania.

1.20 The netback values of gas in power generation were calculated using the economic cost of competing fuels. The actual prices of these fuels differ, however, from the economic cost of the fuels. The prices of domestic coal and lignite in the production area (western region) are close to the international price of coal c.i.f. plus inland transportation of $15 per ton. Low-sulfur fuel oil prices are lower than import prices and close to the level of imported high sulfur fuel oil. The projections prepared for the Gas Development Strategy Study are close to the low scenario of the LCCD study.

Table 1.6 Economic Costs of Alternative Energies

	Fuel reference cost[a] U.S. $/tonne		*Fuel costs delivered to plant up to 2010 U.S.$/t ($/MMBTU)*		
Cost element	*1993*	*2000–2010*	*Western*	*Central*	*Eastern*
Imported Fuel Oil					
HSFO (3.5% S)	90	112.8	124 (3.2)	118 (3.1)	115 (3.0)
LSFO (1% S)	115.0	143.0	156 (4.0)	149 (3.8)	144 (3.7)
LFO	160.0	212.5	225 (5.6)	218 (5.3)	213 (5.2)
Hard coal					
f.o.b Richard Bay	26.4	29.2			
c.i.f Constanta	42.0	46.0	60 (2.6)	54 (2.4)	49 (2.2)
Domestic Coal	35.0		35 (2.5)	43 (3.2)	

[a] Assumes crude oil price of US$19.2 /bbl in 2000-2010.

Future Demand for Power

1.21 Table 1.7 shows a comparison of the power demand projections prepared for the Gas Development Strategy Study. These figures were based on macroeconomic projections, with the power demand projections of the LCCD. This shows that the projections prepared for the Gas Development Strategy Study are close to the low scenario of the LCCD study.

Table 1.7 Power Demand Projections for Romania

Source of projection	*Unit*	*2000*	*2005*	*2010*	*2015*
Gas development strategy	TWh	56.1	62.1	75.0	86.7
LCCD study, low scenario	TWh	59.1	65.0	76.1	87.2
	GW	9.5	10.8	13.0	14.9
LCCD study, high scenario	TWh	59.1	71.0	88.9	106.6
	GW	9.5	12.0	15.1	18.2

Power Sector Development up to 2000

1.22 The LCCD study bases the power sector development plan through the year 2000 largely on the modernization of existing plants and on the completion of plants under construction. The least efficient units should be retired, the more efficient units should be refurbished, and the partially constructed should be completed. There is, however, a minimum requirement for new capacity in order to maintain a reliable supply.

1.23 More specifically, the plan requires RENEL capacity additions up to the year 2000 including (a) the refurbishment of 1,800 MW of existing capacity coal and lignite; (b) the completion of the existing Cernavoda 700 MW nuclear plant, the Turceni 300 MW lignite plant, and a number of small cogeneration plants; (c) the retirement of 1,300 MW of existing capacity; and (d) the refurbishment of 340 MW of existing hydroelectric and completion of 480 MW of new hydroelectric capacity.

1.24 The total available capacity planned for the year 2000 is 17 GW. Of this, the available capacity designed for oil and gas could amount to 4 GW, with 1.4 GW of this burning gas. These capacities represent a potential gas demand of about 2 bcmy for gas-fired plants and an additional 4 bcmy if the oil- and gas-fired plants are converted to burn gas only. Currently, about 1 bcmy of natural gas is used as complementary fuel in lignite- and coal-fired plants, and continuation of this practice could further increase the potential demand for gas. Therefore, the total potential consumption of gas for power generation and associated cogenerated heat by the year 2000 is estimated at 6 to 7 bcmy.

Power Sector Development Beyond 2000

1.25 The LCCD study indicates that the fuel options are still open for plants to be built after the year 2000 and that these options will depend on the relative cost of alternative generation modes. For the period beyond 2000, the LCCD study considers the following power plant options: (a) the refurbishment of existing oil and gas-burning plants; (b) completion options, including six cogeneration plants under construction, four nuclear units that remain to be completed, and hydroelectric capacity; and (c) the construction of new plants, which would include a combination of gas-fired combined-cycle plant (300 and 660 MW), conventional coal, lignite, and fuel-oil-based power plants (300, 500, and 700 plus MW), as well as a few hydro plants.

1.26 The results of the least cost analysis indicated that the lowest generation cost would be about $0.04/kWh and that this cost would be achieved by the second stage of the Cernavoda power plant, currently under construction. The next-best option would be a new coal-fired power plant, and a gas combined-cycle plant, the latter depending on the cost of gas. The rehabilitation of existing thermal plants would at best result in a generation cost of $0.045/kWh. The main conclusion is that rehabilitation and modernization should be sufficient to meet the projected demand up to the year 2000, but that from that time on gas would have to compete with the extension and completion of nuclear plants, and with clean-coal-fired power stations.

1.27 In 2010, the gap to be covered by new capacities should be about 2,000 MW and 4,500 MW for the low- and high-power scenarios, respectively. This gap could be entirely covered by new gas-fired units depending on the price of gas. In practical terms, however, the gap will be covered by both gas and other fuels because of fuel availability and security, this being particularly important in the case of gas and coal, which will have to be imported. Assuming that the whole gap is covered by gas-fired units, the maximum potential gas demand corresponding to the 2010 gap is estimated at 4 bcm (low scenario) or 7 bcm (high scenario). For the existing power stations remaining in operation in 2010, the potential gas demand should be about 2.6 bcm in gas-fired plants and another 1.6 bcm in plants converted to gas.

1.28 The potential consumption of gas as a complementary fuel at existing lignite and coal-fired plants can be estimated at about 1 bcmy; this corresponds to the high-power demand scenario. The resulting potential gas demand in 2010 for power generation and associated cogenerated heat would therefore be about 12 bcmy (high scenario), and about 8 bcmy (low scenario).

The Value of Gas in Power Generation

1.29 The value of gas determined in this study for power generation is for three cases, namely (a) existing gas-fired units, (b) existing oil and gas-fired units to be converted to gas, and (c) new gas-fired plants.

1.30 ***Existing Plants.*** The use of gas in an existing gas-fired plant (or as secondary fuel in a plant using another primary fuel) in a region is appropriate when the power generation cost in this plant is less than or equal to that in any alternative existing plant working in the same region under similar conditions of capacity factor.

1.31 To compute the netback value of gas in power generation, the power generation costs for lignite, coal, and oil thermal units (existing, refurbished, or completed) equipped with fuel gas desulfurization (FGD) were estimated. The most competitive solutions among the non-gas options are coal-fired plants and those burning low-sulfur fuel oil. Therefore, the gas value was calculated against these options. Lignite-fired plants are not competitive if FGD investment is required for environmental reasons, because this is a relatively high investment compared with the remaining life of the existing units.

1.32 Assuming that existing gas-fired plants do not require additional investments, the value of gas in these plants (at base-load operation) results from a comparison with the most competitive alternatives, which are coal- or fuel-oil-burning plants that need investments for refurbishments and FGD facilities. In these cases, the value of gas is as shown in Table 1.8.

Table 1.8 Value of Gas in Existing Romanian Three Regions Power Plants, 1994–2010 (Projected)
US$/MMBTU

Period	*Central*	*Eastern*	*Western*
Current (1994)	4.0	3.9	4.1
Projected 2000 - 2010	4.6	4.4	4.9

Source: GDS study estimates.

1.33 ***New Plants***. The least-cost development solution to increase generation capacity in Romania derived from the comparison of the completion of the second and third nuclear units and construction of new coal-fired plants (2 X 700 MW) for base-load operation, and gas turbines using light fuel oil for peak-load service. These are the references used to estimate the gas netback (switching) value in combined-cycle gas turbine (CCGT) options for base-load operation, and gas-fired gas turbine (GT) options for peak-load operation.

1.34 To cover the 2010 load demand, three CCGT sets (each 2 X 700 MW) for the high scenario or three CCGTs (each 1 X 700 MW) for the low scenario should be required as base-load plants. The number of GTs required as peak units depends on the availability of the existing units maintained in service whose efficiency is too low for base-load operation but that can run for peak load.

1.35 Table A-1 (Annex 1) gives the results of the comparison. For example, for a base-load plant in eastern Romania, the gas-switching value of the CCGT option compared with the Cernavoda third nuclear plant (which has to be completed) is $4.1/MMBTU; but compared with a coal-fired plant, it is $4.6/MMBTU. In the central region the gas-switching value is $5.0/MMBTU, and in the western region it is $5.2/MMBTU. The comparison in both cases is with a coal-fired plant using imported coal. For peak load (less than 2,000 hours operation), the gas value is estimated between $5.2 and $5.5/MMBTU for gas-fired GT units, compared with light-fuel-oil-fired GT units. The value of gas when used in new power plants is summarized in Table 1.9.

Table 1.9 Value of Gas in New Romanian Power Plants, Three Regions (US$/MMBTU)

Load factor	*Central*	*Eastern*	*Western*
Base load (CCGT)	5.0	4.6	5.2
Peak load (GT)	5.3	5.2	5.5

Source: GDS study estimates.

1.36 ***Future Gas Demand for Power Generation.*** In 2020 the maximum potential demand for gas for the power sector is about 12 bcmy, but this includes plants where the value of gas is low ($2.5/MMBTU). If the use of gas is restricted to power plants where gas has a value of $3.4/MMBTU or higher, then the total economic gas demand is about 11.3 bcmy, with a peak gas demand for power of 44 million cubic meters per day (MMcmd). In the low power demand scenario, the only difference is that the potential consumption of the CCGTs and GTs is lower by the equivalent of 2,500 MW. The economic demand for natural gas in power generation for the low and high-power demand scenario, is shown in Table 1.10.

Table 1.10 Economic Demand for Gas in Power Generation (bcmy)

	2000		*2005*		*2010*	
Demand source	*Low*	*High*	*Low*	*High*	*Low*	*High*
Demand in existing plants	5.7	5.7	5.3	5.3	4.1	4.5
Demand in new plants	0	0	0	1.0	3.5	6.8
TOTAL	5.7	5.7	5.3	6.3	7.6	11.3

Source: GDS study estimates.

1.37 For cogeneration, RENEL may wish to retain and refurbish the existing cogeneration plants in order to maintain heat supplies to residential and commercial markets. This would correspond to 600 MW of cogeneration capacity in 2010 and could include 500 MW fired by gas and oil in the Bucharest area, 50 MW in the central region, and 50 MW in the North. This could create an additional gas demand for heat production of 0.4 bcmy.

Gas Demand in the Residential and Commercial Sector

The Sectoral Energy Consumption

1.38 The final energy consumption by the residential and commercial sector is shown in Table 1.11. Direct consumption of gas corresponds to about 23 percent of the total energy consumption. Since about 43 percent of the heat supply is derived from natural gas, the total share of gas share is closer to 45 percent. The commercial sector accounts for 20 to 25 percent of the total energy consumption of the residential and commercial sector, broken down into (a) 30 percent direct gas demand, (b) 30 percent electricity, (c) 15 to 20 percent heat from district heating systems, and (d) 20 to 25 percent liquefied petroleum gas (LPG) and other fuels.

Table 1.11 Final Energy Consumption for Residential and Commercial Sector
(thousand terajoules)

Energy source	*Consumption*
Gas (excluding gas to LAA)[a]	70
Electricity	44
Heat	132
LPG	9
Other fuels (excluding LAA)	58
TOTAL	313

[a] LAA-Local Autonomous Authority.

Residential Housing

1.39 Romania's housing stock can be divided into urban and rural stock. In 1992, there were 7.7 million households in Romania, of which 4.1 million were in urban areas. The total population was 22.8 million, with 12.2 million living in urban areas. There are 4.2 million individual houses, of which 0.7 million are in urban areas. Some 80 percent of the housing units are privately owned. Most of the housing units were constructed after 1950, at an average of 70,000 new units per year in urban areas. Nationwide, approximately 100,000 housing units were constructed each year before 1990. Since then, new house construction has declined sharply reaching only 27,000 units in 1992 and resulting in a housing shortage.

1.40 For the future, a construction rate of 2 percent per year of existing stock of residential units is a reasonable assumption. This corresponds to 80,000 new units per year, primarily in urban areas. This 2 percent would include the renewal of existing apartment units without an increase in their total number, with a renovation rate of 1 percent per year for single-family homes and an increase in their number of 1 percent per year.

Gas Utilization Profile

1.41 Table 1.12 shows the distribution of urban households with cookers. Roughly 2.5 million housing units are equipped with a gas cooker supplied by direct piped gas. This includes 325,000 homes (40 percent of the homes in urban areas) and 80,000 blocks (apartment buildings or groups of apartment buildings with an average of 25 housing units per block). Approximately 1.2 million households in urban areas are equipped with a gas cooker fueled by LPG supplied in cylinders, and the remainder use electricity and solid fuels.

Table 1.12 Urban Households with Cookers

Household characteristic	*Number (millions)*	*Percentage*
Urban households	4.1	100
With gas cookers	2.5	61
Single homes	(0.35)	(8)
Apartment blocks	(2.2)	(53)
With LPG	1.2	29
With other fuels	0.4	9

1.42 Table 1.13 shows the distribution of urban households with the various kinds of water-heating systems.

Table 1.13 Urban Households with Water Heating

Household characteristic	*Number (millions)*	*Percentage*
Total urban households	4.1	100
Water heating from a central system	2.9	70
With individual heating system	0.4	10
Water heating by other methods	0.8	20

1.43 Table 1.14 shows the distribution of households equipped with space heating, which accounts for more than 60 percent of the energy consumption of the residential and commercial (R&C) sector.

Table 1.14 Household with Space Heating

Household characteristic	*Number (thousands)*	*Urban*
Total households	7,660	4,076
District heating (RENEL & LAA)	2,430	2,346
Block central heating, of which:	623	586
(Gas fired boilers)	(432)	(424)
Individual heating system, of which	4,650	1,137
Gas	(340)	(244)
Coal	—	(872)

1.44 ***Unit Household Energy Consumption District Heating.*** This is the dominant space-heating system, serving 2.4 million households. The heat production from district heating in 1992 is shown in Table 1.15. The district heating networks presently distribute approximately 132,000 terajoules (TJ) to the residential and commercial sector.

Table 1.15 District Heating: Heat Production and Consumption, 1992
(thousand terajoules)

		Heat consumption		
Entity	*Heat production*	*Residential and commercial*	*Industry*	*Other*
RENEL	192	80	66	10
LAA	208	48	120	4
Industry	100	4	80	0
TOTAL	500	132	266	14

1.45 Table 1.16 shows the gas consumption for district heating (DH) in 1993, which is estimated at 3 bcm (90,000 TJ), and which corresponds to about 70 percent of the energy consumption of 132,000 TJ for district heating. The unit heat consumption per apartment for district heating is estimated at 40 to 55 gigajoules (GJ) per year. Actual demand is higher since heat supplies have been constrained by fuel shortages and closure of heat supplies from industry. The unconstrained demand is estimated at 63 GJ of fuel per housing unit, taking account of the thermal efficiency of heat production and distribution. To supply the current market would require a total heat production of 160,000 TJ, which compares to 132,000 TJ in 1992.

Table 1.16 Gas Consumption and Heat Output for Residential District Heating Plants, 1993
(bcmy)

Entity	*Consumption (bcmy)*
RENEL	1.54
Municipal boiler plants	1.20
Industries	0.28
TOTAL	3.02

1.46 ***Direct Gas-Fired Space Heating.*** This is supplied to 700,000 urban residential units, including 450,000 in apartment buildings served by a central boiler plant, and 250,000 in individual houses with their own heating systems. This represents only 10 percent of all housing units and 17 percent of urban households. In 1992, the total direct gas consumption (LAA excluded) in the residential and commercial sector was 2.4 bcmy in urban areas, which is an average demand of 1,000 m^3 per household. Based on the current patterns of gas usage in Romania along with the potential for reducing gas consumption through better insulation and through efficiency improvements of appliances, we estimate that the average unconstrained unit gas demand for households is as shown in Table 1.17.

Table 1.17 Unconstrained Unit Gas Demand for Households[a]
(cubic meters per year)

Use	*Demand*
Cooking	120
Domestic hot water	400
Space heating, for which:	
(Single-family home)	2,400
(Apartment)	1,100
Space heating average	1,555

[a] Consumers with direct space heating.

1.47 ***General Characteristics of District Heating.*** The heat networks in Romania distribute hot water and steam to residential and industrial customers from three sources, namely: (a) RENEL cogeneration plants, (b) municipal and apartment block boiler plants found in all cities, and (c) industrial complexes. District heating provides hot water to 2.4 million households that is, 60 percent of the urban housing units.

1.48 Bucharest has the most extensive heat distribution system in Romania, operated by RADET. The RADET heat network is supplied by five RENEL cogeneration plants and by approximately fifty gas-fired heat plants owned by RADET. In theory, the RADET network is capable of delivering hot water to 590,000 housing units and to an additional 4,000 buildings. Given the physical condition of the district heating networks, the quality of the fuels, and the insufficient fuel-gas pressure, the average boiler efficiency is roughly 70 percent which compares with normal efficiencies of 85 percent for gas-fired boilers. Networks are mostly buried and heat leaks do not appear to be abnormally large. Heat distribution efficiencies through the network are approximately 80 percent, and the overall efficiency between energy delivered at network outlet and energy consumed at boiler inlet would be about 56 percent.

1.49 The average network operating cost excluding fuel are estimated at about \$1.3/MMBTU at network inlet. This cost is derived from RADET data, and includes salaries, and other fixed costs, and variable costs, excluding gas used as fuel.

1.50 ***Existing District Heating Renovation Costs.*** These include boilers and network per housing unit and are estimated at \$650 for 7,000 kilocalories per hour (kcal/h) per household, with an average network length of 2 per housing unit. Assuming an average demand of 40 GJ delivered per year per housing unit, this implies a cost of \$0.7/MMBTU at boiler inlet. This cost corresponds to a service area with a high housing density and is the same magnitude as the cost of renovating a gas network with a 10 m length per housing unit with similar unit demand conditions. The cost of renovating or of replacing heat-generating installations in heating plants (boilers, burners, controls, supply, storage, and waste gas disposal) can be $40 to $100 perkilowatt for the standard outputs in Romania. This leads to an average cost in the range of $150 to $200 per meter for network renovation with the actual cost dependent on the condition of the network and the degree of urbanization.

1.51 ***New District heating Network Construction Costs.*** These are estimated at $400 per meter ($3.0/MMBTU) delivered to foot of building, assuming an average length of 2.4 per housing unit.

1.52 ***Gas Distribution Network Costs.*** At present, the Romanian gas distribution network's operating cost is estimated at $0.4/MMBTU, excluding depreciation. In the future, unit labor costs will increase significantly, but personnel requirements for network maintenance should decrease due to network renovation, thereby offsetting salary increases. Operating costs have been split between network-related costs and consumer-related costs a ratio of three to one.

1.53 ***Gas Distribution Renovation Costs.*** Renovation is a necessity for practically all of the existing gas network and should be completed in about twenty years at an average cost of about $ 0.4/MMBTU, including service lines.

1.54 ***New Gas Distribution Construction Costs.*** The capital costs corresponding to the expansion of the gas network are estimated to average $50/per meter. Assuming an average network length of 4 per household unit, the discounted capital investment cost for current direct gas demand per residential customer is estimated at $0.7/MMBTU. The cost of service lines is estimated to be $100 per apartment and $400 per single family home. On this basis, the cost of new systems, or the expansion of existing ones, is estimated at $0.8/MMBTU.

1.55 ***Energy Costs.*** To determine the economic value of gas in residential and commercial use, the economic cost of the gas solution is compared to the economic cost of existing or possible alternatives.

1.56 The economic costs of alternative fuels are based on international prices at the border plus the cost of delivery of the fuel to different classes of consumers, including transmission and distribution margins. These are summarized in Table 1.18.

1.57 ***Economic Value of Gas in Residential and Commercial Use.*** The netback value analysis is used to determine (a) the economic viability value of switching existing consumers of gas to alternative fuels, (b) the economic viability value of switching existing consumers of alternative fuels to natural gas, and, (c) the economic viability of supplying gas in the future to new consumers, would result from urban rehabilitation and expansion programs. These three economic viability cases are discussed below.

Table 1.18 Economic Costs of Alternative Energies, 1994

	Fuel reference cost (U.S.$/tonne)		*Costs delivered consumer (US$/MMBTU)*
Energy source	*1994*	*2000-2010*	*2000-2010*
LFO			
c.i.f Constanta	160.00	212.5	—
delivered	185.00	237.5	5.9
LPG			
f.o.b North Africa	130	175	
delivered bulk	250	283	5.8
delivered cylinders	400	502	10.4
Heat	—	—	8.5
Electricity	—	—	27.8

1.58 ***Conversion of Existing Consumers of Gas to Alternative Fuels.*** By international comparisons, the conversion of existing consumers of natural gas to alternative fuels would be unusual. It could only be explained in a situation similar to that of Romania where gas reserves are diminishing, and where all sectors are competing for the limited supplies. It could involve three classes of consumers: (a) consumers (apartment blocks and single family homes) connected to the district heating systems for heat and, in most cases, for domestic hot water supply, but who use gas for cooking and less often for water heating; (b) consumers (apartment blocks and single family homes) who are already connected to the gas distribution system and who use gas for cooking, domestic hot water, and space heating; and (c) commercial consumers who are connected to the gas distribution system and who use gas for hot water and space heating (SH). The netback values for these cases are shown in Table 1.19.

Table 1.19 Gas Netback Values at SLCP for Residential and Commercial Consumers Already Supplied with Gas (US$/MMBTU)

Type of consumer	*Use*	*Apartment blocks*	*Single houses*
Residential			
Connected to DH	cooking	9.03	—
Not connected to DH	cooking	10.03	5.09
Not connected to DH	water & SH	5.56	5.21
Commercial	water & SH	5.55	—

Note: SLCP= service line connecting point.

1.59 These netback values are high because they would imply that in order to switch from gas to alternative fuels, gas consumers would need to purchase new appliances without benefits either in the cost of fuel or in efficiency gains.

1.60 ***Conversion of Existing Consumers of Alternative Fuels to Natural Gas.*** The two main classes of consumers considered here are (a) district heating consumers who are not using gas for cooking and who would be connected to the gas distribution system for cooking only, and (b) district heating consumers who would be converted to central block heating fueled by gas. The results of the analysis are shown in Table 1.20. To convert DH consumers who are currently using LPG or electricity for cooking and who are not connected to any gas distribution system would not be economically justified given a distribution cost estimated at $0.7 to $1.1/MMBTU.

Table 1.20 Gas Netback Values at SLCP for Residential and Commercial Consumers Already Supplied with Alternative Fuels (US$/MMBTU)

Type of consumer	*Use*	*Apartment blocks*
Residential with district heating		
Within gas supply area	cooking	2.07
	water & SH	4.85
Outside gas supply area	cooking	0.31
	water & SH	4.70
Commercial		
Within gas supply area	water & SH	4.85
Outside gas supply area	water & SH	4.70

Note: SLCP= service line connecting point.

1.61 The conversion of district heating consumers to block central heating is more controversial. Taking into account the same distribution cost as above, the netback value at the city gate would be between $3.5 and $3.9/MMBTU. This value is very close to the netback value of gas delivered to district heating plants. It implies that it is economically equivalent to supply gas to district heating plants and to consumers with heat through an efficient district heating network or to supply the same consumer from block boilers fueled with gas. This conclusion assumes that the heat network is in reasonable shape and can be rehabilitated within the cost parameters listed above, which may not be the case in some areas. It is clear therefore that each situation will have to be looked at separately before a decision is made.

1.62 ***Connecting New Future Consumers to Natural Gas.*** Two cases have to be considered here: (a) new consumers are located in areas already supplied with district heating, and (b) new consumers in areas not yet supplied with district heating.

1.63 For areas already supplied with district heating, the choice is between (a) meeting the needs of new consumers for domestic hot water and for space heating through the existing district heating systems (which are likely to have excess capacity in the medium term), with cooking needs covered by electricity, LPG, or natural gas; or (b) meeting the needs of new consumers for cooking, domestic hot water, and space heating through existing, rehabilitated, or new gas distribution systems.

1.64 In economic terms, this case is equivalent to the conversion of existing buildings from district heating to gas, as presented above. The gas netback value at the service line connecting point (SLCP) is estimated to be \$4.6/MMBTU. If new consumers are connected to the DH system, the netback value for cooking and water heating would be between \$2.1 and \$2.8/MMBTU, and gas supply would therefore not be justified.

1.65 For areas not yet supplied with district heating, the gas netback value (in this case for cooking, domestic hot water, and space heating) is estimated at \$4.9/MMBTU, which appears consistent with the cost of gas delivered to the city gate and with distribution costs (rehabilitation, expansion, and/or construction).

1.66 ***Summary of Results for the Residential and Commercial Sector.*** The gas demand forecasts developed for this study for various levels of netback value at the SLCP, (and the regional breakdown) are given in Tables A-2 and A-3 (Annex 1).

1.67 For direct utilization of gas, a high-gas-demand scenario of 5.1 bcmy is estimated for the year 2010, assuming a gas netback value of \$3.8/MMBTU at the SLCP (\$2.7/MMBTU at the city gate). A low-demand scenario of 4.1 bcmy is estimated with a gas netback value of \$4.2/MMBTU at the SLCP (\$3.0/MMBTU at the city gate) The demand scenarios derived from these tables are shown in Table 1.21.

Table 1.21 Natural Gas Demand in Residential and Commercial Sector, 1993–2010 (bcmy)

		2000		*2005*		*2010*	
Sector	*1993*	*high*	*low*	*high*	*low*	*high*	*low*
Residential and commercial	4.3	4.0	3.6	4.4	3.7	5.1	4.1

1.68 For heat generation (LAA and RENEL), a gas demand of 1.7 bcmy in the year 2010 for a SLCP gas value of \$3.9/MMBTU is estimated, assuming the nonreplacement of RENEL cogeneration power plants. If RENEL maintains its heat output at the present level, gas demand will be lower. The analysis of the future gas demand concludes that in the year 2010, distribution networks will supply 3 million housing units, broken down as follows:

a. 805,000 collective dwellings in DH areas that use gas for cooking only

b. 280,000 collective dwellings that already use gas for cooking and that could use gas for cooking, space heating, and water heating

c. 378,000 collective dwellings that do not currently use gas but that could use gas for cooking, space heating, and water heating

d. 648,000 new collective dwellings, outside DH areas that could use gas for cooking, space heating, and water heating

e. 270,000 new collective dwellings, within existing DH area, that could use gas for cooking, space heating, and water heating

f. 251,000 houses that now use gas for cooking only but that could use gas for cooking, space heating, and water heating

g. 42,000 houses connected to the gas network that do not currently use gas but that could use gas for cooking, space heating, and water heating

h. 234,000 houses that are not presently connected to the gas network but that could use gas for cooking and water heating

i. 92,000 new houses that could use gas for cooking, space heating, and water heating.

In addition to these housing units, gas distribution networks could supply 30,000 commercial and industrial users.

Gas Demand in the Industrial Sector

1.69 ***Sectoral Energy Consumption.*** Between 1988 and 1992 total energy consumption in Romania's industrial sector dropped from approximately 47 million tons of oil equivalent (MTOE), to about 30 MTOE (880,000 TJ). Table 1.22 shows the energy consumed by fuel in the industrial subsector in 1992. Direct use of gas accounts for nearly 40 percent of total energy and feedstock consumed by industry. The heat the industrial sector consumes but does not produce itself is provided by RENEL in plants fueled with gas, and as a result gas is the largest source of energy in the Romanian industrial sector.

Table 1.22 Industrial Energy Consumption, 1992
(thousand terajoules)

Industry	*Gas*	*Other fuels*	*Heat*[a]	*Electricity*	*TOTAL*
Extractive	14.6	8.8	20.5	14.6	58.5
Food processing	5.9	8.8	26.3	5.8	46.8
Chemical	216.5	137.5	58.0	17.5	429.5
(Feedstock)	(93.6)	(67.3)			(170)
Metallurgy	38.0	64.4	17.5	26.3	146.2
Construction materials	29.3	17.6	6.0	8.8	61.7
Other manufacturers	35.1	17.5	58.0	26.3	136.9
TOTAL	339.4	254.6	186.3	99.3	879.6

[a] Heat purchased from outside sources.

1.70 Energy consumption in the chemical, metallurgical, and construction material industries accounts for about 70 percent of total consumption, and for more than 80 percent of the total gas consumption. This consumption is concentrated in few large industries as shown in Table 1.23.

Table 1.23 Energy Consumption in Energy-Intensive Industries
(thousand terajoules)

Industry	*Gas*	*Other fuels*
Fertilizers and methanol	118	
Cement plants	11	17
Iron and steel	38	65
TOTAL	167	82

1.71 ***Nitrogenous Fertilizers.*** Up to the end of the 1980s, the nominal capacity of ammonia production in Romania was about 4.5 million tons per year (MMty). Ammonia production was divided into eight industrial complexes: Arad, Bacau, Craiova, Fagaras, Piatra Neamt, Slobozia, Tirgu Mures, and Turnu Magurele. Three generations of ammonia plants existed at that time. These were (a) the first-generation plants built in the early 1960s, (b) the second-generation plants built in the late 1960s and early 1970s (ICI process), and (c) the third-generation plants built in the late 1970s (Kellog process).

1.72 Under the present situation, the first-generation plants have been closed down, the second-generation plants are on standby, and the third-generation plants are generally operating (except for the Arad plant). The total nominal capacity of operating units in 1994 was 2,430,000 tons per year of ammonia, and the nominal capacity of units on standby was about 1,800,000 tons per year (the Arad plant included).

1.73 ***Ammonia Production in Romania.*** The estimated total ammonia production in Romania and corresponding gas usage from 1990 to 1993 are shown in Tables 1.24 and 1.25.

Table 1.24 Ammonia Production in Romania, 1990–1993
(thousand tons per year)

Producing unit	*1990*	*1991*	*1992*	*1993*
Five complexes[a]	1795	1,253	1,579	1447
Other	0	450	320	395
TOTAL	2245	1570	1974	1807

[a] Bacau, Craiova, Slobozia, Tirgu Mures, and Turnu Magurele.

Table 1.25 Gas Consumption for Ammonia and Nitrogen Fertilizers, 1990–1993
(MMcmy)

Consuming unit	*1990*	*1991*	*1992*	*1993*
Five complexes[a]	3002	2,247	2744	2497
Other	594	420	520	475
TOTAL	3,596	2667	3264	2972

[a] Bacau, Craiova, Slobozia, Tirgu Mures, and Turnu Magurele.

1.74 ***Forecast of the Ammonia Production for Fertilizers in Romania.*** Domestic consumption of nitrogen fertilizers in Romania is estimated at 80 kg of nitrogen per hectare in 1990. This corresponds to about 780,000 tons of nitrogen and 950,000 tons of ammonia for the domestic nitrogen fertilizer market. Of the 2.0 million tons of nitrogen fertilizers produced in 1990, approximately 1.05 million tons of ammonia were for exports.

1.75 The current consumption of nitrogen per hectare in Romania is only 40 kg, which means roughly 425,000 tons of ammonia for the domestic fertilizer market. Consequently, about 70 percent of the ammonia produced in 1993 was exported in the form of nitrogen fertilizers. In the future, the consumption of nitrogen per hectare is expected to return to the 1990 level, this being about 90 to 100 kg/hectare, which is equivalent to 1.1 to 1.3 million tons of ammonia for the domestic market.

1.76 Domestic demand for urea fertilizer was low, at approximately 0.3 million tons in 1992. In 1993, total production was around 1.3 million tons from a total nominal capacity of 1.75 million tons per year from six units of plants currently in operation. It is estimated that future use of nitrogen fertilizer will be roughly 100 kg per hectare.

Consequently, about 1.3 million tons of ammonia per year will be necessary to meet the domestic demand.

1.77 ***Value of Gas in Fertilizer Production.*** In estimating the value of gas in fertilizer production, two types of fertilizers complexes have been considered: (a) a Slobozia-type complex based on the production of urea and ammonium nitrate and (b) a Craiova-type complex based on the production of urea, ammonium nitrate, calcium ammonium nitrate, and nitrophosphate.

1.78 In 1991 the price for urea f.o.b Eastern Europe fluctuated between \$130 and \$150 per ton. In 1992 the f.o.b price varied between \$115 and \$125 per ton, and in 1993 the situation was bad for the fertilizer industry, as the price decreased to \$95 per ton. In 1994 the situation improved, and the price increased to \$150 per ton. The urea price forecast used for this study is based on a 1994 value of \$130 per ton for export f.o.b Constanta.

1.79 The netback values for gas use in fertilizer plants were estimated at \$3.95 and \$4.48/MMBTU for the Slobozia and Craiova complexes, respectively. The analysis concludes that

- Continuing to run the seven plants currently in operation, each a 1,000 tons per day ammonia unit (six Kellog-type units installed between 1977 and 1983 and one older Piatra Neamt unit) would result in an aggregate production capacity of more than 2 million tons of ammonia per year. Two of these units have already been revamped, and the others could also be revamped at a reasonable cost.
- The Romanian fertilizer industry was developed as a major exporter. In the near future, however, the industry's strategy will have to focus on the domestic market, which requires fertilizers such as ammonium nitrate, calcium ammonium nitrate, NPK, and (to a lesser extent) urea.
- The future nitrogen demand for Romanian soil is expected to be between 1.0 and 1.2 million tons per year (MMty) of nitrogen, which is equivalent to 1.2 to 1.45 million tons of ammonia per year. This production could be covered by five or six ammonia plants.
- The excess production capacity would be allocated to exports such as urea.
- The urea production could be ensured by four or five urea plants, especially based on the CO_2-stripping Stamicarbon process, which is the most up-to-date process.
- The gas consumption for the production of ammonia and derived fertilizers can be estimated at 2.3 bcmy, as shown in Table 1.26. The gas value is estimated at around \$4.4/MMBTU in the nitrate fertilizer complexes that primarily supply the domestic market, and at \$3.9 per million BTU in the units aimed at the export market.

Table 1.26 Future Demand for Gas in the Fertilizer Industry (bcmy)

	1993	*2000*	*2005*	*2010*
Economic demand	3.5	2.3	2.3	2.3

1.80 These gas demand estimates must be considered as maximum; they assume market prices for fertilizers remain high enough to justify a permanent continuous production. When fertilizer prices are low, it would be economically justified to cease production or to operate on an intermittent basis.

1.81 ***Methanol Production.*** Two Romanian complexes produce methanol, in DOLJCHIM at Craiova (capacity 215,000 tons/y) and VIROMET at Victoria (225,000 tons nominal capacity). The production of methanol since 1990 is summarized in Table 1.27.

Table 1.27 Methanol Production in Romania, 1990–1993
(tons per year)

Plant	*1990*	*1991*	*1992*	*1993*
Craiova	44,300	—	not operating	—
Victoria	162,700	123,000	92,200	121,600

1.82 The Craiova plant ceased production in 1991, but resumed in May 1994 because of the high international price of methanol. The consumption of natural gas for methanol production is shown in Table 1.28.

Table 1.28 Consumption of Natural Gas for Methanol
(MMcmy)

1990	*1991*	*1992*	*1993*
279.45	166.05	124.20	162.00

1.83 ***Methanol Price.*** Over the past decade the international price of methanol has been volatile. The collapse of crude oil prices in 1986 led to a reduction in demand for methanol used as a low-cost gasoline additive. European spot prices began at $145/ton and ended at $79/ton that year. Methanol prices rebounded to $120/ton in 1987, and rose to $200/ton in 1988. Prices varied between $75 and $120 per ton in 1989 and 1990. The Gulf war had a drastic effect on the price of methanol in 1991, when it rose to $280/ton. It fell to $110/ton in 1992 and 1993, however. The increase of methanol spot and contract prices was rapid due to the closure of three world units and a higher demand for formaldehyde in the United States.

1.84 World methanol markets should remain tight through 1997, as demand growth exceeds likely capacity additions. After 1997 new units will probably start up, and high prices should decrease. For the beginning of the next decade, a range of prices between \$180 and \$210/ton may be assumed. In the high scenario, the Victoria-based methanol production is retained (capacity of 225,000 tons/y), which corresponds to an annual gas consumption of about 0.3 bcmy. We assume that the production of methanol is of the same value as nitrogen fertilizers. In the low scenario, methanol production is stopped.

1.85 ***Iron and Steel.*** Steel production in Romania reached its maximum in 1989, with an output of 14.4 million tons, and by 1993 the output had fallen to 5.2 million tons. The net consumption of steel in Romania has declined from 12 million tons (raw steel) prior to 1988 to 7 million tons in 1991—that is, from more than 500 kg per capita to 300 kg per capita. Romania's 1993 steel production is shown in Table 1.29.

1.86 The energy consumed for steel production was 26 GJ/ton of raw steel (32 GJ/ton of finished product) in 1993. There is a large variation in energy consumption between the different production units in Romania, with energy consumption is directly linked to the production structure.

Table 1.29 Steel Production in Romania in 1993

Type of production	*Million tons*	*Percentage*
Blast furnace coke	2.6	
Pig iron	3.0	
Rolled steel	5.2	
Martin steel	(1.0)	(19)
Converter steel	(2.9)	(56)
Electric steel	(1.3)	(25)
Continuous casting	2.4	46

1.87 The general trend of the world's iron and steel industry can be characterized by the processes they use, by the type of production unit, and by their associated energy requirements. These are as described below.

- *Integrated steel plants.* These include blast furnaces, oxygen steelmaking and continuous casting, as well as rolling. The global net energy consumption is roughly 20 to 25 GJ/ton of raw steel, primarily provided by coal and byproduct gas obtained from the process. The typical fuel breakdown for such plants in Western Europe is given in Table 1.30, which shows that these plants use very little gas.

Table 1.30 Energy Consumption of Integrated Steel Plants

Fuel	*Percentage*
Coke and coal	80/85
Electricity	10/15
Oxygen	2 or 3
Natural gas or HFO	less than 1

- *Semi-integrated steel plants.* These are electricity based and use scrap. Energy consumption is approximately 10 GJ/ton of rolled product, and the primary energy used is electricity. A complement of energy of about 1.5 GJ/ton is required, and it can be provided from a variety of fuels, including natural gas.

1.88 With regard to international practices, the share of open-hearth steelmaking in today's Romanian steel production is comparable to that of Western Europe in the early 1970's. Romania's oxygen steelmaking is similar to that prevailing in Western Europe in the late 1970's and its electrical steelmaking is similar to that currently in use in Western Europe. As for continuous casting, its share is relatively low and is comparable to that prevailing in Western Europe during the period from 1980 to 1985. The present structure of steelmaking in Romania is similar to that prevailing internationally in the 1970s and 1980s, and the general trend leads us to suppose that Romania's production structure by 2005 to 2010 should be similar to that of Western Europe today.

1.89 ***The Future Development of the Romanian Iron and Steel Industry.*** The industry's objective during the 1970s and 1980s was to produce 20 million tons of steel per year. Following the 1989 economic changes, targets needed redefining, and the sector needed restructuring. Both are now being undertaken. The various iron and steel plants have been grouped within the framework of a relatively autonomous holding company, SIDEROM. The production target set for the restructuring, which uses existing infrastructure and equipment as well as that under construction, is approximately 9.5 million tons per year, or an average of 400 kg per capita. Production plants in Romania can be classified into three main categories:

a. *Large, integrated, relatively modern steelworks.* This category includes the SIDEX (Galati) and SIDERCA (Calarasi) steelworks on the Danube in southeastern Romania. Designed for ambitious targets, these plants have not yet been completed.

   SIDEX (Galati) is the main combinate integrated steelworks in Romania. Based on the pig-iron-oxygen converter process, it uses imported minerals. Once modernization is complete, the continuous-casting method will be generalized. The steel production capacity of this complex is 6 million tons. SIDEX supplies practically all of the country's flat products and is now looking to develop downstream steel activities such as coating, strips, and coils. Its specific energy consumption should approach international levels. This means a total consumption of 120 to 150,000 TJ, primarily coal, and less than 200 MMcm of gas (steel-rolling mills), given the production capacity. Gas consumption in 1993 was 0.46 bcmy, supplied by ROMGAZ, plus another 20 MMcm per month from ROMPETROL.

SIDERCA (Calarasi) still requires large capital investments before it closes its metallurgical loop (oxygen converter steelmaking) with continuous casting and secondary metallurgy to produce sectional products. According to its designed production capacity, SIDERCA is scheduled to produce 1.4 MMty of steel by the year 2002. Adopting the same assumptions as for SIDEX, energy consumption at SIDERCA could be around 30 to 35,000 TJ, with but a very small quantity—perhaps less than 50 MMcm—of gas used for steelmaking.

The use of electric furnace steelmaking processes should decrease at SIDEX and SIDERCA, with a shift to semi-integrated plants in western Romania.

b. *Semi-integrated steelworks to be modernized.* This category includes four plants: SIDERURGICA (Huneadoara), CSR (Resita), SOCOMET (Otelu Rosu), and COST (Tirgoviste). Of these, the first three use the open-hearth process and face a major handicap in the supply of raw material (primarily imported iron ore and coke), because of their location and their higher consumption.

SOCOMET (in the northwest) also has an electric furnace combined with continuous casting. According to medium-term plans, the open-hearth process should be replaced by electric furnaces at SOCOMET and at CSR. Therefore, of these three, only the Huneadoara unit (1993 production over 1 million tons) would continue to use an open-hearth process (reduced) in parallel with the electric furnace process.

COST (Tirgoviste) is the only Romanian plant that specializes in the production of special steels. Nonferrous fusion is also performed at this plant. The electric furnace process currently used should be continued and complemented by casting and rolling units. For its steelmaking needs, no significant energy consumption aside from electricity is foreseen. In 1993, the total gas consumption (for ferrous and nonferrous products) reached 108 MMcm for a relatively low activity rate (400,000 tons produced for a 1-million ton capacity). For the future, with the use of continuous casting, the implementation of efficient production means (for example, furnaces), improved furnace heat efficiency, heat recovery and control, gas consumption can only decrease to perhaps 50 MMcm.

c. *Non-integrated mills.* There are several rolling mills that depend on semi-products supplied by the integrated steelworks. The problems these mills are currently facing are attributable to an input shortage caused by a drop in domestic production and a lack of foreign currency to pay for imported semi-products, and high transportation costs for the inputs. There are also some 20 enterprises involved in secondary steel-processing activities. Their activity has also decreased as a consequence of the decline in rolled-steel production and in demand for steel products. The specific energy consumption of these nonintegrated industries varies but is considered high because of the current low activity rate and the poor condition of some of the equipment. Table 1.31 presents the energy consumption characteristics observed in the Romanian secondary metallurgy sector.

Table 1.31 Specific Energy Consumption in Secondary Metallurgy, Romania versus International Standards
(gigajoules per ton)

Type of unit	*Romania*	*International*
Cast-iron foundry	6	2.4 to 4.8
Steel foundry	7	3
Nonferrous foundry	16	
Forging	9	

1.90 The 1993 levels of consumption for forging and casting could probably be halved from 1993 levels by rationalizing working capacities to required production levels and by modernizing equipment. In conclusion, future gas consumption for steelmaking and rolling is estimated at 150 MMcm at SIDEX (Galati), at 50 MMcm at SIDERCA (Calarasi), and at 50 MMcm at COST (Tirgoviste).

1.91 ***The Value of Gas in Iron and Steel Production.*** Iron and steel plants are relatively unrestricted in their choice of energy; they look for the least-expensive energy option, which is usually coal or HFO, and these will be the main competitors to natural gas in the future. The economic costs of the fuels competing with gas and delivered to the eastern region are shown in Table 1.32. Regardless of whether considering existing dual-fuel equipment, renovated, or new, the capital and operating costs are essentially the same and thermal efficiencies are similar. For these applications, if the fuel replaced is LSFO, the value of gas in the iron and steel industry will be about $3.9/MMBTU for the period from 2000 to 2010, and the equivalent total gas consumption will be 250 MMcmy.

Table 1.32 Economic Costs of Fuels, Current and 2000–2010 (US$/MMBTU)

Fuel	*Current*	*2000–2010*
Coal (metallurgic)	2.1	2.6
HFO	2.5	3.7
LFO	3.2	5.1

1.92 ***Cement Production.*** Cement production in Romania reached its maximum in 1988 with 13 million tons. Cement output had fallen to 6.8 million tons by 1933; of this, 2.3 million tons were exported. The net consumption of cement fell from 500 kg per capita in 1988 to 200 kg per capita in 1993, which reflected the slowdown in the construction sector. This represents roughly half the per capita consumption in the European

Community. The aggregate production capacity for the dozen or so cement plants in Romania is about 47,000 tons per day.

1.93 The wet process, which corresponds to a capacity of 3,000 tons per day, has been abandoned in Romania. Dry-process kilns, with a total capacity of 44,000 tons per day, are currently being used at 47 percent capacity. Their output is largely sufficient to cover future domestic needs, estimated at 9 million tons of cement per year, for an assumed annual average per capita consumption of 400 kg. Cement (or clinker) exports are not justifiable for a country that has to import energy. Most cement plants operate on dual-fuel systems using heavy fuel oil and natural gas, and fuel consumption in 1993 was 960,000 tons of oil equivalent (28,000 TJ). The breakdown of fuel consumption is shown in Table 1.33.

Table 1.33 Fuel Consumption in the Romanian Cement Industry (tons of oil equivalent)

Fuel	*Consumption*	*Share (%)*
Natural gas	370,000	38.5
Heavy fuel oil	573,000	60.0
Oil coke	17,000	1.5

1.94 With recent improvements in kiln temperature reductions and air preheating, the specific energy consumption of some kilns is not far from that usually encountered throughout the world with use of the dry process. The future energy consumption for a cement production of 9 million tons will be roughly 30,000 TJ, or the equivalent of 0.9 bcmy of gas.

1.95 ***The Value of Gas in Cement Production.*** The cost of energy in cement production is the determining factor for its selection. There is no technological advantage in supplying cement kilns with natural gas, and it is better to use coal. For this reason, as well as because of the lack of reliability of the gas supply, the conversion of cement kilns to coal or coke is being considered for about 85 percent of the energy consumption of the cement industry. The cost of converting all Romanian kilns to coal, including coal storage and treatment and preparation of infrastructure has been estimated at $200 million. Given the cost of coal, the gas netback value can be estimated as shown in Table 1.34.

1.96 These gas netback values leave little room for the purchase and transportation of gas. The remaining fuel consumption (15 percent) that is not shifted to coal and is intended for ancillary activities and for office space heating can continue to use gas, fuel oil, or both. For this situation, the gas value in the eastern region can be estimated at $3.9/MMBTU as in the iron and steel industry. The corresponding potential gas demand for the various cement plants is approximately 150 MMcmy.

Table 1.34 Gas Netback Value at Plant Gate for Cement Production (US$/MMBTU)

Cost element	*Current*	*2000–2010*
Coal cost	1.7	2.1
Cost conversion to coal	0.8	0.8

1.97 ***Nonspecified Industries.*** The consumption of energy that can be replaced by gas in nonspecified industries (NSIs) in 1992 is about 9.5 MMtoe (electricity and feedstock excluded). The decrease in energy consumption between 1988 and 1992 in the NSIs is estimated to be 40 percent of the 1988 level. This decrease is caused primarily by the slowdown in industrial activity and by the introduction of energy-saving measures. For industries including food, ceramics, and textiles, the specific energy consumption can range from that of comparable industries in Western Europe to five times this level of consumption. On the basis of the survey of a sample of the industrial enterprises as well as studies by the Romanian Energy Conservation Agency (ARCE), it is possible to conclude that major energy savings can come from at boiler plants, processes, and space heating of premises.

1.98 ***Boiler Plants.*** The Romanian industrial structure is dominated by large, integrated industrial plants. Heat generation is often centralized for several enterprises in close proximity. The restructuring or closing down of some of these complexes, the increased cost of energy, and the objective of achieving better control over the supply and use of energy will lead to the multiplication and dispersion of boiler plants. Independent boiler plants will be sized to meet the needs of each enterprise and distribution networks will be shortened. New boilers will include condensate recovery and control systems and will be equipped with preheaters for water and air. As a result of improved control and thermal efficiencies (currently 70 percent in generation instead of the 85 percent with modern facilities and 80 percent for distribution), the possible savings can reach 20 to 30 percent.

1.99 ***Process.*** Numerous savings are possible. Changing a metallurgy burner can yield a 20 percent savings, and the simple renovation of equipment undertaken during a modernization to improve product quality and productivity could lead to a gain of 30 percent or more. Where possible, direct firing at the point of use could result in a gain of around 20 percent.

1.100 ***Space Heating of Industrial Premises.*** The conventional method for space heating of industrial premises is to use convectors fed by steam from a local network (if one exists), even if the enterprise has its own boiler plant for its process use. There is no economic justification for separating heat generation into space heating and process. Romanian industrial premises are usually vast, ventilated, and noninsulated. The convector-based space heating that is currently used offers little comfort compared with the quantity of energy consumed, and it could be replaced by radiant systems, which provide greater comfort and offer an energy savings of around 30 percent.

1.101 It is likely that the overall energy consumption level reached in the period 1992 to 1993 will be more or less maintained over the 1995 to 2010 period based on an average growth rate of about 5 percent per year from 1995 on. This increase would result in almost a 100 percent increase in generation between now and 2010. This increase may be partly offset by energy savings of approximately 50 percent, which can be expected from the restructuring of the sector toward light industries using modern equipment. These savings will justify capital investments for modernization and will offset, at least in part, the higher cost of energy.

1.102 ***The Share of Gas.*** Table 1.35 shows the energy consumption (electricity and feedstock excluded) in light and medium industries. The other fuels shown in Table 1.35 include mostly oil products consumed in dual-fuel installations in Romania. Heat purchases from outside the industrial sector account for almost 40 percent of energy consumption. The industrial enterprises will become increasingly autonomous, and growing competition will push them to invest in modern equipment in particular to save in energy use. The consumption of purchased heat is therefore destined to disappear and to be replaced by gas or fuel oil used in central boiler plants in individual enterprises.

Table 1.35 Energy Consumption in Light and Medium Industries, 1992

Energy	*10^6 mtoe*
Gas	3.4
Other fuels	2.2
Heat (purchased outside the industry)	3.8
TOTAL	9.4

Note: mtoe=million tons of oil equivalent

1.103 If the relative consumption of gas and other fuels is maintained at the present level and the heat substitute market is evenly split between gas and fuel oil, the resulting consumption should be about 7,700 MMcm (8.8 million toe) of gas, which is roughly 56 percent of the total consumption, excluding electricity. The only European countries with such a high proportion of gas in the industrial sector are the Netherlands (gas exporter) and the United Kingdom (major gas producer). Even in Italy, where the share of gas in industry is the highest among the European gas importing countries, it is still well below this level.

1.104 ***The Value of Gas in Industry.*** The value of gas in industry depends on the type of utilization and the alternative solution in direct competition with natural gas. Most of the energy used by industry is consumed in the form of steam, and the share of energy used in boilers is 60 percent or 75 percent (electricity excluded) of the energy consumed. The remaining energy is used for direct firing, usually in ovens (drying, fusion, reheating, temperature holding, and cooking), and in heating systems. The direct use of energy, notably due to a growing share of gas for direct use, will increasingly replace imported heat and steam. Gas valuation is estimated according to the type of use.

- *Central heat generation and space heating.* For central heat generation, the installation of a new boiler plant offers an opportunity to make general improvements in heat distribution networks and to install new control systems. This type of operation should produce savings on primary energy of at least 20 percent regardless of the fuel used.

  Whether the operation consists of replacing the external heat network, installing a new boiler plant, or supplying existing dual-fuel (gas/fuel-oil) boilers, the value of gas is determined by the cost of the replacement liquid fuels, taking into account the capital and operating costs of the alternative solutions.

- *Direct uses.* Here, the equipment costs differ depending on the gas or nongas solution selected. Premium factors ranging from 1.08 (for industrial dryers) to 1.2 (for high-temperature furnaces) can be used. Such premium factors may be used to assess the netback value of gas in each end use. Assuming that some industries could continue to use high-sulfur fuel oil in competition with gas for certain uses or in less sensitive areas with regard to pollution, the gas value would be around $3.2/MMBTU. By contrast, gas can be better valued when it is in competition with lightfuel oil or LPG, which are both high-cost, premium fuels. The value of gas in these situations is about $5.7/MMBTU.

1.105 The estimated potential gas demand and gas netback values are summarized in Table 1.36.

Table 1.36 Potential Gas Demand and Netback Values

Use	*(MMcm)*	*(US$/MMBTU)*
In boilers	5.2	3.2
Same (replacing HSFO)	0.7	4.1
Non metallic (furnaces)	0.6	4.4
Food industries (furnaces)	0.2	4.6
Metallurgy (furnaces)	0.2	4.8
Replacing L F.O.	0.7	5.7

The Aggregate Gas Demand Forecast

1.106 Table A-4 presents the total and the peak gas demand for industry and by region in the year 2010. For the high scenario, the annual gas demand is estimated at 10.6 bcm, and the peak demand at 48 MMcmd. A low scenario can be developed by assuming a lower penetration rate in light industries (80 percent related to the preceding case) and subtracting the gas demand for fertilizers and for methanol production. This low-demand scenario is 6.5 bcmy in 2010, with a peak demand of 32 MMcmd.

1.107 The economic forecasts for natural gas demand that were developed for this study are summarized in Table 1.37.

Table 1.37 Romania: Natural Gas Demand to 2010 (bcmy)

		2000		*2005*		*2010*	
Demand source	*1993*	*high*	*low*	*high*	*low*	*high*	*low*
Residential and commercial	4.3	4.0	3.6	4.4	3.7	5.1	4.1
Industrial	11.8	10.6	9.0	10.6	9.0	10.6	6.5
Power	10.6	5.7	5.7	6.3	5.3	11.3	7.6
TOTAL	26.5	20.3	18.3	21.3	18.0	27.0	18.2

1.108 The high scenario gives a gas demand of 27.0 bcmy in 2010, which represents the technical potential for gas within economically acceptable limits. The low scenario gives a gas demand of 18.2 bcmy in 2010 and assumes that (a) for security of supply reasons not all future power plants will be gas based, (b) the use of gas as a supplemental fuel for steam generation in existing lignite- and coal-fired power stations will be eliminated once these plants are rehabilitated, (c) the level of gas penetration in the residential and commercial sector, as well as in light and medium industries will decrease, and (d) the gas demand for production of nitrogeneous fertilizer and methanol will cease.

1.109 The netback values and the gas demand for each consumer category in the year 2000, calculated at the point of ex-transmission, are summarized in Table 4 of the Executive Summary. In this table, the netback value for power and for large industries is given ex-transmission. The netback values for residential, commercial, and light industries is given at the inlet of the service line. They do not include the distribution cost, which is estimated at about $1/MMBTU (based on a weighted average of the rehabilitation of existing distribution networks and the cost of constructing new network extensions). This distribution cost must be subtracted to obtain the netback value ex-transmission.

2

Natural Gas Infrastructure

2.1 This chapter presents an analysis of the technical issues facing the Romanian gas sector and the formulation of a gas infrastructure investment plan up to the year 2010. The first issue is the impact that declining field production and pressures will have on the production facilities needed in the future. The next issues are the transmission system and underground storage facilities, where future development and investments are highly dependent on the successful exploitation of domestic tail gas reserves. The present analysis uses a transmission system simulation incorporating the volumes and directions of natural gas imports needed to meet the shortfall in domestic gas supply, regional availability of domestic tail gas, locations of future underground storages, and regional peak demand for natural gas. The major technical issues facing gas distribution are then discussed, and, an overall investment plan up to the year 2010 is presented.

Production Facilities

Declining Field Pressures

2.2 The production decline profile is shown in Figures 2.1 and 2.2. These indicate that in 1995 approximately 75 percent of the total production was supplied at wellhead pressures equal to and above 10 bar and that this percentage will fall to 20 percent, 14 percent, and 13 percent in years 2000, 2005, and 2010, respectively. In 2010, 50 percent of the total production (or 3.5 bcmy) will be available at 4 bar at the wellhead. Geographically low wellhead pressures are encountered mainly in the Transylvanian basin; average pressures are higher in Oltenia (Craiova), Muntenia (Bucharest), and Moldavia.

2.3 A key issue for the development of Romanian gas infrastructure facilities will be the successful exploitation of the low-pressure tail gas that will be produced in Transylvania in the period from 2000 to 2010.

2.4 ***The Implications of Declining Production.*** Three possible solutions to the declining field pressures can be envisaged: (a) raising the wellhead pressures up to transmission pipeline pressures to transport this gas either within or outside the region, (b) delivering the gas directly to low-pressure distribution networks, and (c) supplying low-pressure gas to new power generation projects.

Figure 2.1 ROMGAZ: Cumulative Natural Gas Production versus Wellhead Pressure

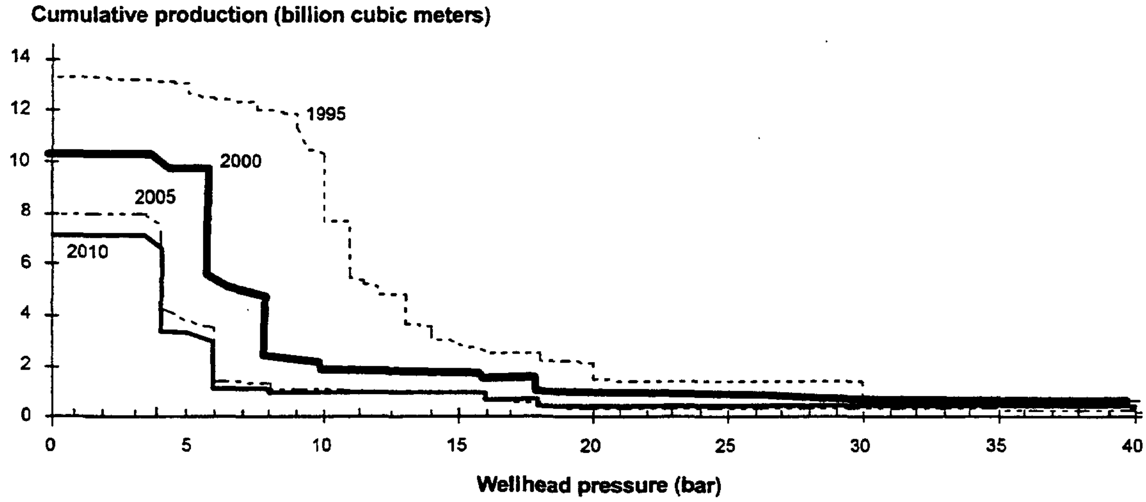
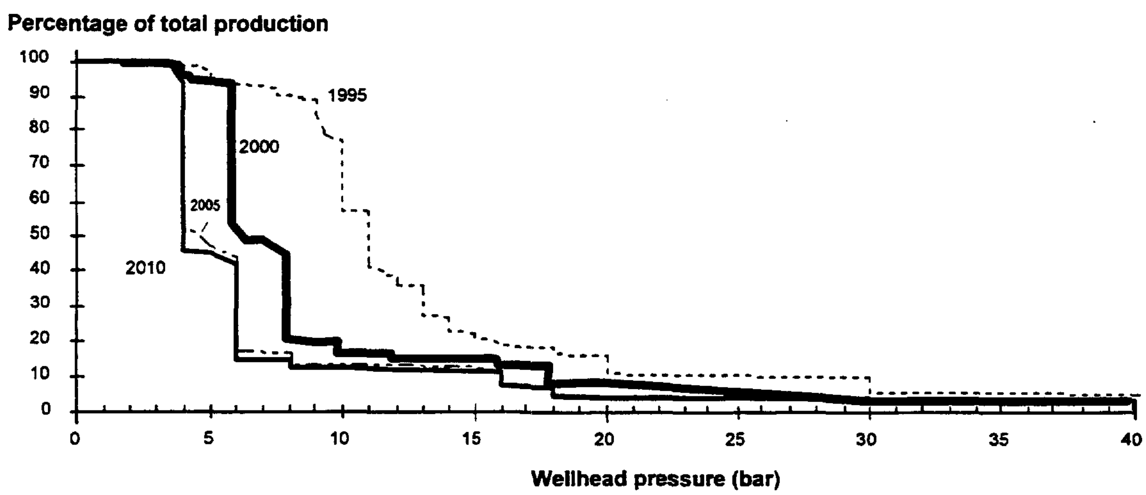


Figure 2.2 ROMGAZ: Percentage of Total Natural Gas Production Versus Wellhead Pressure



2.5 *Raising Wellhead Pressures.* This could be achieved by installing additional compressors or by reconfiguring the existing compressor stations and pipeline arrangements to make the best use of available power. More than 100 MW of field compression power was installed between 1975 and 1993 in Transylvania to cope with declining reservoir pressure. However, most of these compressors are now operating below their design pressures and capacities.

2.6 It is expected that Russian gas will be supplied to this region in the future through a high-pressure pipeline from Ukraine. This implies that the main transmission lines leaving the region will be operated at their maximum pressure of 35 bar, and so the domestic gas must be raised to 35 bar in order to transport the gas through the main transmission lines. This would require a large revamping (modification or replacement) of the existing compressors and the installation of additional compressors.

2.7 Because the decline of domestic production will be offset by imports, Transylvanian gas will have to be transported over increasingly shorter distances and, at the end of the period, production will nearly balance regional demand (base case). In addition, pipeline corridors leaving Transylvania are typically composed of several parallel pipelines operated at different pressures. It can be envisaged that the higher-pressure pipelines (35 bar) will carry imported gas outside the region, whereas lower-pressure pipelines will be used to transport domestic production within the region. Therefore it will not be necessary to raise the domestic gas pressure to the maximum transmission pressure systematically. Instead, less-radical solutions such as compression up to 20 bar can be implemented.

2.8 *Delivering Gas Directly to Local Low-Pressure Distribution Networks.* Several gas fields are already connected directly to local low-pressure systems in Transylvania. This practice could be extended to new fields. The residential and commercial demand in the Tirgu. Mures, Harghita, Sibiu, and Cluj districts will amount to 879 MMcm in 2010, and a share of this could be supplied directly by low-pressure fields at around 4 bar, since the typical distribution pressure is 2 bar. This is provided that the field is not located too far from the distribution network (10 to 20 km).

2.9 This option has several technical limitations, including the fact that a large distribution network will have to be supplied from different locations around the town, which may be difficult to achieve in the absence of medium pressure. In addition, load management is difficult because there would be no upstream pressure reserve. If demand were higher than the maximum production, distribution pressure would rapidly decrease unless backup supplies could be brought in.

2.10 *Supplying Low-Pressure Gas to New Power Generation Projects.* The gas demand forecast for power generation in the Transylvania region in 2010 is about 3,120 MMcm to be used for the existing Ludus thermal plant and in a projected 1,400 MW CCGT plant. This demand represents 59 percent of the region's projected production in 2010. The existing thermal plant presently receives gas at a pressure around 10 to 12 bar, which is reduced to 3 to 6 bar at the delivery station. Because the plant is located at some distance from the gas field (assumed 40 to 50 km), however, a 4-bar wellhead pressure compression will be required at the departure of the pipeline wellhead supplying the plant. This compression is even more essential in the case of CCGT plants, which require a supply pressure of 25 bar.

2.11 ***Existing Gas Production Facilities.*** Gas-gathering networks are designed for different nominal pressures of 6, 25, 40, and 55 bar. The pipelines are buried at a sufficient depth to mitigate freezing and are coated but not cathodically protected. In the future, the gathering networks will be operated at much lower pressures than originally designed, but flow rates will also decrease.

2.12 The main issue is the capacity of existing gathering networks to handle produced quantities at low pressures. In some cases, additional gathering lines and water separators may be required. One of the key parameters is the velocity of the gas flowing through gathering lines and separators. Higher velocities entail higher pressure losses. Gas velocity is directly related to the actual flow volume produced by the field. In some fields where actual flow volumes will increase after 1995—that is, the decrease in production will be less than the decrease in wellhead pressure. In that case, some gathering networks may not have enough capacity to handle future production while keeping pressure losses at acceptable levels.

2.13 ***Gas Dehydration Plants.*** The gas fields operated by ROMGAZ are producing a natural gas that has a very high methane content and that is free of any impurities and corrosive components. The only treatment required is free water removal and gas drying in order to reach pipeline-quality gas. The Romanian specifications for gas quality do not impose a rigid requirement with respect to water dew point, and gas dehydration is achieved by adsorption on solid substances (silica gel). The gas produced in Transylvania is free of CO_2 and H_2S, and the risk of formation of corrosive agents is therefore limited.

2.14 The existing drying units are designed to lower the water dew point to -5°C to avoid water condensation under pipeline operational pressures and temperatures. The main issue is that these plants no longer operate under their design specifications because of the strong decrease of gas field pressures and flow rates. The plants are typically upstream from the production compressors and cannot benefit from the pressure achieved by these stations. Under current specifications, the available wellhead pressures are now well below the design conditions of the plants. Even if the flow rates are lower than design values, the pressures are even further reduced, resulting in higher gas velocities through the silica gel units and less residence time in the adsorbers. The efficiency of the drying process is reduced, and the natural gas injected into the network does not generally meet the water dew point specification of –5°C.

2.15 The main issue is to decide if it is necessary to dry the low-pressure tail gas that ROMGAZ intends to produce in the period from 2000 to 2010 and, if so, to identify the best solution for this purpose. The elements to be taken into account are as follows:

- Romanian standards appear to have no strict requirement for gas humidity. All transporters, however, typically require water dew points of –5 to –10°C at maximum transmission pressure.
- Gas produced in the Transylvania basin will be transported over shorter distances as imported gas quantities increase.
- Even if domestic gas does not contain corrosive components, it may be mixed with imported gases with different compositions.
- Water content will increase as field pressures decline. It is therefore recommended to maintain gas drying for the largest possible share of domestic gas produced by the Medias Production Unit (PU Medias) in Transylvania. The possible solutions are (a) revamping the existing plants, with the addition of new adsorbers to accommodate larger actual volumes and with an increase of regeneration capacity; or (b) installing new dehydration plants downstream from the compressor stations using tri-ethylene-glycol (TEG).

2.16 The advantage of the second solution is that with 3 new dehydration plants located downstream from the Filitelnic, Danes, and Botorca compressor stations, the treated gas would represent, respectively, 48 percent, 54 percent, and 59 percent of the PU Medias production in the years 2000, 2005, and 2010. Gas would be processed at a pressure in the 20 to 35 bar range, provided that the compressor stations are revamped. The total investment for these 3 new plants is about $30 million.

2.17 ***Production Compressor Stations.*** A large program of compressor installation was implemented in the early 1980s to raise gas pressure prior to injection in the transmission system. But because of the rapid depletion of the gas fields, the installed power is now insufficient to raise the pressure up to the pipeline design pressure. On average, the inlet pressure of existing stations is only about 75 percent of the design pressure, and the present flow capacity is about 50 percent of the original design capacity. As a consequence, gas is generally injected into the transmission system at a pressure much lower than that of the original design and lower than the present maximum-allowable operating pressure (MAOP).

2.18 ***Future Requirements for Field Compression.*** All ROMGAZ production compressor stations are located in the Transylvania Basin, where wellhead pressures are expected to decrease rapidly by the year 2000 and thereafter. On the basis of flow and pressure data provided by ROMGAZ, an assessment of future compression requirements was prepared for the years 2000, 2005, and 2010. Transylvanian gas will need to be compressed either to 18 to 20 bar or to 35 bar in order to be transported and delivered within the region or to be injected into pipelines dedicated to imported gas. The analysis of this study shows that the overall future power requirements do not exceed the installed power but that all stations and compressors will have to be heavily revamped to match future flows and pressures. Such revamping could consist of (a) modification of compressor configuration (parallel to series); (b) restaging of compressors (modification of cylinders); (c) moving of compressor from one station to another; (d) reallocation of fields to different stations, depending on pressure levels; (e) installation of new compressors and drivers, either for the replacement of existing units or for fields not presently connected; and (f) total reconstruction of a compressor station.

2.19 The key elements are the discharge pressure to be attained and the feasibility of the revamping of compressors, depending on the characteristics and technology of each compressor and its driver. The extent of the revamping and reconfiguration required to adapt compressors to new operating parameters must not be minimized because ***all*** stations are concerned. As a preliminary estimate, the amount of investment required could reach 50 percent of the value of the installed power, resulting in expenditures of $140 million in the period from 1995 to 2005. The above analysis applies to the ROMGAZ gas production facilities. PETROM gas production comes mainly from the Oltenia region and much of it has to be transported to Bucharest. In this case, pressure has to be raised up to 30 bar and it is likely that additional compression capacity will be required.

2.20 ***Investments.*** In the year 2000, half of the ROMGAZ gas production (5.1 bcmy) is expected to be available at well head pressures lower or equal to 6 bar. Large investments will be required to process low-pressure gas delivered to its customers, even if consumers are located within the production area. Additional investments will also be required in subsurface facilities, including new wells and workovers. For production facilities, the main objectives are (a) to dry the majority of the wet gases produced by PU Medias to achieve a water dew point of -5 °C at 20 or 35 bar (b) to maintain the supply pressure in pipelines in the 20 to 35 bar range to permit the utilization of the gas in the central region and vicinity.

2.21 The required investments for ROMGAZ production facilities are shown in Table 2.1.

Table 2.1 Investments for ROMGAZ Production Facilities up to 2010 (millions of U.S. dollars)

Investment	*1995–2000*	*2000–2005*	*2005–2010*
Subsurface	not included		
Dehydration	30	—	—
Compression	100	40	—
TOTAL	130	40	—

The Transmission Network

2.22 The first natural gas transmission pipelines in Romania were laid before World War II. Bucharest was first supplied with natural gas in 1943, and since then the network has developed to cover the whole country. The network was originally developed on a radial pattern, with natural gas produced in the central part of the country and transported to the periphery. In the 1970s and 1980s, additional transmission lines were laid in the eastern part of the country for gas imports from the Commonwealth of Independent States, and for natural gas transit to Bulgaria and Turkey. The total length of the transmission pipelines is 11,500 km, with diameters ranging from 10 to 32 inches. The network is divided into ten subsystems, with six high-pressure transport systems and four local low-pressure networks near the gas fields in Transylvania.

2.23 Gas is delivered to the transmission network through 174 gas-receiving stations. which meter the flow of gas entering the network. There are five transmission compressor stations with a total installed power of about 45 MW. The ROMGAZ transmission division operates three additional compressor stations, which boost gas production pressure. There are some 378 gas-delivery stations on the transmission network. These perform filtration, gas heating, pressure reduction, and metering. They also supply gas to industrial customers and to distribution networks.

ROMGAZ Transmission Organization

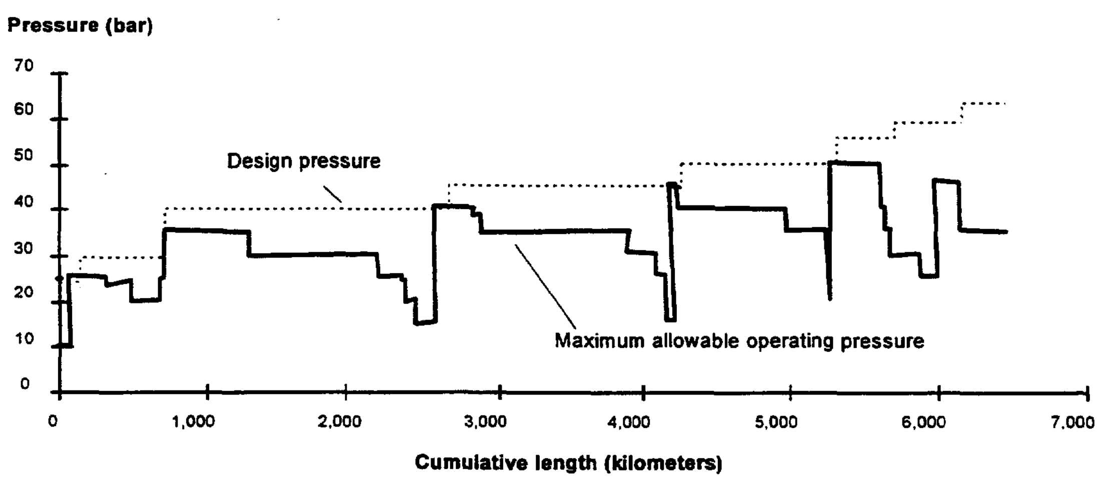
2.24 The ROMGAZ transmission division is based in Medias with 3,500 employees. The transmission system is divided into 9 geographic regions, and further divided into 53 sectors. It is noted that ROMGAZ transmission division has no operational control of the production compressor stations nor of the underground storage.

Existing Transmission System Facilities

2.25 ***Transmission Pipelines.*** The ROMGAZ transmission pipeline statistics show that 38 percent of the high-pressure pipelines are more than 30 years old and that the rate of expansion of the network decreased steadily during the 1970s and 1980s. These statistics do not take into account the recent replacement of pipeline sections carried out by ROMGAZ. Over the next 15 years, ROMGAZ will have to replace a substantial length of its pipeline system. Pipeline sections should, however, be replaced according to their condition or usefulness with respect to future gas transportation requirements, and not necessarily only according to their age. Old pipelines that have a good coating and that transport clean gas can reach lifetimes of much longer than 35 years.

2.26 ***Pipeline Operating Pressures.*** The Romanian transmission network shows two striking features: (a) a high number of different operating pressures, and (b) large differences between the original design pressures and the MAOP. Typically, a pipeline designed for 50 bar now has a maximum operating pressure of 35 bar. Figure 2.3 shows the actual MAOP versus the cumulative length of the pipelines for each level of design pressure. The average derating, weighted by pipeline length, is about 25 percent.

Figure 2.3 Differences between System Design Pressure and Present Maximum Allowable Operating Pressure, Romanian Gas Transmission Network



2.27 The high derating factor is an indicator of the average condition of the pipelines, but there is no correlation between the age of the pipeline and its level of derating. The issue of raising the MAOP toward the initial design pressure is a difficult one. In order to requalify a line to a new MAOP, a new hydrostatic test must be performed that requires putting the line out of service for several weeks. This operation can only reasonably be done if there is sufficient certainty that the line will pass the test successfully, and if the test requires extensive line inspection with wall thickness measurements to identify defective zones and necessary subsequent repair work.

2.28 Most of the Romanian transmission lines cannot be pigged because of diameter changes, reduced-bore line valves, and other constrictions, and it is not feasible to run intelligent pigs to check the integrity of the pipes. An assessment of the condition of a pipeline. These can only be based on (a) past inspection records, including measurements of samples taken out for replacement or other work; (b) incident or accident reports; (c) as-built data files and in-weld radiographic images; (d) cathodic protection measurements to identify coating defects; and (e) dug-out sections for visual inspection and wall thickness measurements. Given the age of the pipelines, a general requalification to a higher operating pressure is not a recommended option because of its complexity and risks. The requalification option should only be considered for specific sections where higher pressure would be needed, and after having considered all other alternatives, including the construction of new pipeline sections.

2.29 ***Corrosion Protection.*** The natural gas produced in Romania is almost pure methane and is free from corrosive components such as H_2S and CO_2. The main problem lies with the water content of the gas, which is not always in accordance with specifications. Imported gas from Russia meets standard pipeline specifications according to contractual terms. The water content sometimes exceeds the contractual limit, however, and may create the conditions for hydrate formation at pressure reduction stations. In Western Europe, Russian gas is further dehydrated at border metering stations to avoid this problem. In Eastern Europe, gas is systematically heated prior to pressure reduction, which eliminates the problem.

2.30 About 75 percent of the transmission lines are cathodically protected, and it is assumed that this low-average coverage reflects a full coverage of the high-pressure subsystems and a very low coverage of the local low-pressure subsystems. There are more than 300 cathodic protection stations for the main network, and a large number of these stations are not in good working condition as a result of lack of maintenance and spare parts. The monitoring of the cathodic protection through test point measurements is regularly carried out by ROMGAZ, but the data are not fully exploited because of the lack of processing equipment.

2.31 Internal corrosion does not appear to be a major issue for the Romanian transmission lines. External corrosion is a more serious problem, and ROMGAZ has already identified the most critical sections of the network requiring priority attention. These total 600 to 1,000 kilometers. ROMGAZ expects to achieve a pipeline replacement rate of 200 km/year, which represents about 2 percent per year of the total length of the network.

2.32 It would be beneficial for ROMGAZ to pursue the program for the replacement of corroded sections through development of a pipeline condition data base, identifying the corroded sections and giving priority to locations that pose major hazards to populated areas. For the rehabilitation of its corrosion protection system, ROMGAZ could improve the operation and monitoring of cathodic protection systems through intensive cathodic protection measurements using the Pearson method for sections of pipelines known to suffer from corrosion problems or coating defects.

2.33 For large sections of pipeline to be replaced in the future and for other new pipelines, ROMGAZ should specify modern coating techniques, such as three-layer coating applied in the factory. This type of coating includes (a) a thin inner layer (about 100 µm) of fusion bond epoxy (FBE), (b) an outer jacket (about 3 mm) of polyethylene (PE), and (c) an intermediate layer (about 250 µm) of copolymer adhesive. The key points to ensuring the proper lifetime of a pipeline are the quality of materials and of workmanship. ROMGAZ should develop a quality control system covering material supply and construction workmanship, to be used as an integral part of any supply or construction contract. This implies the development of specifications and procedures and the training of ROMGAZ staff as well as contractor personnel.

2.34 ***Transmission System Gas Metering Stations.*** A general feature of the Romanian gas transmission system is its low level of instrumentation and automation caused by Romania's inability to procure modern equipment due to the scarcity of foreign exchange. Generally, all types of transmission stations are permanently staffed with operators whose duties include actuation of valves, taking of instrument readings of temperatures and pressures, hand calculation of flow rates, and reporting by phone to local control centers.

2.35 Gas metering is achieved by orifice measurement between ISO 5167 and 5180, although not all of the installations are in strict compliance with the ISO standard. There are no operational flow transmitters of any kind on the network, however. The composition of Romanian dry gas and imported gas is very stable, but this is not always the case for associated gas. Gas quality measurements are made by taking samples for laboratory analysis. There is no continuous measurement of gas quality or of heating value. Customer invoicing is made on a volume basis, but in the future, customers will likely require invoicing based on energy content.

2.36 Gas imports from different sources will play an increasing role in satisfying Romania's gas demand. Meters that continuously record the heating value of gas delivered to a given area (region) will have to be installed at some major network nodes. Invoicing can then be based on monthly average heat content of the different gases supplied to the area.

2.37 Within the framework of the Petroleum Sector Rehabilitation Project, ROMGAZ has received a loan from international financial institutions for a SCADA and telecommunication project. This includes the provision of instrumentation for gas metering, including transmitters and flow computers, and will substantially raise the accuracy of data communication in the transmission and gas metering system. The SCADA project is a first step in the modernization of metering stations. It is designed to be very flexible and will easily support the modernization of other station equipment not included in the project—for example, the remote control of valves.

2.38 ***Gas Delivery Stations.*** Gas delivery stations for industrial customers and distribution networks typically include gas filtration and liquid removal, gas heaters, and orifice plate metering lines. Pressure reduction is achieved by self-governing pressure regulators, sometimes through two or three pressure stages (for example, 19 to 8 bar and 8 to 3.5 bar). With modern pressure regulators, one single-stage pressure reduction would be sufficient. Stations are not equipped with automatic shut-down safety valves and the gas heaters are not instrumented. This requires that the stations be permanently attended by at least one operator. For delivery stations to be modernized through the SCADA project, we recommend the installation of shut-down safety valves or of new regulators incorporating shut-down safety valves. In case of closure, the safety valve would send an alarm signal to the dispatching center calling for operator intervention.

2.39 ***Interconnection Stations.*** There are 17 major interconnection nodes on the Romanian gas transmission system. These stations, which are permanently attended by operators, achieve the following functions: (a) interconnection between pipelines, (b) pressure and flow control on outgoing pipelines; (c) flow metering on some pipelines; and (d) temperature, pressure, and flow reporting to control centers.

2.40 Valves are manually operated to configure the interconnection station according to gas-dispatching instructions. Within the scope of the SCADA project, these nodes will be partially modernized to include (a) installation of metering systems that are not intended to provide very accurate measurements but to meter flows for gas-dispatching purposes, (b) installation of instrumentation on existing orifice plate metering systems, and (c) installation of flow control valves on some stations to control the flow of gas leaving the station for gas-dispatching purposes. The next step is the full remote control of these nodes by the installion of actuators on the main valves, if technically feasible, or the complete replacement of the valves by motorized valves.

2.41 ***Transmission Compressor Stations.*** The transmission system compressor stations achieve a high degree of availability. The installations are well-maintained by qualified and experienced staff, provided that spare parts are available. The first issue is the low pressure level now prevailing in the transmission network. A review of the suction and delivery design pressures of the compressor stations show that compressors have been designed for higher suction pressures and flow rates, and the available installed power cannot be used efficiently to raise the pressure to required levels. This situation does not apply to the Silistea compressor station, which compresses imported gas to Bucharest, because the pressure at the border station (Isaccea) is normal.

2.42 The second issue is the age of the units: Some 65 percent of the units are more than 20 years old and have reached the end of their normal operating lives. Even if the supply pressure could be brought back to normal values, most of the stations would not work as designed because pipeline pressures have been strongly derated. The necessary investments in compressor stations are of two kinds: (a) those needed in the short term to improve the operation of stations in line with present transportation directions from the center of the country to the periphery; and (b) those needed in the longer term as a result of future transit schemes with imported gas gradually replacing domestic gas.

2.43 Short-term investments will be for the provision of spare parts (most of the units are of foreign origin) and compressor revamping in accordance with the present flow and pressure regime. Our network simulations show that under the assumption of gas imported only from Russia (from Isaccea and Satu Mare), several existing stations, such as Sinca and

Batani, will not be needed in 2010. The decision to replace older units will be based on detailed studies of future transit schemes, both for the medium and long term.

2.44 ***SCADA and Telecommunication.*** The main objectives of the project funded by the international institutions are to (a) improve the real-time knowledge of the operation of the network (pressure/flow data) for better control of supply demand balance, (b) provide the basis for better forecasting exercises, and (c) improve the accuracy of metering. The project scope includes (a) installation of instrumentation (transmitters, flow computers) and data acquisition equipment on selected sites; (b) development of a private telecommunication system that transmits data between sites and dispatching centers in coordination with the public system; and (c) the installation of data-processing systems at two regional dispatching centers (Medias and Bucharest), as well as one national dispatching center (Bucharest). The project cost is estimated at $58 million.

2.45 ***Odorization.*** Natural gas flowing in the Romanian transmission system is not odorized. Odorization using mercaptan odorant is usually performed at the delivery stations for public distribution networks. Given the poor condition of distribution networks, a properly controlled and monitored odorization is very important to ensure leak detection by the public. The large number of delivery stations for distribution networks makes it difficult to adjust and control the level of odorant in delivered gas properly. Drip-type or bypass absorption-type odorizers cannot be easily controlled, and it is difficult to proportion the odorant to a fluctuating demand. Western European gas companies are moving toward centralized odorization systems, which odorize the gas at a few major nodes of the transmission system using injection pumps. This removes the need to operate and maintain a large number of small and low-technology odorization systems at delivery stations. With proper instrumentation and control systems, it is possible to minimize the risk of over-odorization, which would be detrimental to the quality of gas required for some industrial users (chemicals, glass, and ceramics). Given the larger expected share of the residential and commercial demand, it is recommend that ROMGAZ initiate a shift from distributed odorization to centralized odorization.

Investments in Transmission System Modernization

2.46 The key objectives for the transmission system are to (a) maintain the integrity of the system by identifying and replacing the most corroded sections; and (b) improve the operation of the network by incorporating new technologies that will result in a better use of the work force. To reach the first objective, the following short-term priority actions are recommended:

- Improve the cathodic protection system, develop CP monitoring with intensive surveys and data-processing equipment to enable the processing of measurements and to help in identify defective sections.
- Modernize the coating technique to be used for pipe replacement and new pipelines.
- Develop quality control procedures and actions to guarantee the quality of pipeline works.

2.47 For the second objective, the current SCADA project is a first step toward improving the quality of metering and the ability to monitor, control, and optimize operation of the network. A second step will consist of an extension of the SCADA system to cover more stations. Full automation of stations (inlet, delivery, and interconnections) without permanent staff is a medium term-objective that will require either a complete overhaul of the station or the installation of new equipment.

2.48 Table 2.2 shows the transmission investments needed up to the year 2010.

Table 2.2 Investments for Rehabilitation and Modernization of the Transmission Network through 2010
(Millions of U. S. dollars)

Transmission network component	*1995–2000*	*2000–2005*	*2005–2010*
Rehabilitation and replacement of Pipeline component (including cathodic protection)	360	360	*300*
SCADA Project Phase I	58	—	—
SCADA Project Phase II	—	20	*10*
Modernization of stations (inlet, delivery, interconnection), including valve replacement (with actuators), regulators and safety valves, instrumentation	25	25	*25*
Rehabilitation of transmission compressor stations (short-term)[a]	10	—	—

[a] For future compressor requirements, see below.

Underground Gas Storage

Existing Storages

2.49 The first underground gas storage in Romania was developed in Urziceni in 1977 using a depleted gas reservoir. The goal was to meet demand fluctuations in the Bucharest area. Two additional storage sites were subsequently developed, Bilciuresti in 1983 and Balaceanca in 1993, both of these being depleted gas reservoirs near Bucharest. Table 2.3 presents the characteristics of these storages, which are operated by the Ploiesti Production Company, a subsidiary of ROMGAZ.

Table 2.3 Existing Underground Gas Storage

Facility characteristic	*Urziceni*	*Bilciuresti*	*Balaceanca*
Type of storage	Depleted gas field	Depleted gas field	Depleted gas field
Average depth (m)	1,400	2,000	600
Working pressure range (bar)	70–82	41–86	23–56
Production wells (number)	28	58	10
Working capacity (MMcm)	60	590	50
Withdrawal flow rate (MMcm/d)	0.45	5.7	0.3

2.50 The total available storage capacity is 700 MMcm, with a maximum withdrawal rate of 6.45 MMcd, but given the gas shortages in Bucharest during the winter, it is evident that this capacity is insufficient. Furthermore, the available capacity is near Bucharest, and the fluctuating demand of the other main consumption areas in the country can only be met by the production flexibility. With the expected decrease in domestic production, storage requirements will increase dramatically.

Future Underground Storage Projects

2.51 ***Expansion of Existing Storages***. ROMGAZ plans to increase its underground storage capacity and the peak withdrawal capacity for the year 2000. The first step is to increase the capacity of the existing storages, and the second is to develop new storages in other areas of the country.

2.52 The two sites that have a potential for capacity increase are Bilciuresti and Urziceni. For Bilciuresti, the objective is to increase the working capacity up to 1,200 MMcm and the withdrawal flow rate to 10MMcmd, representing nearly a doubling of capacity. To reach this objective, it will be necessary (a) install 40 percent of the 58 existing wells with filters and gravel packs, multiplying the well productivity by a factor of four; (b) to drill 15 additional wells; and (c) to reinforce the compressor station to reach a maximum pressure of 120 bar instead of 90 bar. It will also be necessary for the gas supply pressure from the transmission network reaches the nominal of value 21 to 28 bar.

2.53 A similar expansion program for Urziceni is foreseen to include (a) the improvement of well completion (filters and gravel pack), (b) additional wells, (c) the modification of the existing compressor station to increase the discharge pressure from 73 to 80 bar. The expected working capacity would reach 120 MMcm with a withdrawal flow rate of 1.0MMcmd day.

2.54 ***New Storages***. ROMGAZ has made a survey of depleted gas fields to identify candidates for underground gas storage development. The ROMGAZ selection criteria are (a) gas fields with enough remaining gas in place to act as cushion gas. With the high cost of imported gas, ROMGAZ cannot currently undertake the development of storages that would require the buildup of cushion gas capacity, which is typically of the same order of magnitude as the working capacity; (b) gas fields that are located as close as possible to large consumption areas; and (c) prioritization of gas fields that will not require large investments in compression, given the low available pressure from the transmission network. This leads to the selection of fields with depths ranging from 300 to 500 meters. This criterion differs from the West European practice, where storage depths are closer to 500 to 1,000 meters, with pressures at or above 100 bar, but where transmission networks operate at 50 to 84 bar.

2.55 The most likely new underground storage projects are at Sarmasel, Roman-Margineni, and Slimnic-Ghercesti, as detailed below:

- *Sarmasel.* This is a multilayered gas field in the Transylvania Basin. The layer targeted for storage is 500 meters deep and used to contain 1.8cm^3 of natural gas at 75 bar. At the end of 1994, the remaining gas was 0.58 bcm at 19.5 bar. The objective is to develop a storage capacity of 200 MMcm with a 2 MMcmd withdrawal flow rate for the year 2000. The first development step will consist of injecting 100 MMcm in the existing installations in 1995. One particular feature of this project lies with its low operating pressure ranging from 19 to 25 bar, which will limit its utilization to local needs. This storage could be expanded in a second stage either by using deeper layers of the field (500–2000 m) or other nearly fields.
- *Roman-Margineni.* This is a depleted gas field in the northeastern Romania (Moldavia). It had initial gas reserves of 4.7 bcm at 298 bar, and its remaining reserves are presently around 1.4 bcm at 86 bar. A 300-MMcm storage capacity could be developed by the year 2000, with further expansion to 900 MMcm by the year 2010 (9 MMcmd withdrawal flow rate). The investment cost required for the expansion by the year 2000 has been estimated by ROMGAZ at about $48 million.
- *Slimini -Ghercesti.* This is a depleted gas field located in the south of Romania close to one of the possible routes for the future gas pipeline from the Middle East to Europe. This large structure is 300 meter deep and could have a capacity of more than 2 bcm. The main shortcoming of this storage facility is its low operating pressure of about 20 bar, which is much lower than that of the pipeline. Furthermore, the cushion gas volume would be very important, since 200 MMcm are required to raise the pressure by 1 bar. It is therefore unlikely that this site would be viable as a storage.

2.56 Other possibilities include salt deposits, which could be exploited by mining or leaching techniques. This solution does not appear attractive in Romania , however, where there are many depleted gas fields that could be converted into storage at a much lower cost.

2.57 ***Storage Requirements to 2010.*** Table 2.4 summarizes the ROMGAZ storage development program up to the year 2010. Taking into consideration the feasible sites, the total capacity in 2010 could reach 3,150 MMcm, with a peak withdrawal flow rate of 26.1 MMcmd.

Table 2.4 ROMGAZ Underground Storage Development Program up to 2010

Site	Location	*Peak Rate (MMcmd)* 1995	2000	2010	Start Year
Bilciuresti	Bucuresti	6.0	10.0	10.0	1998
Urziceni	Bucuresti	0.7	1.0	1.0	1997
Balaceanca	Bucuresti	0.4	0.4	0.4	—
Sarmasel	Transylvania	1.2	2.1	4.1	1995
Roman-Margineni	Moldavia	—	5.6	5.6	1996
Roman-Silistea	Moldavia	—	—	5.0	
TOTAL		8.3	19.1	26.1	

2.58 Based on the gas demand forecasts developed for this study, however, there could be a need for additional storage over and above that already planned by ROMGAZ. The future storage requirements will depend on the supply flexibility of production and of imports. Declining domestic production will play a smaller role in balancing supply and demand because it will represent a the smaller share of the total supply, and low wellhead pressures will allow less flexibility. Three cases were considered.

- *Case 1.* The peak daily production will not exceed 125 percent of the annual average, and the peak import is 110 percent of the annual average (Table 2.5). The domestic production assumes full exploitation of tail gas reserves. Failure to exploit these reserves increases the storage requirement from 3.1 bcm to 3.8 bcm, and the peak from 52 MMcmd to 56 MMcmd.

Table 2.5 Storage Requirements in 2010, Case 1

	Annual (bcm)	*Winter (bcm)*	*Summer (bcm)*	*Average (MMcmd)* Daily	Winter	Summer	*Peak (MMcmd)*
Demand	26.9	18.2	8.7	74	100	48	138
R&C	5.1	4.1	1.0	14	22	5	43
Industry	10.5	6.8	3.7	29	37	20	48
Power	11.3	7.3	4.0	31	40	22	47
Supply	26.9	15.1	11.8	74	83	65	86
Production	11.6	7.0	4.6	32	38	25	40
Imports	15.3	8.1	7.2	42	44	39	46
Storage							
Shortfall		3.1			17		52
Surplus			3.1			17	

- *Case 2.* The peak daily production will not exceed 110 percent of the annual average, and the peak import is 110 percent of the annual average (Table 2.6). The domestic production assumes full exploitation of tail gas reserves. Failure to exploit these reserves increases the storage requirement from 3.7 bcm to 3.9 bcm, and the peak remains unchanged at 57 MMcmd.

Table 2.6 Storage Requirements in 2010, Case 2

	Annual (bcm)	*Winter (bcm)*	*Summer (bcm)*	*Average(MMcmd) Daily*	*Winter*	*Summer*	*Peak (MMcmd)*
Demand	*as case 1*						
Supply	26.9	14.5	12.4	74	79	68	81
Production	11.6	6.4	5.2	32	35	29	35
Imports	15.3	8.1	7.2	42	44	39	48
Storage							
Shortfall		3.7			20		57
Surplus			3.7			20	

- *Case 3.* The peak daily production will not exceed 100 percent of the annual average, and the peak import is 100 percent of the annual average. This is a zero-flexibility case but corresponds quite closely to current conditions with respect to imports. Because of the zero supply flexibility, the storage requirements are independent of the level of tail gas production (Table 2.7).

Table 2.7 Storage Requirements in 2010, Case 3

	Annual (bcm)	*Winter (bcm)*	*Summer (bcm)*	*Average(MMcmd) Daily*	*Winter*	*Summer*	*Peak (MMcmd)*
Demand	*as case 1*						
Supply	26.9	13.5	13.5	74	74	74	74
Production	11.6	5.8	5.8	32	32	32	32
Imports	15.3	7.7	7.7	42	42	42	42
Storage							
Shortfall		4.8			26		84
Surplus			4.8			26	

2.59 A comparison of the load management requirements with those planned by ROMGAZ is shown in Table 2.8. Except for one case of supply flexibility, the planned storage capacity is below that required, and there is a substantial gap between peak demand and supply in all cases. Case 3 can be considered somewhat pessimistic with respect to flexibility of production and imports, and Case 2 is more realistic. This means that a total storage capacity of 4 to 4.2 bcm will be needed in the year 2010.

Table 2.8 Load Management Requirements in 2010

	Supply flexibility					
	Seasonal capacity (3.15 bcm)			*Peak day requirements (26 MMcmd)*		
ROMGAZ-planned underground storages	*Case 1*	*Case 2*	*Case 3*	*Case 1*	*Case 2*	*Case 3*
Full tail gas exploitation						
Load management needs	3.1	3.7	4.8	52	57	64
Gap	0.0	0.55	1.65	26	31	38
No tail gas exploitation						
Load management needs	3.8	3.9	4.8	56	57	64
Gap	0.65	0.75	1.65	30	31	38

2.60 The possible solutions for reducing the supply and demand imbalance in winter peak days are (a) increasing the peak delivery potential of the existing and planned storages; (b) developing additional storage capacity; (c) acting, on the demand side, by creating a portfolio of interruptible customers; and (d) installing peak-shaving facilities near the high-peak-demand areas (Bucharest).

2.61 With respect to the first option, ROMGAZ is already planning to increase the well productivity of its existing storages, and the new wells should have a higher delivery potential than the old wells (in the 300,000 cmd range). The ratio between storage capacity and peak sendout is 122 days. This is high compared with underground storages in Europe, where this ratio can be as low as 40 days (for aquifer storage). Depleted fields do not have reservoir characteristics as favorable as those of aquifer storage. In addition, the Romanian underground storages are generally low, a limiting factor for high-send-out flows. Another option consists of developing additional storage capacity given the large number of depleted fields. This capacity could be used as both operational and seasonal storage.

2.62 In the present gas-shortage situation, ROMGAZ is already managing a large portfolio of interruptible consumers (mainly industries). Plans for reduced deliveries are prepared in advance to cope with different degrees of cold weather. In 2010, this load management technique should be limited to severe cold weather situations, and it cannot be assumed that the industrial and power peak demand will be reduced by more than 10 percent. This would reduce the demand by 11 MMcmd. It should also be noted that the high-demand scenario includes gas deliveries to dual-fired power plants, which have a total peak demand of 6 MMcmd.

2.63 Peak-shaving facilities (LNG or LPG-air) can provide high peak flows during a few days (typically 5 to 10 days) to supply large peak demand concentrated in a few areas (large cities). They cannot contribute to seasonal balancing because their storage capacity is small. These plants are expensive. Given the large potential in depleted fields, these solutions do not appear attractive.

Investments in Underground Storages

2.64 The investments in underground storages have been estimated assuming the (a) development of total storage capacity of 4.0 to 4.2 by 2010, (b) increase of the peak send-out capacity of some of the existing and planned storages by targeting a capacity to a peak rate of 100 days instead of 122 days, (c) development of additional storages of 0.6 to 0.8 bcm for strategic and operational purposes, (d) maintenance of a portfolio of interruptible industrial consumers to provide a reduction in peak demand of 11 MMcmd, and (e) installation of five LPG air peak shaving plants.

2.65 Table 2.9 shows the total estimated investment in load management to the year 2010, assuming the full exploitation of tail gas reserves.

Table 2.9 Investments in Storages and Peak-Shaving Plants up to 2010

	Capacity in	*Peak capacity*	*Investments (million U.S.$)*		
Investment objectives	*2010 (bcm)*	*2010 (MMcmd)*	*1995–2000*	*2000–2005*	*2005–2010*
ROMGAZ UGS program	3.2	38.4	127	45	50
Storage expansion	1.4	17.0	—	80	120
LPG peak shaving plants	—	0.6	7	—	—
TOTAL	4.6	46.0	134	125	170

Evolution of the National Transmission System

Introduction

2.66 This study contains an analysis of the impact of the future supply and demand configuration on the gas transmission network and an evaluation of its ability to meet future peak gas demand. The transmission network delivered about 42 bcm in 1986, compared with 24 bcm in 1994. The high-demand scenario projects a demand of 27 bcm in 2010, and it might therefore be expected that the available capacity is more than enough to satisfy future gas demand, provided that rehabilitation and modernization efforts are carried out. The location of future gas sources and the structure of the demand are expected to change greatly, however, and the decreasing domestic production will not be able to play the major role in load management it did in the past.

The Supply and Demand Balance

2.67 ***Demand.*** Table 2.12 shows the gas demand in 2010 for the high scenario. This peak demand can be compared with past peak winter deliveries when there were no gas supply shortages, which were 135 MMcmd in 1988 and 134 MMcmd in 1989. The network simulation carried out for this study allocated the demand to the nodes of the transmission network, taking into account geographical location of the main infrastructure facilities, the urban population, industrial areas, and the most likely location of future gas power plants.

Table 2.10 Natural Gas Demand in 2010

Demand	*R&C*	*Industrial*	*Power*	*Total*
Annual (bcm)	5.1	10.5	11.3	26.9
Peak (MMcmd)	43.4	48	46.5	137.9

Supply

2.68 To meet a demand above peak-day gas demand, three sources of supply were taken into account:

1. Domestic production, for which two production scenarios were considered:

   o *Scenario with Exploitation of Tail Gas Production.* This assumes a total domestic production of 12 bcm in 2010, of which 7 bcm is from ROMGAZ fields, and about 5 bcm is from PETROM fields. Based on the future gas production profiles on a field-by-field basis, the regional production was allocated to the nodes of the network, as shown in Figures 2.4 and 2.5.

   o *Scenario with Non-Exploitation of Tail Gas Production.* With this scenario, the total domestic production in 2010 will reach 2.7 bcm.

2. *Natural gas imports.* The simulation considered Russian Gas imports from the existing interconnection point at Isaccea, and through a new pipeline project between Ukraine and Satu Mare in the northwest of Romania. Gas imports from other directions would lessen the impact on the development of the transmission system.

3. *Underground storage.* The future capacities and location of the UGS needed in 2010 were described above.

Network Simulation Results

2.69 Data on the characteristics of existing network facilities including pipelines, compressor stations, storage sites, and delivery stations were entered into a simulation program. Only the high-pressure systems were considered. The gas demand forecasts disaggregated by consuming sector and by geographical region were allocated to the delivery nodes of the high-pressure transmission network, taking into account the location

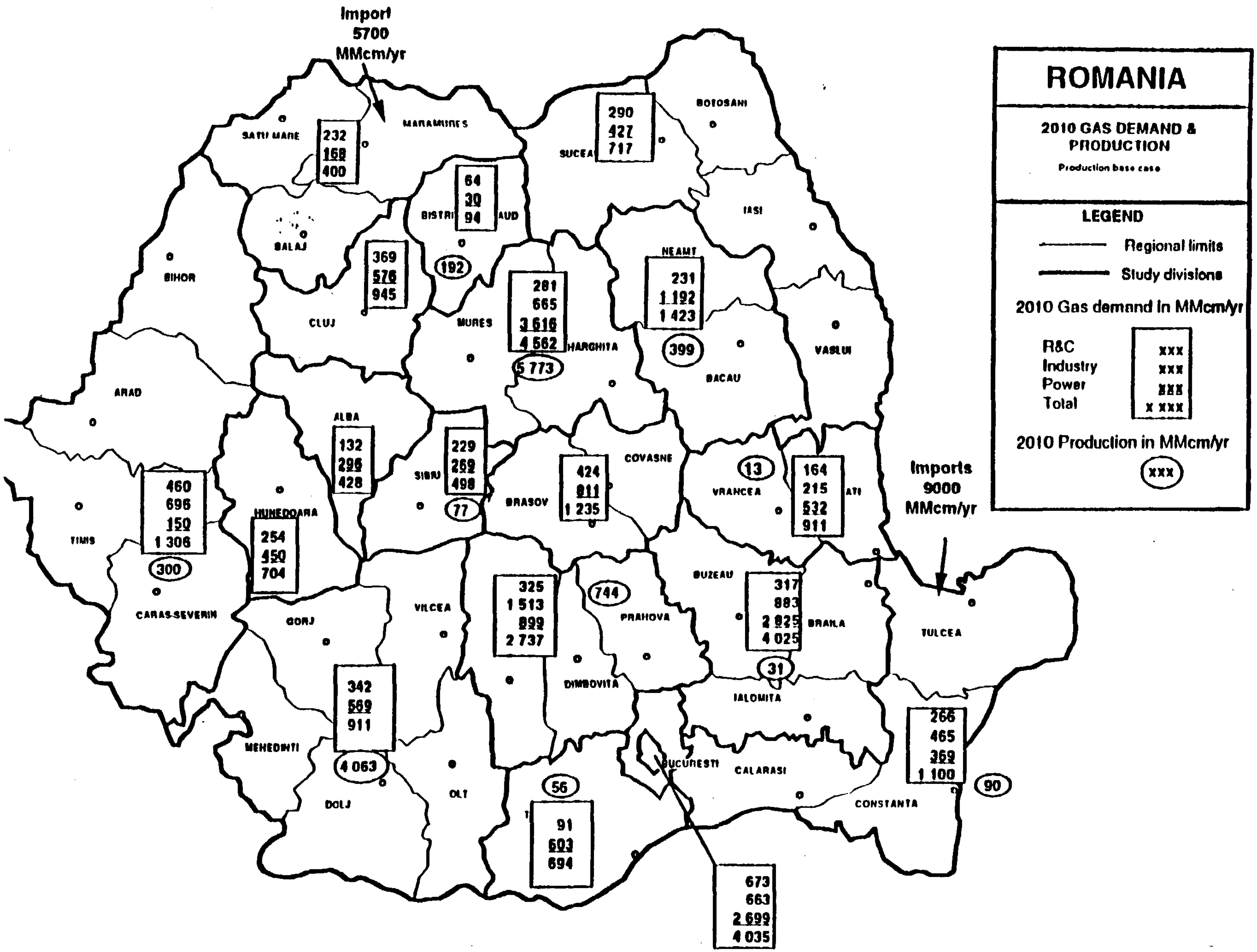
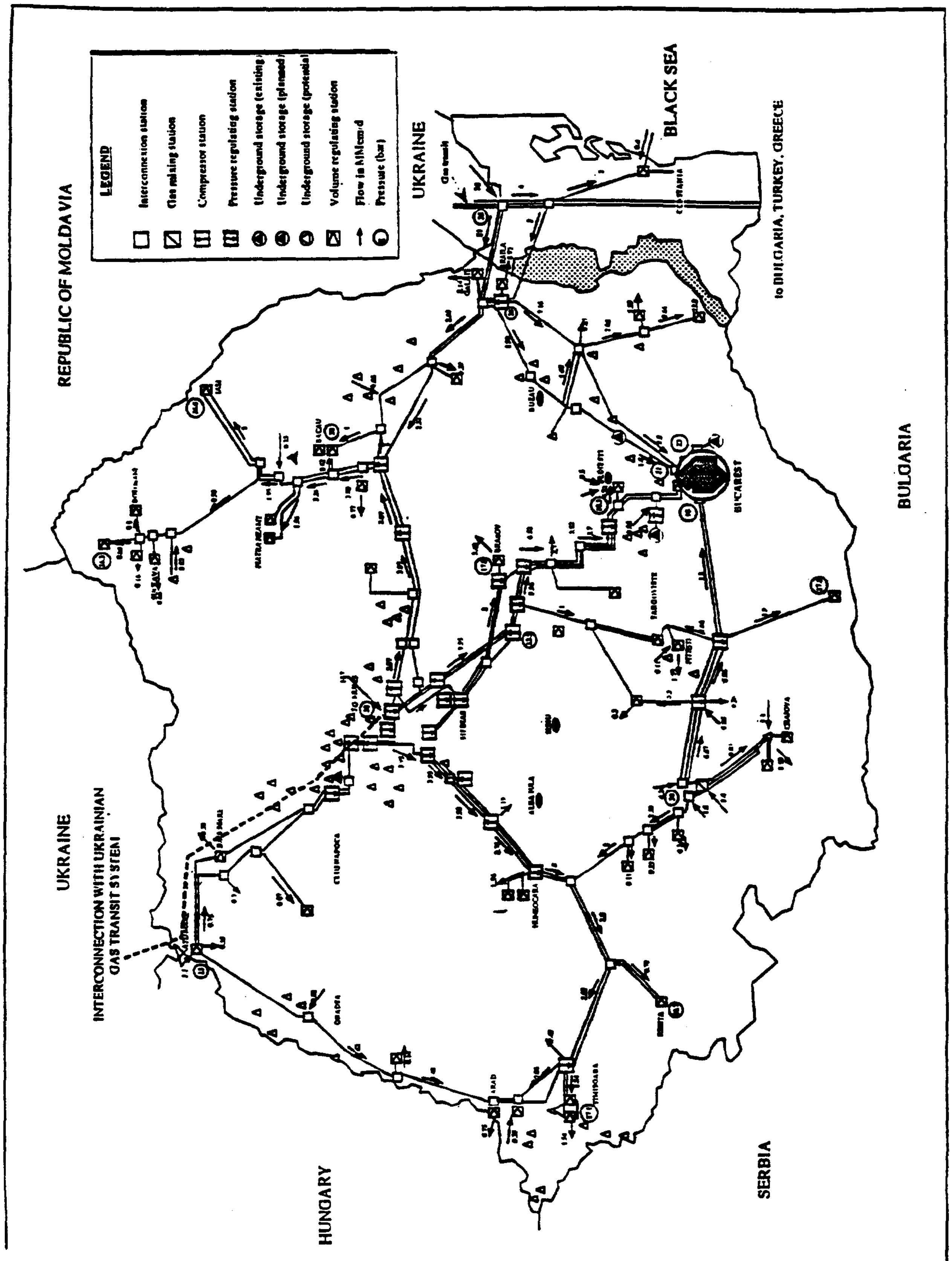


Figure 2.4 Romania Gas Demand and Production 2010

Figure 2.5 Romania Schematic Flow Chart
(base case - 2010 Average day demand)



of the large industries, power plants, and population centers. For each of the production scenarios noted above, the simulation was performed for both an average day and for a peak day. The simulations assumed that the low-pressure production would be consumed locally and would not appear in the high-pressure production transmission network. The present maximum operating pressures of the pipelines have been taken into account during the computation.

2.70 The main conclusion from the simulation is that the existing transmission network will be able to meet future peak-day requirements primarily because of the more advantageous locations of supply sources, the new interconnection with the Russian gas export network, and the new gas underground gas storage facilities. Nevertheless some critical issues have been identified.

- *For the scenario where tail gas production is fully exploited, and assuming the transmission pipelines retain their present MAOPs, there is only one major reinforcement needed.*
- *For the scenario where tail gas production remains unexploited, a reinforcement would be necessary between Galati and Tecuci to supply the northeastern region of Romania with Russian gas coming from Isaccea, since the old pipelines have low operating pressures.* In the same way the Magurele–Corbu pipeline should be looped to ensure an acceptable pressure range.

Investments in Transmission System Development

2.71 The investments shown in Table 2.11 result from the simulations of the transmission network carried out for the year 2010. They include the identified network reinforcements, the interconnection with Ukraine, and the expansion and modernization of transmission compressor stations.

2.72 For the future development of the transmission system, it is concluded that the present system has a large potential capacity because it transported 40 bcmy in the past and because the estimated overall peak transmission capacity is roughly 140 MMcmd. At present, this capacity is underutilized because of gas shortage and low supply pressure. In 2010, a potential gas demand is estimated at 26.9 bcmy, with an expected daily peak of 137 MMcmd.

2.73 In the scenario where tail gas production is exploited, field pressure decline is significant in the period from 1995 to 2000. Gas pressure has to be raised prior to injection in the pipelines. The priority is to invest in production compressor stations. With starting pressures back to normal levels, existing compressor stations will be able to operate in better flow and pressure regimes. Domestic production can supply most of the demand within each producing region. After the year 2000, high-pressure gas imports will be available in the central region, and the peak-day simulation shows that no compressor will be needed in 2010. Therefore, no additional compression power is required in this case, and the issue is to maintain the most recent units in a working condition for the period from 1995 to 2000.

Table 2.11 Investments for Transmission System Development (Millions of U.S. dollars)

Scenario	*Description*	*Cost (millions US$)*	*Implementation*
Full Exploitation of Tail Gas			
Interconnection with Ukraine			
Pipeline	300 km-30"-75 bar	180	2000-2005
Compression	40 to 75 bar-30 MW	55	2000-2005
Reinforcement			
Corbu-Magurele	89 km-20"-30 bar	30	1995-2000
No Exploitation of Tail Gas			
Interconnection with Ukraine			
Pipeline	300 km-42"-75 bar	250	1995-2000
Compression	40 to 75 bar-50 MW	90	1995-2000
Reinforcements			
Corbu-Magurele	89 km-20"-30 bar	30	1995-2000
Sendreni-Tecuci	55 km-32"-30 bar	30	2000-2005
Band-Botorca	42 km-24"-35 bar	18	2000-2005
Compressor stations			
Vintu	Reconstruction-7 MW	15	2000-2005
Silistea	Expansion-12 MW	25	2000-2005
Onesti	reconstruction-6 MW	15	2000-2005

2.74 In the alternative scenario where tail gas remains unexploited, gas imports must be increased rapidly (connection with Ukraine and increase of the capacity through Isaccea). The small amount of domestic production means that gas will have to flow over longer distances than in the preceding scenario. Our network simulations for 2010 show that there is a need for increased compression power for Silistea and that Vintu and Onesti will have to remain in operation and must consequently be reconstructed.

2.75 To make full use of the capacity available to transport gas out of Transylvania, the declining domestic production must be replaced by imports bringing high-pressure gas into this central region. The future configuration of (a) a very high pressure system comprising new pipelines (75 bar or above) to supply gas imported from Ukraine to the central region, and for the Iran-Europe transit line; (b) high-pressure national pipelines (30 to 45 bar), transporting mostly imported gas; (c) medium-pressure regional pipelines (20 to 35 bar), transporting domestic production and imported gas injected from the high-pressure system; and (d) a low-pressure line (typically 10 to 20 bar) for local transmission within the region.

Distribution Systems

Introduction

2.76 ROMGAZ has two gas distribution subsidiaries: the Tirgu Mures subsidiary, which covers Romania north of the Carpathians and the Bucharest subsidiary for the southern part of the country. In 1943 natural gas was delivered to Bucharest through German-manufactured steel pipes. With the conversion of manufactured gas to natural gas, rubber-joint cast-iron pipes were progressively replaced throughout the country by steel distribution pipes, which are now used in all the distribution networks. Only 25 percent of these pipes have cathodic protection.

2.77 The general arrangement is that gas flows from the transmission system to the medium-pressure secondary network and to the reduced or low-pressure distribution network. The different pressure levels are high pressure, $\geq$ 6 bar; medium pressure, 2–6 bar; reduced pressure, 0.2–2 bar; intermediate pressure; 0.05–0.2 bar; and low-pressure, $\leq$ 50 mbar. This represents a classical design for a distribution network. The Romanian gas industry is preparing new standards for polyethylene (PE) pipes based on Western European standards.

Current Distribution Activities

2.78 ***Technical Issues.*** The ROMGAZ distribution subsidiaries face several key technical problems.

2.79 *Low System Pressures.* Because of the lack of gas, pressures in the distribution networks can fall to very low levels, especially during the winter. This can necessitate total bypass of the pressure-reducing stations, which are supposed to control network pressures from secondary network to the distribution network. This problem of insufficient pressure could cause a safety hazard and becomes unacceptable to final consumers, especially in winter.

2.80 *Deficiencies in the Operation of the Networks.* ROMGAZ's operators are not in an adequate position to control the networks for which they are responsible. In fact, they do not have the funds necessary to keep networks in satisfactory working condition, to maintain them, or to repair them except in emergencies.

2.81 In 790 cases of detected defects in Bucharest in 1990, only 800 meters of pipeline were renewed. From January to October 1994, 4,000 defects were detected but only 10 km of pipe were replaced. This indicates a progressive worsening of the situation. Maintenance—defined as deliberate processes intended for keeping installations in their normal operating condition while safeguarding people and property—is not properly carried out due to the lack of financial resources. During the past decade, efficient maintenance was not carried out because few companies in Romania were interested in the maintenance and repair business, believing it to be unprofitable.

2.82 Today, because of the dearth of financial resources, operators check their installations in manner that does not consistently prevent gas leaks. Installations are checked, but nothing can be done to prevent the inevitable deterioration caused by aging. A disproportionate amount of resources are spent checking a network that is worn out in places. It would be more profitable to maintain pipelines while they are still in good condition. In conclusion, there is no genuine maintenance policy. Operators can only make sure that there is no leak while delaying for as long as possible the necessary repairs or required replacements. A systematic search for leaks would be a fairly simple process.

2.83 Since 1993, ROMGAZ has been using ten mobile leak detection unite, which have been found to be helpful, although the scope of current operations could warrant a doubling of the number of these units.

2.84 *Installation defects.* The defects most frequently encountered on buried pipes can be classified in order of decreasing frequency. These include (a) stray currents (tramlines, for example), which damage pipes that are without cathodic protection; (b) the characteristics of the subsoil, especially poorly constructed backfills; (c) interventions by other public utility companies (aggression by third parties); and (d) bad condition of asphalt combined with heavy traffic.

2.85 *Cathodic protection.* The distribution networks in Romania are all-steel, with 25 percent equipped with cathodic protection and with large disparities between the regions. Cathodic protection was first used in Bucharest in 1954. During the past 20 years, ROMGAZ has not been in a position to plan any network extensions because it has had to carry out unplanned new extensions as determined by authorities. Cathodic protection needs to be carefully studied, however, so that impressed current or draining stations are properly sized and judiciously located. Unplanned development has not resulted in the best protection of network extensions. Currently, cathodic protection is hardly ever applied to distribution networks because of too many stray currents (tramlines, electricity networks, or subways for example), and the increase in stray currents is attributable to the bad condition of these networks. Because of the presumed poor condition of most pipelines, however, cathodic protection development would no longer be justified any more due to high cost.

2.86 *Building and renewal.* As mentioned above, even new networks are not commissioned in a satisfactory way. In fact, ROMGAZ operators are well aware of the fact that the defects described above can appear at any time. For example, it is not rare to see a road subsiding a short time after a gassing-up operation (because of bad backfilling construction associated with heavy road traffic). Construction is not satisfactorily supervised. A new pipe must offer a total guarantee of safety as soon as it is commissioned, but this does not always seem to be the case. Construction should only be accepted after verification that it will be carried out properly.

2.87 *High Demand for Natural Gas and Lack of Planning.* The available quantities of natural gas are too low to meet the demand of the distribution companies. Natural gas is very attractive to domestic consumers, not only because of its low price ($0.6/MMBTU) but also because its supply is deemed noninterruptible, unlike other energies such as district heating. On public opening days of ROMGAZ offices, there are long lines of applicants for natural gas. The costs of necessary network extensions are borne by the customers who wish to be connected. ROMGAZ must obtain authorization to connect a new customer, and this makes the procedure long and difficult. For example, ROMGAZ has to receive authorization from the Ministry of Industry for a connection using more than 20 m^3/h. The ministry decides supply quotas at a national level. These constraints, together with the increasing shortage of natural gas, make it difficult for ROMGAZ to respond to the enthusiastic public demand for natural gas. Industrial customers pay a higher price for natural gas ($1.5/MMBTU in October 1994). Gas supplies are allocated to industries by central authorities on a short-term basis, but this does not apply to industries contracting directly with foreign gas suppliers and paying in hard currencies. As a consequence, there is no longer any planning for gas supply and demand balances. Most large industries have managed to keep their large gas allocations up to now, and ROMGAZ has only limited control over gas deliveries to industrial customers. The result of the absence of planning and of the centralized system of authorization is that ROMGAZ cannot design network extensions in a rational way.

2.88 *Safety.* ROMGAZ did not provide any data on incident/accident statistics. We understood that because of the high level of monitoring, the number of incident/accident is not high. A lot of effort is put into the detention of leaks and consequently most failures are detected at an early stage. The number of failures might increase, however, when pressures in the pipes are raised to their normal values in the future.

2.89 *Gas losses.* There is no realistic way to properly evaluate gas losses. Given the accuracy of the transmission metering facilities and the lack of meters in the distribution network, balance methods are impracticable. ROMGAZ estimates gas losses at 3 to 4 percent of total throughput.

2.90 ***Customer Management.*** A computerized billing system exists (see Annex 5.4) for domestic and commercial consumers in the large gas distribution region of Craiova. This system seems to be used more or less in all of Romania. Metering and billing operations seem to work properly. Consumption data are collected monthly. Billing is often altered, however, because installations without meters or with defective ones still exist (this varies from one region to another). About 25 percent of ROMGAZ customers do not have meters. This is a high proportion. The situation should improve with the construction of meter manufacturing and repair facilities in cooperation with western companies. The Sibiu and Cluj areas are particularly unprofitable for ROMGAZ because they are mainly made up of domestic customers.

Distribution Network Replacement and Expansion

2.91 The rate of distribution network replacement since 1989 is shown in Table 2.11. ROMGAZ is engaged in a replacement program of 1,000 km of corroded distribution lines using PE pipes. This program is funded by the World Bank. It is important to note that the cost of replacement is very similar to the cost of new installation for PE pipes, because it is not possible to use insertion of PE pipe into existing steel pipe, due to flow capacity limitations. For the period from 1995 to 2000, ROMGAZ foresees an expansion of its distribution network for the Bucharest subsidiary at 170 km/yr, and for the Tirgu Mures subsidiary at 210 km/yr.

Table 2.12 Distribution Pipeline and Branch Line Replacement, 1989–1993 (kilometers per year)

Year	*Bucharest*	*Tirgu Mures*
1989	10.3	88.8
1990	6.2	87.7
1991	22.0	70.2
1992	15.4	70.1
1993	8.9	61.7

2.92 The assessment of end-use markets supplied by distribution networks is essential in order to define the future evolution of gas distribution activities. Section 2 of this study identified the future requirements regarding the rehabilitation and development of distribution networks. The study concludes that in the year 2010, distribution networks will supply 3 million housing units, broken down as follows :

a. 805,000 collective dwellings in DH areas that use gas for cooking only

b. 280,000 collective dwellings that already use gas for cooking and that could use gas for cooking, space heating, and water heating

c. 378,000 collective dwellings that do not currently use gas but that could use gas for cooking, space heating, and water heating

d. 648,000 new collective dwellings outside DH areas that could use gas for cooking, space heating, and water heating

e. 270,000 new collective dwellings within existing DH areas, that could use gas for cooking, space heating, and water heating

f. 251,000 houses that now use gas for cooking only, but that could use gas for cooking, space heating, and water heating

g. 42,000 houses connected to the gas network, that do not currently use gas but that could use gas for cooking, spaceheating and water heating

h. 234,000 houses that are not presently connected to the gas network, but that could use gas for cooking and water heating

i. 92,000 new houses that could use gas for cooking, space heating, and water heating.

In addition to these housing units, gas distribution networks could supply 30,000 commercial and industrial users.

2.93 Given the condition of existing steel distribution networks, it is reasonable to assume that in the next 15 or 20 years, most of these networks will need to be replaced, either by steel pipes for large diameters or by PE pipes. The same can be assumed for service lines and meters. The networks will keep their medium-pressure level of 2 bar with a possibility to extend this to 4 bar (new networks or networks undergoing large rehabilitation work). The total investment in distribution networks will reach $1.0 billion plus $0.52 billion for the service lines. This represents an upper bound because it is likely that pipes under cathodic protection will be less subject to replacement than the other pipes.

2.94 A number of recommendations can be made to improve distribution operations, namely:

a. *New distribution networks will have to be designed in a more rational way than in the past.* ROMGAZ has the necessary technical skills and tools to carry out technical studies. New regulations dealing with PE pipes are now being completed. The key issue lies with a proper evaluation of the demand and its modulation. Distribution companies should conduct detailed market surveys in coordination with local authorities and with representatives of the commercial and industrial sectors. This is the only basis on which an optimum network design can be achieved.

b. *In general, steel distribution pipes are in poor condition, and this situation cannot be changed overnight.* The ROMGAZ staff will continue to have to deal with the detection and repair of leaks through the years to come. It is recommended that ROMGAZ increase the number of mobile leak detection units from 10 to 20 so as to improve the efficiency of leak detection.

c. *The present quality of replacement work appears to be deemed unsatisfactory by the ROMGAZ staff.* ROMGAZ should prepare detailed material and construction specifications covering these activities and should ensure that contractors comply with such standards by using stricter supervision (during a transitory period). The objective is that by establishing a set of qualified and reliable contractors, ROMGAZ will be confident in the quality and safety of replaced sections.

d. *The first networks made from polyethylene will be introduced into Romania within the framework of the renovation of 1,000 km of steel pipes identified as being seriously corroded.* This work will have to be done with great care, particularly with regard to civil works (including backfilling and restoration), supervision by ROMGAZ, and commissioning procedures. Once commissioned, the polyethylene networks must have a normal lifetime through appropriate operation and maintenance. Frequent training sessions will be essential for the staffs of ROMGAZ and of its contractors.

e. *The open-trench technique will be used for laying polyethylene networks.* The insertion technique will not be used, because the service pressure is already 2 bar and increasing it to 4 bar could not bring enough of a diameter reduction to enable the insertion of the polyethylene pipe into the steel pipe.

f. *Meeting the demand of the existing customer is a priority.* The present shortage of gas is a difficult issue that must be solved by slowing down the decline of domestic production and by acquiring additional imports. We believe, however, that industrial customers connected to the network have a role to play. Their gas consumption is excessive, mainly because of old and inefficient installations, and it could be reduced. Even if gas prices to the industrial sector are raised further, the modernization of the industrial installations will primarily bring an improvement in the efficiency of gas utilization. ROMGAZ could set up a team of gas utilization experts within its commercial division. These experts would focus on promoting new gas utilization technologies.

g. *The situation in some distribution areas, where approximately 25 percent of consumers have either no meter or only a defective one, must be addressed.* ROMGAZ is planning to import second-hand meters. In some gas-operating units, there are workshops for meter checking and repair. These workshops are presently over-loaded and their capacities should be increased.

h. *In Craiova metering, computerized billing, and payment collection seem to work properly, but this should be the case throughout the country.* Because of the lack of meters, consumption estimates and checking have to be done much more frequently than would be otherwise necessary. A better organized collection of consumption data would bring only some improvement. The goal still has to be the installation of meters to ensure complete coverage of distribution customers.

i. *In the future, ROMGAZ will have to upgrade its billing system to invoice energy consumed instead of volumes.* Gas calorific value will have to be measured at a small number of locations on the transmission network.

Summary of Infrastructure Investments to 2010

2.95 Table 7 of the Executive Summary gives the investments identified for each type of infrastructure and the quantities of gas that will be handled by these infrastructures. It should be noted that the investments in production facilities must be considered only as a part of the investments required for the production scenario that assumed tail gas exploitation, since investments in subsurface facilities are not included.

3

Gas Sector Restructuring

Background

3.1 The Romanian gas industry is vertically integrated, with ROMGAZ, the national gas company, in charge of the production from its own fields, the transportation of gas through the national transmission system, and the low-pressure distribution of gas to final consumers. PETROM, the national oil company, is also a major gas producer and sells gas to ROMGAZ at the inlet of the National Transmission System (NTS). Ownership of these enterprises is entirely within the public sector. Reform of the hydrocarbon sector is now under way with the new Petroleum Law, which was approved by Parliament in December 1995 (the law will allow ROMGAZ to make gas transportation services available to third parties in return for a transmission tariff), the creation of the National Agency for Mineral Resources (NAMR) as the independent regulatory agency for the sector, and the restructuring of ROMGAZ.

3.2 ROMGAZ has its headquarters in Medias, with operations being carried out by three production units (Medias, Tirgu Mures, and Ploiesti), a single gas transmission unit located in Medias, and two distribution units (Tirgu Mures and Bucharest). ROMGAZ is currently undergoing the first stages of restructuring, the objective of this first stage being the divestiture and privatization of drilling units and the establishment of four strategic business units (SBU) as separate, accountable profit centers, one for exploration and production, one for transmission, and two for distribution. It is intended that the exploration and production SBU will contract sales of gas directly with end users or with distribution companies. The transmission SBU will become a rate-regulated common carrier, and the distribution SBUs will become one or more rate-regulated utilities.

3.3 An ultimate objective of the government is to privatize gas distribution activities. The Petroleum Law implies that the national transmission system (NTS) will remain within majority public ownership, but the introduction of third-party open-access (TPA) is expected to further stimulate international companies to invest in exploration and production in Romania. It is also expected to remove institutional barriers for gas importers to supply gas directly to large consumers (industries and distribution companies) in

Romania. The structural features of the industry, including the degree of vertical integration, the level of competition possible at each stage, and the ultimate objectives with respect to privatization, will have an impact on how the industry can be regulated. Although the details of the restructuring and regulatory environment are outside the scope of this study, some observations concerning approaches to open access can be made.

Approaches to Open Access

3.4 The characteristics of three approaches to the operation of the national transmission system with respect to access by third parties are described below. Under the current restructuring model, its operation as a merchant pipeline is excluded, and the NTS can be operated either as a full open-access pipeline or as a hybrid pipeline. Whichever mode is selected will affect the ability of the NAMR to regulate the industry effectively. As an open-access pipeline, the transmission company would transport gas for third parties only, without itself being involved in buying and selling gas as a commodity. As a hybrid pipeline, the transmission company would transport gas for third parties *and* would transport its own gas. In the hybrid approach, the transmission company would be allowed to buy and sell gas on its own account, but would also have to offer open-access to its transportation capacity to third parties. However, to ensure a level playing field, the merchant and the transport functions of the transmission company must be run as arms'-length activities in separate subsidiaries. The same transportation terms and tariffs must apply to the merchant business as to the third-party users. However, it should be noted that the hybrid pipeline will be more difficult to regulate than the open-access pipeline to ensure that third parties are able to use pipeline capacity on a truly nondisciminatory basis. On the other hand, the hybrid pipeline would allow the transmission company to perform an important role in aggregating a substantial proportion of the supply contracts to ensure that supply and demand are in balance and storage requirements are met.

3.5 For a transportation company operating under a full open-access regime, the distribution companies and suppliers (domestic and foreign) bear the volume risk and must ensure that all the gas they contract is sold into the market. The take-or-pay risks are therefore transferred away from the transport company, which will accrue its revenues on the basis of ship-or-pay contracts, where it will agree to provide a specific transport capacity to gas merchants and will be paid a regulated transport fee irrespective of whether gas is actually transported.

3.6 The characteristics of the main approaches to open-access are summarized below and illustrated in Figure 3.1.

a. The merchant pipeline:

- The transmission company buys gas from producers, and sells gas to customers. It is not required to transport gas for third parties. In effect, all customers have to buy from the transmission company.

- Prices are negotiated between the transmission company and the producers on the one hand and between the transmission company and the customers on the other hand.
- The transmission company owns the gas in its system. There is therefore no visible transportation tariff.

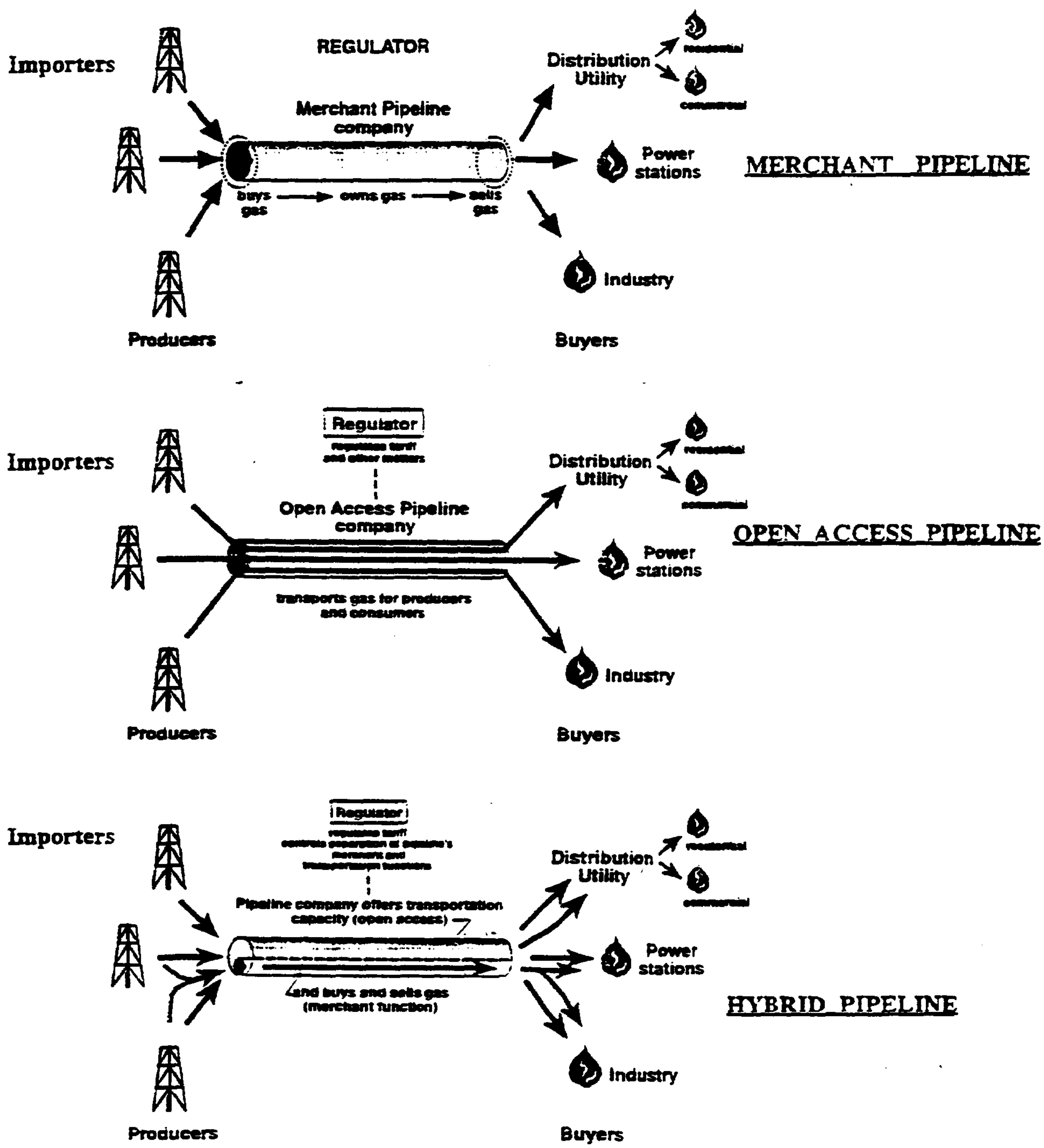
b. The open-access pipeline:

- The transmission company is not allowed to buy or sell gas. It must transport gas for third parties on a nondiscriminatory basis.
- Producers sell directly to large industrial customers, and prices are set by direct negotiation between the producers and the customers.
- The producers or the customers, not the transmission company, own the gas in the pipeline system.
- The transmission company charges a tariff for transporting gas; the tariff is regulated by an external regulator.
- Distribution companies are needed to serve smaller customers because producers need to sell on long-term take-or-pay contracts and these are only viable from large customers.

c. The hybrid pipeline:

- The transmission company is allowed to buy and sell gas on its own account, but it must also offer open access to its transportation capacity to third parties.
- Prices are set by negotiation. The customers and the transmission company compete to purchase gas from producers, and the producers and the transmission company compete to sell to customers.
- To ensure a level playing field, the merchant and the transport functions of the transmission company must be run as arms'-length activities in separate subsidiaries. The same transportation terms and tariffs must apply to the merchant business as to the third-party users. Ownership of the gas is passed on from the merchant function to its customers at the inlet of the pipeline.
- Transportation tariffs and access rules must be regulated.

Figure 3.1: Merchant, Open Access, and Hybrid Pipelines



ANNEX

Table A-1: Potential Gas Demand for Power in 2010

Table A-2: Residential and Commercial Potential Gas Demand in 2010

Table A-3: Residential and Commercial Potential Gas Demand in 2010 by Region

Table A-4: Industrial Gas Demand in 2010

Table A-1 Potential Gas Demand for Power Generation in 2010

Plant	Region	Main Fuel	Capacity	Gas switching value		Potential gas demand		Peak demand	
						Individual	Cumulative	Individual	Cumulative
			MW	USD/GJ, LHV	USD/MMBTU	MMcm	MMcm	1000 m3/d	1000 m3/d
BORZESTI 2	C	Coal	150	2,4	2,53	38	12040	149	46497
DEVA	W	Coal	600	2,7	2,85	136	12002	531	46348
PAROSENI	W	Coal	150	2,7	2,85	34	11866	133	45817
SUCEAVA	C	Coal	100	2,7	2,85	25	11832	99	45685
TURCENI	W	Lignite	1620	3,2	3,38	410	11807	1605	45586
ROVINARI	W	Lignite	1390	3,2	3,38	352	11397	1377	43981
GOVORA 2	W	Lignite	100	3,2	3,38	32	11045	124	42604
BRASOV	C	Lignite	100	3,4	3,59	32	11013	127	42480
GALATI	C	Oil & Gas	210	3,4	3,59	532	10981	2081	42353
NAVODARI	E	Oil & Gas	150	3,5	3,69	369	10449	1444	40272
BRAZI 8,9	C	Oil & Gas	200	3,7	3,90	426	10080	1668	38828
BRAZI	C	Oil & Gas	100	3,7	3,90	246	9654	963	37160
PITESTI SUD	C	Gas	50	3,7	3,90	127	9408	496	36197
CCGT	E	Gas	1400	3,9	4,11	2109	9281	8256	35701
BRAILA 4	E	Gas	300	4,3	4,54	565	7172	2211	27445
PROGRESUL	C	Gas	200	4,3	4,54	439	6607	1720	25234
LUDUS	C	Gas	800	4,4	4,64	1507	6167	5897	23514
CCGT	C	Gas	1400	4,7	4,96	2109	4661	8256	17617
CCGT	W	Gas	1400	4,9	5,17	2109	2551	8256	9361
GT	E	Gas	400	4,9	5,17	147	442	368	1105
GT	C	Gas	400	5,1	5,38	147	295	368	736
GT	W	Gas	400	5,2	5,49	147	147	368	368
Total			11620			12040		46497	

C: Central region
E: Eastern region
W: Western & Northern

Table A-2 Residential and Commercial Sector-Potential Gas Demand in 2010 (Residual DH Market Excluded)

	Type of Households	Use	Households (thousand) ** Initial	Households (thousand) ** 2010	Gas Demand MMcm/year	Gas netback Value (SLCP)* USD/GJ	Cumulative Number Thousand	Cumulative demand MMcm	Cumulative demand relat. to maxi %	Cumulative Gas value MMUSD
:w	H	C			11	2,00	2999	5008		335
› DH connected,	C	C	incl. below		45	2,70	2999	4997		451
H connected,not using gas	C	C	incl. below		0	2,70	2999	4952		451
:w (in DH area)	C	C			78	2,70	2999	4952		451
› DH connected	C	SH & WH	600	378	567	3,65	2999	4874	75%	596
her	T				126	3,65	2621	4307	66%	526
› gas connected	H	C & WH	350	234	122	3,80	2621	4181	64%	531
:w (not in DH area)	C	C			32	3,90	2387	4059	62%	529
:w	H	SH & WH		92	257	4,01	2387	4027	62%	539
:w (in DH area)	C	SH & WH		648	971	4,46	2295	3770	58%	562
H connected	C	SH & WH	2400	0	0	4,46	1648	2798	58%	593
H connected,	T				0	4,46	1648	2798	58%	563
·w (in DH area)	T				265	4,46	1648	2798	58%	563
·w (not in DH area)	C	SH & WH		270	405	4,70	1648	2534	39%	378
:w (not in DH area)	T				265	4,70	1378	2129	39%	399
ready using gas	H	SH & WH	incl. below		702	4,96	1378	1865	29%	293
ready using gas	C	SH & WH	incl. below		420	5,26	1378	1162	18%	193
ready using gas	T				560	5,26	1378	742		204
s connected, not using gas	H	C & WH	50	42	22	5,60	1378	182		32
ready using gas in DH area	C	C		805	97	8,55	1336	160		30
ready using gas	H	C	300	251	30	8,70	531	64		18
ready using gas	C	C	400	280	34	9,50	280	34		10
›tal			4100	3000						

H: houses C: cooking
C: dwellings WH: water heating
T: commercial SH: space heating

1 USD/GJ = 1.055 USD/MMBTU

* SLCP: at service line connecting point
** noted only once for each category, and when it is no more competitive

Table A-3 Potential Gas Demand in Residential and Commercial Sector

Area	1992 MMcm	2000 MMcm	2005 MMcm	2010 MMcm	Gas peak Demand MMcm/day
Arad, Timis, Bihor, Caras Sev	163	259	345	460	3,9
Huneadora (Deva)	58	112	169	254	2,1
Maramures, Satu Mare, Salaj	257	246	239	232	2,0
Bistrita Nasaud	8	20	36	64	0,5
Cluj (Turda)	402	387	378	369	3,1
Alba	129	130	131	132	1,1
Mures (T. Mures, Ludus), Hargita	181	220	249	281	2,4
Sibiu (Medias, Copsa Mica)	247	239	234	229	1,9
Brasov, Covasna	450	438	431	424	3,6
Dolj, Gorg, Olt, Vilcea, Mehedinti	194	249	292	342	2,9
Teleorman, Giurgiu	1	7	26	91	0,8
Arges (Pitesti), Dimbov., Prahova (Ploiesti)	334	330	327	325	2,7
Iasi, Botosani, Suceava, Vaslui	133	188	234	290	2,4
Bacau, Neamt (Borzesti)	270	252	241	231	1,9
Galati, Vrancea	52	87	119	164	1,4
Buzeau, Braila, Ialomita (Slobosia)	97	164	228	317	2,7
Constanta, Tulcea, Calarasi	1	12	56	266	2,2
Municipiul Bucuresti	587	624	648	673	5,7
Total	3564	3963	4382	5143	
Total Gas peak Demand (MMcm/day)	30,0	33,4	36,9	43,4	43,4

Table A-4 Gas Demand in Industry in 2010 (High Scenario)

Area	In 1992	Gas Demand in MMcm in 2010					Gas peak demand in 2010				
	Directly supplied (excl.L.Ind.)	Other	Large industries			Total	Other	Large industries			Total
			Fertilisers & methanol	Iron & steel	Cement			Fertilisers & methanol	Iron & steel	Cement	
ad, Timis, Bihor, Caras Severin	750	696				696	3,5				3,5
ıneadora (Deva)	431	400		50		450	2,0		0,2		2,2
ıramures, Satu Mare, Salaj	181	168				168	0,8				0,8
strita Nasaud	33	30				30	0,2				0,2
ıj (Turda)	621	576				576	2,9				2,9
ha	319	296				296	1,5				1,5
ıres (T. Mures, Ludus), Hargita	329	305	360			665	1,5	1,2			2,7
ıiu (Medias, Copsa Mica)	289	269				269	1,3				1,3
ısov, Covasna	831	771			40	811	3,9			0,2	4,1
ılj, Gorg, Olt, Vilcea, Mehedinti	204	189	360		20	569	0,9	1,2		0,1	2,2
leorman, Giurgiu	17	243	360			603	1,2	1,2			2,4
ges (Pitesti), Dimbov, Prahova (Ploiesti)	1199	1113	360		40	1513	5,6	1,2		0,2	7,0
i, Botosani, Suceava, Vaslui	461	427				427	2,1				2,1
cau, Neamt (Borzesti)	487	452	700		40	1192	2,3	2,4		0,2	4,9
lati, Vrancea	70	65		150		215	0,3		0,5		0,8
zeau, Braila, Ialomita (Slobosia)	563	523	360			883	2,6	1,2			3,8
nstanta, Tulcea, Calarasi	40	415		50		465	2,1		0,3		2,4
ınicipiul Bucuresti	714	663				663	3,3				3,3
tal	7537	7600	2500	250	140	10490	38	8	1	1	48

Joint UNDP/World Bank
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89--	
	Francophone Household Energy Workshop (French)	08/89	103/89
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa	06/96	182/96
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95

Region/Country	Activity/Report Title	Date	Number
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87

Region/Country	*Activity/Report Title*	*Date*	*Number*
Mauritius	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Morocco	Energy Sector Institutional Development Study (English and French)	07/95	173/95
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Republic of South Africa	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Energy Assessment (English and French)	07/91	8017-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vol. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
Republic of South Africa	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--

Region/Country	Activity/Report Title	Date	Number
Tanzania	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
Togo	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
Zambia	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Petroleum Management Assistance (English)	12/89	109/89
	Power Sector Management Institution Building (English)	09/89	--
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--

EAST ASIA AND PACIFIC (EAP)

Region/Country	Activity/Report Title	Date	Number
Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
Fiji	Energy Assessment (English)	06/83	4462-FIJ
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86

Region/Country	*Activity/Report Title*	*Date*	*Number*
Indonesia	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979/SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
Western Samoa	Energy Assessment (English)	06/85	5497-WSO

SOUTH ASIA (SAS)

Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88

Region/Country	Activity/Report Title	Date	Number
India	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84Nepal
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Fomulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86

EUROPE AND CENTRAL ASIA (ECA)

Bulgaria	Natural Gas Policies and Issues	10/96	188/96
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy	12/96	192/96
Turkey	Energy Assessment (English)	03/83	3877-TU

MIDDLE EAST AND NORTH AFRICA (MNA)

Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
	Energy Sector Institutional Development Study (English and French)	05/95	173/95
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector(English)	06/90	115/90
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96

Region/Country	Activity/Report Title	Date	Number
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	National Energy Plan (Spanish)	08/91	131/91
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--

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Jamaica	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

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