INTERNATIONAL NATURAL GAS MARKET

Working Consulting Group

October 1987
WP-87-102

Report by the Working Consulting Group of the President of the Soviet Academy of Sciences on Long-Term Energy Forecasting, Acad. M. Styrikovich, Research Leader.

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Foreword

The International Gas Study was organized in form of a collaborative research effort and focused on the future prospects for natural gas in European energy markets. One of the most active participants outside IIASA was the Working Consulting Group of the President of the Soviet Academy of Sciences. Unlike IIASA, where the geographical scope of the study was limited to the European energy markets with special emphasis primary on gas related technical evolutionary change, the Working Consulting Group adopted a comprehensive global scope and a primary focus on international gas trade. During a series of working meetings at IIASA and in the Soviet Union the two research teams developed an effective and mutually beneficial relationship at both the working and social level.

This report summarizes the research activities of the Working Consulting Group under the leadership of Academician M. Styrikovich during 1984-1986.

Hans-Holger Rogner
Leader
International Gas Study

Preface

For the last two years the International Institute for Applied Systems Analysis (IIASA), together with some other national organizations, has conducted research on the future prospects of the international natural gas trade. Soviet research institutes have also taken an active part in this program. Moreover, the Working Consulting Group of the President of the Soviet Academy of Sciences on Long-Term Energy Forecasting (the leading Soviet organization participating in the research) has prepared a "shadow project" that addresses the problem on the international natural gas market over the next 30–40 years.

Natural gas has long been viewed as a source of energy capable of reducing the dependence of industrialized nations on oil imports. In the early 1980s, global energy studies confirmed the versatility and economic viability of this resource, and economic assessments showed that only natural gas can compete with oil, when long-distance interregional gas transportation as LNG or by pipeline becomes practicable.

The worsening ecological situation called into question the prospects for wide-scale coal applications, and the continuing opposition toward nuclear energy enhanced interest in natural gas as an ecologically clean fuel.

At the same time, it became clear that the high cost of natural gas transportation and distribution substantially weakens its competitiveness, even at a high price. Under these conditions only a limited number of suppliers possessing large gas resources at low production costs can enter the world natural gas market. These suppliers include countries in the Middle East (Iran, Qatar, etc.); some countries in North Africa (Algeria, Nigeria); Southeast Asia (Indonesia, Brunei, Thailand, etc.); the US neighbors – Mexico and Canada; and two European countries – Norway and the USSR.

The international natural gas trade was originally expected to expand on a larger scale in the near future. Today, however, the prevailing expectation is that of moderate growth for the next decade. This can be ascribed to virtually stable energy demand in industrialized capitalist countries, which reduces the scope for the development of natural gas, nuclear energy, and the coal industry. Developing countries, in which further growth in energy consumption is expected, do not have the necessary infrastructure for natural gas utilization. On the other hand, the recent twofold drop in oil prices will have a strong influence on natural gas prices and will impede the expansion of gas utilization, despite its obvious advantages from an ecological point of view. Here one should also mention security of supplies from individual regions, which is an issue of particular concern for Western countries. This factor plays an increasing role in planning interregional pipeline gas transportation. That is why regions with an unstable political climate may have limited access to the markets of industrialized capitalist countries. All these issues should be taken into account in modeling the international natural gas market.

The world gas market in this Working Paper is divided into three large regions (local markets) and several large gas suppliers, some of which have a possibility of entering all three markets with large volumes of gas supplies. Thus, the problem acquires global significance. We focus on evaluating the dependence of marginal natural gas prices on gas consumption volumes on the basis of detailed energy forecasts for the regions and large energy consumers. Three scenarios of the world natural gas market with respect to various hypotheses of price growth in competitive energy sources (notably oil) have been considered. With the help of the dynamic model for the international natural gas market, levels of industrial development within the regions and volumes of gas imports, as well as expected natural gas prices in the case of balance between supply and demand in local markets, have been determined. An assessment has been made of the overall effect derived from the world natural gas trade for gas consumers and suppliers.

Throughout the research the Working Consulting Group has constantly maintained contacts with IIASA to coordinate and verify initial data and scenarios for computing. As for the rest, both studies are quite independent research efforts made on a similar data base. Specific features of each of the studies allow us to regard the latter as mutually complementary.

M. Styrikovich
Research Leader

Content

INTERNATIONAL NATURAL GAS MARKET

Working Consulting Group

Chapter 1

The Current World Energy Scene and Factors Conditioning Energy Prospects Throughout the Remainder of the 20th and the Beginning of the 21st Century

More than a decade has elapsed since the OPEC countries for the first time drastically raised world oil prices. The worsened energy situation pushed energy supply issues to the forefront. After numerous and heated discussions at scientific forums and in the press, where the most conflicting views on future energy prospects were expressed, it became clear that the world energy demand will follow an upward trend. Its growth prospects will be conditioned by the world's population growth and by the impossibility of providing satisfactory living conditions without a manifold increase in per capita energy consumption in developing countries. The growth rates will be different for developed and developing countries. A stable energy demand six to eight times the present level is likely to be achieved by the end of the next century.

We are now enjoying a period of virtually stable energy supply: supply in the world market is well in excess of demand; traditional buyers of energy resources have become more self-sufficient; strategic oil stocks are available in case of interruptions in energy supply; new technologies are ready to come on-stream but are impeded by the low price of basic energy resources.

Against this background, with respect to future energy development, the situation in developing countries has become a matter of growing concern. The rise in energy prices resulted in a dramatic increase in the debt of developing countries, which in the mid-1980s collectively owed a total of nearly 900 billion dollars. As a result, many international projects of the 1970s for accelerating economic development were not realized. New economic growth was hard to achieve during a financial crisis. A shift in the weight of global energy problems from developed to developing countries over the next 50 years will require prompt action for a timely restructuring of the world energy economy with a view to avoiding more serious complications in future than experienced in the past. These problems are likely to retain their critical importance for the next few decades.

Everyone realizes now that mankind has entered the so-called period of transition from the energy economy based on fossil fuels to an economy based on virtually inexhaustible energy resources such as nuclear and thermonuclear energy, solar, etc. Analysis of global fossil fuel resources (coal, oil, natural gas) with regard to extraction and utilization costs shows that they will continue to play a leading role in the world energy balance, perhaps into the middle of the next century. Fossil fuel resources proved substantially larger than expected earlier. Even in the case of oil, available data point to additional recoverable resources. Here, after the cheapest resources are extracted, the world must mine more expensive fuels, which will inevitably result in higher energy prices.

In the early years of the past decade, great hopes were pinned on renewable sources of energy regarded as virtually unlimited and ecologically clean. Subsequent studies proved that renewable-based energy supply is too costly compared with coal, natural gas, and nuclear options. That is why, though the role of renewable sources of energy in future energy supply is not clear up to now, their contribution in the foreseeable future will obviously be limited to local applications.

There were also fears of global changes in the earth's climate resulting from the burning of fossil fuels and from thermal pollution. These problems have not been adequately studied, though calculations show that only more than a tenfold increase in energy consumption from the current level may lead to the overheating of the earth's surface to a threatening degree. As mentioned above, energy forecasts suggest not more than a six- to eightfold rise in energy consumption. In the loger run, the overheating can be partly compensated for through an increase in the earth's albedo, due to deforestation, urbanization, etc. A less certain factor that may affect global climate is the growth of CO_2 atmospheric concentrations and the "greenhouse effect". The influence of CO_2, however, is now seen to be not so great as expected. Moreover, due to some processes (enhancement of CO_2 solubility in the waters of the world ocean, intensified growth of vegetation), CO_2 concentration growth rates will be lower than predicted earlier, and the volume of CO_2 emissions will grow at a slower pace as the share of nuclear energy increases and fossil fuel consumption declines. Besides, in middle latitudes, the "greenhouse effect" may even have some positive impact on biomass growth.

True, though in the long run ecological problems do not seem to require careful consideration on a global level, environmental protection o a local and regional level is of great concern. "Acid rains" resulting from increased SO_x and NO_x emissions pose a serious problem for some developed countries in Central Europe, the US eastern states, and some parts of Japan.

To sum up, now and in the foreseeable future, mankind is not threatened with "energy famine" but various trends in energy prices and ecological considerations influence the order of priorities of energy technologies, necessitating radical changes in the present energy economy.

Liquid and gaseous fuels retain their dominant share in today's world energy balance: 60% in developed and 40% in developing countries.[1] The latest sharp rise in world oil prices in the 1979-1980 period resulted in declining energy consumption in some developed market economies (it is quite possible that some of them have already reached a stable level of consumption, after which one can expect absolute energy consumption to drop); in a considerable reduction in the oil demand of developed market economies after the year 1980; in accelerated oil and gas exploration and a rise in the oil and gas production of the non-OPEC countries; in large-scale oil stockpiling in oil-importing countries, namely, market economies; and in a glut in the oil market.

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[1] Styrikovich, M.A., Yu.V. Sinyak, and S.Ya. Chernavsky (1982), Long-term energy prospects, *Achievements and Prospects, Series Energy Fuel (8)*, Moscow.

It is obvious that current trends in the world energy scene are directed toward energy-saving policies (energy conservation as a whole, including capital-intensive measures) and toward substituting other resources, notably coal and in some countries nuclear energy and natural gas, for oil.

The price elasticity of oil consumption proved much higher than the majority of experts predicted earlier. The substantial drop in the oil demand of industrially developed countries that occurred after the year 1980 was caused not only by the general economic recession – total gross national product in recent years would not decline but even slightly increased – but also by fuel, mainly liquid fuel, conservation and the use of oil substitutes encouraged by the situation in the marked and, in some cases, by government policies. In the United States the above decline was accompanied by a significant rise in coal production and consumption. Coal production in some coal-exporting countries (especially in Australia) has substantially increased, and international trade in coal expanded. In the short run, further expansion of the world trade in natural gas is expected, and the possibility of establishing a world gas market is now being discussed.

The following figures (in percent) illustrate these positive shifts in the energy economy of developed nonsocialist countries between 1973 and 1980.[2]

Gross domestic product (GNP)	+ 19
Total energy consumption	+ 4
including	
oil consumption	- 3
oil import	- 14
Electricity/GDP ratio	- 13
Oil consumption per unit of GDP	- 20
Domestic energy production	+ 13
oil	+ 9
coal	+ 93
nuclear energy	+ 206

These trends became more pronounced in the first half of the 1980s.

Forecasts of energy consumption are now being revised, and the erroneousness of earlier projections of liquid fuel consumption has been unanimously recognized. The errors were based on the underestimation of the response of world oil demand to high liquid fuel prices and the overstating of the volumes of global oil consumption in the 1990-2000 period and beyond. High world prices of hydrocarbon fuel created an incentive for accelerating oil prospecting and production in non-OPEC countries, Mexico, Great Britain, and Norway among them.[3] According to the majority of forecasts, oil production in developed nonsocialist and developing countries will rise slightly from the 1980 level through to 1990 and will total 2300-2400 million t/yr and 2500-2600 million t by 2000.[4]

[2]Calculated from *World Energy Outlook*, IEA/OECD, Paris (1982).

[3]Oil production in nonsocialist countries dropped to 2000 million t from 2500 million t between 1979 and 1985. In the OPEC countries it declined from 1800 to 850 million t.

[4]Manne, A.S., L. Schrattenholzer, A. Svoronos, with the assistance of J.L. Rowley (1985) International Energy Workshop: Summary of Poll Responses. Laxenburg, Austria: International Institute for Applied Systems Analysis.

1.1. The continuing impact of oil prices

The price of oil is of critical importance for the energy economy of the world and its regions, since oil and oil products not only continue to play a leading role in the present world energy scene but, due to the availability of considerable idle oil production capacities, oil gradually becomes a marginal resource in the world's energy balance, i.e., it affects energy decisions. That is why forecasting long-term trends in oil prices has now become a key issue in energy studies. Recent forecasts (between the late 1970s and the early 1980s) suggested a very high oil price (60-80 dollars/barrel in the 1980 prices) by the end of the century. Today this estimate has dropped to 20 dollars; and the majority of experts now think that over the next one or two years oil prices may decline by several dollars but then will inevitably rise again, though at far more modest rates than in the 1970s. As far back as the summer of 1985 it was expected that by 2000 prices will rise 10-15% from the 1980 level and 20-25% by 2010, i.e., much lower than predicted earlier.[5] Today, however, it is most likely that prices will reach the 1980 level only by 2020.

The present world energy scene offers limited opportunities for an economically viable growth of energy prices. Moreover, because of the unforeseen drop in oil consumption, oil prices are, quite to the contrary, declining to prevent demand from sagging, though in the near future this decline will change to slow growth again. This can be attributed to large-volume liquid fuel uses in those energy-consuming sectors (electric utilities, boiler plants, and industrial furnaces) where the price elasticity of oil consumption is high and oil substitutions (less costly and available) are cost effective when oil prices rise. Oil prices over a long time will condition the rates of the structural evolution of the world fuel and energy balance, notably owing to liquid fuels' declining contribution. It is clear now that due to this factor a viable large-scale transition to alternative energy sources and oil substitutes can be expected only beyond the year 2000.

1.2. The prospects for natural gas

International trade in natural gas will also have a certain restraining influence on oil prices. Natural gas, the cleanest fuel from an ecological point of view, is the best fuel for stationary consumers. Emissions resulting from its burning can be almost entirely excluded as there is no bound nitrogen in gas, and sulfur available in the form of H_2S has to be completely removed to avoid corrosion of pipelines. This process is relatively cheap and, in some cases, is offset by the cost of released sulfur. Under these conditions the delivered price of gas will be set equal to middle distillates with low sulfur content. The gas consumer will obtain a **price plus pipeline transportation costs which can be rather high, if gas is transported over large distances, even provided high-capacity pipelines are used. The seasonal nature of natural gas consumption makes it necessary to construct far more costly storage facilities compared with oil and coal.**

Moreover, compressor stations consume a large fraction of gas delivered; even in the case of the world's largest pipelines regarded as standard in the Soviet Union (d = 1.42 m, P_{max} - 7.5 MPa) with the world's highest throughput capacity, the gas turbine drive of compressor stations consumes ≈ 10% of gas over a distance of 3000-4000 km (for instance, Tyumen – Ukraine) and 15% over a distance of 6000 km (Tyumen – Ukraine – West Europe).

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[5] Manne, A.S., L. Schrattenholzer, A. Svoronos, with the assistance of J.L. Rowley (1985) International Energy Workshop: Summary of Poll Responses. Laxenburg, Austria: International Institute for Applied Systems Analysis.

In the future, switching over to electric drive (it appears cheaper to meet baseload demand from nuclear-derived electricity compared with costly gas) and raising pressure to 10 MPa will result in higher throughput capacity.

Gas cooled to -30°C and especially to -60 and -70°C can substantially increase a pipeline's throughput capacity.[6] Calculations prove this to be a viable proposition, despite some technical complexities involved. But it appears cost effective only for large-volume transportation, provided cooling does not require decreasing a pipeline's diameter. Projects for transportation by larger-diameter pipeline or as LNG are unlikely to be realized. As for scattered or seasonal gas consumers, it is necessary to take into account capital investments required for a distribution network and seasonal underground storage. The latter leads to higher gas prices, since even if exhausted gas or oil fields are used for storage, one should take into account the cost of buffer gas storage, which is nearly equal to the active volume of the gas stored, and the average amount of natural gas. With no gas or oil fields available in the proximity of the consumer, use can be made of man-made seasonal gas storage facilities. And this also involves heavy investments even under favorable geological conditions.[7]

Gas transportation by sea, including the start-up and operating costs of liquefaction and regasification facilities and tankers, appears more costly compared with transportation by large-diameter pipeline with electrically driven compressor stations. Only in those cases where gas is transported over large distances and liquefaction and regasification costs are but a small fraction of total transportation costs may transportation as LNG be comparable with pipeline, especially when the volume of gas transported over a given route is not too large and, consequently, a smaller-diameter pipeline is used.

Since the cost of dry natural gas transportation is higher compared with oil, it may be reasonable to consider regional systems, including prospective importers such as Western Europe, Japan, and the US and their respective exporters. In some cases, the conversion of remotely located gas to more transportable products, such as methanol, ammonia, etc., at or close to the point of production may prove a practicable proposition.

On the whole, given the advantages of gas as an ecologically clean fuel, as a feedstock, and its availability in some parts of the world, gas may prove to be optimal in the energy balance of some regions, especially those with strict pollution-control laws. In large cities and urban areas, with high motor fuel consumption and relatively modest specific capital investments in gas compressor stations, one should consider the use of methane for automobile transport. In the near future the Soviet Union will have hundreds of thousands of methane-fueled trucks; at first use will be made of 20 MPa steel cylinders, which will eventually be replaced by light composite cylinders.

The world natural gas market, owing to its varying effectiveness for different consumers and in different regions, poses a serious problem that calls for careful consideration. Work in this field is being done by some international organizations under the auspices of the International Institute for Applied Systems Analysis, Laxenburg, Austria.

But despite all the advantages of gas, the world natural gas market will be limited compared with oil because of the high cost of transportation by pipeline and especially as LNG. The delivered price of natural gas will be set relative to the

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[6]Gas transportation in permafrost regions will involve measures to avoid defrosting the ground underneath a pipeline. This will require the use of pre-cooled gas.

[7]In some cases it may be necessary to regulate daily consumption from underground gas storage.

price of liquid fuel, at least until the end of this century. High transportation costs will limit the international natural gas trade to a few gas producers which have an abundance of cheap gas reserves (Iran and other Persian Gulf states, Indonesia, Algeria, Nigeria, and the Soviet Union). In gas fields remote from the market, it will be desirable to develop energy-intensive industries, notably the petrochemical industry, which uses gas both as a source of energy and a feedstock.

1.3. The prospects for coal

Less certain is the situation in the rapidly growing world market for high-grade coals, the demand for which is rising steadily (from 200 million t in 1977, to 250 million t in 1980, and to 306 million t in 1985). According to some forecasts, the coal market is to expand to 450-460 million t by 2000,[8] although they no longer point to the boom (up to 1 billion t in 2000) predicted earlier.[9]

Prices for coals with high calorific value and low sulfur content (less than 1%), which are transported by sea over large distances (South African, North American, and even Australian coals at the ports of West Europe), constitute 50-60 dollars/t, in terms of coal equivalent, i.e., twice as low as current prices for a heat-equivalent amount of fuel oil. This creates incentives for building new electric plants and large coal-fired boiler plants with pulverized coal combustion, even in coastal regions remote from the point of production if the latter is located close to an ocean port.[10] Moreover, even a costly switch of fuel oil units over to coal is paid back relatively rapidly, in some cases. For instance, two 300 MW power-generating units in South Korea, when switched over to Australian coals, were paid back in two years. This shift proves far more economical at the point of production of internationally traded coal (Middle East, Central America), because the price of coal there is lower as it does not include freight costs.

It should be noted that a highly probable considerable rise in the demand for power-generating coals is unlikely to lead to higher real prices, since quite a few countries have large reserves of high-grade coals, cheap at the point of production, located close to seaports. Besides such countries as the United States, Australia, South Africa, and Poland, which are now large exporters of power-generating coals, large-scale penetration of the Soviet Union, Canada, China, and India into the world market is expected in the long run, which will make it possible to keep the coal/fuel oil price ratio at a constant level.

The main factor that impedes large-scale coal consumption is ecological constraints. In the case of large plants equipped with electric precipitators, particulate emissions do not pose any threat to the atmosphere because, with a precipitator whose efficiency ranges from 99 to 99.5%, these emissions can be comparable with fuel oil ash emissions (fuel oil units are not equipped with gas cleaning systems). But fly ash electrostatically precipitated consists of sub-microparticles with heavy metals, contained in coal ash, concentrated on their surface. These emissions may be a health hazard.

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[8] Forecast of Chase Manhattan Bank, 1985.

[9] Häfele, *et al.* (1981), *Energy in a Finite World. A Global Systems Analysis* (Ballinger, Cambridge, Mass.).

[10] With further progress in coal fluidized bed combustion medium- and small-capacity plants will be shifted to coal.

A major obstacle in the use of coal in large industrial plants is SO_2 and NO_x emissions in stack gases, which are not only toxic but are also the cause of so-called acid rains. The latter may have a detrimental effect on vegetation and biohydrosphere (Scandinavia, Canada, etc.). In sparsely populated areas this can be avoided by dissipating emissions through high stacks. But main prospective coal importers and consumers are, as a rule, densely populated regions where special plants have to be installed to desulfurize stack gases. Such plants involve high operating costs and, in particular, enormous investments. Whereas operating experience gained with these plants ensures sufficiently deep desulfurization of stack gases, nitrogen oxides can be removed only through catalytic oxidation of NO to NO_2, which makes a plant more costly and prevents wide-scale applications of this method. With the help of inexpensive methods of reducing the temperature in the flame-kennel, one can suppress the formation of nitrogen oxides from the air, but the nitrogen contained in coal itself forms NO_x at moderate temperatures as well.[11]

On the whole, wide-scale use of coal at large industrial plants meets, in some cases, with certain objections. Medium- and low-capacity plants, where neither stacks nor gas cleaning facilities can be installed, pose a far more serious problem Substantial progress has recently been made in coal utilization with CaO and $CaCO_3$ additions in fluidized bed combustion furnaces. This will probably be an attractive option for medium- and low-capacity consumers in regions with strict pollution control. But the use of fluidized bed combustion in large industrial plants encounters certain difficulties.

In any case, because one has to take into account both higher operating costs and especially capital investments compared with liquid fuel, therefore coal remains unsuitable for peak-load plants with a short operation period. Still, for some economic reasons one should expect coal's contribution to grow both in developed and developing countries. Coal's growth prospects in developing countries will be limited because of the lack of developed transportation systems and, consequently, high transportation costs, especially if one takes into account that even transportation by rail not adapted to electric traction, let alone automobile transport, involves considerable volumes of oil products. As a result, a substantial rise in coal consumption can be expected only in those countries that have a widely branched network of water- and railways, for instance, India and China, as well as in coastal regions and areas close to the point of production.

Though current coal prices will tend to increase in the long run, still they will be more stable compared with oil and natural gas, which will create incentives for a shift to coal in the future, especially due to the introduction of new technologies (for instance, fluidized bed combustion) that are ecologically cleaner compared with traditional ones. As international trade in high-grade coals expands, coals with low calorific value and partly oil shales, whose transportation by land, in particular, is costly, will remain cheap fuel locally produced. In regions with abundant coal reserves energy-intensive industries and, in the more distant future, synfuel production will develop.

Analysis of future prospects suggests that prices for main fossil fuels will change to varying degrees. As to natural gas and low calorific fuels, their prices in some regions will remain relatively low. This will condition structural changes in the energy mix of developed countries and the creation of new power-generating capacities in developing countries with regard for currently established ratios

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[11]Successful work has recently been done in NO_x reduction through injection of NH_3 in gases.

and, to a far greater degree, for proportions anticipated over the next 20–30 years.

1.4. Energy supply of developed countries and urbanized areas of developing countries

Future energy supply of developed countries and urbanized areas of developing countries will be conditioned by the replacement of liquid fuel by more available and less costly sources of energy; by the introduction of new energy-saving technologies and reduction of air pollution, which poses a particular threat to densely populated areas. On the whole, the above will be capital-intensive measures. In developed countries they will be aimed mainly at saving labor resources.

Further energy development, first and foremost, will be characterized by higher growth rates of the electricity share in the fuel and energy balance than occurred in the past.

Due to the great advantages of electricity for many consumers, the share of electricity in the world energy balance was steadily growing even at a time of cheap oil availability when the cost of electricity under a base-load pattern of consumption was four times the cost of direct liquid fuel use (mainly owing to low conversion efficiency not exceeding, as a rule, 40%, and, to a lesser degree, to capital investments in electric plants). Under these conditions the use of electricity for low-temperature (space heating, ventilation) and even high-temperature heat production was limited to relatively few cases where technological advantages outweighed the high cost of electricity.

In many countries (for instance, the US) the use of electric traction on railways was rather limited. Until recently even in the Soviet Union, where freight traffic is very heavy, a little more than half of freight was carried by diesel locomotives, because capital investments were paid back rather slowly as there was little difference between diesel fuel and fuel oil (used as fuel for electric plants) prices.

Today, for almost any large base-load consumer of high-temperature heat, a shift from liquid fuel to electricity proves cost effective.

Direct utilization of high-temperature nuclear-based heat appears promising only for some industrial processes, namely, for those requiring medium temperatures (lower than 700–800°C). In the long run, for higher temperatures, electric heating with an increasing share of plasma technology is likely to be the dominant method.

Taking into account the leading role of the power industry in the energy economy of developed countries, one should expect that the greatest changes will occur in this field. Nuclear energy or coal substitution for liquid fuel will reduce its share in newly constructed large electric plants. In the majority of developing countries new large power-generating units operating on liquid fuel are no longer laid down, excluding peak-load units in some cases.

Introduction of nuclear electric power plants with their share exceeding certain limits poses some problems. As is known, nuclear plants are characterized by very high specific capital investments and low current costs; at the same time they are the cheapest source of electricity used to meet the base-load demand of the majority of industrialized world regions (with the exception of a few regions with very low-priced indigenous coals or very efficient hydropower resources). Operating in the base-load part of the load curve, nuclear plants oust other plants of the system. If the load curve is rather dense (areas where heavy industry is concentrated) and other electric plants are highly maneuverable, then, technically and economically, nuclear plants can generate the greater part of electricity and cover the entire load curve (minimum load at night and a sightly higher load on days off). In the latter case, however, all other electric plants would be shut down more than 300 times and stand idle during some 50% of the year. Since this is unacceptable for many of the plants, hydro-pumped storage plants have to be constructed. These plants operate during the night and on days off as pumps, increasing the minimum load of the system, and as sharp peak-load turbines (750 h/yr) when the load is at a maximum. The efficiency of these plants does not usually exceed 70%, i.e., they are not producers but net consumers of electricity. In mountainous regions, for instance, in Japan, their construction does not involve heavy investments and proves economically viable.

Quite different conditions exist in some other parts of the world, for instance, in the European part of the USSR, where the greater part of the country's population lives in the vast almost flat East European lowland. Since the development of mainly highly energy-intensive industries is concentrated in Central Siberia, which has an abundance of cheap coal reserves and highly efficient hydropower resources, the load curves in the European part will remain nonuniform and with time this nonuniformity will tend to increase. Due to a relatively high price of coal in the region, newly constructed base-load plants are nuclear. Existing power plants are mainly supercritical pressure thermal units, which are unsuitable for frequent startups and shutdowns, especially coal-fired units. Besides, a considerable part (30%) of the total electric capacity is met from cogeneration plants, which combine electricity generation with heat production, and the latter, greatly increasing in winter, slightly declines at night hours and on days off. Consequently, even if nuclear plant capacity constitutes but a small fraction, to provide them with base-load under these conditions poses a problem. The use of hydro-pumped storage plants to eliminate the nonuniformity of the load curve is not economically justified, as their construction in flat country proves more costly compared with mountainous regions. The above considerations make one think of other ways to store energy, which require additional investments and produce only a partial effect. This results in great variations in the cost of electricity, depending on the consumption pattern, and it becomes desirable to regulate the pattern itself.

Many consumers can substantially change their consumption pattern. For this, relatively small additional current expenditures and capital investments would be required. Moreover, at the low cost of "off-peak" energy, it might be desirable to organize special consumer-regulators. Here belong industries with very high energy intensity per unit of capital investments and employed labor force, which permit load reductions or interruptions in a process (for instance, aluminum production), thanks to the accumulation of products.

The use of nuclear plants for electricity generation above certain limits, which are heavily dependent on local conditions, will involve additional expenditures reducing the cost effectiveness of their application. Similar factors (though to a lesser degree) condition the construction of coal-fired plants, as investment costs have greatly increased (mainly because of ecological constraints), and the plants are far less maneuverable compared with gas-and-oil-fired units.

Much more complex is the use of the great number of existing thermal power plants with gas-and-oil units. This problem is of particular significance to countries with a high share of fuel oil in electric utilities' fuel supply (for instance, the USSR).

The simplest technical solution here is the ousting of liquid fuel from existing thermal plants with gas-and-oil units by shifting these plants to natural gas.[12] Dur-

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[12]With a simultaneous shift to a shutdown mode of operation or deep load reduction at "off-peak"

ing the next 10–15 years this project will be realized on a wide scale in the Soviet Union and some other gas-exporting countries. In those countries where the penetration of natural gas into the world market is hampered, on-site gas utilization will develop, particularly for the needs of the petrochemical industry. The rapidly growing demand for oil as a feedstock has already been met from dry natural gas ("chemistry C_1"), notably heavy fractions extracted from associated gas and gas condensate fields. In the long run, one can expect partial return to coal chemistry (in the first place, on the basis of high-speed pyrolysis of coal and oil shales and syngas production from coal). In the majority of countries where a shift from existing gas-and-oil units to natural gas is not economically viable, switching them over to coal is the greatest concern. To overcome ecological constraints, the shift to coal involves rather long and costly reconstruction of plants; however, this is already under way in some countries (the US, Denmark, etc.). At the same time fuel oil units, even those recently constructed, are being shifted to a sharp peak-load zone or are completely shut down (Great Britain, Sweden, etc.).

Thus, one should expect a substantial reduction in liquid fuels' contribution to electricity generation and industry, two major fuel oil users. Taking into account that today's fuel oil production throughout the world accounts for 800 million t/yr, it is hard to overestimate the effect that the fuel oil replacement may have on future demand prospects for oil. Substantial progress is being made in this field in some developed market economies. For instance, in the United States, fuel oil yield at oil refineries dropped to 6% from a low level of 11% in 1979; in Great Britain this reduction accounted for 17% compared with 32%; in the FRG it dropped from 21% to 16%; in France – from 29 to 20%.[13] Many countries still have great possibilities for further reductions in the fuel oil yield.

In some developed countries the residential and commercial sectors have high shares in the overall consumption of gas and oil products, namely, for space heating and hot water supply. The scope for high-quality fuel replacements is heavily dependent on climatic conditions, the type of housing, and existing methods of low-temperature heat supply. Today major low-temperature heat consumers are cities and urbanized areas where the greater part of the population of developed and, in some cases, developing countries lives. The pattern of settlement of urbanized areas varies from country to country. For instance, in the Soviet Union cities are planned and developed as a system of residential areas built up with multistory apartment houses. Under these conditions centralized heat supply from large heat-generating plants, namely cogenerating ones, proves most cost effective.

Usually gas or liquid fuel is used as fuel for cogeneration plants as in this case less effort is required to ensure clear community air and to reduce the site occupied by a cogeneration plant. In the Soviet Union, owing to the sharp rise in liquid fuel prices, existing cogeneration plants are being gradually shifted to gas.[14] In the longer run, even in this country, which has an abundance of gas resources, the price of gas will continue to rise, and a switch from cogeneration plants to coal or nuclear fuel will appear economically justified. In both cases this will involve additional expenditures conditioned, in the case of coal-fired plants, by ecological constraints and the need to deliver large amounts of solid fuel and to remove ash and slag. In the case of nuclear cogeneration plants with water-cooled

hours. For this it will be necessary to construct low-cost gas storage facilities for daily or weekly regulation.

[13] *Oil and Gas Journal* 82(32):23 (1984).

[14] But because urban heat supply is largely of seasonal nature and long-distance gas pipelines require constant load, the shift to gas necessitates developing a network of underground seasonal gas storage facilities.

reactors producing low-pressure steam, electricity generation per 1 Gcal of supplied heat is substantially lower. Besides, safety considerations require that such plants be located at some distance from big cities, which necessitates long-distance transportation of low-temperature heat (in the form of hot water). Such transportation proves fairly cheap, provided large-diameter pipelines with high average annual load are used. As a result nuclear cogeneration plants appear cost effective only in the case of year-round heat supply, i.e., in meeting part of big cities' annual heat demand. To improve a distant heat supply from nuclear cogeneration plants, it becomes necessary to develop new ways of long-distance heat transportation, especially as recent projects seem neither economically viable nor cheap.

One of the options for supplying urban heat is the construction of nuclear heat supply plants. The latter, when operating at low pressure, can be brought to such safety standards that it will become possible to locate them in densely populated areas. They can effectively supply hot water and process steam not only to apartment houses but also to many other municipal low-pressure steam users. In the Soviet Union such plants are being built in Gorky, Voronezh, and other towns.

Coal- or nuclear-based centralized heat supply appears highly promising for residential areas dominated by multistoreyed houses or for large industrial consumers, including agricultural/industrial complexes (for instance, very large greenhouses).

In residential areas, where cottages are dominant, low-temperature heat production through heat pumps, especially for space heating and air-conditioning, proves cost effective. Heat pumps are very economical in supplying hot water with simultaneous warm water discharge, since a rise in the temperature of such a good heat-transfer medium as water does not require large heat-exchange surfaces. Such conditions exist at many industrial and agricultural/industrial complexes and biological purification plants. In many cases, natural (particularly ice-free) ponds or man-made reservoirs can be used as a source of low-temperature heat. Heat pumps are especially attractive for seaside resorts where requirements for clear air are especially strict and there is a need to produce low-temperature heat for swimming pools.

Even at present with oil prices in decline, there are great possibilities for viable liquid fuel substitution for almost all consumers with the exception of cars and trucks, buses, planes, river boats and medium-sized ships, tractors, self-propelled combines, etc. In the longer run, however, one can expect partial liquid fuel substitution even in these fields.

This will involve, in the first place, intracity mass transportation. Naturally, the existing system established during the period of cheap oil availability should be reconstructed with a view to increasing the share of electric-powered transport to a maximum. Even in case of a successful solution of technical problems, reconstructing the entire urban infrastructure will take time. It is unlikely that by 2000 the greater part of intracity transport will be replaced by electrically driven vehicles. Far clearer are the prospects for developed systems of public transport, at least in the Soviet Union and countries with a similar settlement pattern, where orientation of public transport (mostly electrically driven) toward everyday journey to work and back has already proved economically justified. It is especially important to take into account the possibilities for developing public transport in large cities of developing countries where population growth rates are extremely high and automobile transport consumes an enormous amount of liquid fuel and causes heavy air pollution. Development of high-speed mass transit before new residential areas are densely built up is relatively cheap.

In many cases, developing countries are oriented toward the settlement pattern that has gained wide acceptance, especially in the United States, where residential areas with cottage-type housing are clustered around the city center forming a belt with a radius of 50–80 km and more. Such a pattern requires enormous capital investments in a transportation network and makes it necessary to use private cars for everyday journeys to work. Much cheaper and more realistic is the orientation toward constructing multistoreyed apartment houses. This pattern has been accepted in many countries, though often with little regard for the development of public transport. It is clear that these options lead to widely varying projections of motor fuel consumption in developing countries.

Of course, under any conditions the world's private car fleet will continue to grow.[15] But various economic factors, notably the high cost of motor fuel, will create incentives for limiting the use of private transport (especially in everyday life) and for developing public transport and, what is more, will reduce specific motor fuel consumption per 100 km of travel. Great progress has already been made in this field due to both the growing share of diesel-powered vehicles in the car fleet and a shift to small economical cars, in particular. Improvement in the efficiency of vehicles, especially passenger cars, will substantially compensate for the growth of the world's car fleet which is likely to be completed during the next 20 years; thereafter, the growth of fuel consumption in multipurpose (inter- and intracity) transport will be almost proportional to the number of cars.

Those are briefly the lines along which work will be done to solve energy problems of developed and urbanized areas of developing countries.

1.5. Energy supply of rural areas of developing countries

The greatest part of the population of developing countries lives in rural areas (more than 75%). Providing satisfactory living conditions for this part of the world's population will inevitably lead to a rise in energy consumption, which in its turn is impeded by lack of capital. Energy supply of developed and developing countries should be considered differently for each group, i.e., for developing countries solutions must be as cheap as possible, provide maximum employment, agree with traditional lifestyle, etc. Hence it follows that rural areas should be oriented toward building small (local) unsophisticated plants, which can be serviced by indigenous personnel properly instructed. For the majority of less developed countries, capital investments in such equipment will be lower compared with developed countries (primarily due to the availability of a cheap labor force). At the same time this does not mean that less developed countries should use obsolescent technologies. Quite the contrary, such equipment should be manufactured with regard for the latest achievements in science and technology. But new technologies should be optimized with respect to the above conditions – different for different countries.

Up to now the basic energy requirements of these areas have been met by so-called noncommercial (conventional) energy resources: wood and charcoal, agricultural wastes, muscular power. On the whole, the share of these resources in the

[15]In a number of developed countries, however, automobile transport has almost reached a level of saturation and further growth (two and three cars per family) will not result in a noticeable increase in mileage.

energy supply of developing countries accounts for not less than 20%. In less developed countries it is far higher; in Africa more than 85% of energy demand is met from noncommercial energy resources, in Asia – about 64%.[16]

The use of fuelwood together with "burnt-out" agriculture has resulted in catastrophic deforestation in the torrid zone. The resultant ecological hazard is hard to estimate, though, as is known, it has a direct bearing on the living standards of people.

Deforestation around human settlements has led to catastrophic fuel shortages in many rural areas. Many fuelwood users do not purchase but collect it. Wood collecting is time-consuming, eventually causes real damage to the economy, and poses a threat to human health. The impact of wood shortages on the diet has not yet been studied; meanwhile the population of some parts of Western Africa and Latin America must often do without cooked food. Peasants in Haiti and Nepal have to cut down on vegetables requiring heat treatment. A similar situation exists in other parts of the world. Very often collecting wood keeps children from school, which poses a social problem.

Suffering from wood shortages, rural inhabitants have to burn crop residue and dry dung. As a result, organic matter and nutrients are withdrawn from the fields and burned in open fires. This reduces the amount of fertilizers applied to soil and, consequently, soil fertility. According to the Food and Agriculture Organization, in the developing countries of Asia, Middle East, and Africa about 400 million tons of dry dung is burned annually. One ton of burned dung is equivalent to the loss of 50% of crop, i.e., the use of dung as fuel may reduce corn production throughout the world by 20 million tons. Under these conditions abandoning these practices as soon as possible is a matter of prime concern.

Deforestation has a direct bearing on disastrous floods, reduces water flow, and results in overdried springs and silted reservoirs. Wind erosion, salinization, and leaching also cause heavy damage. In preparing for the International Conference on Desertification (1977), estimates were made of reduced fertility of grazing and arable lands in arid zones. The damage caused by desertification accounts for more than 12 billion dollars/yr. It is hard to assess to a full degree the damage resulting from felling trees that once prevented erosion, improved microclimate and, in many cases, replenished nutrient reserves in soil. Still, it is clear that this damage constitutes a significant problem, which is confirmed by the data on increased land productivity resulting from protective afforestation in semi-arid zones. We dwell at length on the issues of fuelwood supply to show that it is not only an energy problem; it is connected with the entire range of problems that are of crucial importance to developing countries and should be solved on a systems basis in the shortest time possible.

Of primary concern for developing countries is the search for ways of reducing fuelwood consumption. The latter can be done: (1) by using other indigenous energy resources; (2) by expending fuelwood resources through afforestation; (3) by improving the efficiency of wood burning in conventional household stoves and, in many places, in open fires.

Even scanty data on coal and peat resources in developing countries show that in many cases solid fuel locally produced can replace wood. At the same time indigenous solid fuel production will provide the basis for the national economy and ensure employment. Capital investments required for this venture are, of course, rather heavy, but they are much lower compared with other options. Only

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[16] *Global Energy in Transition, Environmental Aspects of New and Renewable Sources for Development*, UNIPUB Publication 4, New York (1981).

orientation toward indigenous resources and labor force together with the use of mature and, therefore, sufficiently reliable and cheap technologies can promote further economic development of less developed countries.

Of no less importance here is the fact that coal and peat can be used in conventional wood stoves virtually everywhere. This will require no change in traditional housekeeping; hence, one can expect that this option may produce the most successful results.

Anaerobic fermentation of agricultural and domestic wastes should gain wider acceptance. Substantial progress made in this field in China, India, and some other countries has proved its simplicity and feasibility of the manufacture of required equipment by local labor from indigenous materials. Anaerobic fermentation offers an immediate solution to the following three problems: (1) improvement in sanitation; (2) production of high-quality fertilizers (according to some estimates, fermentation wastes applied to soil raise its productivity by 10–12% compared with composting);[17] (3) biogas production in the range from 0.5 to 0.6 tce/m^3/yr, for swine manure digestion, from 0.08 to 0.1 tce/m^3/yr, for poultry manure. The biogas produced is an excellent fuel for meeting domestic needs of small farms and rural communities. True, social incentives for introducing anaerobic fermentation are not as obvious as in the case of fuelwood replacement. This technology is new and in some regions it does not match the traditional lifestyle of rural population. That is why, despite its obvious advantages, the wide-scale application of this technology requires time and effort though some countries (namely, China and India) have already proved its cost effectiveness.

Here perhaps ends freedom of choice as far as wood replacement options for rural areas of developing countries are concerned. Recommendations for a wider use of renewables (notably solar energy) for these purposes are apparently untimely for the following reasons: immaturity of solar technologies; high cost of solar installations due to the use of manufactured equipment often imported; and far greater contradictions between the nature of these technologies and traditional lifestyle of rural communities. In the future, with the creation of economic and social incentives these technologies are likely to penetrate into developing countries. Still, wide-scale applications even in low-temperature heat supply cannot be expected earlier than the beginning of the next century.

The expansion of wood resources can be achieved in two ways: by afforestation and through improvements in the use of fuel (fuelwood in particular) in conventional installations for cooking and space heating. These two approaches should be intensively implemented, though one should bear in mind that, owing to catastrophic wood shortages in some regions, it will be difficult to preserve forest plantations until they reach productive maturity.

There is much room for improvement in the efficiency of conventional stoves. At present open fires whose efficiency does not exceed 10% have been most widespread in rural areas. The application of closed-type stoves with primitive heat insulation permits increasing their efficiency to 30–40%. The cost of such installations manufactured from indigenous materials with the maximum use of imported materials is comparatively low (10–20 dollars). Most of the expenditure may be offset by the use of poorly qualified, often surplus labor. The application of primitive closed-type installations to produce coke (badic fuel) in larger settlements, instead of burning it out in heaps, results in a several-fold increase in coke yield.

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[17] Owing to high animal-based organic matter content in the residue, the latter, when dried, can be effectively used as an additive to fodder.

The above are complementary options that do not exclude one aother. They should be in the focus of developed countries' government programs and international economic aid projects. Here, much depends on the countries themselves and on their willingness to solve their domestic problems.

While considering energy supply of rural areas of developing countries, one cannot help mentioning the use of electricity in the residential and commercial sector. Solutions to this problem will be different from the options realized in centralized energy supply.

Experience gained in some Soviet Asian Republics and other countries has shown that only with the help of electricity can one solve the problem of social reconstruction of rural areas, provide access to education and world culture, and put advanced technologies into practice. That is why the use of electricity in rural areas should be regarded as capable of changing not only the economy of developing countries but also the lifestyle and the way of thinking of the greater part of their population.

At present the most widespread installation for electricity generation in rural areas is a diesel power plant. The fuel it consumes has now become very costly.

In decentralized electricity supply, among other alternatives to diesel fuel, the following technologies based on indigenous energy resources should be given the highest priority:

(1) Mini-hydropower plants on small water flows with a capacity ranging from a few kilowatts to a few megawatts. In rocky terrain and regions with a developed network of waterways, such flows are usually located close to rural settlements. One of the effective ways of decreasing the cost of electricity derived from small hydropower plants is to reduce capital-intensity of energy equipment through full-scale production and package delivery;

(2) Gas-motor electric plants operating on producer-gas solid fuel (coal, peat, wood, dry agricultural wastes). This is a fairly mature and reliable technology that does not require highly skilled personnel for its maintenance. Unlike most other technologies, it can be manufactured directly in many developing countries. It can operate on virtually any kind of solid fuel. In some cases locomobile plants may also appear an attractive alternative, especially when combined with low-temperature heat users;

(3) Wind electric plants in regions with favorable wind velocity conditions, namely, coastal regions; and

(4) Solar photovoltaic converters, provided there is a significant reduction in specific capital investments, say, by a factor of 10^2.

Thus, there exist definite opportunities for energy supply in rural areas of developing countries on the basis of indigenous energy resources and cheap and, in most cases, mature technologies without radical changes in traditional lifestyle. At the same time even orientation toward these rather simple solutions will involve a considerable amount of developing countries' resources and broader cooperation with developed nations under the auspices of international organizations and on a bilateral basis.

Elaborating a strategy for world energy development is a hard but quite a feasible task that will require joint efforts of developed and developing nations.

Those are briefly the main lines along which the world energy economy will develop to the end of this century and the first quarter of the next century. In the subsequent sections dealing with prospects of the international natural gas market, we have consistently taken the above trends into account and tried to quantify them.

Chapter 2

Energy Demand Scenarios for Industrialized Market Economies

1.2. Methodology

To assess future prospects for the world natural gas market, the present study uses the forecasts of primary energy demand by region with the subsequent breakdown into potential gas consumers as a point of departure. This allows us to project a potential demand for natural gas. The actual levels of energy consumption will be conditioned by the potential consumers' efficiency in using natural gas (marginal gas prices), on the one hand, and by gas prices set in the market relative to the price of other competitive energy resources; by gas producers' and consumers' own costs; by government policies aimed at reducing dependence on imports and creating incentives for the development of alternative sources of energy or the domestic gas industry by laying a tax on exporters, etc., on the other hand.

There are two approaches to the assessment of energy demand levels:

(1) A *top-down approach* implies that from given economic growth rates total energy consumption growth rates are calculated; further, the share of electricity is projected and final energy demand is determined, which is then divided into separate elements (for instance, economic sectors); and

(2) A *bottom-up approach* would determine the levels of final energy consumption for each sector on the basis of economic growth rates and other indicators typical of each sector and of projected specific energy consumption. By summing up these data we obtain estimates of final energy demand for the country, as a whole. If the share of electricity in the final energy demand of each sector is forecast, then total electricity generation and consumption are determined, which provides the basis for developing forecasts of fuel consumption at electric plants. From the data on final energy consumption and consumption at electric plants (or rather generation losses), estimates are made of the total primary energy consumption.

Both approaches often produce different results. The first approach allows us to obtain fairly sound estimates at the upper level; but the lower the level, the less sound they seem. As for the other approach, here, on the contrary, the seemingly valid estimates at the lower level appear hardly acceptable at the upper level. In order to ensure internal stability of projections at all levels, an iterative procedure is required.

Central to the entire system of calculation is the expert on whose qualification, intuition, and outlook the validity and reliability of forecasts ultimately depends. In elaborating a forecast the expert uses a great number of methods, from logical thinking to mathematical modeling.

The energy forecasts for the US, Western Europe, and Japan considered in the present paper have been developed on the basis of the main assumptions of social and economic development given in Table 2.1. The following three scenarios have been developed:

Minimum Scenario – corresponding to high prices for oil and other energy forms. This scenario envisages improved energy conservation in all sectors of final energy consumption and a higher share of electricity in the energy balance.

Table 2.1. Major economic indicators used in energy scenarios.[a]

Region	1980	1990	2000	2010	2020
USA					
Population, million	228	245	265	285	300
Economic growth rates[b], %/yr	-	2.2-2.5	2.2-2.5	2.2-2.5	2.0-2.2
Western Europe					
Population, million	415	435	455	470	480
Economic growth rates (GNP), %/yr	-	2.5-3.0	2.0-2.5	2.0-2.5	1.5-2.0
Japan					
Population, million	116	123	130	132	132
Economic growth rates (GNP), %/yr	-	3.5-3.8	3.0-3.5	3.0-3.5	2.0-2.5
World Oil Market Price (1980 dollar/t)					
Minimum level	230	125	145	175	220
Medium level	230	150	180	220	270
Maximum level	230	175	205	260	330

[a]Government policies assumed: (1) energy conservation through more efficient use of energy and industrial structural changes; (2) reducing dependence on energy resource imports, enhanced development of indigenous sources of energy; (3) diversification of energy imports; (4) a vigorous taxation policy; (5) cooperation with other countries in the development of new sources of energy; and (6) improvement in the reliability and security of energy supplies.

[b]Low rates – at high oil prices; high rates – at moderate and low oil prices.

Medium Scenario – reflecting the hypothesis of moderate growth rates of oil prices. As a result, more modest efforts in energy conservation and a lower electricity share are expected.

Maximum Scenario – suggesting low oil price growth rates, which are now regarded as most probable. This scenario assumes higher rates of economic development founded on both domestic resources and orders coming from developing countries where lower oil prices are expected to generate economic activity.

The subsequent sections of the paper deal in greater detail with the forecasts of energy consumption for the industrial, transportation, residential, and commercial sectors of the regions under consideration. The paper also provides overall estimates of energy consumption and anticipated levels of the regions' potential demand for fossil fuel – in this case, for natural gas.

2.2. Industrial energy consumption

Industrial energy consumption in developed market economies is now being influenced by the following main factors: improved energy efficiency per unit of industrial output; and industrial structural changes. These factors will continue to play an increasingly important role in the future.

Improving the efficiency of energy use is part and parcel of society's effort aimed at switching over to energy-saving (in the broader sense) technologies. This has been the main line of the development of industrial production throughout the world. The term "energy-saving technologies" includes:

(1) Technologies that permit the reduction of processing stages to a minimum. This results in greater material and energy savings. To these technologies belong: direct iron reduction, continuous casting, electrophysical or electrochemical machining, etc.

(2) Technologies that imply deep wastes utilization or allow us to reduce the amount of resultant wastes through the use of higher-quality feedstock and improved methods of processing. This includes energy savings obtained throughout the entire energy chain – from production to final consumption.

(3) Large-scale applications of new materials that possess the necessary properties but are less costly and capital-intensive, for instance, reinforced concrete and plastics, man-made fibers, etc.

(4) Combination of technology proper with microelectronics. This considerably improves process control, which is the main factor in reducing all kinds of losses and, consequently, preventing the squandering of energy.

Dramatic changes in industrial production are accompanied by noticeable changes in its structure. For various objective reasons (the costs of feedstock, energy, and labor force; environmental considerations; development of productive forces in developing countries), developed countries are slowly curtailing large-scale energy-intensive industries like ferrous and nonferrous metallurgy, petroleum refining, the chemical industry. Over the past few years these industries have either fallen into stagnation or reduced their production volumes. The future may see continued reduction in this field. (But one can hardly agree that energy-intensive industries that provide the basis for the existing infrastructure will be completely ousted from developed and transferred to developing countries.)

These "old traditional" industries are being replaced by high technology featured by a severalfold lower volume of production, in terms of per unit weight, compared with conventional industries, and by a multifold rise in unit production costs. The development of such less energy-intensive industries as microelectronics and electrical engineering, biotechnology, and fine mechanics enables developed countries to retain their leading role in the world economy. For ecological reasons, too, energy-intensive industries in Western Europe will be replaced at a higher rate than in the United States and Japan.

Thus, in assessing energy demand prospects in the industry of developed countries it is necessary, first and foremost, to analyze the impact these two factors may have on future demand levels as well as on the energy mix with particular reference to the growing electricity share resulting from current industrial structural changes.

Scenarios of industrial energy demand for the US, Western Europe, and Japan are based on the evaluation of the following three demand levels: the ***minimum level***, corresponding to the hypothesis of maximum crude oil and natural gas prices over the period under consideration; the ***medium level***, suggesting moderate price growth rates; and the ***maximum level***, based on the assumption of minimum energy prices. The hypothesis is that the level of oil and gas prices has a certain additional effect on the general downward trend in energy intensity and on the structural evolution of industrial production. Besides, it has been assumed that the price of electricity will grow at a slower pace compared with fossil fuels, and the gap between the cost of useful electricity-derived heat and that of resulting from direct fuel burning will be narrowed. This will create an incentive for using electricity in industrial processes (especially high-temperature processes). As a result, the minimum scenario suggests a higher electricity share compared with the maximum scenario (at low fuel prices).

On the whole, different considerations will condition the scope for electricity in industry. In those industries where coal can be used (for example, cement production, structural clay products, brick-making, etc.), one can hardly expect the share of electricity to grow. Electrical use is likely to increase in those sectors where it will be able to replace liquid or gaseous fuel. In processes with a long life cycle use can be made of base-load electricity derived from nuclear or coal-fired thermal plants and of off-peak electricity, in processes with a short life cycle.

In a general case, prospective energy demand has been calculated from the following projections (forecasts):

(1) Gross domestic product (GDP);

(2) Industry share in GDP (our research suggests no drastic change in this figure in the future);

(3) Pattern of industrial production broken down into two groups of industries: ***energy-intensive*** – primary metals, the chemical industry, petroleum refining, building materials, wood-pulp and paper, others; and ***nonintensive*** – metal fabricating, food processing, wood-working, and light industry;

(4) Energy intensity of an industrial production increment;

(5) Pattern of industrial energy consumption with the split between motor load and thermal uses. For the regions under consideration, we adopted the hypothesis of a constant pattern of final energy consumption throughout the entire time frame (Table 2.2);

(6) Electricity use for industrial processes as determined in relation to the level of prices; from these data the volume of direct fuel use is calculated and allocated between boiler plants and industrial furnaces on the basis of expert appraisal. The latter breakdown provides a more sound basis for identifying the dependence of the marginal price of natural gas on growing demand (Chapter 9).

The main results obtained from the forecasts of industrial energy consumption are given in Tables 2.3–2.5. Let us consider briefly the projections made for each region individually.

The US. According to the assumptions adopted, the share of energy-intensive industries will drop from 56% in the year 1980 to 40% (minimum scenario) or to 48% (maximum scenario) by 2020. At the same time, due to technological advances, the energy intensity of industrial production will be reduced by a factor of 2–2.2 (minimum scenario) and 1.3–1.6 (maximum scenario). As a result, final energy consumption will heavily depend on the level of energy prices: at low prices it will continue to rise (by a factor of 1.12 by 2000 and by the same factor by 2020) and to decline at high prices (by 2020 the level of energy consumption in industry will be 10% lower compared with 1980). There will be a sharp rise in the share of electricity from 22% in 1980 to 56–58% in 2020. At the same time, the volume of direct fuel use decreases by a factor of 1.5–2.2 depending on the assumption adopted. On the whole, it should be noted that the potential fossil fuels (including natural gas) market for the industry will steadily decline.

Western Europe. Similar trends will emerge in West European industry. Our projections for this region suggest a decrease in the share of energy-intensive industries from 47% in 1980 to 33–40% in 2020 and a decline in the energy intensity of production by a factor of 1.5–2.0. According to our forecast the overall level of energy consumption in West European industry will be 20% lower compared with 1980, in the case of high energy prices, and 25% higher, in the case of low energy prices. The electricity share will grow from 20% in 1980 to 47–51% by 2020, and the direct use of fuel will somewhat increase by 2010, in the case of low prices, but

Table 2.2. Energy consumption pattern, by industry (%).

Industry	Lighting, Motor Load, Electro-lysis	Thermal-Processes	Including				
			100°C	100-350°C	350-550°C	550-1000°C	1000°C
Food	14.6	100.0	39.8	57.8	2.8	-	-
Woodworking and wood pulp and paper	7.1	100.0	15.3	78.4	6.3	-	-
Chemical and petro-leum refining	11.0	100.0	4.8	63.8	14.5	15.7	1.2
Building materials	11.5	100.0	1.6	9.7	2.4	20.3	68.4
Primary metals	27.6	100.0	9.3	3.6	7.3	-	79.8
Metal fabricating	35.0[a]	100.0	12.3	43.8	20.0	-	23.9
Others	25.6	100.0	60.0	40.0	-	-	-

[a]Expert appraisal.

SOURCES: *Report on Building a Sustainable Future*, Vol. 2, SERI, US Government Printing Office, Washington, DC., 1981; and Boerker, S.W., *Characterization of Industrial Process Energy Services*, ORAU/IEA-79-9(R), Technical Report, 1979.

Table 2.3 Forecast of industrial energy consumption for the US (million tce/yr).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industrial energy consumption (excluding feedstock needs)	458	450	445	430	410
Including electricity	108	145	200	250	250
Electricity consumption, billion kWh	878	1180	1630	2030	2030
Electricity share, %	24[a]	32	45	58	60
Direct fuel use, total	350	305	245	180	160
Including					
Industrial furnaces[b]	105	110	100	90	80
Industrial boiler plants[b]	245	195	145	90	80
Medium (moderate prices)					
Industrial energy consumption (excluding feedstock needs)	458	465	500	535	540
Including electricity	108	150	220	300	310
Electricity consumption, billion kWh	878	1220	1790	2440	2520
Electricity share, %	24[a]	32	44	56	58
Direct fuel use, total	350	315	280	235	230
Including					
Industrial furnaces[b]	105	115	120	120	120
Industrial boiler plants[b]	245	200	160	115	110
Maximum (low prices)					
Industrial energy consumption (excluding feedstock needs)	458	475	515	580	580
Including electricity	108	155	230	320	330
Electricity consumption, billion kWh	878	1260	1870	2600	2680
Electricity share, %	24[a]	32	44	55	57
Direct fuel use, total	350	320	285	260	250
Including					
Industrial furnaces[b]	105	115	120	120	120
Industrial boiler plants[b]	245	205	165	140	130

[a]Rounded.
[b]Expert appraisal.

Table 2.4 Forecast of industrial energy consumption for Western Europe (million tce/yr).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industrial energy consumption (excluding feedstock needs)	458	450	440	415	360
Including electricity	110	125	160	200	220
Electricity consumption, billion kWh	894	1015	1300	1625	1790
Electricity share, %	24	28	36	48	61
Direct fuel use, total	348	325	280	215	140
Including					
Industrial furnaces[a]	100	100	90	80	70
Industrial boiler plants[a]	248	225	190	135	70
Medium (moderate prices)					
Industrial energy consumption (excluding feedstock needs)	458	480	520	530	545
Including electricity	110	130	170	220	300
Electricity consumption, billion kWh	894	1055	1380	1790	2400
Electricity share, %	24	27	33	42	55
Direct fuel use, total	348	350	350	310	245
Including					
Industrial furnaces[a]	100	100	100	100	100
Industrial boiler plants[a]	248	250	250	210	145
Maximum (low prices)					
Industrial energy consumption (excluding feedstock needs)	458	485	540	615	670
Including electricity	110	130	175	245	330
Electricity consumption, billion kWh	894	1055	1545	1990	2680
Electricity share, %	24	27	32	40	49
Direct fuel use, total	348	355	365	370	340
Including					
Industrial furnaces[a]	100	105	110	110	110
Industrial boiler plants[a]	248	250	255	260	230

[a]Expert appraisal.

Table 2.5 Forecast of industrial energy consumption for Japan (million tce/yr).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industrial energy consumption					
(excluding feedstock needs)	143	155	160	160	140
Including electricity	29	47	65	85	85
Electricity consumption,					
billion kWh	236	380	530	690	690
Electricity share, %	20	30	40	53	61
Direct fuel use, total	114	108	95	75	55
Including					
Industrial furnaces[a]	34	32	30	23	17
Industrial boiler plants[a]	80	376	65	52	38
Medium (moderate prices)					
Industrial energy consumption					
(excluding feedstock needs)	143	163	185	210	225
Including electricity	29	47	65	85	100
Electricity consumption,					
billion kWh	236	380	530	690	770
Electricity share, %	20	29	36	40	45
Direct fuel use, total	114	116	120	125	125
Including					
Industrial furnaces[a]	34	35	35	38	40
Industrial boiler plants[a]	80	81	85	87	85
Maximum (low prices)					
Industrial energy consumption					
(excluding feedstock needs)	143	167	200	230	260
Including electricity	29	47	70	90	110
Electricity consumption,					
billion kWh	236	380	570	815	895
Electricity share, %	20	28	35	39	42
Direct fuel use, total	114	120	130	140	150
Including					
Industrial furnaces[a]	34	36	40	42	50
Industrial boiler plants[a]	80	84	90	98	100

[a]Expert appraisal.

by the end of the period will not exceed the 1980 level. All other scenarios suggest a decline in direct fuel use. This makes us regard an expansion of a potential natural gas market as highly probable for the period under consideration.

Japan. As for Japanese industry, the above trends are likely to emerge on a larger scale and at higher rates compared with the US and Western Europe. The reason is the scarcity of indigenous raw material and energy resources. Owing to this fact, one may expect that energy-intensive industries will be replaced at far higher rates compared with other developed countries. As a result, the share of energy-intensive industries will drop from 48% in 1980 to 25–33% in 2020. Energy intensity will also decline at accelerated rates. But due to higher economic growth rates, which are supposed to persist in the future, and higher population growth, the energy demand in the Japanese industry will continue to grow to the year 2000 and beyond, at low energy prices or, stabilizing at the level of the year 2005 to 2015, will begin to decline at a slow pace. The share of electricity will substantially increase. In the case of low energy prices, the direct use of fuel will grow throughout the entire time frame but, in the case of high prices, will steadily decline. That is why both Japan and Western Europe have possibilities for expanding their fossil fuel demand for industry.

On the whole, for the developed market economies, one can expect a rise in industrial energy consumption only if prices for energy resources remain comparatively low. In this case, the direct use of fuel will increase in Western Europe and Japan but will decline in the United States.

2.3. Transportation

In studying energy intensities of various transport vehicles, aggregated estimates have been made of energy consumption for transportation for the US, Western Europe, and Japan. The transportation sector is divided into two areas. To the first area belong all kinds of motor vehicles that have gained wide acceptance in the above regions and to which rigorous conservation measures are applied to achieve considerable savings in specific liquid fuel consumption. The other area includes electrically powered city transport, rail, water, and air transportation (including oil, gas and, in the future, pulp pipelines) as well as new modes.

Calculations have been made for three scenarios of energy consumption: the ***minimum scenario*** – the highest oil prices and maximum energy conservation; the ***medium scenario*** – moderate oil prices and modest conservation practices; the ***maximum scenario*** – the lowest oil prices and minimum conservation.

The following assumptions have been made:

(1) Specific freight turnover per unit of GDP (tkm/thousand dollars) is expected to decline due to the general trend in developed countries toward an increase in the value of transported freight per unit of weight and a corresponding decrease in overall dimensions.

(2) For all regions the share of diesel-powered motor freight transportation is assumed to reach 85–95% of total transport energy consumption by the end of the period under consideration. It is expected that the share of diesel-powered passenger transportation will also increase. Bus transportation has already been dieselized 100%.

(3) The number of cars per 1000 inhabitants will increase and reach a saturation level by 2010–2020.

(4) Total energy consumption in this sector per unit of GDP (thousands of toe/dollar GDP) declines for all regions;

(5) Energy consumption for other (with the exception of motor transportation) modes of freight and passenger transportation is estimated as the difference between the total energy consumption and energy consumption for motor transportation.

(6) The share of electrically driven transport is expected to increase as a result of the introduction of battery-driven vehicles in passenger transportation (up to 15–20% of the total energy consumption) and the increasing share of electricity in other modes of transportation (up to 25–30% of the total energy consumption in the sector).

(7) Given the possibilities for replacing liquid fuels by compressed or liquefied natural gas or by methanol derived from natural gas, an average replacement coefficient of 1800 m sup 3 of natural gas per one ton of gasoline is assumed. With more efficient use of methanol or its derivatives as additives, one ton of methanol can replace 1.5 tons of gasoline.[1]

The results of the calculations are summarized in Tables 2.6–2.8.

The minimum scenario suggests a greater reduction, compared with the other scenarios, in motor freight and passenger turnover and, consequently, in energy consumption for energy-intensive motor transport, and also a more rapid rate of declining liquid fuel consumption due to the increasing share of electricity, natural gas, and methanol.

Total energy consumption for all modes of transportation and freight and passenger turnover is assumed to be correlated with GDP and population growth.

The evaluation of priorities for different natural gas uses shows that methanol-based synthetic fuel substitution for hydrocarbon fuels in the period under consideration (at anticipated crude oil prices) is not economically viable. That is why one can expect wide-scale application of synthetic fuels in motor transport only beyond 2020.

2.4. Residential and commercial sector

US. The UN forecast of population[2] as well as that of a family factor (number of persons per household)[3] (Table 2.9) served as source data for residential and commercial energy consumption predictions in the US.

The assessment of energy consumption, with regard to major energy uses in this sector, has been made for three scenarios corresponding to different consumption levels: the minimum scenario assuming rigorous conservation practices and, consequently, greater energy savings in the future; the maximum scenario suggesting modest energy conservation and greater energy consumption; and the medium scenario based on moderate conservation measures.

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[1] Jewetz, P. (1984), *Using Natural Gas to Open the Way for Other Future Gas and Alcohol Sources*, presentation made at the International Gas Meeting, October 18–19, 1984 (International Institute for Applied Systems Analysis, Laxenburg, Austria).

[2] *World Population Prospects as Assessed in 1980*, United Nations, New York (1981).

[3] Williamson, Robert H. (1985), *A Low Energy Future for the United States*, Soviet-American Symposium on Energy, Moscow, PU/CEES Report No. 186 (Princeton University, Princeton, N.J.).

Table 2.6. Forecast for US transportation: total energy consumption (million tce), and natural gas' potential contribution (billion m sup 3).

Transportation Scenario	1980	1990	2000	2010	2020
Minimum					
Total energy consumption (TEC)	608.2	635	575	505	415
Including					
Oil-derived fuels	607.1	610	515	415	285
Methanol	0.2	5	15	25	35
Natural gas	0.5	15	30	35	50
Electricity	0.4	5	15	25	45
Natural gas' contribution	0.4	20	45	65	85
Including					
Compressed or liquefied gas	0.1	15	25	30	45
Methanol	0.3	5	20	35	40
Natural gas as % of TEC	0.1	4	10	15	25
Medium					
Total energy consumption (TEC)	608.2	655	690	755	800
Including					
Oil-derived fuels	607.1	633	655	714	610
Methanol	0.2	5	8	16	20
Natural gas	0.5	12	15	30	50
Electricity	0.4	5	12	25	40
Natural gas' contribution	0.4	15	30	45	60
Including					
Compressed or liquefied gas	0.1	10	15	25	30
Methanol	0.3	5	15	20	30
Natural gas as % of TEC	0.4	3	6	9	12
Maximum					
Total energy consumption (TEC)	608.2	700	850	985	1085
Including					
Oil-derived fuels	607.1	685	812	924	1004
Methanol	0.2	3	9	22	31
Natural gas	0.5	10	20	20	20
Electricity	0.4	2	9	20	30
Natural gas' contribution	0.4	15	30	45	55
Including					
Compressed or liquefied gas	0.1	10	15	15	15
Methanol	-	5	15	30	40
Natural gas as % of TEC	0.1	3	4	8	9

Table 2.7. Forecast for West European transportation: total energy consumption (million tce), and natural gas' potential contribution (billion m sup 3).

Transportation Scenario	1980	1990	2000	2010	2020
Minimum					
Total energy consumption (TEC)	317.8	330	350	350	320
Including					
Oil-derived fuels	312.1	292	288	249	205
Methanol	0.2	8	12	16	25
Natural gas	0.6	20	35	60	60
Electricity	4.9	10	15	25	30
Natural gas' contribution	0.5	15	30	50	50
Including					
Compressed or liquefied gas		5	15	25	25
Methanol	0.5	10	15	25	25
Natural gas as % of TEC	0.18	6	10	17	19
Medium					
Total energy consumption (TEC)	317.8	335	370	385	390
Including					
Oil-derived fuels	312.1	304	316	309	305
Methanol	0.2	5	12	16	20
Natural gas	0.6	20	30	40	40
Electricity	4.9	6	12	20	25
Natural gas' contribution	0.5	15	25	35	35
Including					
Compressed or liquefied gas		5	10	15	15
Methanol	0.5	10	15	20	20
Natural gas as % of TEC	0.18	6	8	10	10
Maximum					
Total energy consumption (TEC)	317.8	375	450	475	485
Including					
Oil-derived fuels	312.1	352	407	412	402
Methanol	0.2	5	8	13	18
Natural gas	0.6	12	25	35	45
Electricity	4.9	6	10	15	20
Natural gas' contribution	0.5	10	20	30	35
Including					
Compressed or liquefied gas		3	9	10	10
Methanol	0.5	7	11	20	25
Natural gas as % of TEC	0.18	3.2	6	7	10

Table 2.8. Forecast for Japanese transportation: total energy consumption (million tce), and natural gas' potential contribution (billion m^3).

Transportation Scenario	1980	1990	2000	2010	2020
Minimum					
Total energy consumption (TEC)	74.8	85	85	75	70
Including					
Oil-derived fuels	72.7	79	71	43	43
Methanol	0.1	1	4	7	12
Electricity	2.0	5	10	15	15
Natural gas' contribution	0.1	1	5	10	16
Including					
Methanol	0.1	1	5	10	16
Natural gas as % of TEC	0.13	1.2	5	9	17
Medium					
Total energy consumption (TEC)	74.8	85	90	95	105
Including					
Oil-derived fuels	72.7	79	82	84	89
Methanol	0.1	1	2	4	6
Electricity	2.0	5	6	7	10
Natural gas' contribution	0.1	1	4	8	14
Including					
Methanol	0.1	1	4	8	14
Natural gas as % of TEC	0.13	1.1	6	9	14
Maximum					
Total energy consumption (TEC)	74.8	105	130	145	150
Including					
Oil-derived fuels	72.7	100	121	130	130
Methanol	0.1	1	2	7	10
Electricity	2.0	4	7	8	10
Natural gas' contribution	0.1	1	4	8	14
Including					
Methanol	0.1	1	4	8	17
Natural gas as % of TEC	0.13	1	4	7	11

Table 2.9. Population and family factor forecasts for the US.

	Unit	1980	1990	2000	2010	2020
Population	million	227.66	245	263.8	281.7	299
Family size	person/family	2.79	2.61	2.57	2.5	2.42

A final energy consumption pattern in the residential sector was calculated from the data of the mid-1970s[4] with recalculation of electric energy use to a physical equivalent, the efficiency of energy production and transmission being equal to 0.298.

Space heating accounts for the greater part of residential energy use in the US. Energy consumption for heating in 1980 and succeeding years has been calculated from heat requirements per apartment/household. This value has been defined both for the old housing stock (i.e., built prior to 1980, which serves as a base year for the given forecast) and the new stock to be built in the periods under consideration with regard to three types of houses: a single-family house, generally, an individual cottage; a multifamily multistory building, and a mobile house. The housing stock of 1980, by house type, is assumed to consist of:[5]

Single-family houses	65%
Multifamily houses	31%
Mobile houses	4%

In 1980, the final energy consumption in the residential and commercial sectors was a total of 318.54 million tce and 192.35 million tce, of which electric energy accounted for 88.14 million tce and 68.6 million tce, respectively.[6]

For 1980, heat consumption per apartment of each type of house has been calculated on the basis of total energy consumption, the final energy consumption pattern, and the housing stock structure. Specific heat consumption in new housing during the periods under consideration is assumed to be half the consumption in old housing, according to the literature (for instance, see Williams, *op. cit.*, p. 30).

In forecast calculations, changes in specific heat consumption in old housing stock were evaluated with regard to the obsolescence of the housing stock and projections for new housing. The following rates of obsolescence have been assumed: for stationary houses – 2.5% every five years; for mobile houses – 5%. Heat losses at the end of the projection period in new buildings are assumed to account for 70–80% from the base year for the maximum scenario, and for 40–50% for the minimum scenario.

Future changes in the volume of the housing stock for each house type have been calculated taking into account the assumed rate of the obsolescence of the housing stock, population forecasts, and family size. Then the obtained data have been corrected according to the experts' estimates.[7]

In order to determine the pattern of energy consumption, the total housing stock has been divided into houses with electric heating and houses that use heat pumps as a source of low-temperature heat.

According to statistical data, in 1980, 16% of all one-family houses and 26% of multifamily houses used electric heating. It is typical of the last decade that electric heating in the new housing stock accounts for 50% of single-family houses and two-thirds of the multifamily ones.[8] In 1980, the total number of heat pumps

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[4]Ross, Marc H. and Robert H. Williams (1980), Our Energy-Regaining Control. New York: McGraw-Hill.

[5]*Gas Facts, 1981. A Statistical Record of the Gas Utility*. American Gas Association, Arlington, Virg. (1982).

[6]*Energy Balances of the OECD Countries 1971–1981*. International Energy Agency, Paris (1983).

[7]Hirst, Eric, Janet Carney, and Dennis O'Neal (1978), Feasibility of zero residential energy growth, *Energy 3*:427-438.

[8]Gas Facts, 1981, *op.cit.*, p. 138; *Statistical Abstract of the United States* (1981), US Department of

installed in the houses amounted to 4 million with the annual sale of more than 500 thousand pumps, these values forecasted to increase in the future.[9] Assuming heat pump life to be 15 years and taking into consideration the given percentage of the stock obsolescence, the following quantitative forecasts of electric heating and heat pump distribution have been made: The proportion of apartments with electric heating in the new housing stock during the projected ten-year periods will increase up to 75% for one-family houses and up to 90% for multifamily houses at the end of the forecast period. Of these houses, two-thirds will have heat pumps as a source of heat by 2000 while by the end of the designed period the percentage of houses with heat pumps will account for 90% of total new housing stock with electric heating. Other nontraditional heat sources have not been considered in the present study.

Final energy required for heating in the housing stock has been calculated with due regard for the following efficiency values of heating units: for fossil fuel – 0.8; for direct electric heating – 1.0; and for heat pumps a conversion factor is assumed of 2.5 up to 2000 while for a longer term – 3.5.

Lacking adequate data, the subdivision into central and decentralized heat supply (heating and hot water supply) has been made conditionally according to the percentage of single-family and multifamily houses in the housing stock.

Energy consumption for other needs in the residential sector has been calculated for 1980 on the basis of total energy consumption and consumption pattern. Future prospects call for further increase in the percentage of basic appliances, in particular, air conditioners, electric cookers, and hot water supply using electric energy, with efficiency improvements of all the above appliances. The minimum scenario assumes the complete substitution of all appliances by more advanced technology available in the mid-1980s.[10] The maximum and medium scenarios suggest only partial substitution, i.e., the average increase in efficiency of air conditioners and coolers by 40-50%, lighting equipment by 1.5-2 times, and so on.

The forecast of energy consumption in the commercial sector is based on the following assumptions: the total area of nonresidential buildings will continue to decline, and specific energy consumption per square meter of area will drop at a higher rate due to more efficient use of energy. As a result, the future per capita energy consumption in the commercial sector will continue to decrease.

Forecast of total energy consumption in the residential and commercial sectors is shown in Table 2.10.

Thus, total energy consumption in the residential and commercial sectors in all scenarios does not increase by the end of the forecast period. On the contrary, it shows a decline that is particularly notable for the minimum scenario. Electricity consumption increases slightly in the maximum scenario and remains virtually unchanged in the minimum scenario. A proportion of electric energy in total consumption increases from 30% in 1980 to 38–40% in the 2020 forecast in all scenarios. Total per capita energy consumption decreases from 2.24 tce/man-year in 1980 to 1.7 tce/man-year in 2020 in the maximum scenario and up to 1.84 tce/man-year in the minimum one.

Commerce, Bureau of the Census (Washington, DC); and *Energy Conservation Indicators*, Energy Information Administration, Annual Report, October 1984 (Washington, DC).

[9]Electricity growing as home heat source, *Hydrocarbon Process 63*(10):1-19 (1984).

[10]Williams *op. cit.*, pp. 29-31.

Table 2.10. Forecast of energy consumption for residential and commercial sectors, US.

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Energy consumption,					
million tce	510.9	474.3	450.0	430.0	410.0
Including fossil fuel	351.3	330.5	300.0	270.0	240.0
Including					
space heating and					
hot water supply					
- centralized[a]	57.8	51.0	44.0	37.0	32.0
- decentralized	147.7	139.0	122.0	105.0	89.0
cooking	6.6	3.8	2.2	1.2	-
Electricity, million tce	156.8	145.0	152.0	160.0	165.0
Electricity, billion kWh	1280.0	1170.0	1240.0	1290.0	1330.0
Electricity share, %	30.0	31.0	34.0	37.0	40.0
Per capita consumption,					
tce/per cap	2.24	1.93	1.7	1.52	1.4
Medium (moderate prices)					
Energy consumption,					
million tce	510.9	497.0	495.0	495.0	500.0
Including fossil fuel	351.3	344.0	324.0	310.0	300.0
Including					
space heating and					
hot water supply					
- centralized[a]	57.8	53.5	49.5	45.3	43.0
- decentralized	147.7	140.4	127.5	116.0	106.0
cooking	6.6	6.2	5.2	5.0	4.0
Electricity, million tce	156.8	153.5	170.0	185.0	200.0
Electricity, billion kWh	1280.0	1250.0	1380.0	1510.0	1640.0
Electricity share, %	30.0	31.0	34.3	37.0	40.0
Per capita consumption,					
tce/per cap	2.24	2.0	1.88	1.75	1.67
Maximum (low prices)					
Energy consumption,					
million tce	510.9	518.6	530.0	535.0	550.0
Including fossil fuel	350.3	362.8	357.0	346.0	346.0
Including					
space heating and					
hot water supply					
- centralized[a]	57.8	59.5	59.2	57.5	57.7
- decentralized	147.7	155.6	153.6	147.3	135.0
cooking	6.6	6.2	5.2	5.3	4.2
Electricity, million tce	156.8	155.8	174.0	190.0	207.0
Electricity, billion kWh	1380.0	1270.0	1415.0	1540.0	1680.0
Electricity share, %	30.0	30.0	33.0	35.0	38.0
Per capita consumption,					
tce/per cap	2.24	2.12	2.0	1.9	1.84

[a]Expert appraisal.

Western Europe. The forecast has been developed for the residential and commercial sector as a whole.

Existing trends in the energy consumption of different West European countries vary to a great extent. That is why, to develop forecasts of energy demand of the most developed countries in this region, the FRG was chosen as a point of departure, because it is located in Central Europe, has climatic conditions typical of the region, and possesses a relatively detailed data base for research into higher energy efficiency. If other countries' conditions (for instance, Turkey's or Yugoslavia's) differ greatly from those of the FRG, the forecasts have been correlated with regard for this inhomogeneity. This involves, in the first place, average annual growth rates of energy consumption, as a whole, and electricity, in particular.

The total energy consumption in the sector with electricity singled out for the year 1980 has been calculated from sources listed below;[11] projections of the overall volumes have been made on the basis of populations (Table 2.11) and per capita energy consumption forecasts (Table 2.12).

The per cap consumption forecast has been based on the following assumptions: Because of conservation practices in the residential and commercial sector and nonresidential buildings, the maximum scenario assumes a 20% reduction in the energy used for space heating by the end of the period under consideration. For new buildings, a 50% reduction in heat loss has been assumed compared with existing buildings (for the US, this figure is 60–70%). The minimum scenario suggesting maximum energy conservation assumes a 35% reduction in space heating energy needs, which corresponds to a 70–80% decrease in heat loss in new buildings compared with existing ones. Besides, energy conservation (especially in oil products) will be achieved through widespread use of new space heating systems such as electric heating with night-time heat storage, heat pumps, and standby boilers on liquid fuel in individual homes. By 2000 when put into practice in the FRG, these systems are expected to yield energy savings of 1.3 million tce and 6.1 million tce, respectively.[12]

The pattern of per capita electricity consumption includes electric heating: 290 kWh/per cap/yr. It is assumed that in 1980 some 25% of homes with hot-water heating and 5% of homes with warm-air heating had electric heating.[13] Electric cooking plus hot water supply constitute some 5% of the total consumption, i.e., 50 kWh/per cap/yr. The remainder – lighting, electric appliances – account for about 1300 kWh/per cap/yr.

It is assumed that by the end of the forecast period about 20% of the housing stock may use electric heating, including heat pumps, which equals some 950 kWh/per cap. For the US, this figure is 35% of the entire housing stock; but the European housing stock is more sluggish and its renovation takes more time. It is also assumed that all cooking and 50% of hot water supply will be shifted to electricity, which will account for 800–815 kWh/per cap by the year 2020.

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[11] *Energy Balance of OECD Countries 1971–1981*, Organisation for Economic Cooperation and Development, Paris (1983); *Annual Bulletin of General Energy Statistics for Europe*, United Nations, New York (1985); and *World Energy Outlook*, Organisation for Economic Cooperation and Development, Paris (1982).

[12] Coenen, R. *et al.* (1984), Kummer mit Kohle, *Energie 36*(9):23-41.

[13] Khan, Arshad M. and Alois Hölzl (1982), *Evolution of Future Energy Demand til 2030 in Different World Regions: An Assessment Made for the Two IIASA Scenarios*, Research Report RR-82-14 (International Institute for Applied Systems Analysis, Laxenburg, Austria).

Table 2.11. Population projections for Western Europe, 1980-2020.

Region	Population, million					Annual Growth Rate, %			
	1980	1990	2000	2010	2020	1980-1990	1990-2000	2000-2010	2010-2020
Central	216,972	217,797	219,028	217,146	214,822	0.04	0.06	-0.09	-0.10
Northern	17,216	17,774	18,125	18,465	18,735	0.12	0.02	-0.10	-0.15
South-Eastern	133,955	150,979	166,924	179,998	192,392	1.12	0.90	0.72	0.66
South-Western	47,214	50,835	54,438	57,647	60,628	0.79	0.65	0.50	0.39
Total	415,253	435,875	455,664	468,743	480,507	0.45	0.45	0.28	0.25

SOURCE: *World Population Prospects as Assessed in 1980*, United Nations, New York, 1981.

Table 2.12. Forecast of energy consumption for residential and commercial sectors, Western Europe.

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Energy consumption,					
million tce	435.7	460	470	470	460
Including fossil fuel	342.6	330	315	290	265
Including					
space heating and					
hot water supply					
- centralized[a]	16.2	25.6	40	46	53
- decentralized	304	290	260	230	200
cooking	18	16	14	12	10
Electricity, million tce	83.4	101	125	145	170
Electricity, billion kWh	679	820	1000	1180	1380
Electricity share, %	19	22	27	31	37
Medium (moderate prices)					
Energy consumption,					
million tce	435.7	460	480	490	490
Including fossil fuel	342.6	340	335	330	320
Including					
space heating and					
hot water supply					
- centralized[a]	16.2	27.2	40	52	65
- decentralized	304	295	280	260	245
cooking	18	16	14	12	10
Electricity, million tce	83.4	101	125	143	165
Electricity, billion kWh	679	820	1000	1160	1340
Electricity share, %	19	22	26	29	34
Maximum (low prices)					
Energy consumption,					
million tce	435.7	470	500	530	550
Including fossil fuel	342.6	350	348	347	345
Including					
space heating and					
hot water supply					
- centralized[a]	16.2	34	44	55	65
- decentralized	304	300	290	280	270
cooking	18	16	14	12	10
Electricity, million tce	83.4	101	125	150	170
Electricity, billion kWh	679	820	1020	1220	1400
Electricity share, %	19	22	26	28	31

[a]Expert appraisal.

The forecasts of other domestic energy needs are based on the following considerations. Because of a high level of saturation with regard to all electric household appliances in the region (for example, in the FRG, the present washing machine market has been saturated by 90%, and the refrigerator market by 95%), manufacturers now concentrate their efforts on improving quality, energy efficiency, and widening the range of operations.

An up-to-date washing machine or a dishwasher consumes 15% less energy than it did ten years ago. This can be attributed to water conservation (water is regenerated inside the unit itself) and a decrease in temperature resulting from the use of highly efficient detergents (a decrease in temperature to 60 from 95°C reduces energy consumption by 40%).

The use of electronic equipment for temperature and operating controls of household appliances, space heating, and lighting also results in energy savings. Over the five-year period, 1978-1983, energy consumption in gas cookers dropped by 15.4%; in automatic gas heaters by 6.6%; and in gas water heaters by 6–18%.[14] Energy savings are achieved through improved insulation, utilization of waste-gas heat, and better control systems.

At the same time, there appears to be new concepts in household appliances, for example, air purification equipment, including vacuum cleaners with dust filters suppressing 0.5 mm particles; cooking appliances with induction heating, which increases efficiency up to 90% compared with 65% of existing appliances; and halogen heating of microwave ovens, which make it possible to greatly reduce cooking time as a result of uniform heat distribution over the entire product.

The per capita energy consumption in cooking and a hot water supply in absolute values is assumed equal for all the three scenarios; a change is envisaged only in the energy mix.

As a result, the share of electricity in the energy consumption in the residential and commercial sectors of Western Europe will increase from 19% in 1980 to 37% by 2030, for the minimum scenario, and to 31% for the maximum scenario.

Japan. The commercial and residential sectors in Japan consume a relatively low proportion of the total energy as compared to other developed capitalist countries. In 1980, this proportion amounted to 18% for Japan, while for the US and the West European countries it amounted to 30–35%.[15] By 1983, the proportion of energy consumed in these Japanese sectors jumped to 24%.[16] The main trend in Japanese energy consumption for the period of 1990–2000 will continue to consist of significant growth in the residential and commercial sectors as compared to other sectors.

Nevertheless, for those who live in one-storeyed houses the historically established peculiarities of energy consumption by domestic processes will be maintained. This can be seen from the energy consumption pattern in the residential sector, which differs essentially from that in other developed capitalist countries. In 1980, the energy consumption pattern in the residential sector was as follows: hot water supply 40%, heating 30%, cooking 6%, air conditioning 1–2% (this particular item tends to increase rapidly).

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[14] *USSR Bulletin of International Commercial Information (BIKI) 114* (5847), 26 September 1985.

[15] Tanaka, S. (1983), The status of R&D of solar heating and coolig systems in Japan. In *A Long-Range Forecast of Energy System Development, its Maneuverability and Reliability. Proceedings, Third Soviet-Japanese Energy Symposium.* Riga: "Zinatue" Publishing House.

[16] Fudzimo Wakiti (1985), Changes in energy situation and future prospects. *Energetika 22 (10).*

In Japan, traditional energy carriers in the residential and commercial sectors are kerosene, distillate, gas and electric energy (in order of distribution). Electric energy consumption will increase rapidly in years to come. According to the forecast made by the Ministry of Foreign Trade and Industry of Japan, growth of electric energy consumption in the residential sector will exceed its average growth in industry and in the country by the late 1990s.

Average annual growth rates of electricity consumption in the residential and commercial sectors will be 5.3 and 4.2% in the 1980–1990 and 1990–2000 periods, respectively, whereas for the country as a whole they will be 4.3 and 3.5%, respectively.[17]

At present, a typical individual house has two to three heating units with oil-fired furnaces using natural drought (with 2–3 kW heat output), one to two room air conditioners (with 2–2.5 kW power), and gas system of hot water supply. Air conditioners with heat pump-type "air-air" have become common. In 1980, about two million domestic units with heat pumps were in use. In 1984, annual sales of heat pump units amounted to two million. Multistory residential and commercial buildings are generally equipped with central (housing) systems of air conditioning (electric or with heat pumps). At present, new systems of energy supply for domestic purposes are being developed and introduced on the basis of heat pumps with gas drive as well as combined heat and electricity supply systems with diesel engines. According to estimates made by Japanese specialists,[18] operating costs of such combined systems are lower than for the gas-driven systems.

Forecasts on energy conservation predict decreased expenditures for heating due to improvements in heat insulation of buildings (second window-frames, wall glass-wool insulation 100–150 mm thick in northern areas and 50 mm thick in southern areas) and wide use of solar energy for heating and hot water supply. As for the other trends in energy use in the home, the main tendency consists in the production of appliances with electronic control systems and, as a consequence, in automation of housekeeping.

Japanese industry ranks first in the world in the production of electronic appliances, and the Japanese population is saturated with all kinds of up-to-date domestic appliances. These include: sound recording and reproducing equipment, television sets, image recording and reproducing equipment, microwave ovens, electronic games, and electronic watches, calculators, and musical instruments. In the last few years, there has been a tremendous growth in the production of personal computers.

Forecasts of energy use in the residential and commercial sectors in Japan has been made on the basis of predicted population (Table 2.13) and per capita energy consumption in the sectors (Table 2.14). Population growth is assumed according to UN estimates. In 1980, urban population accounted for 76%.[19] Rates of energy consumption growth up to 1990 in the sector are given in the work by

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[17] *Forecast of energy production and use in Japan. USSR Bulletin of International Commercial Information (BIKI) 17*(VI) (1982).

[18] Kawamura Konti (1985) Combined systems of energy supply in everyday life. *Energetika 22*(10).

[19] Palston, J. (1983), Japan is number one? Social problems of the next decades. *Futures*, October, pp. 342-356.

Naoto Sagawa,[20] and thereafter extrapolated using our estimates for the three scenarios. Prospective average annual growth rates of electricity consumption have been assumed on the basis of the above trends.

Table 2.13. Forecast of population in Japan.

	1980	1990	2000	2010	2020
Population (in million)	116,551	123,185	129,300	132,600	132,000
Average annual growth of population (%)	0.55	0.48	0.25	0.04	-

NOTE: Growth values refer to a subsequent decade.
SOURCE: *World Population Prospects as Assessed in 1980*, United Nations, New York, 1981.

Space heating and hot water supply are subdivided into centralized and decentralized heating on the basis of aggregated indicators presented in an IIASA report.[21]

Calculations show that perspective per capita energy consumption and the absolute value of energy consumption in Japan's residential and commercial sectors increase by a factor of 1.5 for all the three scenarios, the share of electricity consumption increasing to 45% from 24% in 1980 for the maximum scenario and up to 55% for the minimum scenario. The great share of electricity obtained for the minimum scenario can be attributed to higher average annual electricity consumption growth rates assumed in this scenario due to a smaller difference between the cost of electricity and that of its substitute.

2.5. Electricity demand prospects

Electricity demand prospects for the US, Western Europe, and Japan have been calculated from the fairly detailed historical data on the demand for electricity and anticipated growth rates of the electricity share in the national economy and households. Based on the base year data and long-term projections, an expert appraisal has been made of electricity losses in the grid.

As for electricity generation, the following two types were considered: electricity derived from nuclear, hydro, and other renewable sources of energy; and electricity generated at fossil-fired thermal power plants. The distribution of the latter over the zones of the load curve was assumed equal for all regions. From these data estimates were made of specific fuel consumption for different types of electric plants. Specific fuel consumption rates were averaged for all types of electric plants and regions, which is, of course, a very simplifying assumption. But since the purpose of the present paper is to make rough estimates of the potential demand for fossil fuels in electricity generation, the approximate nature of the above calculations is fairly justified. The results of these calculations are given in Tables 2.15–2.17.

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[20] Sagawa, N. (1983), The role of energy conservation in Japanese energy demand structure and the future prospects, *Proceedings of the Fourth Japan-USSR Energy Symposium*, General Research Organization, Tokyo.

[21] Khan, A.M. and A. Hölzl (1982), *Evolution of Future Energy Demands Till 2030 in Different World Regions: An Assessment Made for the Two IIASA Scenarios*, Research Report RR-82-14 (International Institute for Applied Systems Analysis, Laxenburg, Austria).

Table 2.14. Forecast of energy consumption for residential and commercial sectors, Japan.

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Energy consumption,					
million tce	86.14[a]	105	127	137	136
Including fossil fuel	65.38	70	74.5	72	61.3
Including					
space heating and					
hot water supply					
- centralized	1.2	4.8	8	12	16
- decentralized	55.3	61.0	62.0	55	42
cooking	5.3	5.0	4.5	4	3.3
Electricity, million tce	20.76	34.8	52	65	75
Electricity, billion kWh	168.95[a]	283.5	420	540	610
Electricity share, %	24	33	40.6	47.5	55
Per capita consumption,					
tce/cap/yr	0.739	0.857	0.985	1.03	1.03
Medium (moderate prices)					
Energy consumption,					
million tce	86.14[a]	107.7	131.0	143.0	140.0
Including fossil fuel	65.38	72	77.6	81	69
Including					
space heating and					
hot water supply					
- centralized	1.2	5	9	12	14
- decentralized	55.3	61.7	64	65	52
cooking	5.3	5.3	4.6	4	3
Electricity, million tce	20.76	34.8	52.8	61	70
Electricity, billion kWh	168.95[a]	283.5	430	500	570
Electricity share, %	24	32.3	39.3	42.7	50
Per capita consumption,					
tce/cap/yr	0.739	0.874	1.013	1.078	1.06
Maximum (low prices)					
Energy consumption,					
million tce	86.14[a]	110	135	148	150
Including fossil fuel	65.38	75	85	87.2	82
Including					
space heating and					
hot water supply					
- centralized	1.2	5.1	11	14.5	17.5
- decentralized	55.3	64.6	70	68	61
cooking	5.3	5.3	4.5	4.5	3.5
Electricity, million tce	20.76	33.3	49.1	60.2	67.6
Electricity, billion kWh	168.95	270	400	490	550
Electricity share, %	24	30.2	36.3	40.6	45
Per capita consumption,					
tce/cap/yr	0.739	0.893	1.044	1.116	1.136

[a]*Energy Balances of OECD Countries, op. cit.*.

Table 2.15. Electricity generation and consumption in the US (billion kWh).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industry	880	1180	1630	2030	2030
Transport	3.2	25	120	210	365
Residential and commercial sector	1280	1170	1240	1290	1325
Electricity consumption, total[a]	2355	2750	3425	3940	4060
Nuclear and hydro	527	665	1000	1200	1650
Fossil fuel power plants	1828	2085	2425	2740	2410
Base load (%)	50	45	40	30	20
Intermediate load (%)	30	35	40	45	60
Peak load (%)	20	20	20	20	20
Fossil fuel consumption (billion tce)					
Base load	330	330	320	260	145
Intermediate load	200	255	320	430	430
Peak load	135	145	160	175	145
Medium (moderate prices)					
Industry	880	1220	1790	2440	2520
Transport	3.2	25	100	205	315
Residential and commercial sector	1280	1250	1380	1510	1640
Electricity consumption, total[a]	2355	2845	3660	4590	4830
Nuclear and hydro	527	665	1000	1200	1650
Fossil fuel power plants	1828	2180	2660	3390	3180
Base load (%)	50				
Intermediate load (%)	30				
Peak load (%)	20				
Fossil fuel consumption (billion tce)					
Base load	330	345	350	320	190
Intermediate load	200	270	350	535	570
Peak load	135	150	180	215	190
Maximum (low prices)					
Industry	880	1260	1870	2600	2680
Transport	3.2	15	70	155	245
Residential and commercial sector	1280	1270	1415	1540	1680
Electricity consumption, total[a]	2355	2900	3760	4720	4970
Nuclear and hydro	527	665	1000	1200	1650
Fossil fuel power plants	1828	2235	2760	3520	3320
Base load (%)	50				
Intermediate load (%)	30				
Peak load (%)	20				
Fossil fuel consumption (billion tce)					
Base load	330	350	365	330	200
Intermediate load	200	275	370	500	600
Peak load	135	155	180	220	200

[a]Including other consumers' losses.

NOTE: The following values of specific fuel consumption were assumed in the calculations: 360 g/kWh for 1980; 350 g/kWh for 1990; 330 g/kWh for 2000; 315 g/kWh for 2010; and 300 g/kWh for 2020.

Table 2.16. Electricity generation and consumption in Western Europe (billion kWh).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industry	893	1015	1300	1625	1790
Transport	40	60	120	185	240
Residential and commercial sector	679	815	1000	1150	1380
Electricity consumption, total[a]	1853	2150	2720	3260	3680
Nuclear and hydro	544	775	970	1250	1710
Fossil fuel power plants	1309	1375	1750	2010	1970
Base load (%)	50	48	40	30	20
Intermediate load (%)	30	32	40	50	60
Peak load (%)	20	20	20	20	20
Fossil fuel consumption (billion tce)					
Base load	235	235	230	190	120
Intermediate load	140	155	230	320	355
Peak load	95	100	115	125	120
Medium (moderate prices)					
Industry	893	1055	1380	1790	2400
Transport	40	50	95	150	190
Residential and commercial sector	679	810	1015	1150	1340
Electricity consumption, total[a]	1853	2180	2790	3400	4250
Nuclear and hydro	544	775	970	1250	1710
Fossil fuel power plants	130	1405	1820	2150	2540
Base load (%)	50				
Intermediate load (%)	30				
Peak load (%)	20				
Fossil fuel consumption (billion tce)					
Base load	235	235	255	205	150
Intermediate load	140	160	255	340	460
Peak load	95	100	120	135	150
Maximum (low prices)					
Industry	893	1055	1545	1990	2680
Transport	40	50	85	120	155
Residential and commercial sector	679	860	1100	1220	1400
Electricity consumption, total[a]	1853	2260	3060	3660	4570
Nuclear and hydro	544	775	970	1250	1710
Fossil fuel power plants	1309	1485	2090	2410	2860
Base load (%)	50				
Intermediate load (%)	30				
Peak load (%)	20				
Fossil fuel consumption (billion tce)					
Base load	235	250	275	230	170
Intermediate load	140	165	275	380	515
Peak load	95	105	140	150	170

[a]Including other consumers' losses.

NOTE: The following values of specific fuel consumption were assumed in the calculations: 360 g/kWh for 1980; 350 g/kWh for 1990; 330 g/kWh for 2000; 315 g/kWh for 2010; and 300 g/kWh for 2020.

Table 2.17. Electricity generation and consumption in Japan (billion kWh).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industry	236.0	380	530	690	690
Transport	15.4	40	70	115	125
Residential and commercial sector	168.9	285	420	540	610
Electricity consumption, total[a]	577.0	800	1140	1475	1540
Nuclear and hydro	83.4	150	320	480	620
Fossil fuel power plants	493.6	650	820	995	920
Base load (%)	50.0	45	40	30	20
Intermediate load (%)	30.0	35	40	45	60
Peak load (%)	20.0	20	20	20	20
Fossil fuel consumption (billion tce)					
Base load	90.0	105	110	95	55
Intermediate load	55.0	80	110	140	165
Peak load	35.5	45	55	60	55
Medium (moderate prices)					
Industry	236.0	380	530	690	770
Transport	15.4	30	55	70	95
Residential and commercial sector	168.9	280	420	520	560
Electricity consumption, total[a]	577.0	790	1120	1410	1540
Nuclear and hydro	83.4	150	320	480	620
Fossil fuel power plants	493.6	640	800	930	920
Base load (%)	50.0				
Intermediate load (%)	30.0				
Peak load (%)	20.0				
Fossil fuel consumption (billion tce)					
Base load	90.0	100	105	90	55
Intermediate load	55.0	80	105	130	165
Peak load	35.5	45	55	60	55
Maximum (low prices)					
Industry	236.0	380	570	815	895
Transport	15.4	30	55	65	85
Residential and commercial sector	168.9	270	400	500	550
Electricity consumption, total[a]	577.0	775	1150	1520	1650
Nuclear and hydro	83.4	150	320	480	620
Fossil fuel power plants	493.6	625	830	1040	1030
Base load (%)	50.0				
Intermediate load (%)	30.0				
Peak load (%)	20.0				
Fossil fuel consumption (billion tce)					
Base load	90.0	100	110	100	60
Intermediate load	55.0	75	110	145	185
Peak load	35.5	45	55	65	60

[a]Including other consumers' losses.

NOTE: The following values of specific fuel consumption were assumed in the calculations: 360 g/kWh for 1980; 350 g/kWh for 1990; 330 g/kWh for 2000; 315 g/kWh for 2010; and 300 g/kWh for 2020.

As shown by calculations, by 2000 electricity consumption in Western Europe will rise by 40–60% compared with 1980, and by 50–70% by 2020 compared with 2000. The share of nuclear- and hydro-based electricity will jump to 32–37% in 2000 from 29.3% in 1980 and to 35–45% in 2020. As a result, fossil fuel consumption at thermal power plants will amount to 550-685 million tce in 2000, i.e., up to 20–45% from 1980, and by 2020 will reach 670–950 million tce. Electricity/GDP ratio will drop to 0.8-0.9 kWh/dollar from 1.14 kWh/dollar and then slightly increase. This trend can be attributed to the structural evolution of the main sectors of the West European economy.

In the case of the US, electricity consumption will go up 40–50% by 2000, and then 20–60% by the year 2020. The share of nuclear- and hydro-based electricity will increase from 1980's 22.4% to 33–40%, fossil fuel consumption at thermal power plants will rise to 800–915 million tce by 2000 from 1980's 665 million tce and then decline at a slow rate (minimum scenario) or will continue to grow slowly (maximum scenario). The electricity/GDP ratio is expected to decline throughout the entire time frame to 0.95–1.2 kWh/dollar in 2020 from 1980's 1.3 kWh/dollar, but will still remain higher compared with Western Europe and Japan.

As for Japan, here electricity consumption growth rates will outstrip economic growth rates by 80–100% by 2000 and by 30–40% in 2020. The share of nuclear- and hydro-based electricity will rise to 28% by 2000 from 1980's 14.5%, and then by 2020 will be up to 37–40%. Fossil fuel consumption will increase to 265–275 million tce in 2000 from 180 million tce and further to 270–300 million tce by 2020. The electricity/GDP ratio will sowly decline to 0.75–0.80 kWh/dollar by 2020 from 0.9 kWh/dollar in 1980.

As follows from these projections, the electricity generation sector will remain the largest fossil fuel consumer in the energy balance of developed countries.

2.6. Energy demand scenarios for the US, Western Europe, and Japan

Tables 2.18–2.20 summarize the data on the primary energy demand prospects in the regions under consideration for three scenarios: minimum, medium, and maximum. The base year, 1980, indicators are taken from Energy Balances of OECD Countries, 1971–1981 *op. cit.*[22]

An expert appraisal is made of fuel reprocessing and transportation losses; it is assumed that their share in absolute energy consumption will sowly decline.

Depending on energy prices the *United States* may see no growth in energy consumption by the year 2000 (minimum scenario) or a slight increase of 15–25% (medium and maximum scenarios). After the year 2000 the difference will be more pronounced: if prices remain high, then energy consumption may begin to decline and by 2020 will be lower compared with 1980; in the case of moderate and low prices, energy consumption will continue to grow (as a result, by 2020 the volume of consumption will increase by 10–25% compared with 2000). Fossil fuel consumption at low prices will decline, whereas at moderate and low prices a reduction will occur only beyond 2000.

[22]This is an important aspect, since the base year indicators vary to some extent depending on statistical source. In this paper, all forecasts for subsequent years have the same base year indicators.

Table 2.18. Energy consumption scenarios for the US (million tce).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industry	458.0	450	445	430	410
Agriculture	19.7	22	25	20	20
Transport	608.2	635	575	505	420
Residential and commercial sector	510.9	475	450	430	410
Final consumption, total	1596.8	1582	1495	1385	1260
Nonfuel needs	109.1	140	160	160	150
Energy losses at electric power plants	560.0	625	710	755	720
Conversion and transportation losses	183.2	200	200	190	180
Primary energy resources consumption, total	2449.0	2547	2565	2490	2310
Nuclear, hydropower, and other renewables	200.0	245	310	440	545
Fossil fuel consumption, total	2249.1	2302	2255	2055	1765
Medium (moderate prices)					
Industry	458.0	465	500	535	540
Agriculture	19.7	25	30	35	35
Transport	608.2	655	690	760	800
Residential and commercial sector	510.9	500	495	495	500
Final consumption, total	1596.8	1645	1715	1825	1875
Nonfuel needs	109.1	150	180	190	200
Energy losses at electric power plants	560.0	645	760	880	855
Conversion and transportation losses	183.2	205	210	215	215
Primary energy resources consumption, total	2449.1	2645	2865	3110	3145
Nuclear, hydropower, and other renewables	200.0	245	310	410	545
Fossil fuel consumption, total	2249.1	2400	2555	2700	2600
Maximum (low prices)					
Industry	458.0	475	515	580	580
Agriculture	19.7	25	30	35	40
Transport	608.2	695	850	980	1080
Residential and commercial sector	510.9	520	530	535	550
Final consumption, total	1596.8	1715	1925	2130	2250
Nonfuel needs	109.1	150	180	190	210
Energy losses at electric power plants	560.0	660	780	905	880
Conversion and transportation losses	183.2	205	215	220	225
Primary energy resources consumption, total	2449.1	2730	3100	3445	3565
Nuclear, hydropower, and other renewables	200.0	245	310	410	545
Fossil fuel consumption, total	2249.1	2485	2790	3035	3020

Table 2.19. Energy consumption scenarios for Western Europe (million tce).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industry	458.0	450	440	415	360
Transport	317.8	330	350	350	320
Residential and commercial sector[a]	435.7	460	470	470	470
Final consumption, total	1211.5	1240	1260	1235	1150
Nonfuel needs	170.0	190	210	220	240
Energy losses at electric power plants	439.7	490	560	625	650
Conversion and transportation losses	91.7	95	95	90	85
Primary energy resources consumption, total	1912.9	2015	2125	2170	2195
Nuclear, hydropower, and other renewables	206.9	290	350	430	565
Fossil fuel consumption, total	1706.0	1725	1775	1740	1630
Medium (moderate prices)					
Industry	458.0	480	520	530	545
Transport	317.8	325	370	380	380
Residential and commercial sector[a]	435.7	465	490	500	500
Final consumption, total	1211.5	1280	1380	1410	1425
Nonfuel needs	170.0	190	210	220	240
Energy losses at electric power plants	439.7	495	580	650	750
Conversion and transportation losses	91.7	95	100	100	100
Primary energy resources consumption, total	1912.9	2060	2270	2380	2515
Nuclear, hydropower, and other renewables	206.9	290	350	430	565
Fossil fuel consumption, total	1706.0	1770	1920	1900	1950
Maximum (low prices)					
Industry	458.0	485	540	615	670
Transport	317.8	375	450	475	485
Residential and commercial sector[a]	435.7	470	500	530	550
Final consumption, total	1211.5	1330	1490	1620	1705
Nonfuel needs	170.0	190	210	225	245
Energy losses at electric power plants	439.7	515	630	700	810
Conversion and transportation losses	91.7	95	100	105	110
Primary energy resources consumption, total	1912.9	2120	2430	2650	2870
Nuclear, hydropower, and other renewables	206.9	290	350	430	565
Fossil fuel consumption, total	1706.0	1830	2080	2220	2305

[a]Including agriculture.

Table 2.20. Energy consumption scenarios for Japan (million tce).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Industry	143.3	155	160	160	140
Transport	74.6	80	75	75	70
Residential and commercial sector	86.1	106	125	140	135
Final consumption, total	304.0	341	360	375	350
Nonfuel needs	64.4	70	75	80	80
Energy losses at electric power plants	136.7	180	235	285	270
Conversion and transportation losses	50.7	55	55	55	45
Primary energy resources consumption, total	555.8	646	725	795	745
Nuclear, hydropower, and other renewables	31.7	52	105	150	185
Fossil fuel consumption, total	524.1	594	620	645	560
Medium (moderate prices)					
Industry	143.3	163	185	210	225
Transport	74.6	85	90	95	105
Residential and commercial sector	86.1	108	130	145	140
Final consumption, total	304.0	356	405	450	470
Nonfuel needs	64.4	74	78	82	85
Energy losses at electric power plants	136.7	180	230	270	270
Conversion and transportation losses	50.7	55	58	60	50
Primary energy resources consumption, total	555.8	665	771	862	865
Nuclear, hydropower, and other renewables	31.7	52	105	150	185
Fossil fuel consumption, total	524.1	613	666	712	680
Maximum (low prices)					
Industry	143.3	167	200	230	260
Transport	74.6	105	130	145	150
Residential and commercial sector	86.1	110	135	150	150
Final consumption, total	304.0	382	465	525	560
Nonfuel needs	64.4	75	80	85	90
Energy losses at electric power plants	136.7	175	240	290	290
Conversion and transportation losses	50.7	58	60	65	60
Primary energy resources consumption, total	555.8	690	845	965	1000
Nuclear, hydropower, and other renewables	31.7	52	105	150	185
Fossil fuel consumption, total	524.1	638	740	815	815

The share of nuclear energy and renewable will rise to 10–12% and 15–24% by 2000 and 2020, respectively, from 8.2% in 1980.

There will be some changes, although not radical, in the pattern of final energy demand (%):

	1980	2000	2020
Industry	28.7	29.0	30-32
Agriculture	1.2	1.7	1.5-1.8
Transport	38.0	37-40	32-41
Residential and commercial sector	32.1	29.3-32.3	27.2-34.5

Electricity's share will rise from 34.6% in 1980 up to 40–44% in 2000 and up to 42–53% in 2020.

The energy/GDP elasticity until 2000 will be on the level of 0.3 (minimum), and 0.8 (maximum), and after the yer 2000 at 0.5 (minimum) and 0.6 (maximum). The corresponding electricity elasticity over the course of the period will remain less than 1.0 and by 2020 will be 0.4–0.85. The reason for this projection lies in the great potential of the US power industry to restructure and conserve energy, which is expended with less efficiency than in Western Europe and Japan.

Western Europe will be characterized by almost the same trends: by 2000 total energy consumption will be up 11–27% compared with 1980, then further growth should be expected. The share of nuclear energy and renewables will be higher than in the US and will amount to 14–16% by 2000 from 1980's 10.8%. The share of electricity in the region's energy balance will rise to 48–50% by 2020 from 34.5% in 1980. Changes in the pattern of final energy consumption will follow the same line as in the United States.

The forecasts developed for *Japan* show that energy consumption will continue to grow by 2010, after that a decline may follow, providing energy prices remain high. In any case by 2000 the level of energy consumption will be 30–50% higher than in the base year, 1980. The share of nuclear energy and renewables is expected to increase to 12–14% by 2000, and 19–25% by 2020, from 5.7% in 1980. The electricity share will rise from 38% to 50–60% by the end of the period under consideration. The energy/GDP elasticity will be within the 0.3–0.5 range by 2000 and 0.12–0.18 by the first quarter of the next century.

Thus, the projections made in this study for total energy consumption suggest far more moderate growth rates of energy consumption compared with the forecasts of the early 1980s (see, for instance, a collection of recent forecasts prepared by IIASA).[23] Our projections, however, exceed some extreme forecasts – for instance, the forecasts for the US developed at Princeton University,[24] which envisage a manyfold decrease in absolute energy consumption. True, it is appropriate to mention here that all estimates assuming a great decrease in energy consumption in developed countries beyond the year 2000, in fact, emphasize possibilities for energy conservation rather than give forecasts, which is not the same.

[23]Manne, A.S. and L. Schrattenholzer (1986), International energy workshop: a progress report, *OPEC Review* X(3):287-320.

[24]Williams, R.H. (1985), *A Low Energy Future for the United States*. PU/CEES Report No. 186. Princeton University, Princeton, NJ.

2.7. Potential natural gas market

A potential natural gas market has been assessed on the basis of the above forecasts of energy consumption. The maximum volumes of gas consumption at the stage of final energy demand in the industrial and residential/commercial sectors have been defined as a difference between final energy and electricity consumption (by physical equivalent). It is assumed that natural gas can successfully compete with other fuels. For transportation, an expert appraisal has been made of the maximum possibilities for introducing natural gas-derived substitutes (methanol, methanol-based motor fuels, etc.) or natural gas directly (for instance, in compressed form). Demand for natural gas as a feedstock has been evaluated with respect to the following three mass-produced products: ammonia, ethylene, and methanol.[25] A potential natural gas market for electric plants is assumed equal to the demand for natural gas for this category of consumers.

Tables 2.21–2.23 project potential demand for natural gas for the US, Western Europe, and Japan.

Based on these projections, natural gas consumption growth rates are calculated in Chapter 10 and arranged in decreasing order with respect to the price each category of consumers is willing to pay. For all consumers 25-year service life is assumed, which approximately corresponds to a 4%/yr coefficient of replacement of obsolescent equipment.

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[25]To avoid double counting, methanol production is divided into (a) chemical methanol considered in the calculation of demand for gas as a feedstock and (b) fuel methanol taken into account in the transportation sector.

Table 2.21. Potential natural gas market, US (billion m sup 3).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Ethylene	-	-	5	10	25
Methanol	3.6	7	10	11	17
Ammonia	14.6	14	15	14	13
Industrial furnaces	88.2	93	85	75	67
Industrial boiler plants	205.9	165	122	75	67
Space heating and hot water					
- centralized	48.6	43	37	31	27
- decentralized	124.1	116	103	88	75
Cooking	5.5	3	2	1	0
Thermal power plants					
- Base load	277.0	277	270	220	120
- Intermediate load	170.0	215	270	360	360
- Peak load	115.0	120	135	150	120
Methanol addition to gasoline	0.4	5	10	22	28
Compressed gas in transportation	-	9	16	16	16
Medium (moderate prices)					
Ethylene	-	-	5	10	25
Methanol	3.6	7	10	11	17
Ammonia	14.6	14	15	14	13
Industrial furnaces	88.2	92	100	100	100
Industrial boiler plants	205.9	170	134	100	92
Space heating and hot water					
- centralized	48.6	45	42	37	36
- decentralized	124.1	117	106	97	89
Cooking	5.5	5	4.5	4	3.3
Thermal power plants					
- Base load	277.0	290	295	270	160
- Intermediate load	170.0	225	295	450	480
- Peak load	115.0	125	150	180	160
Methanol addition to gasoline	0.4	5	10	22	28
Compressed gas in transportation	-	8	9	15	18
Maximum (low prices)					
Ethylene	-	-	5	10	25
Methanol	3.6	7	10	11	17
Ammonia	14.6	14	15	14	13
Industrial furnaces	88.2	95	100	100	100
Industrial boiler plants	205.9	172	140	120	110
Space heating and hot water					
- centralized	48.6	50	50	49	48
- decentralized	124.1	130	130	125	115
Cooking	5.5	5.5	4.8	4.5	3.5
Thermal power plants					
- Base load	277.0	295	305	275	170
- Intermediate load	170.0	231	310	420	505
- Peak load	115.0	130	150	185	170
Methanol addition to gasoline	0.4	5	10	22	28
Compressed gas in transportation	-	8	11	14	22

Table 2.22. Potential natural gas market, Western Europe (million m sup 3).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Ethylene	-	-	4	10	19
Methanol	3.5	6	7	10	14
Ammonia	9.5	11	12	13	13
Industrial furnaces	85	85	75	67	60
Industrial boiler plants	208	190	160	115	60
Space heating and hot water					
- centralized	14	22	34	40	45
- decentralized	255	245	220	195	170
Cooking	15	14	12	10	8
Thermal power plants					
- Base load	197	200	195	160	100
- Intermediate load	118	130	195	270	300
- Peak load	80	80	95	105	100
Methanol addition to gasoline	0.5	6	9	14	14
Compressed gas in transportation	-	4	7	5	4
Medium (moderate prices)					
Ethylene	-	-	4	10	19
Methanol	3.5	6	7	10	14
Ammonia	9.5	11	12	13	13
Industrial furnaces	85	85	85	85	85
Industrial boiler plants	208	210	210	180	125
Space heating and hot water					
- centralized	14	22	34	44	55
- decentralized	255	250	235	220	205
Cooking	15	14	12	10	8
Thermal power plants					
- Base load	197	200	205	175	125
- Intermediate load	118	135	215	285	385
- Peak load	80	85	100	115	125
Methanol addition to gasoline	0.5	6	9	14	14
Compressed gas in transportation	-	2	8	9	6
Maximum (low prices)					
Ethylene	-	-	4	10	19
Methanol	3.5	6	7	10	14
Ammonia	9.5	11	12	13	13
Industrial furnaces	85	88	92	92	92
Industrial boiler plants	208	210	215	218	195
Space heating and hot water					
- centralized	14	28	37	46	55
- decentralized	255	255	245	235	230
Cooking	15	13	12	10	8
Thermal power plants					
- Base load	197	210	230	195	140
- Intermediate load	118	140	230	320	430
- Peak load	80	90	115	120	190
Methanol addition to gasoline	0.5	6	9	14	14
Compressed gas in transportation	-	2	6	9	9

Table 2.23. Potential natural gas market, Japan (billion m sup 3).

Scenario	1980	1990	2000	2010	2020
Minimum (high prices)					
Ethylene	-	-	2	6	11
Methanol	0.8	2	4	7	8
Ammonia	-	4	7	8	8
Industrial furnaces	28.7	29	25	20	15
Industrial boiler plants	67.1	65	55	45	32
Space heating and hot water					
- centralized	1.0	4.0	7	10	13
- decentralized	46.5	51	52	46	35
Cooking	4.5	4.2	3.8	3.4	2.8
Thermal power plants					
- Base load	75	90	92	80	45
- Intermediate load	46	65	90	120	140
- Peak load	30	38	45	50	50
Methanol addition to gasoline	0.1	1	5	10	16
Medium (moderate prices)					
Ethylene	-	-	2	6	11
Methanol	0.8	2	4	7	8
Ammonia	-	4	7	8	8
Industrial furnaces	28.7	30	31	32	35
Industrial boiler plants	67.1	68	71	73	82
Space heating and hot water					
- centralized	1.0	4.2	8	10	12
- decentralized	46.5	52	54	55	44
Cooking	4.5	4.5	3.9	3.4	2.5
Thermal power plants					
- Base load	75	85	88	75	45
- Intermediate load	46	65	90	110	140
- Peak load	30	38	50	50	45
Methanol addition to gasoline	0.1	1	4	8	15
Maximum (low prices)					
Ethylene	-	-	2	6	11
Methanol	0.8	2	4	7	8
Ammonia	-	4	7	8	8
Industrial furnaces	28.7	30	33	35	42
Industrial boiler plants	67.1	70	75	82	84
Space heating and hot water					
- centralized	1.0	4.2	9.2	12	15
- decentralized	46.5	54	59	57	51
Cooking	4.5	4.5	3.8	3.8	2.9
Thermal power plants					
- Base load	75	85	92	85	50
- Intermediate load	46	65	92	120	155
- Peak load	30	37	45	55	50
Methanol addition to gasoline	0.1	1	4	8	14

Chapter 3

Modeling the International Natural Gas Market

As a general case, the situation in the international natural gas market can be described as follows. In a region there is a finite number of fuel consumers who are ready to change to natural gas, provided the price of gas at the burner tip is set at a level ensuring an additional profit compared with other energy sources. The willingness-to-pay values for natural gas, arranged in decreasing order, depend on the gas price per volume of the gas delivered to the region. Gas suppliers are represented by domestic gas producers and also outside exporters, each characterized by certain expenditures involved in gas production and transportation (as LNG or by pipeline). Marginal costs of gas suppliers, in their turn, also depend on the volume of gas supplies. In the simplest case, the intersection of these two curves (those of the willingness-to-pay and of marginal costs) corresponds to an equilibrium state in the market, when the overall effect for both gas producers and gas consumers is maximized. With the availability of several gas markets, the situation is described in a similar way. Government regulations of this market mechanism are taken into account through certain limitations (for example, on individual exporters' share of deliveries, etc.) or taxes and subsidies, which are taken into account in the calculation of the willingness-to-pay values.

For the purpose of simplification, it is assumed that the effect of the willingness-to-pay variable on natural gas consumption is linear, and the marginal costs are described stepwise. These assumptions allow us to reduce the problem to a linear one with a quadratic objective function. Figure 3.1 gives a schematic presentation of this simple view of the natural gas market.

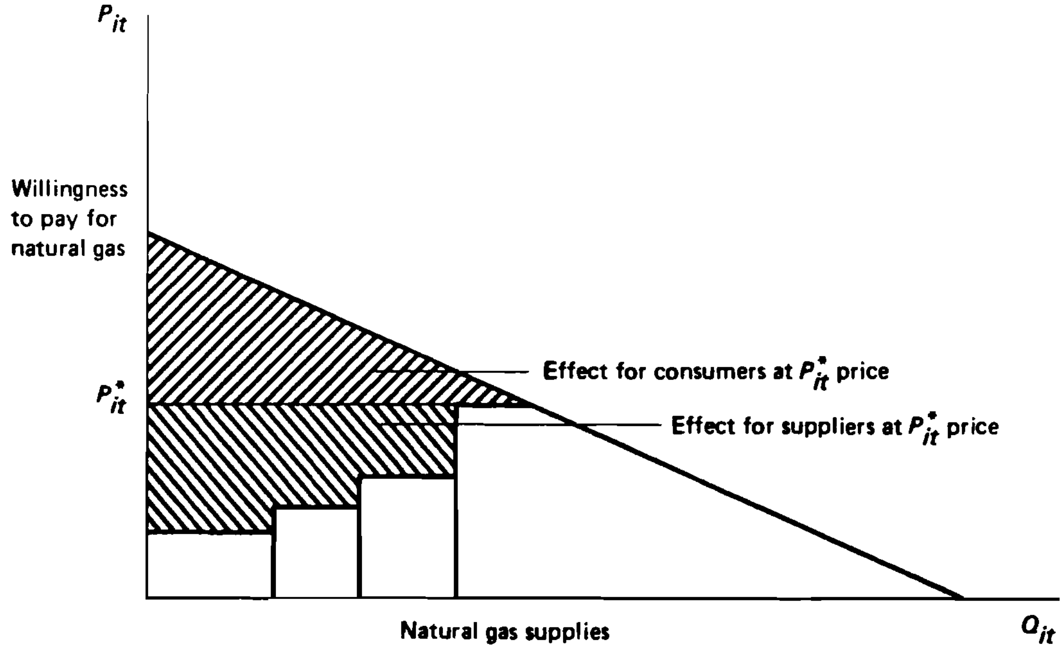

Figure 3.1. A picture of the natural gas market i: at P^*_{it} when gas demand equals Q^*_{it} and is met from several suppliers (domestic production + exporters).

Taking into account the dynamics of the market involves certain complexities. The dynamics are conditioned, on the one hand, by the service life of equipment and by contract terms, on the other. The volumes of gas consumption at every moment of time are determined with regard for possible changes in the natural gas price and deliveries in the succeeding years.

To reduce the dimensions of the problem, consideration is given to ten-year intervals within which a point corresponding to the middle of the interval is defined.

The model is described as follows.

Objective: To elaborate a strategy ensuring maximum effect both for gas suppliers and gas consumers over the projection period t.

Indexes:

i	= Natural gas markets (Western Europe, the US, and Japan);
k	= Exporters – the USSR, Algeria, Norway, the Persian Gulf countries (Iran and Qatar), Canada, Mexico, Southeast Asia, Australia;
t	= Time frame (ten-year intervals beginning from 1990, on the whole four periods up to 2020).

Subscripts:

Q_{it}	= Potential growth of natural gas demand;
$\underline{Q}^*_{it}$	= Economically viable supply to meet potential demand;
$\overline{P}_{it}$	= Maximum values of willingness to pay in the market i;
P^*_{it}	= Optimal price for gas in the market i; (dependence of willingness to pay on natural gas consumption volumes);
M'_{kit}	= Total volumes of natural gas supplies of the exporter k to the market i;
M_{kit}	= Volume of gas supplies of the exporter k to the market;
Π'_{it}	= Growth of indigenous gas production in the region i over the period t;
$\overline{\Pi}_{it}$	= Maximum volume of gas production in the region i;
G_{kt}	= Maximum volume of gas production in the exporter k;
α_{kit}	= Coefficient of gas transportation losses;
β_{kit}	= Maximum share of the exporter k in gas supplies to the market i;
C_{it}, C_{kt}	= FOB costs of gas production in the region i or at the exporter k;
t_{kit}	= Cost of natural gas transportation from the exporter k to the market i.

Model Constraints:

(1) The total demand for natural gas in the market i is met from indigenous production with regard for the changes caused by the depletion of gas field and from gas imports:

$$\sum_k M'_{kit} + \sum_t^{t-2} \alpha_t \Pi'_{it} = \sum_t^{t-2} Q^*_{it} \quad .$$

(2) The growth of natural gas demand in the market i must not exceed its maximum possible growth over the period t:

$$Q^*_{it} \leq Q_{it} \quad .$$

(3) The volume of indigenous natural gas production within the region i, given as total gas production from capacities introduced during the last 30 years[1] with expectation of a decline in production resulting from deteriorating geological and mining conditions, must not exceed the maximum production level determined on the basis of gas field reserves:

$$\sum_t^{t-3} \alpha_t \Pi'_{it} \leq \overline{\Pi}_{it} \quad .$$

(4) The total volume of natural gas supplies of the exporter k to the market i is equal to the sum of contracts signed during several previous periods:

$$M'_{ki,t} + M'_{ki,t-1} + M'_{ki,t-2} = M_{kit} \quad .$$

(5) The total volume of gas supplies of the exporter k to the market i over the period t must not exceed a given share of this exporter in the gas market:

$$M_{kit} \leq \beta_{kit}(\sum_k M_{kit}) \quad .$$

(6) The total gas export from the region k, including transportation losses, must not exceed the region's export potential:

$$\sum_i \alpha_{kit} \cdot (M'_{kit} + M'_{kit-1} + M'_{kit-2}) \leq G_{kt} \quad .$$

(7) Every i market during the period t is characterized by the following dependence of the willingness to pay for natural gas on the volume of supplies:

$$P^*_{it} = a_{it} + b_{it} \cdot Q^*_{it} \quad .$$

where

a_{it}, b_{it} = Coefficients previously defined from the analysis of the region i energy balance.

(8) Non-negative values of the model's variables:

$$M'_{kit}, M_{kit}, \Pi'_{it}, Q^*_{it}, P^*_{it} \geq 0 \quad .$$

Objective Function: To maximize the overall effect derived from natural gas trade for both exporters and indigenous gas producers over the 1990–2020 period:

[1] It is supposed that the time of gas field exploitation depends on local conditions.

$$\max \sum_t \Big(\sum_i \Big[10 \cdot \frac{(\bar{P}_{it} - P^*_{it})}{2} \cdot Q^*_{it} + 10 \cdot (P^*_{it-1} - P^*_{it})$$

$$\cdot Q^*_{it-1} + 10 \cdot (P^*_{it-2} - P^*_{it}) \cdot Q^*_{it-2}\Big] + \sum_i \Big[10 \cdot (P^*_{it} - C_{it})$$

$$\cdot \Pi'_{it} + 10 \cdot (P^*_{it} - C_{it-1}) \cdot \Pi'_{it-2}\Big] + \sum_k \Big[10$$

$$\cdot (P^*_{it} - (C_{kit} + t_{kit}) \cdot \alpha_{kit}) \cdot M_{kit}\Big] \quad .$$

Method of Solution: Mathematical programming with a quadratic objective function.

Chapter 4

Economic Evaluation of World Natural Gas Resources

Earlier (Section 1.2), we assessed the resource base of the gas industry both for the main consuming regions – the US and Western Europe– and for the actual and prospective exporting countries with market economies. Gas resources in the USSR were not considered in the study, as they were analyzed in detail in earlier IIASA papers.[1] When appraising the resource base of these countries we used many sources but preferred the official data and data of national geologic surveys. When the range of estimates was large (for example, in the case of Mexico), extreme values were excluded.

As the objective of the study was to identify the main features of a future world gas market, we focused our attention on actual and prospective gas exporters. We made use of the estimates of the resource base and its cost pattern for various countries made by Modelevsky (1985).[2] The cost estimates of gas resources were based on the studies of the Stanford Research Institute (1977)[3] and of the Technical Energy Group of the ACC Task Force on Long-Term Development Objectives of the UN (1983).[4]

Gas discovery and production costs are assessed with reference to the high risks associated with capital investments in oil and gas development. A considerable part of investments in natural gas discovery goes to the drilling of dry wildcats. A field's production capacity may appear smaller than projected earlier. The capital investment risk in offshore development is also great, owing to the high probability of accidents.

In view of the above, we assumed a 15% rate of return on investments in our estimates for all regions. The costs calculated on the basis of these assumptions are technical economic costs as they exclude royalties and taxes.

The costs of natural gas production (Tables 4.1–4.8) are estimated with regard for the main objective of the study, i.e., to determine the optimal development of world gas trade in the period under consideration. Besides discovery and production costs, the estimated specific development costs include:

- costs of offshore gas transportation;
- costs of long-distance gas pipeline transportation of Arctic gas for the US, a gas importer, and Canada, a gas exporter; and
- costs of gas transportation from Norway to Western Europe.

In the model costs of interregional gas transportation are assumed equal for all resources. In fact they depend on location. We include costs of offshore gas transportation in the development costs of offshore resources. For Canada this

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[1]See for example data prepared for IIASA's "Energy Systems Project" by Soviet researchers (1979); and Sinyak, Yu. (1984), Natural Gas Industry of the Soviet Union. Contribution to IIASA's International Gas Study (International Institute for Applied Systems Analysis, Laxenburg, IIASA).

[2]Modelevsky, M.S., G.S. Gurevich, and E.M. Khartukov (1985), *World Cheap Crude Oil and Natural Gas Resources*, presented at the International Energy Workshop, June 11-13 (International Institute for Applied Systems Analysis, Laxenburg, Austria).

[3]*Fuel and Energy Price Forecasts*. Final report, vol. 2. Stanford, Calif.: Stanford Research Institute (1977).

[4]*Economics of Exploration and Development of Energy Resources*. Report of the Technical Group, UN Fifth Session, New York (1983).

Table 4.1. Proven reserves and potential natural gas resources, the US and Western Europe (trillion m^3).

Region	Total	With Production Costs (in 1980 US dollars per 1000 m^3) up to 130	130-180	above 180
US	23.0	12.0	6.0	5.0[a]
Western Europe[b]	5.7	3.9	0.8	1.0

[a]Alaskan natural gas resources; transportation costs are included in the cost of extraction.
[b]Excluding Norway.
SOURCES: Author's estimates; Browne, T.E. and M.F. Searls (1977), *Fuel and Energy Price Forecasts*. EPRI-EA-433 vol. 2. Palo Alto, Calif.: Electric Power Research Institute; Modelewski, M.S., G.S. Gurlewich, and E.M. Kchartukov (1986), Global resources of cheap oil and natural gas. *Achievements and Prospects. Series "Energy Fuel" 10* (Moscow).

Table 4.2. Natural gas resources, Mexico (trillion m^3).

Scope of Estimate	Total	With Production costs (in 1980 US dollars per 1000 m^3) up to 80	80-150	150-200	above 200
All reserves	6.9-11.6	1.9-2.8	2.6-4.6	1.5-2.4	0.9-1.8
Proven reserves as of 1.1.85	2.2	1.0	0.6	0.6	-
Potential resources	4.7-9.4	0.9-1.8	2.0-4.0	0.9-1.8	0.9-1.8

SOURCES: Natural gas survey. *Petroleum Economist* 8:271-273 (1985); and see footnotes for Table 5.2.

Table 4.3. Natural gas resources, Southeast Asia (trillion m^3).[a]

Scope of Estimate	Total	With Production Costs (in 1980 US dollars per 1000 m^3) up to 10	10-45	45-80	80-150	above 200
All resources	5.7-13.6	0.5	1.1-1.8	1.1-1.8	1.2-2.6	2.8-6.9
Proven resources, as of 1.1.85	2.7	0.5	0.8	0.8	0.6	-
Potential resources	3.0-10.9	-	0.3-1.0	0.3-1.0	0.6-2.0	2.8-6.9

[a]Indonesia, Malaysia, Brunei.
SOURCES: See footnotes for Tables 4.2 and 5.2.

Table 4.4. Natural gas resources, Persian Gulf (trillion m^3).[a]

Scope of Estimate	Total	With Production Costs (in 1980 US dollars per 1000 m^3)			
		up to 10	10-45	45-80	above 80
All resources	4.2-11.6	3.4-5.2	8.0-9.0	7.0	2.0
Proven reserves, as of 1.1.85	23.0	12.0	6.0	5.0	-
Potential resources	12.6-18.2	6.6-11.2	2.0-3.0	2.0	2.0

[a]Iran, Qatar, Saudi Arabia, Abu-Dhabi.
SOURCES: See footnotes for Tables 4.2 and 5.2.

Table 4.5. Natural gas resources, Algeria (trillion m^3).

Scope of Estimate	Total	With Production Costs (in 1980 US dollars per 1000 m^3)		
		up to 80	80-150	150-200
All resources	4.2-11.6	3.4-5.2	0.5-4.2	0.3-2.2
Proven reserves, as of 1.1.85	3.1	3.1	-	-
Potential resources	1.1-8.5	0.3-2.1	0.5-4.2	0.3-2.2

SOURCES: See footnotes for Tables 4.2 and 5.2.

Table 4.6. Natural gas resources, Canada (trillion m^3).

Scope of Estimate	Total	With Production Costs (in 1980 US dollars per 1000 m^3)				
		up to 45	45-80	80-150	150-200	above 200
All resources	6.7-20.7	0.8	1.6-4.6	1.6-5.6	1.5-5.5	1.2-4.2
Proven reserves, as of 1.1.85	2.7	0.8	0.6	0.6	0.5	0.2
Potential resources	4.0-18.0	-	1.0-4.0	1.0-5.0	1.0-5.0	1.0-4.0

SOURCES: See footnotes for Tables 4.2 and 5.2.

Table 4.7. Natural gas resources, Norway (trillion m^3).

Scope of Estimate	Total	With Production Costs (in 1980 US dollars per 1000 m^3) up to 80	80-150	150-200	200-250	above 250
All resources	4.1-6.5	0.5	0.5	1.2-1.5	0.9-2.0	0.7-1.7
Proven reserves, as of 1.1.85	2.2	0.5	0.5	1.0	0.2	-
Potential resources	1.6-4.0	-	-	0.2-0.5	0.7-1.8	0.7-1.7

SOURCES: See footnotes for Tables 4.2 and 5.2; and *Economics of exploration and development of energy resources*, Report of the Technical Energy Group, United Nations Fifth Session, New York (1983).

Table 4.8. Natural gas resources, Nigeria (trillion m^3).

Scope of estimate	Total	With Production Costs (in 1980 US dollars per 1000 m^3) up to 80	80-150	150-200
All resources	2.7-3.4	2.0-2.3	0.4-0.5	0.3-0.6
Proven reserves, as of 1.1.85	1.3	1.3	-	-
Potential resources	1.4-2.1	0.7-1.0	0.4-0.5	0.3-0.6

SOURCES: See footnotes for Tables 4.2 and 5.2.

approach was applied only to Arctic resources. The development costs of Arctic resources include transportation costs to the continent. The cost pattern of gas resources in the US is also evaluated with reference to transportation costs of Arctic gas.

The cost pattern of natural gas resources in the Persian Gulf countries (Table 4.4), compared with Modelevsky's estimates, is less favorable. This is due to the different estimates of resources in the huff zone, the development of which will involve some technical complexities and additional costs caused by large reservoir depths, high pressure, and high sulfur content.

Chapter 5

Export Potential of Major Gas-Exporting Countries

The export potential of gas-exporting countries is analyzed in two aspects: (1) the availability of gas resources for export up to 2020, and (2) the prospects for realizing this export potential, taking into account the future situation in the world gas market, the benefits to gas exporters, and the utilization policies of each consumer country.

Export potential was calculated as follows:[1]

(1) With assumed annual rates of discovery and estimates of potential resources, the curve of discovered gas reserves was calculated for each country.

(2) The gas production potential was calculated with the reference to reserve/production ratios.

(3) The difference between potential production and domestic gas consumption is the export potential of a country.

Table 5.1. Proven natural gas reserves in individual nonsocialist and developing countries, as of early 1985.

		Including			
		Nonassociated Gas		Associated Gas	
Country	Total[a] (trillion m^3	trillion m^3	%[b]	trillion m^3	%[b]
Abu Dhabi	2.7	0.8	30	1.9	70
Algeria	3.1	2.9	95	0.2	5
Brunei	0.2	na[c]	na	na	na
Canada	2.7	2.6	95	0.1	5
Indonesia	1.1	na	na	na	na
Iran	13.6	12.1	89[d]	1.5	11
Malaysia	1.4	1.1	80	0.3	20
Mexico	2.2	0.6	25	1.6	75
Netherlands	1.9	1.8	95	0.1	5
Nigeria	1.3	0.7	55	0.6	45
Norway	2.2	1.9	85	0.3	15
Qatar	4.3	3.9	90	0.4	10
Saudi Arabia	2.4	0.7	30	1.4	70
Total	39.1	29.1	77	8.7	23

[a]Natural gas survey, *Petroleum Economist* 8:271-273 (1985).
[b]Peebles, M. (1983), World natural gas supply and demand considerations, with particular reference to the development of the international gas trade. In *Proceedings of the Eleventh World Petroleum Congress* (John Wiley & Sons, Chichester).
[c]na = not available.
[d]Including gas caps which constitute 6.4 trillion m^3 or 47% of total resources. See, Gas in the Middle East. An enormous potential, *Petroleum Information* 1596:9–16 (1984).

[1]The calculations are not given here. The initial data for them are summarized in Tables 5.1–5.4.

Table 5.2. Estimates of potential natural gas resources by country (trillion m^3).

Source	Iran	Qatar	Algeria	Nigeria	Canada	Mexico	Norway	Indonesia	Malaysia
M.S. Modelevsky, 1984[a]	9.7	4.9	8.5	1.9	17.2	3.5	1.6		10.9
Geological Survey of Canada, 1984[b]					4-18				
"Pemex", 1980[c]						9.4			
M.F. Acosta, 1979[d]						11.0			
Official estimate, 1984[e]		7.0							
The Third Arab Energy Conference, 1985[f]			1.1						
National Petroleum Directorate, 1984[g]							4.0		
OPEC, 1984[h]				1.4					
Official estimate, 1982[h]				2.1					
Official estimate, 1981[c]								2.3	
V.M. Rummerfield, 1984[i]						4.7			
B. Mossavar-Rahmani, 1981[j]	6.2								

[a]Modelewski, M.S., G.S. Gurlewich, and E.M. Kchartukov (1986), Global resources of cheap oil an natural gas. *Achievements and Prospects. Series "Energy Fuel" 10* (Moscow).
[b]Canada upgrades estimates for offshore fields. *Ocean Industry*, April 1984, pp. 240-242.
[c]*International Energy Outlook*, McGraw-Hill, Washington, 1982.
[d]M.F. Acosta (1979), The role of the oil in the Mexican development plans. *Embajada de Mexico*, June 12.
[e]L. Corst (1984), Natural gas--key to future prosperity, *Petroleum Economist 51*(12):456-457.
[f]T. Ghalem (1985), Development plan of Algerian gas. *The Third Arab Energy Conference, Algiers, May 1985.*
[g]J.P.Stern (1984), *International Gas Trade in Europe. The Policies of Exporting and Importing Countries* (Heinemann, London).
[h]M. Quinlan (1984), Oil policy under the generals, *Petroleum Economist 51*(2):55-57.
[i]B.F. Rummerfield (1984), Mexican petroleum exploration, development, *Oil and Gas Journal*, p. 77, July 2.
[j]B. Mossavar-Rahmani and Sh. Mossavar-Rahmani (1984), World natural gas outlook: what role for OPEC? *Economist Intelligence Unit Special Report No. 157* (EIU, London).

Table 5.3. Initial data for calculating energy demand and natural gas share in gas-exporting countries.

Country	Average Annual GDP Growth Rates (%)		Energy/GDP Elasticity		Average Annual Energy Consumption Growth Rates (%)		Natural Gas Share of Energy Consumption (%)		
	1980-2000	2000-2020	1980-2000	2000-2020	1980-2000	2000-2020	1980	2000	2020
Algeria	4-5	3-4	1.70-2.00	0.70-1.00	6.80-10.0	2.10-4.00	33	50	50
Canada	2-3	2-3	0.20-0.25	0.00-0.20	0.40-0.75	0.00-0.60	27	30	25-35
Mexico	2.5-3.5	2.5-3.5	0.80-1.00	0.70-0.90	2.00-3.50	1.75-3.20	28	30	25-35
Nigeria	3-4	3-4	1.20-1.50	1.00-1.10	3.60-6.00	3.00-4.40	10	20-30	30-40
Norway	2-3	2-3	0.15-0.20	0.00-0.10	0.30-0.60	0.00-0.30	8	8	10-12
Persian Gulf	3-4	3-4	1.50-1.80	0.50-0.60	4.50-7.20	1.50-2.80	29	35-40	40-50
Southeast Asia	4-5	3-4	1.30-1.50	0.40-0.60	5.20-7.50	1.20-2.40	23	30-35	30-40

Table 5.4. Energy and natural gas consumption in gas-exporting countries.

Country	Energy Consumption (million toe) 1980	2000	2020	Gas Consumption (billion m^3) 1980	2000	2020
Algeria	11	40-75	60-160	17	25-45	35-90
Canada	170	190-220	190-270	50	65-75	55-110
Mexico	80	120-160	170-300	29	40-55	50-100
Nigeria	10	20-30	35-70	2	5-10	15-35
Norway	18	20-22	20-25	1	5	5-10
Persian Gulf	56	130-220	180-350	25	55-105	85-200
Southeast Asia	29	80-120	100-190	12	30-50	35-85

For those countries where the portion of gas resources in crude oil fields is large (Iran, Saudi Arabia, Mexico, Nigeria), the export potential was estimated only for gas resources in purely gas fields.[1]

In many countries gas export potential is not fully used, and this tendency will remain in the future. Most of gas-producing countries are crude oil exporters and for them the replacement of crude oil by gas in domestic consumption is highly effective. But in many countries the possibilities for a sharp rise in domestic consumption are limited.

Gas export prospects were assessed with reference to the current level of production costs and expected future changes. Table 5.5 is based on the analysis of the breakdown of resources into categories with respect to specific production costs, as well as on the assessment of discovered reserves and the future production levels.

Table 5.5. Average specific production costs for gas-producing countries (in 1980 dollars per 1000 m^3).

Country	1990	2000	2010	2020
Algeria	10-30	20-40	30-70	50-100
Canada	30-50	40-70	80-100	100-130
Mexico	20-40	40-60	60-100	80-100
Nigeria	30-50	30-50	40-70	60-100
Norway	70-90	80-110	100-150	150-200
Persian Gulf	10-30	10-30	20-40	20-50
Southeast Asia	10-30	30-60	60-100	80-120

SOURCE: Authors' estimates.

After 2000, average specific costs of gas extraction will steadily grow due to exhaustion of the largest fields, the need to develop deeper reservoirs with high pressure, and the greater water depths involved in offshore production.

In the second decade of the 21st century, Norway and Canada will start to develop offshore Arctic gas resources. Production of the even least costly part of these resources will raise sharply the average specific costs (Table 5.5.).

[1] Resources of dissolved gas and gas caps in Saudi Arabia and Mexico are already used mainly in the domestic petrochemical industry.

In the first decade of the next century, Iran and Qatar will possess half of the gas export potential of the nonsocialist world, but they are likely to use only part of it (Table 5.6). Norway's large export potential beyond 2000 will be provided by the development of Troll,[2] which can make Norway one of the leading gas exporters. Algeria is already among them, and the high efficiency of Algerian gas production provides an incentive to enhance the country's export ability. But beyond 2010, owing to rapid growth of domestic gas consumption and decline in new reserves, Algeria's export potential may decrease sharply.

Thus, in 2020 the export potential of nonsocialist gas exporters may range from 350 to 800 bcm/year, but not more than 30–40% of it is likely to be realized.

Concerning the export potential of "other" gas exporters, including the USSR, two strategies were considered: the first one supposes that the annual volume of gas export will remain at the level of 1990 during the whole time frame; the other suggests gas exports will grow at a rate of 30–40 bcm/year every decade, which corresponds to the capacity of a new main gas pipeline.

Taking into account the specific features of this group of exporters, it was assumed that the initial price of gas from "other" exporters in the West European market will be, first and foremost, determined by production and transportation costs of gas from such large exporters as Algeria and Norway.

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[2]The development of the Troll field will be expensive owing to unfavorable geological conditions: large water depths (320–350 m), a soft seabed, low reservoir pressure. Because the reservoir extends over 700 km^3, the development of this field will require drilling of numerous production wells.

Table 5.6. Estimates of production, consumption, exports, and export potential of several gas-producing countries.

Country	Production			Consumption			Exports			Export Potential	
	1983	2000	2020	1983	2000	2020	1983	2000	2020	2000	2020
Abu Dhabi	7	10-13	10-30	5	7	10-20	2	3-6	0-10	5-10	0-20
Iran	9	25-35	50-100	9	25-35	40-50	0	0	10-50	80-160	120-240
Qatar	5	16-20	20-70	5	10	10-20	0	6-10	10-50	50-100	60-150
Saudi Arabia	6	40-50	60-80	6	40-50	60-80	0	0	0	0	0-20
Persian Gulf, total	27	91-118	140-280	25	82-102	120-170	2	9-16	20-110	135-270	180-430
Algeria	36	65-85	80-120	17	35-45	60-80	19	30-40	20-40	45-55	20-70
Canada	71	80-90	70-110	50	70	70-90	21	10-20	0-20	10-30	0-50
Mexico	31	40-60	60-110	29	40-50	50-80	2	0-10	10-30	20-30	40-50
Netherlands	73	65-70	30-40	36	35-40	30-40	37	30	0	30	0
Nigeria	2	8-20	20-60	2	8-15	20-40	0	0-5	0-20	15-25	25-35
Norway	24	20-30	40-70	1	2	5-10	23	18-28	35-60	65-70	60-110
Southeast Asia, total	36	75-100	80-135	14	40-50	50-75	22	35-50	30-60	50-80	30-60
Including Indonesia	21	45-60	45-60	8	25-30	30-40	13	20-30	15-20	20-30	15-20
Total	300	444-573	520-925	174	312-374	405-585	126	132-199	115-340	370-590	355-805

Chapter 6

Economics of Interregional Natural Gas Transportation

Specialized, highly capital-intensive transportation facilities will condition the prospects of natural gas development, the international gas trade, and possibilities for developing gas resources in remote areas.

The small volume of internationally traded gas compared with oil can be attributed mainly to the high costs of long-distance gas transportation and the need for enormous investments in specialized transportation facilities. When gas is transported over a distance of several thousand kilometers, transportation costs constitute the majority of the total cost to consumers.

LNG carriers cost about seven to eight times more than crude carriers of the same capacity (in terms of heat equivalent). The maximum heat transport capacity of crude tankers is, however, considerably greater than that of LNG carriers. As a result, specific costs of LNG transportation are 10–12 times higher than crude oil transportation.

The difference in pipeline transportation costs for equal amounts of crude oil and natural gas – in terms of heat equivalent – ranges from three to four times. A pipeline of the same diameter and working pressure makes it possible to transport five to six times more energy in the form of crude oil compared with natural gas, not counting the reduced power required for pumping.

The choice of long-distance gas transport method is determined by the economics of two conventional modes of natural gas transportation (pipeline and LNG chains) and the one that has not been yet used: methanol production and its sea transportation. The economics depend on several main factors, such as the volume and distance of gas to be transported by sea and land, and the environment that affects construction costs.

Economies of scale are lower for LNG transportation compared with pipeline, in general, and in the 5–10 BCM/yr capacity range, in particular.

Specific transportation costs (in Tables 6.1 and 6.2) are calculated in US dollars with a 12% rate of return, excluding taxes and transit fees. Real specific transportation costs will be in fact higher than the costs estimated under these technical and economic assumptions; the difference will be most significant in the case of gas pipeline transportation. When natural gas is transported as LNG, the only fees paid are for passing through the Suez canal. Specific transportation costs for the methanol option are not presented because the latter does not appear to be economically viable.

Table 6.1. Costs of interregional natural gas transportation.

Route	Transportation Costs (1980 \$/10^3, m^3/year)	Pipeline Gas (%)
Persian Gulf – North of Central Europe	70	10
Algeria – South of Western Europe	35	4
Algeria – North of Central Europe	55	7
Algeria – Western Europe (on the average)	45	5
Canada – US		
1990-2000	70	5
2010-2020	110	8
Mexico – US	40	5

NOTES: Costs include 12% ROI; they do not include returns on investments during construction, fees, and royalties. Estimates are based on flow volumes assumed for each route.
The cost of fuel gas consumed at compressor stations is included in transportation costs as a price of 100 \$/10^3m^3.
SOURCES: Authors' estimates; and R.N. DiNapoli (1984), Economics of LNG projects, *Oil and Gas Journal 82*(8):47-51.

Table 6.2. Costs of interregional LNG transportation.

Route	Transportation Costs 1980 \$/10^3 m^3/year	Fuel Gas (%)
From the Persian Gulf to		
the US	180	18.3
Japan	140	17.9
Western Europe (Rotterdam)	125	17.8
From Southeast Asia to		
Japan	100	17.5
the US	145	18.0
From Algeria to		
Western Europe (Rotterdam)	90	17.4
the US	105	17.6
From Nigeria to		
the US	105	17.6
Western Europe	105	17.6

NOTES: Costs include 12% ROI; taxes, land owners' charges, fees, royalties, and returns on investments during construction are not included.
Major components of LNG transportation costs (at 100 \$/10^3m^3 for fuel gas): distance-dependent costs – 4.5 \$/10^3m^3/year; costs that are not distance-dependent – 68 \$/10^3m^3/year.
SOURCES: see footnotes for Table 6.1.

Chapter 7

Economics of Intraregional Gas Storage and Distribution

Intraregional gas transportation involves both transmission and distribution costs. The US has built a wide natural gas transmission and distribution network with transmission lines exceeding 27% of the total length of the US pipeline system. For the US, it is assumed that the whole intraregional gas pipeline network has already been constructed and that the gas distribution network will be completed by 2000.

In Western Europe, the transmission/distribution pipeline ratio is less than 14% and is unlikely to change in the future, if one takes into account geographical locations of natural gas's entry into the West European market. Nevertheless, for Western Europe we assumed constant expansion of the transmission and distribution pipeline network, with the "old"/"new" network ratio varying from 30/70 in 1990 to 80/20 in 2020 (Table 7.1).

Table 7.1. Cost of intraregional natural gas transport ($/1000 m^3).

Region	1990	2000	2010	2020
US				
Intraregioal mains transport	5	5	5	5
Town distribution transport including gas storage				
Municipal and residential sector in the developed areas (%) ($30/1000 m^3)	90	95	100	100
In new areas (%) ($70/1000 m^3)	10	5	0	0
Average value	34	32	30	30
Commercial users in the developed areas (%) ($6/1000 m^3)	90	95	100	100
In new areas (%) ($18/1000 m^3)	10	5	0	0
Average value	7.2	6.6	6.0	6.0
Western Europe				
Intraregional mains transport				
Old network (%) ($4/1000 m^3)	30	40	60	80
New network (%) ($13/1000 m^3)	70	60	40	20
Average value	10.3	9.4	7.6	5.8
Town distribution transport including gas storage				

Municipal and residential sector in the developed areas (%) ($35/1000 m^3)	30	40	60	80
In new areas (%) ($90/1000 m^3)	70	60	40	20
Average value	73.5	68	57	46
Commercial users in the developed areas (%) ($5/1000 m^3)	30	40	60	80
In new areas (%) ($15/1000 m^3)	70	60	40	20
Average value	12	11	9	7
Japan				
Intraregional mains transport				
Old network (%) ($2/1000 m^3)	40	60	80	100
New network (%) ($5/1000 m^3)	60	40	20	0
Town distribution transport including gas storage				
Municipal and residential sector in the developed areas (%) ($35/1000 m^3)	40	60	80	100
In new areas (%) ($90/1000 m^3)	60	40	20	0
Average value	68	57	46	35
Commercial users in the developed areas (%) ($5/1000 m^3)	40	60	80	100
In new areas (%) ($15/1000 m^3)	60	40	20	0
Average value	11	9	7	5

As for the natural gas pipeline network in Japan, it now comprises mainly local low-pressure gas distribution systems. To provide a comparison of gas transportation costs, it is assumed that Japan's natural gas pipeline system will substantially expand, providing a pipeline is constructed to import Soviet gas from the gasfields in Sakhalin or Yakutiya).

While transport cost for basic gas mains is amenable to evaluation, estimation of transport cost through local gas pipeline systems seems to be difficult because of the absence of clear classification of the available gas distribution network and lack of comprehensive statistical data. There is no such concept as "intraregional distribution gas transportation" outside the USSR. The notions "distribution pipelines" including "gas mains" and "gas service lines" accepted outside the USSR refer exclusively to the town gas distribution networks; the latter, in the USSR, do not enter into the sphere of the gas industry but form a subsystem of municipal economy. Outside the USSR, town gas distribution lines are, generally, made of small-diameter pipes (up to 2-3").

In the last few years, plastic pipes have found application in these gas distribution networks (mainly when reconstructing the existing gas distribution lines). This tendency is typical of all countries outside the Soviet Union (see relevant articles in *Gas Enginering and Management*, *Neue DELIWA-Zeitschrift*, and *Pipeline and Gas Journal*). Nevertheless, a relatively low percentage of plastic pipe distribution lines is currently in use. It is likely that in future plastic distribution pipelines will be used more extensively because they cost less than half of gas lines made of steel tubes.[1]

Lack of reliable publications on investments (except for US data published in *Gas Facts*) as well as on operational costs for gas mains and distribution lines compelled us to seek indirect data. Indirect information included, for example, average distance of natural gas transportation, cost of constructing a one-kilometer gas line, relationship between costs of constructing pipelines and compressor stations, and relationship between investments and operational costs.

Thus, when estimating expenses for intraregional gas mains in the US, it was assumed that average distance of gas transportation amounted to 1400 km, average diameter of regional gas pipelines = 762 mm, at an average pressure of 65 psi. The calculated cost of approximately \$4.9/1000 m^3 (in 1980 dollars) is comparable to the costs estimated in the Stanford University study[2] – \$5.8/1000 m^3.

For Europe, an average distance of natural gas transport was assumed to be 600 km. Based on the cost of gas transportation through gas pipelines 1000 km long and gas production of three to six billion m^3 /year,[3] the cost of a new network was estimated at \$13-19/1000 m^3.

For Japan, an average distance of natural gas transportation was assumed to be 200 km with average pipeline diameter 508 mm.

When estimating town distribution costs (as applied to municipal, residential, and industrial consumption sectors both in developed and newly supplied areas), the above mentioned data obtained from Stanford University were used as well as the data from the International Energy Agency[4] and the Research Institute of the Ohio University (US).[5]

Since irregularities in gas consumption have an appreciable effect on gas transportation economics and underground gas storage is one of the basic means of controlling these irregularities, the cost of town distribution gas transportation includes the cost of storage as well. For US conditions, the cost of gas storage has been assumed according to the International Underground Gas Storage Conference held in Rio de Janeiro 1983,[6] while for West European countries the cost was taken from International Energy Agency data.

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[1] One foot of 2" steel pipe costs \$10.5 on the average; the same length of polyethylene pipe – \$4.3 (*Pipe Line Industry*, October 1984, p. 21). By the end of 1983, 380,000 km of plastic gas distribution lines had been run in the US at a cost of more than \$5 billion (*Pipe Line Industry*, May 1984, p. 4).

[2] *Fuel and Energy Forecasts*, Volume 2, Data Base, 1977, Stanford Research Institute, pp. 3.34–3.35.

[3] Economics of gas import to Europe from OAPEC, *Oil and Gas Journal*, August 1980, pp. 55–58.

[4] *Natural Gas Prospects to 2000*, IEA/OECD, Paris, pp. 43-61 (Tables 5 and 6) (1982).

[5] A simulation model of market expansion policies for natural gas distribution utilities, *Energy* 5:1013-1043 (1980).

[6] Clausing, R. (1983), Philosophy and economics of underground gas storage in the US, IGU Gas Council Technical Session, *Proceedings of the International Underground Gas Storage Conference*. Rio de Janeiro.

The above considerations have allowed us to estimate costs of intraregional gas transportation through gas mains in the US at \$5/1000 m^3 for the whole period from 1990 to 2020; in Western Europe from \$10.3/1000 m^3 in 1990 to \$5.8/1000 m^3 in 2020; and in Japan from \$3.8/1000 m^3 in 1990 to \$2.0/1000 m^3 in 2020 (see again Table 7.1).

Average costs of town gas distribution transport including gas storage cost are estimated for domestic users (municipal and residential sector) at \$30-34/1000 m^3 in the US; from \$73.5/1000 m^3 in 1990 to \$46/1000 m^3 in 2020 in Western Europe; and from \$68 to \$35/1000 m^3, correspondingly, in Japan. The same costs (on the average) for commercial users in the US would be maintained at the same level throughout the whole period under consideration, while in Western Europe and in Japan they would actually decline twice (in Western Europe from \$10.3/1000 m^3 in 1990 to \$5.8/1000 m^3 in 2020, and in Japan from \$11 to \$5/1000 m^3, correspondingly).

Chapter 8

Ecological Advantages of Natural Gas Over Other Types of Fossil Fuels

When estimating the total public costs of traditional energy resources, one has to take into account, among other components, not only expenditures on the nature-conservancy measures that might be considered a function of a given fuel, but also the social expenditures on compensation for (a) damage from the discharges and exhausts of pollutants plus (b) residual damage from antropogenic pollution, which affects all the geospheric components as well as public production branches and elements. The majority of studies in this field are concerned with the atmospheric pollution by ash, sulfur, and nitrogen oxides. For all that, problems connected with direct hydrosphere pollution (e.g., the substance washout from ash dumps), soil pollution, "small" pollutants, and the heavy metal aerosols and carcinogenic aromatic cyclic hydrocarbon discharges are usually ignored.

It is a rather complicated problem to estimate the damage incurred to biosphere and society from antropogenic pollution because this would require performing a detailed study of the pollutant turnover in nature and reactions of all recipients to contact with a pollutant, depending upon contact intensity and duration. Every particle of the chemical substance, while participating in biogeochemical cycles, can, passing from one medium to another, from one biosphere component or element to another, exert a harmful influence for a long period. Therefore, the damage per unit (e.g., damage per one kilogram of antropogenic SO_2) will gradually increase. This process can continue until the harmful substance decays into a harmless compound or becomes an inert form that takes no part in active turnover (e.g., chemically inert oceanic bottoms). Mechanisms of pollutants' migration, transformation, and deposition (nonparticipation in active turnover) have not yet been studied sufficiently.

Over the last years in the USSR and other countries, methods have been developed allowing us to estimate a pollution damage cost and compare it with expenditures on prevention, i.e., the "expenditures-effect" estimate. Based on these methods an endeavor has been made to estimate the damage from a thermal station. These studies, though incomplete and on the preliminary level, are worthy of thorough investigation, full support, and a further development. This chapter attempts to compare social losses suffered from consumption of different forms of organic fuel. The estimates presented below are based on a review of some non-Soviet studies and additional estimations performed by the authors.

Following available methods for assessing measures aimed at atmospheric protection from thermal stations and boiler house discharges,[1] the economic efficiency of these environmental protection measures is evaluated by the minimum costs or payback term criterion. One should take into account changes in technical and economic indicators herein, reduced damage to the national economy from atmosphere pollution, and the benefit gained from new products yielded from trapped substances. The total economic effect is equal the total savings of annual national expenditures for energy, public health, municipal services, agriculture,

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[1]Temporary methods for estimating the economic efficiency of measures aimed at atmosphere protection from pollutant discharges containing dirty gas of thermal stations and boiler houses, *Soyuztechenergo.M.* (1982).

and forestry, when comparing the costs for a base case under consideration. Both cases should be comparable with respect to their ecological consequences. For that, it is necessary that the level of surface air pollution should not exceed standard sanitary norms. Such a requirement conditions the choice of technical solutions. With constant plant capacity and burned fuel quality, these solutions are comparable ecologically, provided that the products of generalized parameters of dissipation conditions (per volume of pollutant discharge) are equal.

Findings of the studies conducted abroad in the thermal plant field are summarized to a certain degree in Shang-Zhi Wu's study,[2] which is mostly based on the methods used in the research efforts accomplished under OECD's aegis.[3] A.H Awad and T.N. Veziroglu in their study have attempted to estimate the damage per 1 tce on a global scale, i.e., in fact taking into account long-distance pollutant carryover, proceeding from the damage to various industries.[4]

Without thorough analysis of environmental impacts at each stage of pollutant migration, and a consistent procedure for summarizing specific damage to each industry, these estimates should be regarded as rather approximated. They turn out to represent an order of the magnitude of the phenomenon under consideration rather than a precise quantitative estimate.

In estimating an ecological component within the total costs of electric energy, Shang-Zhi Wu discusses a case of a coal-fired thermal station with rated capacity ranging from 500 up to 2000 MW. All costs are in 1982 US dollars, and the legal limit on ash and SO_2 discharges is in accordance with the one adopted in the US and countries of Western Europe. The average expenditures on the atmosphere protection from dirty gases of thermal stations generated by coal are estimated at $250/kW of capital investments and about of 1 cent/kW/hour of current expenses.

Today's technology cannot protect the atmosphere from thermal station pollution any further. In this connection, the compensation estimates from such pollution starts to play an increasing role.

According to Shang-Zhi Wu's paper, the OECD studies tried to estimate the damage from thermal station discharges of SO_2 into the atmosphere and the damage reduction resultant from declining exhausts. The economic damage (the first component) was determined to be the sum of the damage incurred to the structure from corrosion, decreased crop capacity, and a declining fishing industry, leaving aside the damage inflicted upon forestry, cattle breeding, cultural and historical values, recreation landscapes, and so on.

The harm to public health (the second component) was determined separately and interpreted, eventually, as the loss of products resulting from decrease in the mean expected life duration. It still remains unclear whether this estimate covered the increased expenditures for public health, social security, and reduced labor productivity due to the deterioration of individual health. There is no estimate of the damage suffered from all the pollutants contained in all thermal station discharges either. It is evident, therefore, that al the above estimates are only preliminary ones, which do not fully reflect an "ecological" component in the total social costs of the energy produced by thermal stations.

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[2] Shang-Zhi Wu (1984), *Air pollution costs of electric power generation systems*. Cambridge, Mass.: Massachusetts Institute of Technology.

[3] *The Costs and Benefits of Sulfur Oxide Control*, Organisation for Economic Cooperation and Development, Paris, 1984.

[4] Awad, A.H. and T.N. Veziroglu (1984), Hydrogen versus synthetic fossil fuels, *International Journal of Hydrogen Energy* 9(5):355–366.

In estimating the benefit from decreased pollution by country, transboundary migration was assumed conventionally equal to zero. A linear dependence of the damage decrease on pollution reduction was assumed as well. The study presents a wide range of estimates, both the first and second component in the SO_2 damage. For example, at a discharge of 7.5 kg of oxides per tce, the first component (economic damage) is estimated at from \$1.6 up to \$9.75 per tce or \$0.21-1.3 per kg of SO_2. At the 15 kg/tce discharge it is estimated at \$3.25-16.25/tce, or \$0.21-1.08/kg of SO_2. At the same time, these estimates highly differ by country. Low estimates range from \$0.04/kg of SO_2 up to \$2/kg; the top ones – from \$0.21/kg up to \$22.5/kg. On average, for eleven countries of Northern and Western Europe, a low estimate is about \$0.25/kg, the top one – \$2.2–2.4/kg. The estimates for the FRG are \$0.4/kg and \$4.0-4.5/kg, respectively.

The cited paper by Awad and Veziroglu estimates the global damage from 1 tce of fossil fuel. When recalculating their data estimates, we assessed the damage from 1 tce of hard and sulfur liquid fuel at about \$156/tce. The damage from gaseous fuel per unit of the consumed primary energy was assumed by these scientists to be one-third that from the hard and liquid fuels. Under such assumption, the damage from natural gas on average will be \$50/tce; and the estimated benefit derived from coal and fuel oil replacement by natural gas, \$100/tce. Based on the Awad-Veziroglu data, we calculated the specific damage resulting from the burning of different fossil fuels, taking into account the total energy consumption structure. The results are shown in Table 8.1.

Table 8.1. Estimates of specific damage to society from the burning of fossil fuels (in 1984 US \$/tce).

Environmental Component	Type of Fuel		
	Hard	Liquid	Gaseous
Population	38	38	13
Stock of land	15	-	-
Agriculture and forestry	29	29	9
Including plant growing	12	12	4
Cattle breeding	5	5	1
Forestry, fauna, and flora	12	12	4
Fishing resources and fishing industry	3	3	1
Buildings and structures	32	30	13
World ocean costs	-	6	-
Total	117/107[a]	106/92	36/30

[a]Numerator = damage to coastal countries; denominator = damage to inland countries.

The average net annual benefit (effect minus expenses) from the pollution decrease when summing the first with second components and having the discharge decrease by 4.8 million t/year or 19% is estimated at \$34.6/capita, and in the case of the entire population – by about \$8 billion/year. Decreasing the discharge by 11.7 million t/year or 48% we get \$98.6/capita and \$16.5 billion/year, respectively. If one extrapolates the expenses/losses ratio, the total benefit from the above reduction in cumulative biosphere from autochthon sources can be estimated at \$50 billion/year or \$200/capita per year.

The cited paper by Awad and Veziroglu estimates the global damage from 1 tce of organic fuel. When correcting their data estimates, the authors assessed the damage from 1 tce of hard and sulfur liquid fuel at about $156/tce. The damage from gaseous fuel per unit of the consumed primary energy was assumed by these scientists to be one-third that from the hard and liquid one. Under such an assumption, the damage from natural gas on average will be $52/tce, and the estimated benefit when replacing coal and fuel oil by natural gas equals $100/tce. Based on the data mentioned in this paper, the authors calculated the damage per unit from different organic fuels taking into account the total energy consumption structure (see again Table 8.1).

Damage to coastal countries includes the damage to the sea coast through oil and oil products leakage plus the damage resulting from a change in the world ocean level due to a probable change of the climate if organic fuel consumption continues unabated.

These estimates suggest that the damage decrease from replacing hard and liquid fuels by natural gas is of $60–80/tce. Awad and Veziroglu (p. 363, Table 6) also contains estimates of the average damage from synthetic gas (similar to natural gas in its composition) equal to $150/tce, and from synthetic fuel oil equal to $217/tce. The damage decrease with the liquid fuel substitution for gas is $70/tce in our case.

According to the data presented in *Options*,[5] the authors have attempted to estimate approximately the damage per unit for the US, which turned out to be $190/tce.

Therefore, the benefit for developed countries (the damage decrease for the society) gained by replacing coal and fuel oil with natural gas in the energy balance in the first approximation might range from $60 up to $120/tce. Our preliminary estimations indicate such a benefit might be $80/tce (in 1984 $). It shows that the use of ecologically clean fuels (notably natural gas) provides additional gains within the mentioned range. At current world market prices for natural gas, the economic effect is about half the selling price.

Looking at alternative energy resources with regard to social costs makes one see the effectiveness of individual technologies in quite a different light. In this respect technologies based on natural gas have substantial economic advantages over other fuels.

In the calculations that follow, this aspect has not been further considered. Therefore, the willingness-to-pay estimate for natural gas and projections of the world market for natural gas proceed from the correlation of "explicit" economic consequences when gas competes with alternate energy carriers. In fact, incorporating a substantial ecological component ("implicit effect") might violate the market equilibrium, causing higher gas consumption and, thus, promoting an increase in the selling price. If the social value of gas greatly exceeds its selling price, this would allow policymakers to tax other, "dirtier" energy carriers and thus induce manufacturers and consumers of gas to expand the gas market.

Owing to the lack of information on the economic damage resulting from the burning of various fuels, we have taken into account only the expenditures involved in environmental protection – notably, gas stack cleaning. Based on the analysis of Soviet and foreign publications, rough cost estimates have been made of desulfurization for the most widespread technologies of fuel burning (Table 8.2). The estimates are given for the periods prior to and beyond the year 2000; it is

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[5]Acid rain, *Options 1*, International Institute for Applied Systems Analysis, Laxenburg, Austria (1984).

assumed that in the future the application of new cheap and more efficient methods of gas cleaning will probably lower the costs. The above estimates have been taken into account in the calculation of marginal natural gas prices. Accordingly, the price of natural gas in individual markets has been determined with regard for this factor.

Table 8.2. Additional expenditures involved in gas stack cleaning, the burning of solid and liquid fuels compared with natural gas (dollar/tce).

Fuel Type	Prior to 2000	Beyond 2000
Solid Fuel (low-sulphur coal)		
Thermal power plants		
Base-load	30	20
Intermediate-load	45	30
Heating boiler plants	55	20
Industrial boiler plants	45	20
Liquid Fuel		
Thermal power plants		
Base-load	15	15
Intermediate-load	20	10
Heating boiler plants	30	15
Industrial boiler plants	20	20
Household installations	15	15

Chapter 9

Evaluation of Marginal Natural Gas Prices

Crucial to the model for the international natural gas market is the dependence of gas consumption on willingness to pay (marginal costs).

The willingness of a consumer to pay for a limited resource is equal to the cost of an energy resource that is marginal for a given consumer. In simple cases, where a marginal resource is given, its marginal price is calculated from the comparison of cost effectiveness of both resources. In more complex situations, in the calculation of cost effectiveness of more than two technologies, a modeling approach is required to determine marginal prices.

In a general case, the expenditures involved in production or services C can be presented as follows:

$$C = P \cdot b + A + E_n \cdot K \quad , \quad \text{dollar/production unit} \tag{9.1}$$

where P is the price of an energy resource; b the consumption; A the operation costs (excluding energy costs) in dollars/production unit; K the capital investment in dollars/production unit; and E_n the normative coefficient of a return on investments.

If a marginal resource for a given consumer is known, then the willingness of the consumer to pay for the limited resource is calculated from the following ratio:

$$C_g = C_m \tag{9.2}$$

$$P_g \cdot b_g + A_g + E_n \cdot K_g = P_m \cdot b_m + A_m + E_n \cdot K_m \quad ,$$

$$\bar{P}_g = P_m \cdot \frac{b_m}{b_g} + \frac{(A_m - A_g)}{b_g} + E_n \cdot \frac{(K_m - K_g)}{b_g} \quad , \tag{9.3}$$

where g index – natural gas; m – marginal energy resource.

A still more complex case occurs when the resultant product is used as a feedstock for further conversion. For example, methanol derived from natural gas or coal can be converted to olefins or motor fuels. This will require that technology be presented as a multistage process beginning when a primary product is put out, including subsequent stages of conversion of semiproducts to an end product in the final stage. In this case, the price of the resource in equations (9.2) and (9.3) is replaced by the values calculated from equation (9.1).

In the case of two stages of conversion (for example, methanol production from natural gas or coal with subsequent conversion to ethylene), the calculation of the marginal price, equation (9.3), has the form

$$\bar{P}_g = P_m \cdot \frac{b_m}{b_g^f \cdot b_f^e} + \frac{(A_m - A_f \cdot b_f^e - A_e)}{b_g^f \cdot b_f^e} + E_n \cdot \frac{(K_m - K_f \cdot b_f^e - A_e)}{b_g^f \cdot b_f^e} \quad , \tag{9.4}$$

where f – primary product (feedstock); e – end product.

Based on this method, approximate assessments of the dependence of marginal gas prices for the largest energy consumers have been made (Tables 9.1–9.13).

All calculations suggest a 12% return on investments.

Table 9.1. Marginal natural gas price, base-load electric power plants (6500 h/yr).

Plant Type	Specific Invest-ments ($/kWh)	Capital Charge ($/kWh)	Operat-ing Costs ($/kWh)	Service Life (yrs)	Specific Fuel Con-sumption (g/kWh)
Coal-fired	1000	$24.0 \cdot 10^{-3}$	$6.65 \cdot 10^{-3}$	30	370
Gas-fired	650	$15.3 \cdot 10^{-3}$	$2.15 \cdot 10^{-3}$	30	260
Fuel oil-fired	700	$16.5 \cdot 10^{-3}$	$2.15 \cdot 10^{-3}$	30	340

SOURCE: Calculated from Durrow, K.G., Nesbitt, D.M., and Marshalls, R.A. (1983), An analysis of the benefits of gas technology R&D, *Energy Systems Policy* 7(3):195-233.

NOTE: Marginal natural gas price depending on marginal technology:

Coal-fired power plants $\bar{P}_g = 1.69 \cdot P_c + 25$, **dollar/1000 m³**

Fuel oil-fired power plants $P_g = 1.08 \cdot P_f + 5$, **dollar/1000 m³**

where

P_c = coal price, dollar/tce; and
P_f = fuel oil price, dollar/t.

Table 9.2. Marginal natural gas price, intermediate-load thermal power plants (3500 h/yr).

Plant Type	Specific Invest-ments ($/kWh)	Capital Charge ($/kWh)	Operat-ing Costs ($/kWh)	Service Life (yrs)	Specific Fuel Con-sumption (g/kWh)
Coal-fired	1000	$43.7 \cdot 10^{-3}$	$6.7 \cdot 10^{-3}$	30	385
Natural gas-fired	650	$30.6 \cdot 10^{-3}$	$2.4 \cdot 10^{-3}$	30	280
Fuel oil-fired	700	$28.4 \cdot 10^{-3}$	$2.1 \cdot 10^{-3}$	30	360
Gas/steam cycle	900	$35.0 \cdot 10^{-3}$	$2.8 \cdot 10^{-3}$	30	280
Gas/steam cycle with coal gasification	1200	$52.5 \cdot 10^{-3}$	$7.5 \cdot 10^{-3}$	30	325

SOURCE: Calculated from Durrow, K.G. *et al.*, *op.cit.*

NOTE: Marginal natural gas price depending on marginal technology:

Coal plants $\bar{P}_g = 1.60 \cdot P_c + 70$, **dollar/1000 m³**

Fuel oil plants $\bar{P}_g = 1.05 \cdot P_f - 10$, **dollar/1000 m³**

where

P_c = coal price, dollar/tce; and
P_f = fuel oil price, dollar/t.

Table 9.3. Marginal natural gas price, peak-load electric power plants (1100 h/yr).

Plant Type	Specific Invest-ments ($/kWh)	Capital Charge ($/kWh)	Operat-ing Costs ($/kWh)	Service Life (yrs)	Specific Fuel Con-sumption (g/kWh)
Gas turbine	230	$32.10 \cdot 10^{-3}$	$2.52 \cdot 10^{-3}$	15	410
Liquid-fueled gas turbine	230	$32.10 \cdot 10^{-3}$	$3.65 \cdot 10^{-3}$	15	410
Pumped storage	500[a] 1200			50	= 0.80
Air storage	800			25	= 0.75

[a]Mountainous regions.

SOURCE: Calculated from Durrow, K.G. *et al.*, *op.cit.*

NOTE: Marginal natural gas price depending on marginal technology:

Liquid-fueled gas turbine plants $\bar{P}_g = 0.60 \cdot P_{ft}$, dollar/1000 m^3

Pumped storage power plants $\bar{P}_g = 3600 \cdot P_{el} + 60$, dollar/1000 m^3 (mountainous regions)
$\bar{P}_g = 3600 \cdot P_{el} + 275$, dollar/1000 m^3

Air storage power plants $\bar{P}_g = 3800 \cdot P_{el} + 150$, dollar/1000 m^3

where

P_{ft} = price of distillate fuel oil, dollar/t; and
P_{el} = price of off-peak electricity, dollar/kWh.

Table 9.4. Marginal natural gas price, industrial boiler plants.

Fuel	Specific Invest-ments ($/Gcal)	Capital Charge ($/Gcal)	Operat-ing Costs ($/Gcal)	Service Life (yrs)	Specific Fuel Con-sumption (kgce/Gcal)
Coal	65	9.9	2.3	25	200
Fuel oil	25	4.0	1.6	25	178
Natural gas	23	3.5	1.4	25	160

SOURCE: Calculated from Durrow, K.G. *et al.*, *op.cit.*

NOTE: Marginal natural gas price depending on marginal technology:

Coal-fired boiler plants $\bar{P}_g = 1.04 \cdot P_c + 50$, dollar/1000 m^3

Fuel oil boiler plants $\bar{P}_g = 0.82 \cdot P_f + 5$, dollar/1000 m^3

where

P_c = coal price, dollar/tce; and
P_f = fuel oil price, dollar/t.

Table 9.5. Marginal natural gas price, industrial furnaces (the heating of metal).[a]

Source of Energy	Specific Invest-ments ($/t)	Capital Charge ($/t)	Operat-ing Costs ($/t)	Service Life (yrs)	Effi-ciency
Natural gas	8-10	1.4-1.8	0.4-0.5	15	0.35
Fuel oil	12-16	2.1-4.5	0.6-0.8	15	0.33
Electricity	3-4	0.55-1.7	0	15	0.80

[a]One should take into account metal burning loss (0.5% for gas and electricity furnaces and 1% for fuel oil furnaces).

SOURCE: Calculated from Durrow, K.G. *et al.*, *op.cit.*, and A.S. Nekrasov and Yu. V. Sinyak (1965), Industrial heat economics, *Gosenergoizdat, M.*

NOTE: Marginal natural gas price depending on marginal technology:

Fuel oil furnaces $\bar{P}_g = 0.88 \cdot P_f + 33$, dollar/1000 m^3

Electric furnaces $\bar{P}_g = 4070 \cdot P_{el} - 9$, dollar/1000 m^3

where

P_f = fuel oil price, dollar/t; and

P_{el} = electricity price, dollar/kWh.

Table 9.6. Marginal natural gas price, space heating and hot water supply (centralized).

Type of System	Specific Invest-ments ($/Gcal)	Capital Charge ($/Gcal)	Operat-ing Costs ($/Gcal)	Service Life (yrs)	Effi-ciency
Gas- or fuel oil-fired boiler plants					0.9
60 MWt/t/5500 h			3.5		
60 MWt/t/7000 h			3.0		
15 MWt/t/4000 h			5.7		
15 MWt/t/5500 h			4.5		
8 MWt/t/1500 h			6.0		
8 MWt/t/3000 h			4.1		
2 MWt/t/1500 h			11.5		
2 MWt/t/3000 h			8.4		
Coal-fired boiler plants					0.8
60 MWt/t/5500 h			8.2		
60 MWt/t/7000 h			7.1		
15 MWt/t/4000 h			12.3		
15 MWt/t/5500 h			9.9		
8 MWt/t/1500 h			16.9		
8 MWt/t/3000 h			11.0		
2 MWt/t/1500 h			33.8		
2 MWt/t/3000 h			24.9		

SOURCE: Calculated from Coenen, R. *et al.* (1984), Kummer mit Kohle, *Energie 36*(9):23-41.

NOTE: Marginal natural gas price depending on marginal technology:

Coal-fired boiler plants:

large plants $\bar{P}_g = 0.9 \cdot P_c + 36$, dollar/1000 m^3

small plants $\bar{P}_g = 0.9 \cdot P_c + 120$, dollar/1000 m^3

Fuel oil-fired boiler plants $\bar{P}_g = 0.8 \cdot P_f$ dollar/1000 m^3

where

P_c = price of coal, dollar/tce; and
P_f = price of fuel oil, dollar/t.

Table 9.7. Marginal natural gas price, space heating of decentralized consumers (one-storeyed houses).

Type of Heating	Specific Invest-ments ($/house)	Capital Charge ($/house/yr)	Operat-ing Costs ($/house/yr)	Service Life (yrs)	Effi-ciency
Radiator hot-water or panel heating					
Natural gas	820	140	0	20	0.8
Distillate	750	125	30	20	0.8
Resistive heating	850	145	0	20	1.0
Heat pump	2000	340	50	20	3.5
Warm-air heating					
Natural gas	1100	185	0	20	0.8
Distillate	1500	255	30	20	0.8
Resistive heating	900	155	0	20	1.0
Heat pump	3400	580	50	20	3.5

SOURCE: Calculated from Schurr, S.H., J. Darmstadter, H. Perry, W. Ramsay, and M. Russel (1979) *Energy in America's Future: The Choice before us*. Baltimore and London: Johns Hopkins Press.

NOTE: Marginal natural gas price depending on marginal technology:

For hot-water heating:

distillate $\bar{P}_g = 0.8 \cdot P + \frac{96}{q}$, dollar/1000 m^3

resistive heating $\bar{P}_g = 7400 \cdot P_{el} + \frac{32}{q}$, dollar/1000 m^3

heat pump $\bar{P}_g = 2100 \cdot P_{el} + \frac{1600}{q}$, dollar/1000 m^3

For warm-air heating:

distillate $\bar{P}_g = 0.8 \cdot P + \frac{640}{q}$, dollar/1000 m^3

resistive heating $\bar{P}_g = 7400 \cdot P_{el} + \frac{190}{q}$, dollar/1000 m^3

heat pump $\bar{P}_g = 2100 \cdot P_{el} + \frac{2850}{q}$, dollar/1000 m^3

where

P = price of distillate, dollar/t;
P_{el} = price of electricity, dollar/kWh; and
q = the building's heat losses during the heating season, Gcal/yr.

Typical heat consumption for one-storeyed houses in the regions under consideration is 18-22 Gcal/yr for existing and 10-12 Gcal/yr for new and prospective housing stock.

Table 9.8a. Marginal natural gas price, hot water supply of decentralized consumers (one-storeyed houses) (in 70 l/person/day at 65°C).

Water Heater	Specific Invest-ments ($/house/yr)	Capital Charge ($/house/yr)	Operat-ing Costs ($/house/yr)	Service Life (yrs)	Effi-ciency
Straight-through systems operating on:					
Distillate	180-190	40-42	0	10	0.8
Natural gas	180-190	40-42	0	10	0.8
Electricity	170-180	37-40	0	10	1.0
Off-peak storage	190-200[a]	42-45	0	10	1.0

[a]Including 500 l water storage at a price of 30-50 dollar/m^3.

SOURCE: Macarthur, J.W., Finn-Carlson, D.W., and Nglyen, H.H (1980), Reducing residential fuel consumption through cost-effective interseasonal energy transfer, *Energy Conservation and Management* *20*(3):161-179.

NOTE: Marginal natural gas price depending on marginal technology:

Straight-through systems operating on

distillate $\bar{P}_g = 0.8 \cdot P_d$, dollar/1000 m^3

electricity $\bar{P}_g = 9260 \cdot P_{el}$, dollar/1000 m^3

Off-peak storage $\bar{P}_g = 9260 \cdot P_{el}^n$, dollar/1000 m^3

where

P_d = price of distillate, dollar/t;
P_{el} = price of electricity (daytime), dollar/kWh; and
P_{el}^n = price of electricity (night-time), dollar/kWh.

Table 9.8b. Marginal natural gas price, cooking.

Type of Range	Specific Invest-ments ($/p)	Capital Charge ($/p/yr)	Operat-ing Costs ($/p/yr)	Service Life (yrs)	Effi-ciency
Gas					0.65
Liquid fuel (distillate)					0.65
Electric					0.80

NOTE: Marginal natural gas price depending on marginal technology:

Liquid fuel range $\bar{P}_g = 0.8 \cdot P$, dollar/1000 m^3

Electric range $\bar{P}_g = 9200 \cdot P_{el}$, dollar/1000 m^3

where

P = price of distillate, dollar/t; and
P_{el} = price of electricity, dollar/kWh.

Table 9.9. Marginal natural gas price, methanol production.

Source	Specific Investments ($/t)	Capital Charge ($/t)	Operating Costs ($/t)	Service Life (yrs)	Specific Fuel Consumption (tce/t[a])
Natural gas	95	18	34	15	1.2
Coal (through gasification)	350	72	190	15	2.0

[a]Feedstocks and fuel.

SOURCES: Chauvel, A. (1981), Utilization de produits organiques oxygenes comme carburants et combustibles dans les moteurs. Deuxieme partie. Les differentes filieres d'obtention des carburols. Analyse technico-economique. *Revue de l'Institut Fracais du Petrole 36*(6):685; Andrew, S. (1984), Liquid fuels from alternative feedstocks. *The Chemical Engineer*, January, p. 28; and Leonard, J.P (1979), Synthetic gas and chemicals from coal: economic appraisals, *Chemical Engineering 86*(7):183.

NOTE: Marginal natural gas price depending on marginal technology:

$$\bar{P}_g = 2 \cdot P_c + 210 \quad , \text{ dollar}/1000\ m^3$$

where

P_c = coal price, dollar/tce.

Table 9.10. Marginal natural gas price, ethylene production.

Source	Specific Investments ($/t)	Capital Charge ($/t)	Operating Costs ($/t)	Service Life (yrs)	Specific Fuel Consumption (tce/t[a])
Naphtha (straight-run petrol)	500	100	-185	15	5.6
Ethane (natural gas)	395	79	110	15	5.7
Methanol	650	130	-30	15	3.1

[a]Feedstocks and fuel.

SOURCES: Mikulla, K.D., H. Bölt, H. Richter (1980), Einsatzflexibilität in Olefinanlagen (Teil I). In *Erdöl und Kohle – Erdgas – Petrochemie vereinigt mit Brennstoffchemie 33*(7):309; Arni, V.R.S. (1982), *Emerging Petrochemicals Technology. Implications for Developing Countries*, UNIDO/IS.350 (United Nations Industrial Development Organization, Vienna); and Berry, R.J. (1980), Gasoline or olefins from an alcohol feed, *Chemical Engineering 87*(8):86.

NOTE: Marginal natural gas price depending on marginal technology:

(a) Ethylene from ethane (marginal naphtha-based technology)

$$\bar{P}_g = 4.4 \cdot p_o - 325 \quad , \text{ dollar}/1000\ m^3$$

(b) Methanol-derived ethylene from natural gas (marginal naphtha-based technology

$$\bar{P}_g = 1.6 \cdot P_o - 135 \quad , \text{ dollar}/1000\ m^3$$

(c) Ethane-derive ethylene (marginal coal methanol-based technology

$$\bar{P}_g = 6 \cdot P_c + 500 \quad , \text{ dollar}/1000\ m^3$$

Table 9.11. Marginal natural gas price, ammonia production.

Source	Specific Invest-ments ($/t)	Capital Charge ($/t)	Operat-ing Costs ($/t)	Service Life (yrs)	Specific Fuel Con-sumption (tce/t[a])
Natural gas	300	60	7	15	1.25
Coal (gasification by Koppers-Totzek)	535-620	105-125	9-11	15	1.5-1.7

[a]Feedstocks and fuel.
SOURCES: LeBlanc, J.R. (1986), Technical aspects of reducing energy consumption in new and existing ammonia plants, *Chemical Economy and Engineering Review 18*(5):22; Petzet, G.A. (1983), U.S. ammonia producers hit by high cost, slack demand, *Oil and Gas Journal 81*(20):25-28; Ennis, K. *et al.* (1977), How small NH_3 plants compete, *Hydrocarbon Processing 56*(12):121; and Williams, G. and W.W. Hoehing (1983), Causes of ammonia plant shutdowns: survey IV. *Chemical Engineering Progress 79*(3):11.

NOTE: Marginal natural gas price depending on marginal technology:

$$\bar{P}_g = 1.4 \cdot P_c + 90 \quad , \quad \text{dollar}/1000\ m^3$$

where

P_c = coal price, dollar/tce.

Table 9.12. Marginal natural gas price, motor fuel production.

Source	Specific Invest-ments ($/t)	Capital Charge ($/t)	Operat-ing Costs[a] ($/t)	Service Life (yrs)	Specific Fuel Con-sumption[a] (tce/t)
From crude oil					
Direct coal liquefaction	1150	230	20	15	4.5
Coal gasification and processing, Fisher-Tropsch	4900	980	-505	15	6.0
Methanol by Mobil process			130[b]	15	2.4

[a]Excluding by-products.
[b]Including capital charge.
SOURCES: Andrew, S. (1984), Liquid fuels from alternative feedstocks. *The Chemical Engineer*, January, p. 28; Arni, V.R.S. (1982), *Emerging Petrochemicals Technology. Implications for Developing Countries*, UNIDO/IS.350 (United Nations Industrial Development Organization, Vienna); Deutsch, D.J. (1980), A big boost for gasoline from methanol. *Chemical Engineering 87*(4):104; Alternate fuel costs detailed. *Oil and Gas Journal 77*(38):94 (1979); Cohen, L.H. and H.L. Muller (1985), Methanol cannot economically dislodge gasoline. *Oil and Gas Journal 83*:119; and Sung, N.W. and D.J. Patterson (1982), Theoretical limits of engine economy with alternative automotive fuels. *Energy Research 2*:121.

NOTE: Marginal natural gas price depending on marginal technology:

Crude oil $\bar{P}_g = 0.5 \cdot P_o - 55$, dollar/1000 m^3

Direct coal liquefaction $\bar{P}_g = 3.3 \cdot P_c + 510$, dollar/1000 m^3

Coal gasification $\bar{P}_g = 6.0 \cdot P_c + 145$, dollar/1000 m^3

Table 9.13. Marginal natural gas price, automobile transport.

Natural gas or its derivatives can be used in automobile transport as:

- Methanol additions to gasoline by weight 10-15%;
- Gasoline produced from methanol by the Mobil process; and
- Compressed natural gas.

When used as an addition to standard gasoline, one ton of methanol is thought to save 1.8 tons of gasoline. Then the maximum price of natural gas used in the production of methanol for additions to gasoline amounts to

$$\bar{P}_g = 1.65 \cdot P_b - 50 = 1.65 \cdot a \cdot P_o - 50 \quad , \quad \text{dollar}/1000\ \text{m}^3 \quad ,$$

where P_b is the price of gasoline; a is the gasoline/crude oil price ratio (it is assumed that $a = 1.3$); and P_o is the crude oil price.

In the case of methanol-derived gasoline, the maximum price of natural gas with regard for efficiency of methanol production (Table 9.12) accounts for

$$\bar{P}_g = 0.5 \cdot P_o - 55 \quad , \quad \text{dollar}/1000\ \text{m}^3 \quad .$$

In order to estimate the maximum price of natural gas used in compressed form, the following assumptions are made: gasoline consumption – 40 l/100 km (for a truck); mileage per year – 50,000 km; gasoline/natural gas calorific value ratio – 1.26; additional investments in the automobile – 2500 dollars; service life – ten years; and with the changeover to natural gas, the coefficient of increased fuel consumption equals 1.2. Under these assumptions

$$\bar{P}_g = 0.66 \cdot P_b - 20 = 0.66 \cdot a \cdot P_o - 20 \quad , \quad \text{dollar}/1000\ \text{m}^3 \quad .$$

SOURCE: Jawetz, P. (1984), *Using natural gas to open the way for other future gas and alcohol sources*, presented at the International Gas Meeting, held at the International Institute for Applied Systems Analysis, Laxenburg, Austria, October 18-19.

Chapter 10

Dependence of Willingness to Pay on Potential Incremental Demand for Natural Gas

Users' willingness to pay, determined by the methods of Chapter 9 and arranged in decreasing numerical value, directly affects resource consumption volume (Figure 10.1).

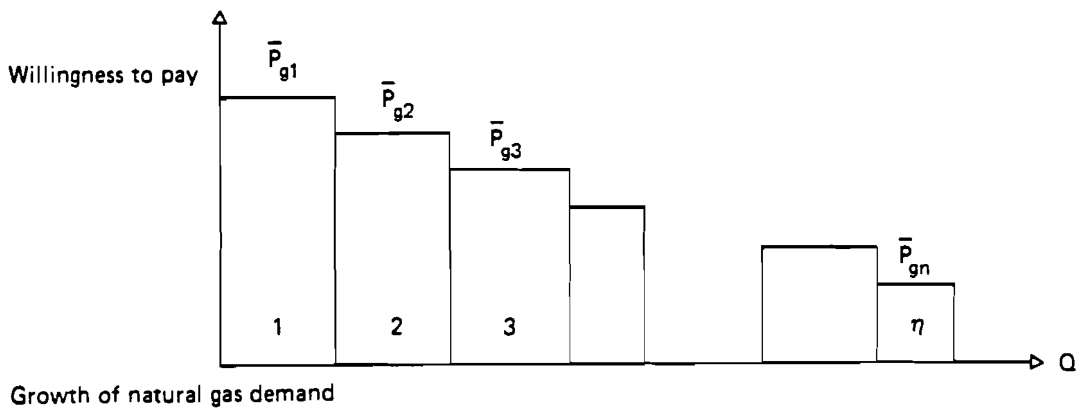

Figure 10.1. Willingness to pay depends on the growth of demand.

This dependence might be applied in explicit form or by means of its approximation in mathematical form (the most simple approximation in the form of the linear dependence is: $p = a + b \cdot Q$.[1]

Willingness to pay is related to FOB user conditions. To determine willingness to pay at the entry to the market, one should subtract from $\bar{P}_g$ the costs of gas distribution within the region and underground storage (the latter for users with clear-cut seasonal uneven consumption). Further, by subtracting from willingness to pay at the entry the long-distance transport costs for exporters, one can determine the willingness to pay at the production site of exporters and by that define which exporters are eligible to enter the market under consideration. The exporters who are prone to participate in the market and volumes of their supplies, in the most simple case, will be determined by a difference between the willingness to pay and individual costs.

Formalization of this idea in the mathematical model enables us to evaluate an optimal strategy for users and exporters in the developing world gas market. (The model description was presented in Chapter 3.)

The willingness-to-pay estimate is carried out for a limited number of major energy users who are in a technological position to use natural gas and a financial position to cover a basic share of the energy demand.

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[1]Linear approximation was chosen for this study to reduce task size, although the choice necessitates applying the square functional to the task of modeling the world natural gas market.

An initial stage involves estimating the status of marginal technologies in each of the gas consumption sectors under consideration. The marginal technology status report is prepared on the basis of additional economic considerations and expert estimate. Table 10.1 estimates marginal technologies in basic sectors of natural gas consumption over the period 1990–2020 for the US, Western Europe, and Japan.[2]

In estimating the natural gas consumption volume, it has been assumed that the energy resources consumption forecasting as well as its direction by markets under consideration (regions) and the time period are known.

It is assumed that the potential growth in the natural gas consumption for a user j is determined by two summands, one of which is the growth over the period achieved with the equipment using natural gas, provided the capacity drop due to the expiration of earlier equipment has been taken into account. The second summand represents the growth in consumption of the alternative energy carriers, which, under certain conditions in the gas market, could be replaced with gas, provided their withdrawal effects have been taken into account. As the general case stands, the potential growth in natural gas demand for user j over period t is equal to

$$Qjt = (Qgjt-(1-\lambda g)Qgjt-1) + \sum_{s} \frac{(Qsjt-(1-\lambda s)}{\eta gjt} Qsjt-1)\,\eta sjt \quad ,$$

where $Qgjt$ – gas consumption by user j; $Qsjt$ – a fuel form S consumed by user j that might be replaced with gas; λs, λs – decline in the gas demand over past period g or in the alternate carrier demand s due to wear and tear on the old equipment; ηgjt, ηsjt – gas utilization efficiency g and that of the alternate energy carrier s for user j.

On completing the calculations of the gas willingness-to-pay $\overline{Pjt}$ and potential consumption volume Qjt, the decreasing order ranging of the above is carried out. Eventually, users with a negative willingness to pay ($\overline{P}gt < 0$) are excluded from consideration as their gas utilization over the period is bound to be inefficient at the given prices for marginal energy resources. A cumulative potential growth in natural gas demand will be $Qt = \sum_{j} Qjt$ (for j under $\overline{P}jt > 0$).

In this way, a graph of the potential demand for natural gas at the market, depending on the gas selling price, is constructed.

A potential demand meets a supply of practically unlimited gas deliveries to the market at a very low price. In fact, actual gas consumption volumes will be determined by the alternate marginal energy resource prices, by market entry costs of gas suppliers, and by state policies toward exporters and importers. As a rule, actual consumption will be considerably less than the potential demand. The actual gas consumption level in the world market is carried out on the basis of the world gas supply system dynamic model.

The willingness of individual categories of consumers to pay for natural gas is determined by two main factors: (1) by the price of a competitive fuel; and (2) by

[2]The expert estimates presented in Table 10.1 were calculated over the course of two stages: First, probable introduction of electric energy into each of the processes has been studied with respect to the expected prices and efficiency. Second, fuel technology developments embracing the technologies marginal to natural gas have been defined.

Table 10.1. Marginal energy resources and technologies used in calculation of marginal natural gas prices for the US. Western Europe, and Japan.

Natural Gas-Consuming Sector	Years			
	1990-2000	2000-2010	2010-2020	2020-2030
Electric power plants				
Base-load	coal-fired plant	LWRs	FBRs	FBRs
Intermediate-load	coal-fired plant	coal-fired plant	coal-fired plant	coal-fired plant
Peak-load	liquid-fueled gas turbine plant	liquid-fueled gas turbine plant	liquid-fueled gas turbine plant	liquid-fueled gas turbine plant
Boiler plants				
Industrial	fuel oil	coal[a]	coal[a]	coal[a]
Heating (large)	fuel oil	fuel oil	nuclear heat supply	nuclear heat supply
Local space and water heating plants	distillate	distillate	distillate	distillate
Cooking	distillate	distillate	distillate	distillate
Industrial high-temperature furnaces	fuel oil	fuel oil	fuel oil	fuel oil
Automobile transport	gasoline diesel fuel	gasoline diesel fuel	gasoline diesel fuel	gasoline diesel fuel
Feedstocks				
Ammonia	coal	coal	coal	coal
Methanol	coal	coal	coal	coal
Ethylene	naphtha	naphtha	naphtha	naphtha

[a]Fluidized-bed combustion.

the natural gas/competitive fuel economics ratio. The latter factor's influence was studied in detail in Chapter 9; here, we briefly consider the price of major competitive fuels – coal and petroleum products.

The present study uses oil price projections as a basis for three scenarios (Section 2.1):

	1980 $/t				
	1980	1990	2000	2010	2020
Minimum level	230	125	145	175	220
Medium level	230	150	180	220	270
Maximum level	230	175	205	260	330

To change from crude oil to petroleum product prices, use has been made of conversion coefficients that were typical of the early 1980s and that are assumed to be constant throughout the projection period (Table 10.2)

Moreover, we have taken into account the costs involved in liquid petroleum products distribution, which are heavily dependent on type of fuel and the consumer category (Table 10.3).

Table 10.2. Petroleum product/crude oil ratio (as of early 1980).

Crude oil	- 1.00
Gasoline, kerosene	- 1.25
Diesel fuel and domestic furnace fuel	- 1.15
Naphtha	- 1.50
Fuel oil	- 0.85

SOURCES: Messner, M. (1984), *User's Guide for the Matrix Generation of MESSAGE II, Part I: Model Description and Implementation Guide and Part II: Appendices*. Working Papers WP-84-71a and WP-84-71b (International Institute for Applied Systems Analysis, Laxenburg, Austria); and Strubegger, M. (1984), *User's Guide for the Post-Processor of MESSAGE II*, Working Paper WP-84-72 (International Institute for Applied Systems Analysis, Laxenburg, Austria).

Table 10.3. Economics of petroleum products distribution (in 1980 $/t).

Petroleum Product	Electric Power Plants	Industry	Residential and Commercial Sector
Fuel oil	10-15	15-20	15-20
Domestic furnace fuel	-	-	60
Motor fuel	-	-	60

SOURCES: Data based on Messner, S. *op.cit.* and Strubegger, M. *op.cit.*

Table 10.4 gives coal cost estimates for major natural gas markets. It is assumed that the values given in the table will persist through to 2000; after that, one can expect coal prices to grow slightly as cheap coals of the main solid fuel exporters are depleted. Table 10.5 provides the values of additional costs of intraregional coal distribution to end users.

Estimates of the potential demand for natural gas by each of the consuming sectors are determined according to the energy consumption forecasts developed in Chapter 2.

The results of calculating the dependence of the willingness to pay for natural gas on its consumption growth are given in Tables 10.6–10.14.

Table 10.4. Economics of coal production and transportation (in 1980 $/tce).

Country	Exploration	Production (denominator, mean value)	Intraregional Transportation to the Shore	Terminals	Sea Transportation to: Western Europe	Sea Transportation to: Japan	Coal Market Price: US	Coal Market Price: Western Europe	Coal Market Price: Japan
US		$\frac{10-100}{90}$ [a]	5-10 (300-1000 km)	4-8	5-10	7-12	50-60	65-75[b]	40-60[c]
Western Europe		$\frac{18-117}{(100)}$	4-5 (200-250 km)	-	-	-	-	100	-
Australia	1-2	$\frac{27-72}{(30)}$	2-3 (100-200 km)	4-8	15-20	6-10	-	55-65	40-50
Canada		$\frac{39-101}{(40)}$	12-15 (600-800 km)	4-8	16-20	6-10	-	70-80	63-76
South Africa		$\frac{13-43}{(20)}$	4-5 (150-200 km)	4-8	9-12	9-12	-	35-50	35-50
Developing Countries (China)		$\frac{20-150}{(20)}$	4-5 (150-200 km)	4-8	15-20	2-3	-	50-60	30-35

[a] The following costs are assumed in subsequent calculations: $50/tce (Eastern coals) and $20/tce (Western coals).
[b] Eastern coals.
[c] Western coals.
NOTE: Calculated from Long, R. (1983), *Coal and the Cost of Energy*, Working Paper No. 64 (IEA Coal Research, London).

Table 10.5. Economics of coal distribution.

Residential and Commercial Sectors[a]	1980 $/tce
Country-side	- 70-80
Small and larger towns	- 45-60
Big cities	- 30-35
Industry	- 15-20
Electric power plants	- 5-10

[a]Calculated from During, K. *et al.* (1979), Central versus decentral energy supply strategies for industrialize countries – soft or hard energy strategies. *Proceedings, Second International Conference on Energy Use Management*, R.A. Fazzolare and C.B. Smith, eds. Oxford: Pergamon Press.

Table 10.6. Dependence of potential incremental demand for natural gas on its price: the US (minimum scenario).

Technology No.	Marginal Price	Incremental Demand	Technology No.	Marginal Price	Incremental Demand
	1990			*2000*	
12	325.00	0.70	12	370.00	2.60
2	280.00	1.70	2	280.00	4.60
7	185.00	23.70	10	210.00	35.60
8	180.00	27.00	4	205.00	51.60
3	160.00	29.00	7	205.00	75.60
4	152.00	44.00	8	200.00	78.20
11	145.00	68.00	3	160.00	81.70
14	145.00	68.00	5	160.00	111.70
9	140.00	96.00	11	160.00	140.70
10	135.00	118.00	14	160.00	149.70
6	130.00	119.30	6	140.00	143.70
5	115.00	147.30	9	140.00	174.70
1	85.00	147.30	1	120.00	175.70
15	50.00	147.30	13	70.00	175.70
			15	60.00	175.70
	2010			*2020*	
12	430.00	5.00	12	520.00	8.00
2	295.00	8.50	2	305.00	12.00
7	235.00	31.50	7	280.00	32.00
8	225.00	34.10	8	270.00	34.00
4	220.00	51.10	1	245.00	39.50
6	205.00	55.10	10	245.00	91.50
10	190.00	95.00	11	230.00	124.50
11	185.00	131.10	4	220.00	145.50
14	185.00	131.10	14	220.00	145.50
1	170.00	143.10	6	215.00	150.50
3	165.00	138.10	3	170.00	154.50
5	145.00	171.10	5	145.00	188.50
9	130.00	199.10	9	135.00	205.50
13	85.00	199.10	13	110.00	205.50
15	75.00	199.10	15	100.00	205.20

NOTE: The technologies are defined as follows: (1) ethylene; (2) methanol; (3) ammonia; (4) industrial furnaces; (5) industrial boilers; (6) space heating and hot water supply in centralized systems; (7) space heating in decentralized systems; (8) same for hot water supply; (9) cooking; (10) thermal power plants, base load; (11) thermal power plants, intermediate load; (12) thermal power plants, peak load; (13) methanol addition to gasoline; (14) gasoline from methanol; and (15) diesel fuel from methanol.

Table 10.7. Dependence of potential incremental demand for natural gas on its price: the US (medium scenario).

Technol-ogy No.	Marginal Price	Incremental Demand	Technol-ogy No.	Marginal Price	Incremental Demand
	1990			2000	
12	368.00	3.25	12	403.00	6.50
2	308.00	6.75	2	308.00	11.50
7	201.00	53.75	7	233.00	54.50
4	173.00	102.05	10	233.00	153.50
3	168.00	109.55	8	198.00	156.50
8	166.0	112.85	4	193.00	206.40
11	153.00	193.85	11	178.00	304.40
9	143.00	290.85	3	168.00	311.90
14	131.00	296.05	1	163.00	314.40
6	128.00	311.05	14	153.00	320.40
10	123.00	386.05	6	148.00	334.40
5	118.00	454.35	5	143.00	388.20
1	113.00	454.35	9	143.00	487.20
13	58.00	454.35	13	73.00	487.20
15	28.00	454.35	15	43.00	487.20
	2010			2020	
12	485.00	14.30	12	595.00	18.20
2	319.00	19.80	7	345.00	54.20
7	310.00	58.80	1	300.00	66.70
8	235.00	61.80	2	300.00	75.20
1	234.00	66.80	8	285.00	77.20
11	219.00	183.80	11	264.00	181.20
4	216.00	233.70	4	250.00	230.80
10	203.00	383.70	14	230.00	242.80
6	194.00	395.70	10	210.00	395.80
14	185.00	405.70	6	205.00	407.80
3	174.00	412.70	3	175.00	414.30
9	139.00	502.70	9	140.00	468.30
5	124.00	542.80	5	125.00	505.30
13	100.00	542.80	13	125.00	505.30
15	64.00	542.80	15	90.00	505.30

NOTE: For definition of technologies see Table 10.6.

Table 10.8. Dependence of potential incremental demand for natural gas on its price: the US (maximum scenario).

Technology No.	Marginal Price	Incremental Demand	Technology No.	Marginal Price	Incremental Demand
	1990			*2000*	
2	308.00	3.50	12	333.00	5.50
12	290.00	7.00	2	308.00	11.50
7	170.00	59.00	10	223.00	115.50
3	168.00	66.50	7	193.00	167.50
14	145.00	72.40	3	168.00	175.00
9	143.00	171.40	4	168.00	225.00
4	140.00	218.40	8	163.00	228.00
8	140.00	221.90	11	148.00	326.00
11	133.00	306.90	5	143.00	382.00
10	123.00	382.90	9	143.00	484.00
6	118.00	400.90	6	128.00	501.00
5	103.00	469.90	14	123.00	508.20
1	73.00	469.90	1	108.00	510.70
13	48.00	469.90	13	58.00	510.70
15	38.00	469.90	15	48.00	510.70
	2010			*2020*	
12	395.00	14.00	12	485.00	18.00
2	320.00	19.50	7	345.00	64.00
7	265.00	69.50	8	335.00	66.00
8	235.00	72.50	2	320.00	75.00
10	210.00	212.50	1	235.00	87.00
4	190.00	262.50	11	220.00	198.00
3	175.00	269.50	4	210.00	248.00
11	175.00	389.50	10	210.10	417.00
1	160.00	394.50	6	205.00	433.00
14	150.00	403.50	14	185.00	447.00
9	140.00	495.50	3	175.00	453.00
6	130.00	511.50	9	140.00	510.00
5	125.00	559.50	5	125.00	554.00
13	75.00	559.50	13	100.00	554.00
15	65.00	559.50	15	90.00	554.00

NOTE: For definition of technologies see Table 10.6.

Table 10.9. Dependence of potential incremental demand for natural gas on its price: Western Europe (minimum scenario).

Technology No.	Marginal Price	Incremental Demand	Technology No.	Marginal Price	Incremental Demand
	1990			*2000*	
12	346.00	3.90	12	403.00	5.90
2	328.00	6.90	2	330.00	9.30
3	178.00	12.30	10	230.00	74.30
4	178.00	54.30	4	205.00	111.30
11	163.00	106.40	1	200.00	113.30
9	153.00	173.40	11	195.00	175.30
1	148.00	173.40	7	183.00	263.30
7	146.00	271.40	3	180.00	269.30
8	141.00	280.40	8	178.00	277.30
6	138.00	287.80	6	170.00	288.30
5	128.00	363.80	9	155.00	353.30
10	113.00	407.80	5	150.00	417.30
14	98.00	409.10	14	133.00	421.80
13	58.00	409.10	13	80.00	421.80
15	50.00	409.10	15	70.00	421.80
	2010			*2020*	
12	540.00	9.10	12	700.00	9.00
2	350.00	14.10	1	415.00	18.50
1	300.00	19.10	2	360.00	25.50
7	250.00	97.10	7	330.00	93.50
11	250.00	165.10	8	320.00	98.50
4	245.00	198.10	11	315.00	163.50
8	240.00	205.10	4	290.00	193.50
10	225.00	295.10	14	260.00	196.50
6	205.00	308.10	10	230.00	296.50
3	190.00	314.60	6	210.00	311.50
14	190.00	323.60	3	195.00	317.90
9	155.00	377.60	9	160.00	351.90
5	135.00	423.60	13	145.00	351.90
13	110.00	423.60	5	140.00	375.90
15	100.00	423.60	15	140.00	375.90

NOTE: For definition of technologies see Table 10.6.

Table 10.10. Dependence of potential incremental demand for natural gas on its price: Western Europe (medium scenario).

Technology No.	Marginal Price	Incremental Demand	Technology No.	Marginal Price	Incremental Demand
	1990			*2000*	
2	328.00	3.00	12	365.00	6.00
12	276.00	6.90	2	330.00	9.50
3	178.00	12.40	10	230.00	81.50
4	163.00	54.40	4	185.00	123.50
9	153.00	121.40	11	170.00	188.50
11	143.00	176.40	7	162.00	282.50
7	126.00	276.70	3	160.00	288.50
8	121.00	285.70	8	157.00	296.50
6	113.00	293.00	1	155.00	298.50
10	113.00	338.00	9	155.00	370.50
5	108.00	422.00	6	150.00	381.50
1	103.00	422.00	5	150.00	456.50
14	66.00	423.30	14	115.00	470.50
13	28.00	423.30	13	65.00	470.50
15	2.00	423.30	15	35.00	470.50
	2010			*2020*	
12	455.00	9.10	12	580.00	9.00
2	350.00	14.10	2	362.00	16.00
1	230.00	19.10	1	317.00	25.50
10	255.00	114.10	11	262.00	100.50
7	215.00	202.10	7	260.00	188.50
11	215.00	277.10	8	250.00	195.50
4	210.00	319.10	4	247.00	237.50
8	205.00	326.10	10	230.00	332.50
6	205.00	341.10	6	210.00	347.50
3	170.00	347.60	14	205.00	352.50
14	155.00	353.60	3	172.00	360.00
9	155.00	412.60	9	162.00	419.00
5	135.00	484.60	5	142.00	469.00
13	95.00	484.60	13	122.00	469.00
15	60.00	484.60	15	87.00	469.00

NOTE: For definition of technologies see Table 10.6.

Table 10.11. Dependence of potential incremental demand for natural gas on its price: Western Europe (maximum scenario).

Technology No.	Marginal Price	Incremental Demand	Technology No.	Marginal Price	Incremental Demand
	1990			*2000*	
2	328.00	3.00	2	330.00	3.50
12	241.00	6.90	12	295.00	8.50
3	178.00	12.40	10	215.00	85.50
9	163.00	82.40	3	180.00	91.50
4	130.00	126.40	4	160.00	137.50
10	115.00	232.40	5	150.00	300.50
6	108.00	241.40	11	140.00	375.50
1	103.00	241.40	7	130.00	473.50
7	101.00	343.40	8	125.00	481.50
8	96.00	351.90	6	120.00	493.50
5	93.00	435.90	1	100.00	495.50
14	61.00	437.20	14	85.00	499.50
13	38.00	437.20	13	50.00	499.50
15	28.00	437.20	15	40.00	499.50
	2010			*2020*	
12	365.00	9.00	12	470.00	9.00
2	350.00	14.00	2	385.00	16.00
10	225.00	121.00	1	235.00	25.00
3	190.00	142.00	8	220.00	122.00
6	205.00	136.00	7	230.00	177.00
4	185.00	188.00	11	220.00	213.00
7	170.00	282.00	6	215.00	231.00
11	170.00	360.00	4	210.00	277.00
8	160.00	367.00	10	210.00	421.00
1	155.00	372.00	3	200.00	427.00
9	155.00	471.00	14	170.00	433.00
5	135.00	558.00	9	165.00	480.00
14	120.00	564.00	5	145.00	558.00
13	70.00	564.00	13	100.00	558.00
15	60.00	564.00	15	90.00	558.00

NOTE: For definition of technologies see Table 10.6.

Table 10.12. Dependence of potential incremental demand for natural gas on its price: Japan (minimum scenario).

Technology No.	Marginal Price	Incremental Demand	Technology No.	Marginal Price	Incremental Demand
	1990			*2000*	
12	360.00	0.70	12	430.00	3.20
2	265.00	1.70	2	268.00	5.20
4	185.00	16.70	4	213.00	17.60
11	170.00	41.70	1	208.00	18.60
7	160.00	61.70	11	203.00	47.60
1	155.00	61.70	7	200.00	68.60
8	155.00	64.30	10	198.00	98.60
3	145.00	66.30	8	195.00	101.20
6	145.00	67.70	6	178.00	103.50
5	135.00	93.80	14	150.00	103.50
9	125.00	123.80	3	148.00	107.00
10	120.00	145.80	5	148.00	129.00
14	115.00	145.80	9	128.00	160.00
13	65.00	145.80	13	88.00	160.00
15	55.00	145.80	15	78.00	160.00
	2010			*2020*	
12	555.00	3.90	12	720.00	10.00
1	305.00	6.90	1	423.00	15.50
2	285.00	10.40	7	345.00	29.50
7	265.00	28.40	8	335.00	31.50
8	255.00	30.40	11	323.00	64.50
11	255.00	63.40	2	298.00	68.50
4	250.00	73.40	4	298.00	76.00
14	205.00	73.40	14	275.00	76.00
6	195.00	76.80	6	208.00	80.30
10	180.00	116.80	10	188.00	102.30
3	155.00	120.80	3	163.00	106.30
5	130.00	138.90	13	153.00	106.30
9	120.00	165.90	15	143.00	106.30
13	115.00	165.90	5	138.00	119.10
15	105.00	165.90	9	128.00	134.10

NOTE: For definition of technologies see Table 10.6.

Table 10.13. Dependence of potential incremental demand for natural gas on its price: Japan (medium scenario).

Technology No.	Marginal Price	Incremental Demand	Technology No.	Marginal Price	Incremental Demand
	1990			*2000*	
12	308.00	0.70	12	380.00	2.60
2	265.00	1.70	2	268.00	6.50
4	170.00	16.60	10	198.00	36.50
3	165.00	18.60	4	193.00	52.40
11	150.00	43.60	7	180.00	74.40
7	138.00	64.60	11	178.00	107.40
8	133.00	67.90	8	175.00	110.00
9	125.00	95.90	3	168.00	113.50
6	125.00	97.30	1	148.00	114.50
10	120.00	119.30	6	148.00	117.50
5	115.00	146.60	5	148.00	146.50
1	110.00	146.60	14	130.00	146.50
14	98.00	146.60	9	128.00	175.50
15	25.00	146.60	13	73.00	175.50
			15	43.00	175.50
	2010			*2020*	
12	470.00	5.00	12	593.00	10.00
2	285.00	8.50	1	323.00	15.50
1	235.00	11.50	2	298.00	19.50
7	230.00	33.50	7	288.00	37.50
8	220.00	35.80	8	278.00	39.10
11	220.00	68.80	11	268.00	68.10
4	215.00	85.70	4	253.00	85.60
6	195.00	89.00	14	223.00	85.60
10	180.00	125.00	6	208.00	89.60
3	175.00	130.00	10	188.00	136.60
14	170.00	130.00	3	178.00	140.60
5	130.00	159.30	5	138.00	173.60
9	120.00	184.30	9	128.00	188.60
13	100.00	184.30	13	128.00	191.60
15	65.00	184.30	15	93.00	191.60

NOTE: For definition of technologies see Table 10.6.

Table 10.14. Dependence of potential incremental demand for natural gas on its price: Japan (maximum scenario).

Technology No.	Marginal Price	Incremental Demand	Technology No.	Marginal Price	Incremental Demand
	1990			*2000*	
12	325.00	0.70	12	370.00	2.60
2	280.00	1.70	2	280.00	4.60
7	185.00	23.70	10	210.00	35.60
8	180.00	27.00	4	205.00	51.60
3	160.00	29.00	7	205.00	75.60
4	152.00	44.00	8	200.00	78.20
11	145.00	68.00	3	160.00	81.70
14	145.00	68.00	5	160.00	111.70
9	140.00	96.00	11	160.00	140.70
10	135.00	118.00	14	160.00	149.70
6	130.00	119.30	6	140.00	143.70
5	115.00	147.30	9	140.00	174.70
1	85.00	147.30	1	120.00	175.70
15	50.00	147.30	13	70.00	175.70
			15	60.00	175.70
	2010			*2020*	
12	430.00	5.00	12	520.00	8.00
2	295.00	8.50	2	305.00	12.00
7	235.00	31.50	7	280.00	32.00
8	225.00	34.10	8	270.00	34.00
4	220.00	51.10	1	245.00	39.50
6	205.00	55.10	10	245.00	91.50
10	190.00	95.10	11	230.00	124.50
11	185.00	131.10	4	220.00	145.50
14	185.00	131.10	14	220.00	145.50
1	170.00	134.10	6	215.00	150.50
3	165.00	138.10	3	170.00	154.40
5	145.00	171.10	5	145.00	188.50
9	130.00	199.10	9	135.00	205.50
13	85.00	199.10	13	110.00	205.50
15	75.00	199.10	15	100.00	205.50

NOTE: For definition of technologies see Table 10.6.

Chapter 11

Future Prospects for the International Natural Gas Trade

The previously considered factors conditioning the development of the international natural gas market have been integrated within several scenarios postulated on the basis of the dynamic model for the international gas market (Chapter 3).

Let us highlight the basic characteristics of the main scenarios considered in the paper:

(a) The time frame is between 1990 and 2020 with a breakdown into ten-year periods.

(b) Major natural gas consumers are the US, Western Europe, and Japan.

(c) Three hypotheses of crude oil price growth are considered: 1 – low prices, 2 – moderate prices, and 3 – high prices.

(d) Two extreme versions of export potential have been accepted for "other" exporters (this group includes the USSR): 1 – throughout the entire time frame, "others" keep their export potential at the 1990 level; 2 – every ten years "others" increase their potential by some 40 bcm/yr, which equals the throughput capacity of a new large-diameter pipeline.

(e) An assessment has been made of the influence of the two strategies of gas-importing countries (notably West European countries) on outside exporters: 1 – of imposing limitations on the share of large individual gas exporters in total gas imports; 2 – of no limitations, the market share of individual gas exporters depends on their compatibility.

The main results of modeling are given in the following tables:

Tables 11.1–11.3	natural gas balance for the US
Tables 11.4–11.6	natural gas balance for Western Europe
Tables 11.7–11.9	natural gas balance for Japan
Tables 11.10–11.12	"direct" discounted effect of natural gas trade.

11.1. The general situation

Proceeding from the future prospects for the energy economy of industrialized capitalist countries (Chapter 2), one can expect the demand for fossil fuels (potential demand for natural gas) to rise rather than to decline.[1] Indigenous gas production in these regions will constantly decline. By 2020 natural gas production in the US is expected to drop by a factor of 4–4.5 from the present level. In Western Europe, excluding Norway, it will fall less than threefold. Against the background of the overall, though much slower than earlier expected, growth of energy prices and also of production and transportation costs, this will have a

[1] The authors think that the low and moderate oil price scenarios are the most probable in the long term. Under this assumption further growth in energy consumption (including fossil fuel) is expected.

Table 11.1. Natural gas balance for the US, minimum scenario (high energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (without limitations on export to Europe)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	2170	2547	2565	2490	2310	2547	2565	2490	2310
Potential demand for natural gas (bcm)	2000	1935	1895	1725	1485	1935	1895	1725	1485
Actual demand (bcm)	578	520	430	305	240	520	430	305	265
Natural gas resources (bcm)									
(a) Domestic production, including introduction of new capacities	548	500	400	260	125	500	400	260	125
category I		55	55	55	-	55	55	55	-
category II		75	180	205	125	75	180	205	125
category III		-	-	-	-	-	-	-	-
(b) Import, total	28	20	30	45	115	20	30	50	140
Canada		18	18	18	18	18	18	18	18
Mexico		2	12	19	29	2	12	19	28
Nigeria		-	-	6	17	-	-	8	17
Persian Gulf		-	-	-	54	-	-	-	70
Southeast Asia		-	-	2	2	-	-	5	7
Natural gas price at the point of entry into the region ($/1000 m^3)		155	195	270	330	155	195	270	310

Table 11.2. Natural gas balance for the US, medium scenario (moderate energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (without limitations on export to Europe)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	2449.1	2645	2865	3110	3145	2645	2865	3110	3145
Potential demand for natural gas (bcm)	1890.0	2015	2145	2270	2185	2015	2145	2270	2185
Actual demand (bcm)		521	430	300	230	521	430	300	250
Natural gas resources (bcm)									
(a) Domestic production, including introduction of new capacities		500	400	255	125	500	400	255	125
category I		55	55	55	-	55	55	55	-
category II		75	180	200	125	75	180	200	125
category III		-	-	-	-	-	-	-	-
(b) Import, total		21	30	45	100	21	30	45	125
Canada		19	19	18	18	19	19	18	18
Mexico		2	11	19	28	2	11	20	30
Nigeria		-	-	8	17	-	-	7	17
Persian Gulf		-	-	-	37	-	-	-	60
Natural gas price at the point of entry into the region ($/1000 m^3)		145	190	245	265	145	190	245	255

Table 11.3. Natural gas balance for the US, maximum scenario (low energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (without limitations on export to Europe)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	2449.1	2730	3100	3445	3565	2730	3100	3445	3565
Potential demand for natural gas (bcm)	1890.0	2090	2345	2550	2540	2090	2345	2550	2540
Actual demand (bcm)		520	430	295	235	521	430	295	255
Natural gas resources (bcm)									
(a) Domestic production, including introduction of new capacities		500	400	250	125	500	400	250	125
category I		55	55	55	-	55	55	55	-
category II		75	180	195	125	75	180	195	125
category III		-	-	-	-	-	-	-	-
(b) Import, total	21.0	21	30	45	110	21	30	45	130
Canada		19	19	18	18	19	19	18	18
Mexico		2	11	19	28	2	11	20	30
Nigeria		-	-	8	17	-	-	7	17
Persian Gulf		-	-	-	47	-	-	-	65
Natural gas price at the point of entry into the region ($/1000 m^3)		125	175	230	260	125	175	230	250

Table 11.4. Natural gas balance for Western Europe, minimum scenario (high energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (with limitations on export				"Others" by Maximum (without limitations on export)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	1912.9	2015	2125	2170	2195	2015	2125	2170	2195	2015	2125	2170	2195
Potential demand for natural gas (bcm)	1435.0	1450	1490	1460	1370	1450	1490	1460	1370	1450	1490	1460	1370
Actual demand (bcm)		240	270	205	225	235	270	215	265	245	290	250	285
Natural gas resources (bcm)		240	270	205	225	235	270	215	265	245	290	250	285
(a) Domestic production, including introduction of new capacities		140	150	80	65	150	145	80	55	150	140	80	60
category I		13	23	23	10	23	23	23	-	21	23	23	2
category II		-	27	27	25	-	17	27	25	-	16	27	28
category III		-	-	30	30	-	-	30	30	-	-	30	30
(b) Import, total		100	120	125	160	85	125	135	210	95	150	170	225
Norway		27	27	40	50	27	27	40	50	27	27	40	50
Algeria		28	38	38	38	17	38	38	38	28	38	38	38
Nigeria		-	-	-	-	-	-	-	-	-	-	-	-
Persian Gulf		-	12	12	35	-	10	14	50	-	7	-	-
"others"		45	43	35	37	41	42	43	72	40	78	92	137
Natural gas price at the point of entry into the region ($/1000 m^3)		160	200	200	280	162	200	190	265	157	195	180	240

Table 11.5. Natural gas balance for Western Europe, medium scenario (moderate energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (with limitations on export				"Others" by Maximum (without limitations on export)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	1912.9	2060	2270	2380	2515	2060	2270	2380	2515	2060	2270	2380	2515
Potential demand for natural gas (bcm)	1433.6	1485	1615	1595	1640	1485	1615	1595	1640	1485	1615	1595	1640
Actual demand (bcm)		240	270	205	235	235	270	215	275	245	290	255	295
Natural gas resources (bcm)													
(a) Domestic production, including introduction of new capacities		141	150	80	65	150	140	80	55	150	145	80	58
category I		13	23	23	9	23	23	23	-	21	23	23	1
category II		-	24	27	26	-	13	25	25	-	17	27	27
category III		-	-	30	30	-	-	32	32	-	-	30	30
(b) Import, total		99	120	125	170	85	130	135	220	95	145	175	237
Norway		27	27	40	50	27	27	40	50	27	27	30	50
Algeria		28	38	38	38	17	38	38	38	28	38	38	38
Persian Gulf		-	11	11	40	-	14	14	55	-	6	6	8
"others"		44	44	36	42	41	51	43	77	40	74	101	141
Natural gas price at the point of entry into the region ($/1000 m^3)		160	195	200	235	163	195	200	220	165	185	195	215

Table 11.6. Natural gas balance for Western Europe, maximum scenario (low energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (with limitations on export				"Others" by Maximum (without limitations on export)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	1912.9	2120	2430	2650	2870	2120	2430	2650	2870	2120	2430	2650	2870
Potential demand for natural gas (bcm)	1433.6	1540	1745	1865	1935	1540	1715	1865	1935	1540	1745	1865	1935
Actual demand (bcm)		240	255	205	220	235	255	260	265	245	280	265	290
Natural gas resources (bcm)													
(a) Domestic production, including introduction of new capacities		145	140	80	65	150	125	80	55	150	135	80	55
category I		15	25	25	10	25	25	25	-	25	25	25	-
category II		-	15	25	25	-	-	25	25	-	-	25	25
category III		-	-	30	30	-	-	30	30	-	-	30	30
(b) Import, total		95	115	125	155	85	130	160	210	95	145	185	235
Norway		27	27	40	50	27	27	40	50	27	27	35	50
Algeria		28	38	38	38	18	38	38	38	28	38	38	38
Nigeria		-	-	-	10	-	-	-	-	-	-	-	-
Persian Gulf		-	10	10	17	-	13	15	50	-	5	5	3
"others"		40	40	40	40	40	50	67	72	40	75	107	144
Natural gas price at the point of entry into the region ($/1000 m^3)		160	185	190	215	165	185	185	205	157	180	185	190

Table 11.7. Natural gas balance for Japan, minimum scenario (high energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (with limitations on export				"Others" by Maximum (without limitations on export)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	555.8	646	725	795	745	646	725	795	745	646	725	795	745
Potential demand for natural gas (bcm)	440.0	500	520	540	470	500	520	540	470	500	520	540	470
Actual demand (bcm)		37	46	50	60	37	43	45	55	38	50	55	70
Import (bcm), total		37	46	50	60	37	43	45	55	38	50	55	70
Persian Gulf		2	3	3	-	2	-	-	-	2	6	6	14
Southeast Asia		34	42	37	50	34	42	37	45	34	40	42	45
others		1	1	10	10	1	1	8	10	2	4	7	11
Natural gas price at the point of entry into the region ($/1000 m^3)		165	190	225	285	165	195	225	285	165	185	220	275

Table 11.8. Natural gas balance for Japan, medium scenario (moderate energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (with limitations on export				"Others" by Maximum (without limitations on export)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	555.8	665	771	862	865	665	771	862	865	665	771	862	865
Potential demand for natural gas (bcm)	440.0	480	490	510	535	480	490	510	535	480	490	510	540
Actual demand (bcm)		38	45	46	60	37	42	50	60	38	52	50	75
Import (bcm), total		38	45	46	61	37	42	50	60	38	52	60	75
Persian Gulf		2.5	1.5	1.5	1	2.4	-	-	-	2.5	7	7	15
Southeast Asia		34	42	36.5	51	34	42	45	50	34	42	43	50
others		1.5	1.5	9	9	0.6	-	5	10	1.5	3	10	10
Natural gas price at the point of entry into the region ($/1000 m^3)		165	190	200	240	166	200	200	260	165	190	200	250

Table 11.9. Natural gas balance for Japan, maximum scenario (low energy prices).

	"Others" at the 1990 Level					"Others" by Maximum (with limitations on export				"Others" by Maximum (without limitations on export)			
	1980	1990	2000	2010	2020	1990	2000	2010	2020	1990	2000	2010	2020
Total energy consumption (million tce)	555.8	690	845	965	1000	690	845	965	1000	690	845	965	1000
Potential demand for natural gas (bcm)	440.0	480	490	525	555	480	490	525	555	480	490	525	555
Actual demand (bcm)		38	46	50	62	37	42	46	60	38	52	58	75
Import (bcm), total		38	46	50	62	37	42	46	60	38	52	58	75
Persian Gulf		2	2	2	2	2	-	-	-	2	8	8	15
Southeast Asia		34	42	40	50	34	42	42	50	34	40	42	50
others		2	2	8	10	1	-	4	10	2	4	8	10
Natural gas price at the point of entry into the region ($/1000 m^3)		165	195	200	245	166	200	200	245	165	190	200	240

Table 11.10. Estimated direct discounted effects (billion $) of natural gas trade, 1990-2020, minimum scenario (high energy prices).

	"Others" at the 1990 Level	"Others" by Maximum (with limitations on export)	"Others" by Maximum (without limitations) on export)
Importers			
US, total	254.9	249.0	285.0
Gas industry	458.4	459.2	418.3
Consumers	-203.5	-210.2	-133.3
Western Europe, total	4.7	44.6	44.5
Gas industry	55.2	34.9	26.8
Consumers	-50.5	9.7	17.7
Japan, total	-19.0	-16.3	-14.4
Exporters			
Canada	61.7	62.2	56.5
Mexico	107.8	108.6	100.0
Norway	164.4	149.5	128.3
Algeria	192.4	180.6	184.0
Nigeria	38.5	39.0	34.0
Persian Gulf	154.0	141.7	132.9
Southeast Asia	123.5	127.7	117.0
Others	221.4	291.4	508.3

Table 11.11. Estimated direct discounted effects (billion $) of natural gas trade, 1990-2020, medium scenario (moderate energy prices).

	"Others" at the 1990 Level	"Others" by Maximum (with limitations on export)	"Others" by Maximum (without limitations) on export)
Importers			
US, total	148.5	141.0	160.0
Gas industry	259.7	269.4	247.5
Consumers	-111.2	-128.4	-87.5
Western Europe, total	47.8	71.4	67.0
Gas industry	31.4	62.4	2.2
Consumers	16.4	9.0	64.8
Japan, total	-12.0	-9.9	-7.6
Exporters			
Canada	40.7	42.1	38.9
Mexico	80.3	82.4	77.6
Norway	135.9	126.4	114.9
Algeria	183.2	163.3	170.1
Nigeria	23.6	24.8	22.0
Persian Gulf	97.6	91.5	85.7
Southeast Asia	102.0	102.4	93.8
Others	202.0	259.4	447.8

Table 11.12. Estimated direct discounted effects (billion $) of natural gas trade, 1990-2020, maximum scenario (low energy prices).

	"Others" at the 1990 Level	"Others" by Maximum (with limitations on export)	"Others" by Maximum (without limitations) on export)
Importers[a]			
US, total	1.7	-6.9	10.5
Gas industry	164.7	175.1	155.2
Consumers	-163.0	-182.0	-144.7
Western Europe, total	27.2	49.9	45.1
Gas industry	7.9	-8.6	-6.3
Consumers	19.3	58.5	61.4
Japan, total	-9.3	-8.0	-5.8
Exporters			
Canada	34.5	36.1	33.2
Mexico	75.2	77.5	73.1
Norway	121.5	113.5	107.2
Algeria	170.3	151.5	158.5
Nigeria	21.9	23.3	20.3
Persian Gulf	88.0	82.1	82.5
Southeast Asia	96.1	97.3	89.5
Others	188.0	236.3	412.3

[a]The overall effect for regions with domestic gas production is equal to that for consumers and the gas industry.

strong restraining influence on natural gas' contribution to the regions' fuel and energy balance.

On the other hand, for some economic, political, and technical reasons, the export potential of main gas suppliers will be limited compared with the theoretical opportunities offered by the resource base (Chapter 5). Under these circumstances it is likely that by the end of the projection period the actual demand for natural gas in the US will decline more than twofold. In Western Europe this trend will be less pronounced. Depending on the price of competitive energy resources and the attitude of West European countries to gas exporters, the actual demand for gas in this region can be expected to increase to some extent; but for all scenarios this rise will not exceed 25–30% by the end of the period. Far more dynamic is the Japanese market, where the present natural gas share is relatively small and one can expect gas consumption to rise by two to three times the current level. But in absolute terms, the Japanese market will be several times less energy-intensive than that of the US or Western Europe.

Despite rather slow growth in gas consumption, the international trade in natural gas will expand. This will be conditioned, on the one hand, by high competitiveness of natural gas as the most cost effective and ecologically clean fuel and by a rapid decline in indigenous gas production in industrialized capitalist countries, on the other. Our estimates show that over the period under consideration (1990–2020), gas imports in the US may increase five to seven times the present level, and by a factor of 1.5–2.5 in Western Europe and Japan. All scenarios suggest that the exporters' potential should be fully realized (with the exception of "others" in the scenario with limitations on exports to Europe, where import from "other" suppliers is restrained artificially), which points to considerable possibilities for expanding the international gas trade, provided there are additional natural gas supplies to support it.

Natural gas prices. As expected, natural gas prices will be heavily dependent on the price of competitive fuels, notably crude oil and oil products, and, under the hypothesis of oil price growth, will also tend to increase. Because natural gas as an ecologically clean fuel has an advantage over other fuels (which was taken into account in the calculation of the willingness to pay for natural gas), the natural gas/oil price ratio remains higher than 0.1 throughout the entire time frame. For all regions, with oil prices falling, this ratio increases. This can be attributed to the lowering share of natural gas in the fuel and energy balance of the countries, in the event of declining energy prices and higher-value uses. After the year 2000, the price ratio, as a rule, appears lower as a result of reduced expenditures involved in gas stack cleaning and higher efficiency of purification facilities, i.e., natural gas as an ecologically clean fuel becomes less advantageous.

Beyond these considerations, energy prices were estimated with regard for the dynamics of the market per unit of gas distribution costs: for regions with a developed gas supply network (the US, some parts of Europe), these costs are far lower compared with those regions where the network is under development.

11.2. The situation in individual natural gas markets

US. Because of the depletion of fairly cheap natural gas resources, domestic gas consumption in this region is expected to drop to some 430 bcm by 2000 and to 230–265 bcm by 2020. This will result in higher gas imports from neighboring countries, Canada and Mexico, whose export potential will be realized during the entire period. Other exporters – Africa, Persian Gulf countries – because of costly gas transportation by sea, may strengthen their position in the American market only after 2000, when the price of natural gas will be at a level ensuring at least a minimum acceptable profit for these exporters. At the same time the growth in gas prices will reduce gas consumption and limit gas imports.

It should be noted that the modeling effort revealed the influence of the West European market on the American natural gas market. If "other" gas suppliers to the West European market have their export potential at some constant level throughout the entire period, this will result in expanded Middle East supplies to Western Europe where marketing conditions are more favorable than in the US. On the other hand, if the export potential of "other" suppliers increase and export limitations are withdrawn, "others" will begin to oust Middle East gas from the European market. As a result, Middle East gas will go to the US and Japan. That is why natural gas imports in the US will grow, while gas prices will decline somewhat.

As shown in Table 11.10, the discounted effect of gas trade for the American market heavily depends on oil prices. If oil prices remain low, the overall effect over the 30-year period will be within ±10 billion dollars. At high oil prices the effect will amount to an estimated 250–280 billion dollars.

Western Europe. The situation in the West European market is the most complex one. First of all, it should be noted that gas supplies will continue to increase. If "other" suppliers do not expand their export potential, one can expect that by 2000 gas imports will constitute only 115–120 bcm/yr by 2000 and 145–150 bcm/yr by 2020. Should the potential of other suppliers increase, gas imports in Western Europe as a whole may rise to 145–150 bcm and 225–240 bcm, respectively.

It would be interesting to see how the strategy of West European countries for limiting some gas exporters' market share affects the European market. With such limitations in existence, the Persian Gulf countries are expected to enter the market as early as 2000, exports from these countries will rapidly increase and by 2020 may account for one-fourth of total gas supplies. It should be noted that under limitations the availability of very big gas exporters (the USSR, Persian Gulf countries, Algeria, etc.) will promote the expansion of the market, increasing to certain limits the volume of supplies of each of the exporters.

If there are no limitations on individual exporters, gas supplies from "others" – notably, the USSR – are likely to expand to a great extent. By the end of the period it may appear that the West European gas market will be dominated by three major exporters: the USSR, Algeria, and Norway. Supplies from the Persian Gulf countries will be but a small fraction. All other exporters will be ousted by these giants.

The overall benefit derived from natural gas trade for Western Europe in the 1990–2020 period amounts to 5–45 billion dollars (high oil prices) and to 25–50 billion dollars (low oil prices). The small difference in the values of the overall effect is due to the fact that the latter is different for gas consumers and producers. As a result, the two extreme strategies produced almost the same values of the overall effect. It should be emphasized that the maximum benefit was derived in the case of limitations on exporters.

Unlike the American market, which benefits by lower natural gas prices, the European market makes the biggest gains at moderate price growth rates when both gas producers and consumers enjoy positive effect. In this case the overall benefit throughout the period is estimated at 50–70 billion dollars (Table 11.12).

It appeared in the final analysis that the strategy of imposing limitations on gas imports from individual exporters is dictated by political rather than economic considerations. Expansion of natural gas trade in the USSR will result in additional gains 1.5–2.0 times the 1990 level.

Japan. Owing to its geographic position, the Japanese market is marginal in the international trade in liquid and gaseous fuels. As mentioned above. throughout the entire time frame, more dynamic demand for energy resources compared with the other regions of capitalist countries will promote further growth in natural gas consumption, supported by strict ecological constraints and scarcity of indigenous coal resources. At high oil prices gas imports will be somewhat higher, though total energy consumption will be far lower than in the case of low prices. This can be attributed to a reduction in gas consumption in Western Europe. As a result, surplus gas will be supplied to the Japanese market, which will lead to a rise in gas imports at higher oil and gas prices. Again, this points to the dependence of the Japanese gas market on the situation in Western Europe.

If "other" exporters do not expand their potential after 1990, the Persian Gulf countries will orient themselves toward the West European market where the benefit derived from gas sales will be higher than in the Japanese market. As a result, gas export to Japan will decline. Limitation policies will lead to higher gas prices and lower gas consumption in Europe. The greater part of Middle East gas will be brought to Europe where it will enjoy more favorable conditions than in Japan. The Japanese market will receive only small quantities of the remaining Middle East gas.

If "others" expand their potential, then under limitations in the European gas market this will create an additional incentive for Middle East gas to come to Europe because the potential of "other" exporters is higher than that of the Persian Gulf countries. This will mean a reduction in gas supplies to the Japanese market.

A quite different situation will arise in the absence of limitations. In this case the European market will be dominated by "other" exporters, who will almost entirely oust Middle East gas from Europe to Japan. As a result, gas consumption in this region will grow.

Particular reference should be made to the possibilities of Soviet gas exports to Japan. This option was not included in the scenarios under consideration, though additional calculations made in this study confirm its cost effectiveness. In this case one can expect that after 2000 natural gas prices in the Japanese market will be 15–20% lower while gas consumption will increase compared with the options excluding Soviet gas exports. A situation is likely to arise when Soviet gas will begin to oust Middle East gas from the Japanese market. Because of its central position between the two markets, it will be advantageous for Middle East gas exporters to switch over to the European market again.

The assessment of the discounted benefit for Japan in the 1990–2020 period shows that on the whole it has a negative value, which increases as oil prices go up. In all scenarios the value of damage was minimal, provided the export potential of "others" expands to a maximum and limitations in the European market are withdrawn (Table 11.13).

11.3. Individual gas exporters

Canada. Proximity to the US – the world's largest natural gas market with dwindling domestic production – ensures full realization of Canada's export potential throughout the entire time frame. Net export revenues over the 30-year period are estimated at 30–60 billion dollars depending on a level of gas prices.

Mexico. A similar situation exists in Mexico, The country can fully realize its export potential, which is likely to increase in the future. Net export revenues will be equal 75–100 billion dollars.

Norway. Future prospects of the Norwegian gas industry are heavily dependent on oil prices and on West European countries' policies toward gas exporters. Under limitations on gas exporters and at high oil prices, Norway can realize its export potential to the full. At low oil prices the development of prospective natural gas fields in Norway (north of latitude 60° north) does not prove economically justified. This will lead to a drop in the country's gas production. But the existence of limitations makes it possible to keep natural gas prices at a level ensuring that costly Norwegian gas will contribute to West Europe's energy supply. On the whole, the export revenues are estimated at 105–165 billion dollars.

Algeria. Algeria fully realizes its export potential. Thanks to its sound position in the European gas market, Algeria's net export revenues over the entire period account for 150–190 billion dollars.

Nigeria. Our study suggests that Nigeria should enter the world natural gas market after 2000. Its exports will be mainly oriented toward the American market. Net export revenues will be 20–40 billion dollars.

Persian Gulf countries. In the case of low oil prices and no limitations in the European market, the marketing of Middle East gas through to 2000 will encounter certain difficulties. Though, theoretically, the Persian Gulf countries possess a large export potential, their real exports will be substantially lower. Of particular practical concern is the construction of a pipeline that must traverse several countries. With regard for the political situation in the region this will involve additional expenditures, which are likely to make Middle East gas a marginal fuel in the European market. In all other cases the export potential of these countries is fully realized. Net export revenues are estimated at 80–150 billion dollars.

Southeast Asia. This exporter sells gas mainly to Japan where it is a marginal gas supplier. Therefore, Southeast Asia is the first to be affected by all fluctuations in the world natural gas market. For example, when gas deliveries from "others" to Western Europe are on the rise, Middle East gas will be switched over to the Japanese market where it will compete with gas coming from Southeast Asia. Soviet gas exports to Japan may also strongly affect exporters from Southeast Asia. Net export revenues could equal 90–125 billion dollars; if the USSR enters the Japanese market, they will drop at least twofold.

"Other" exporters. The realization of their potential will be heavily dependent on West Europe's strategy. If limitations persist, then by 2020 only half of these exporters' potential will be realized. Net revenues derived from gas sales over the forecast period could amount to 190–510 billion dollars, depending on oil prices and export levels. But it should be noted that if the export potential increases fourfold, then their export revenues will rise by only a factor of 2–2.5.

Thus, under newly emergent trends in future energy supply of developed countries, further expansion of the world natural gas trade is important to both gas importers and gas exporters. The first receive an ecologically clean fuel, which permits them to reduce liquid fuel consumption and in some cases coal as well. The indirect effect resulting from reduced health hazard and environmental pollution is far higher than an inevitable rise in the price of gaseous fuels. For exporters, primarily developing countries, the natural gas trade will facilitate the solution of their domestic social and economic problems.

One can hardly expect, however, that natural gas' contribution can be compared with that of oil. Natural gas should be viewed rather as a temporary option for the period of transition from the energy economy based on fossil fuels to an economy based on virtually unlimited energy sources – nuclear and thermonuclear, renewable. A great number of developing countries now have declining rates of fossil fuel consumption, many have already reached a stable consumption level, and in the future a reduction in fossil fuel consumption should be expected. That is why the potential natural gas market, in the long run, is likely to shrink rather than expand. This will increase competition between fossil fuels and promote the development of only the cheapest sources of energy. It should also be mentioned that the possibilities for extracting cheap natural gas are limited, too, and gas transportation costs are far higher compared with oil. This factor will also restrain the international natural gas trade and make many prospective gas exporters consider the possibility of converting natural gas at the production site and hence exporting liquid fuels. Because natural gas is compatible with petroleum products in many uses, it is unlikely that gas prices will be low; they will follow oil prices with a certain lag. It is quite possible that the oil/gas price ratio will be lower than 1.0 due to the advantages of gas as an ecologically clean fuel and the replacement of higher-grade and more expensive oil products.

Success in the world natural gas trade will only be achieved in a climate of mutual trust and cooperation between states, since the complex and cumbersome system of gas transportation, especially by land, is extremely vulnerable to all sorts of political eruptions. Conversely, the world natural gas trade may help improve the global political climate insofar as it involves both developed and developing nations with different political systems whose cooperation offers a real opportunity for solving global problems faced by mankind.