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Energy Sector Review

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Fiscal Year of Borrower	**Weights and Measures**
January 1st - December 31st	Metric System

ACRONYMS

ABEDA	Arab Bank for Economic Development in Africa
ASAC	Agricultural Sector Adjustment Credit
BADEA	Banque arabe pour le développement économique en Afrique (Arab Bank for Economic Development in Africa - ABEDA)
BPPA	Antananarivo Plain Development Project Authority
BTM	National Rural Development Bank
CASA	Crédit a l'ajustement du secteur agricole (Agricultural Sector Adjustment Credit)
CASEP	Crédit à l'ajustement du secteur public (Public Sector Adjustment Credit)
CASPIC	Crédit à l'ajustement du secteur des politiques industrielles et commerciales (Industry and Trade Policy Adjustment Credit)
CCCE	Caisse Centrale pour la Cooperation Economique
CFDT	French Textile Development Company
CIRIR	Rural Irrigation District
CIRVA	Agricultural Extension District
CVA	Centre de la vulgarisation agricole
ERR	Economic Rate of Return
FAC	Aid and Cooperation Fund (French Government)
FANAMALANGA	Mangoro Forest Company
FAO	United Nations Food and Agriculture Organization
FED	European Development Fund
FOFIFA	Agricultural Research Agency
GDP	Gross Domestic Product
HASYMA	Cotton Marketing Parastatal
IDA	International Development Association
IFAD	International Fund for Agricultural Development
ITPAC	Industrial and Trade Policy Adjustment
MPAEF	Ministry of Animal Production, Fisheries and Forests
MPARA	Ministry of Agricult.Production and Agrarian Reform
OED	Operations Evaluation Department
O&M	Operation and Maintenance
PCR	Project Completion Report
PASAGE	Projet d'action sociale et d'appui à la gestion (Economic Management and Social Action Project)
PSAC	Public Sector Adjustment
SAMANGOKY	Development Agency for the Lower Mangoky Valley
SAL	Structural Adjustment Loan
SECAL	Sectoral Adjustment Loan
SAR	Staff Appraisal Report
SOMALAC	Development Agency for the Lac Alaotra Region
UNDP	United Nations Development Programme
WUA	Water User Association

Preface

The Republic of Azerbaijan became a member of the World Bank on September 18, 1992. This report is based upon the work of missions which visited Baku in July and October 1992. These missions would like to thank the Azerbaijani authorities for their warm hospitality, excellent cooperation, and for the openness of the discussions.

The report was prepared by Michael Levitsky (the main author). Contributions on particular topics were provided by: Miguel Montes, Fernando Zuniga-Rivero, Humayoon Ansari and Thomas O'Connor (petroleum exploration and production), Hiroki Okimi and Howard Ash (natural gas), N.C. Krishnamurthi (petroleum refining and marketing), Salem Ouahes (electricity and district heating), Suzanne Barnes (energy pricing and trade), Gary Nicholson (petroleum equipment industry), James Greenlee (oil field environmental issues), and Robert Asher (petroleum law). Brenda Manuel provided data and graphics support, and the report was processed by Banu Setlur.

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i. In order to bring about the most effective contribution of the energy sector to the country's transition to a market economy, the Government should pursue the following policies:

- Final production agreements with international oil companies, leading to the exploitation of the country's undeveloped offshore oil fields, should be concluded as soon as possible. Rapid and efficient development of the oil fields is essential to economic recovery. The Government should take an integrated view of the development of the large offshore fields, working with the oil companies to optimize investment planning. Negotiations need to be carefully structured and the number of separate agreements should be kept to a minimum, possibly by combining negotiations on the three major oil field developments. It is important that consistency and continuity of policy is maintained to ensure rapid progress with the agreements, and to strengthen investor confidence. Retaining suitable highly qualified advisors to the Government and the State Oil Company (SOCAR) in negotiations with the foreign companies should be a top priority. In order to attract foreign investment, the Government should pass legislation to provide a legal framework for investment in petroleum. It would probably be inadvisable for Azerbaijan to attempt to assume a large role in financing the first generation of field developments, in view of the major exposure involved and the need to raise credit for other purposes.

- Rehabilitation of the producing portion of the Guneshli field, which is in danger of a rapid decline in the short term, is the most urgent priority. A substantial decline in oil production from Guneshli would undermine the prospects for economic recovery.

- The Government should continue with its cooperative approach to the development of an oil export pipeline, and related common petroleum infrastructure. Open cooperation with the foreign companies investing in production, with Governments of countries lying along the pipeline route and with international financial institutions is essential if the financing for this large project is to be raised on reasonable terms. In the medium term, there may be a need to seek other options for exporting oil, such as swaps with Russia, in order to ensure an outlet for early production increases.

- The Government should encourage the maintenance of a competitive petroleum equipment industry in Azerbaijan, to capitalize on the country's potential advantage as a supplier to the growing market in other FSU countries, and in order to ensure supplies to local industry at least cost. A comprehensive development strategy for the industry, including joint ventures with foreign companies and participation of private capital should be elaborated. Planning for local participation in the offshore investments should also commence immediately, if the benefits of the oil projects to Azerbaijan are to be maximized. A program to develop local manufacturing of offshore platforms and equipment, and for services, should be developed, in partnership with foreign companies and within a commercial and competitive regime.

- The economics of production in the older oil fields need to be approached in a realistic manner. Wells which are uneconomic should be shut down, and field production systems which cannot be maintained economically, probably including the Oil Rocks field, should be restructured. The reduction in employment in the oil fields can be handled both through retraining and within the

process of social protection during the economic transition. Fields should be put out to tender for joint ventures with private companies within a structured contractual and technical framework. Investment to reduce environmental contamination in the oil fields should be integrated into a restructuring strategy.

- The prospects for oil refining in Azerbaijan need to be examined within a market pricing environment. A substantial part of the older capacity will probably have to be closed down. New investment in refining should be assessed realistically against the option of direct crude oil export by pipeline, with the latter option likely to be the most economic.

- Greater emphasis should be given to the natural gas sub-sector, as this is the main fuel used within Azerbaijan. Improvement in gas usage and exploitation should be a key aim, so as to reduce the rising burden of gas imports. Losses of gas should be reduced through pipeline rehabilitation investment, and urgent implementation of the project to capture gas vented offshore. Gas meters, if possible produced with private participation within Azerbaijan, should be introduced rapidly to improve end usage and allow gas prices to be raised substantially.

- Power sector investment should be based upon a least-cost plan, which should be undertaken as soon as possible. New capacity may not be needed for several years as demand falls, and investment should focus on rehabilitation of existing capacity and systems. The prospects for district heating should be assessed against expanded use of natural gas.

- Energy prices should be raised towards economic levels, according to a structured program of price increases. The aim should be to raise energy prices to economic levels, or international levels where appropriate, as rapidly as possible, conceivably within one year of the implementation of an economic stabilization program. This program should take account of the social and economic impact of price rises. A system of taxation to capture excess profits should be put in place.

- The Government should establish an effective agency responsible for energy policy making and implementation. Such an agency, or Energy Ministry, should be small but capable of providing leadership in national policy and in energy sector relations with foreign Governments and companies. Regulatory agencies should be set up for oil licensing and for gas and power utilities, which would work in a transparent manner and allow efficient functioning of the entities under their control.

- The integrated energy companies in oil, gas and power need to develop along commercial lines. Clear commercial interfaces need to be established between the different stages of energy supply (production/generation, processing, transmission, distribution), which reflect the economics of different business units. Management and financial systems need to be strengthened, and staff trained in modern business practices. The companies should be restructured to eliminate ancillary activities, and internal service units should be made competitive with external suppliers. Restructuring and strengthening of institutional capability is especially urgent for SOCAR to allow it to deal effectively with the very large program of investment in oil development.

- In order to restructure its energy sector in a coherent manner, and develop a viable investment program, the government should seek a comprehensive program of technical assistance from international donors and financial institutions. Both grant and loan financing may be required

to implement the program promptly. Implementation of such a program will ensure that the full potential of the energy sector to contribute to economic recovery is realized.

ii. The Energy Policy Matrix on page xvii summarizes the policy priorities for the energy sector, together with the steps already taken, and the suggested next steps and timing. It is designed to serve as a reference for the policy priorities discussed in this report, and as a tool for planning implementation.

The Historical Legacy of Petroleum

iii. Energy has historically played a key role in shaping Azerbaijan's economy, and will continue to do so in future. Azerbaijan is one of the oldest oil producing regions in the world, and supplied most of the requirements of the Soviet Union until World War II. After WW II, Azerbaijan was eclipsed by new oil producing regions in Russia, and investment in the country lagged behind other regions. Oil production fell from 20 million tons (mt) in 1970, to 11 mt in 1992, just 2 percent of Former Soviet Union (FSU) production. As oil production has fallen, Azerbaijan's importance as an oil exporter has declined, with net exports falling from 8 mt in 1981 to 3 mt in 1991. Most importantly, the Soviet industry failed to exploit the large resources under the Caspian Sea efficientiy, due to shortcomings in technology and insufficient investment funds. As a result, large offshore oil deposits still await development. Undeveloped reserves in discovered fields total some 650 mt, while even larger reserves may exist in unexplored structures. The potential production from these deposits holds the key to the development of Azerbaijan's energy sector and of its economy.

iv. As a result of its unusual history, Azerbaijan's upstream oil industry now presents two very contrasting aspects: On the one hand, the older producing fields onshore and offshore are mostly in a state of advanced decline, with old and dilapidated infrastructure. On the other hand, the large new offshore fields represent some of the major undeveloped petroleum resources in the world, susceptible to development through state-of-the-art offshore technology. This creates a need for a wide range of policies and decisions within the industry, aimed both at exploiting new reserves efficiently, and at restructuring production in the mature areas.

The Need for Restructuring

v. Oil production in the older oilfields has been declining for many years, and average productivity per well is only 0.7 tons/day onshore. The largest mature offshore field, Oil Rocks, sustains a sizeable infrastructure and manpower base on very little production, and is probably no longer economic to operate. It is likely that a large number of the onshore producing wells are uneconomic at international costs and prices, and should be shut down. There is substantial environmental pollution from the oil fields, through oil spills and inappropriate disposal of formation water.

vi. Total oil production has been sustained by development of the large offshore Guneshli field, found in 1979, which now accounts for 60 percent of national oil output. Yet this field has been developed in a sub-optimal manner, using obsolete technology. Reservoir management and production practices have been poor, and the field is in danger of entering a premature decline. A fall in production from Guneshli would have serious effects on Azerbaijan's oil export revenues, with each 10 percent decline cutting Azerbaijan's potential oil exports by 25 percent, or US$75 million per year.

vii. While oil has been a key export item for Azerbaijan, natural gas has been the main fuel for domestic use. Gas consumption, at around 13 billion cubic meters (bcm) in 1991, normally accounts for

60 percent of primary energy use (with oil making up most of the remainder). Gas production has fallen along with oil production, from 14 bcm in 1980, to 10 bcm in 1991. For many years, insufficient attention has been given to system maintenance and to development of gas reserves. In addition, gas usage is extremely wasteful, due to large losses in the transmission and distribution system (over 15 percent of supplies), an almost complete lack of customer metering and inefficient gas-using equipment. About 15 percent of gas production is also vented offshore. Total annual losses thus amount to about 4 bcm.

viii. As a result, Azerbaijan has become a large net importer of natural gas, with net imports (mostly from Turkmenistan) totalling 8.2 bcm in 1991. Under the previous FSU regime such trade interdependency between republics was encouraged, without regard to efficiency considerations and actual resource transfers. Following the break-up of the Soviet Union, the scale of inefficiency and transfers have become apparent, and the cost of gas imports to Azerbaijan is rising very rapidly as Turkmenistan attempts to raise gas prices to world levels. Due to price disputes, net imports from Turkmenistan were greatly reduced in 1992, to only 4.2 bcm. At world prices gas imports could cost Azerbaijan about $600 million per year, or 35 percent of total import costs.

ix. Because of its large gas imports, Azerbaijan is only about 90 percent self-sufficient in energy. In financial terms, however, it may continue to run a small trade surplus over the next one or two years as long as gas import prices remain significantly below the equivalent value of oil product exports. Azerbaijan's energy trade balance is adversely affected by its inefficient energy usage, which makes it one of the least efficient of the FSU Republics. Energy consumption per unit of Gross Domestic Product (GDP) in Rubles in Azerbaijan is 20 percent above the average for Russia. Comparisons using US Dollar GDP figures, while inevitably inexact, suggest that Azerbaijan is at least 50 percent less efficient than even the least efficient Eastern European countries (e.g. Bulgaria), and many times less efficient than Western European countries.

x. Most oil exports from Azerbaijan have been in the form of oil products, processed in the two large refineries located near Baku, and transported either by rail or by Caspian tanker. The capacity of these refineries, at 20 mt per year, has exceeded Azerbaijan's diminished oil production for many years, and the spare capacity was used to process imported crude from Russia and Kazakhstan. This inward processing was probably uneconomic and has largely ceased as prices in FSU oil trade move to world levels. Moreover, the facilities at these refineries are old and lacking in upgrading capacity. The continued viability of much of the current capacity within a market pricing environment must be in question.

xi. Azerbaijan's long history of oil production helped to make it the major center of petroleum equipment manufacturing in the FSU. The industry supplied 65 percent of FSU requirements of most types of production equipment. Since the break up of the Soviet Union, the industry has suffered from a lack of investment funds, a collapse in trading arrangements for inputs and increased competition in the FSU market both from foreign suppliers and from new local manufacturers. The petroleum equipment industry is a key part of Azerbaijan's industrial base, and represents a potential source of hard currency exports. Its continued viability is also important in maintaining competitive low cost supplies to the FSU oil industry, especially in Russia. A comprehensive development strategy for the industry, including joint ventures with foreign companies and participation of private capital, should be elaborated.

xii. Azerbaijan's power capacity is designed to run largely on natural gas, with a modest contribution (about 7 percent) from hydro. Over the last year power stations have been forced to switch to fuel oil,

as gas imports from Turkmenistan have been restricted. The use of fuel oil aggravates the already highly inefficient operation of these stations, some of which are nearing the end of their useful life. The transmission and distribution system is also in need of large scale rehabilitation. Azerbaijan has a significant district heating sub-sector, which is extremely run-down and in need of refurbishment.

xiii. Azerbaijan inherited from the Soviet Union a highly distorted system of energy pricing. Price policy over the past two years, however, has been ad-hoc, and energy price rises have tended to lag behind those in other FSU countries. Producer and product prices for oil remain well below international parities (about 10 percent and 20 to 30 percent of parity respectively). Natural gas producer prices have been kept low to offset the rising cost of imports from Turkmenistan, and prices are now only about 3 percent of import parity. Both gas and electricity prices to residential consumers have been kept low relative to prices to industry, with growing cross-subsidization. The slow pace of price increases has led to rising financial deficits in all the major energy enterprises, which has aggravated the long term problem of inadequate investment in plant maintenance and replacement.

xiv. Azerbaijan's energy sector institutions have begun the process of reorganization, although enterprises continue to operate in much the same manner as before. The oil Producing Associations from the FSU have been abolished, and an integrated State Oil Company (SOCAR) has been formed, including both oil and gas production and the refineries. Gas distribution and transmission have been merged into a single state company, Azerigaz, while the power sector is under the control of Azenergo. Government coordination of the energy sector is weak, with no energy ministry and a lack of high level policy making staff.

Conditions Favoring Energy Sector Restructuring

xv. While Azerbaijan faces significant challenges in restructuring its energy sector to conform to the requirements of a market economy, it also has a number of advantages that make it capable of achieving such a restructuring more easily than many other FSU countries:

- Azerbaijan is a net oil exporter and has substantial oil resources which will make it a much larger exporter in future,

- The country has a simple fuel supply structure (oil and gas), without the large nuclear, coal and hydro sources that can greatly complicate energy policy making in other republics,

- Azerbaijan is relatively compact in area, making internal energy transport and distribution easier than in the large FSU countries (although a new pipeline will be needed for large scale oil exports),

- The institutional structure of the energy sector is relatively simple, with centralized oil, natural gas and electricity companies acccounting for most sector activity, while such activity is often highly decentralized and more difficult to control in other FSU countries,

- There is a large base of skilled manpower which, following some emigration over the last few years, is likely to remain stable in future,

- The country opened up to foreign investment relatively early, particularly in the petroleum sector, where foreign oil companies have established a substantial presence in the country,

- The government has been committed to rapid economic reform, and has been willing to change entrenched sector institutions and business practices.

xvi. All of these factors suggest that Azerbaijan has a good chance of achieving a rapid transformation in its energy sector. However, this will require openness to technical assistance and a willingness to take hard decisions on pricing, institutional reform, and the restructuring of infrastructure.

Impact of Oil Development - Base Case

xvii. Development of Azerbaijan's offshore oil resources will have a profound impact on the country's energy sector, and represents the key to economic transformation. Growing oil production can generate the revenues required to finance restructuring, infrastructure investment and social policies during and after the transition to a market economy. However, the nature of offshore oil development means that the major rewards from oil production are some years away, and the government will have to move quickly to reach agreements on oil development with foreign companies if the benefits are to come when most needed.

xviii. In the short term, Azerbaijan faces a difficult energy situation as oil and gas production continues to decline, and gas import prices rise rapidly. As long as gas import prices remain significantly below the export value of oil products, the country is likely to continue to run a trade surplus in energy. However, the level of this surplus will be modest, amounting to at most US$90 million in 1995. Any delay in the development of the offshore fields, or adverse development in gas import prices or availability, could push Azerbaijan into an energy trade deficit. Since Azerbaijan appears to rely on its trade surplus in energy to offset a deficit on other products, a loss of the energy surplus would represent a serious economic setback.

xix. The development of Azerbaijan's undeveloped offshore fields will require an investment of some $10 bn over the next ten years. Under a Base-Case scenario (which assumes investments proceed as currently planned by the oil companies) this investment will allow production to rise from 11 mt in 1992 to 45 mt in the year 2005. Oil exports will rise from 4.0 mt in 1992, to 40 mt in 2005, making Azerbaijan an exporter equivalent in scale to Nigeria today. The total value of exports will be some $3 bn in 2000 and $5 bn in 2005, representing about 60 percent of total exports.

xx. The growth of production and exports alone provide an incomplete picture of the impact of oil development on Azerbaijan's economy. In the early years of development, much of the impact will come from the large flows of inward investment (about $1.5 bn per year) and from the manner in which this is spent. A large part of the investment will go to import equipment for the offshore projects. Yet because of Azerbaijan's landlocked location, and its capacity to manufacture a wide range of equipment, about 30 percent to 45 percent of investment may go to enterprises in Azerbaijan, resulting in a very large boost to domestic industry. In particular the jackets for offshore platforms are planned to be constructed at a yard outside Baku. Local sources are also likely to supply much of the labor and offshore services, and some 50 percent of annual operating expenditure (reaching about $500 million by 2000) is likely to stay in Azerbaijan. Careful planning will be needed to ensure that Azerbaijan's share in oil investment and operations is maximized while providing competitive supplies to the offshore developments, and avoiding inflationary bottlenecks in the economy.

xxi. Involvement of major foreign oil companies is the only means by which Azerbaijan will obtain the technology, financing and project organization to develop its offshore fields. However, the terms of

the agreements with the oil companies on oil production will have a large effect on net revenues to Azerbaijan. In the Base Case, for example, foreign company oil exports (for investment recovery, operating cost recovery and profit) could amount to $2.2 bn in 2005 (42 percent of total oil exports) under standard production sharing terms. The balance of exports will accrue to the Government, amounting to some US$1.4 bn in 2000, and constituting a major source of revenue for the Government. In addition, Azerbaijan will have to decide on the best means of financing the oil developments. The oil companies may be willing to carry all the costs of the offshore fields, in return for a relatively rapid cost recovery schedule. The timing of revenues to Azerbaijan can also be adjusted through adjusting the shares of revenues received by the Government and companies under the production sharing formulas, to suit Azerbaijan's requirement for earlier revenue. Given the very large sums involved, it is vital that Azerbaijan obtains the best possible advice in its negotiations with the foreign oil companies, and that the assessment of agreements is integrated into an overall macroeconomic framework.

Export Pipeline and Common Infrastructure Requirements

xxii. Development of oil for export will require construction of a crude oil export pipeline with access to world markets, at a cost of at least $1.5 bn. This pipeline would have to cross at least one other country. SOCAR has been assessing the options for the routing of this pipeline together with the foreign oil companies that plan to invest in oil production. The preferred route at present lies across Iran or Armenia and Turkey to the Turkish Mediterranean port of Ceyhan. However, in view of the uncertainties surrounding this project, it would be advisable for Azerbaijan to keep other options open, such as routes across Georgia or Russia to the Black Sea. The commitment to developing the pipeline jointly with the oil producers, as a means of carrying oil to market on a least-cost basis, represents a good start to such a venture. Oil companies represent the most effective means of mobilizing capital for a pipeline, although other agents such as export credit agencies and multilateral institutions may also be involved. Open agreements on tariffs, and reliable and strong project partners with a stake in least-cost operation, are the best guarantees of stable tariff and transport arrangements to future investors in Azerbaijan's oil fields. This, in turn, will ensure that Azerbaijan receives oil investment on the most favorable terms. It is also important for Azerbaijan to maintain a dialogue with its Caspian neighbors (especially Kazakhstan), so as to integrate regional oil exports if this can lead to cost savings.

xxiii. A further issue affecting the offshore developments is the need for common infrastructure and an integrated development strategy. The three major undeveloped oil fields (the undeveloped portion of Guneshli and the Chirag and Azeri fields) all lie in close proximity and may well share reservoirs in common. Hence joint infrastructure (offshore pipelines, terminals, marine fleet, construction yards etc.) would optimize development, while production planning must take account of all field operations. Azerbaijan has begun work on joint infrastructure planning with the oil companies and is fostering a joint approach to field development through unitization - these are steps in the right direction. Azerbaijan might reasonably expect to take a share in financing the joint infrastructure, and the export pipeline, where its participation may be needed to generate confidence among other investors. The organizational and financing arrangements for the joint infrastructure and for the export pipeline, and for the operating structures for the oilfields, are critical issues on which Azerbaijan should seek expert advice.

Impact of Oil Development - Alternative Scenarios and Issues

xxiv. A number of alternative scenarios could alter Azerbaijan's revenues from oil development. If production from the fields is delayed (from the Base Case assumption which assumes large scale foreign investment starting in 1994), this would greatly aggravate the problems of economic adjustment - a delay

of two years would lead to $2 bn less investment before 2000 and an energy trade surplus of $1.2 bn (55 percent) below the Base Case in 2000. Government revenues in the year 2000 would also be about $700 million less. If oil development does not start until after 2000, Azerbaijan is likely to suffer a severe economic decline; in this case the energy trade deficit by 2000 will be about $600 million, compared with a surplus of $2.1 bn in the Base Case. An alternative possibility is that Azerbaijan may pursue a policy of restricting production levels in an attempt to "conserve" oil for "future generations", yet such conservation is likely to be sub-optimal, since it delays the benefits of oil exports and reduces projects to below optimum scale. Lower oil prices would also clearly reduce Azerbaijan's future earnings from oil production - a fall of 15 percent in oil prices would reduce the Government's share of oil exports in 2000 by about 25 percent and cut the energy trade surplus by 20 percent to $1.7 bn. Azerbaijan could, of course, gain even larger revenues from oil development if oil prices are above the Base Case, although past experience of the oil market shows that it would be unwise to plan for this case. It may also be possible to accelerate the pace of development from that shown in the Base case. The gap between the development of the three offshore fields, of around three years, is determined by the capacity of Azerbaijan's construction facilities and support services - a more rapid development program may be possible but would require very large investments to increase local capacity.

xxv. Exploration of the Caspian Sea, and the onshore areas, for new petroleum fields should also be a priority. It is important that this activity is carried out within a coherent legal, commercial and strategic framework. A Petroleum Law should clarify responsibilities and rights of foreign companies, and should also set up a licensing agency. A licensing strategy would involve division of the prospective areas into blocks, structured promotion to the international industry, and possibly licensing rounds designed to ensure orderly and progressive exploration of key areas. In the short term, however, it is important to ensure drilling of the large but unexplored Shach Deniz structure, since this is ready for drilling and knowledge of its contents could allow its development to be integrated into that of the known fields. Azerbaijan's energy sector planning should take into account the high probability that as a result of successful exploration of the Caspian Sea, a "second generation" of new fields will be developed after 2000, to sustain production and investment levels.

Alternative Oil Development Scenarios

	Base Case				Delayed Investment		
	1992	1995	2000	2005	1995	2000	2005
Oil Production (mt)	11.1	9.7	25.6	45.2	9.1	17.4	39.3
Net Oil Exports (mt)	2.6	4.7	20.8	39.7	4.1	12.6	33.8
Net Gas Imports (bcm)	4.3	8.0	10.5	9.2	9.6	11.3	10.6
Energy Trade Balance (US$bn)	0.05	0.09	2.09	4.71	-0.10	0.92	3.80
Cum. Oil Investment (US$bn)	0.0	1.5	9.6	12.2	0.6	7.5	11.6
Gov. Oil Exports (US$bn)	n.a.	0.4	1.4	2.8	0.4	0.7	2.0

Source: Mission estimates.

xxvi. A key issue for Azerbaijan is the type of financing to be adopted for the offshore field developments. In financing the "first generation" of fields, the Government must take account of the fact that SOCAR and Azerbaijan are financially constrained, with limited ability to raise funds on commercial terms, and that there will be substantial calls upon state resources for non-oil investment. The alternative to SOCAR funding its own share of costs is to be "carried" by the foreign companies (i.e. to have its

share of costs paid by the companies). In deciding on the level of SOCAR's participation, the relative costs of funding through a "carry" by the companies and through the financial markets needs to be examined. It may, however, be inadvisable for SOCAR to assume a large role in financing the first generation of fields, since this would both expose Azerbaijan to a large element of project risk and limit the country's financing capacity for other purposes. Macro-economic projections show that Azerbaijan will need to borrow between $400 million and $500 million per year from 1995 to 1999 to meet its funding requirements in the Base Case scenario, even if SOCAR only funds 25 percent of the oil export pipeline and 50 percent of the offshore infrastructure (and is carried by the oil companies for field investments). Until the late 1990s, when oil exports have been established, and Azerbaijan has developed a credit track record, Azerbaijan may not be able to borrow the funds required for development of the first generation of fields on reasonable terms. It may be therefore be more appropriate for Azerbaijan to aim to fund a share of the second generation fields after 2000.

Encouraging Foreign Petroleum Investment

xxvii. While Azerbaijan's resource base presents attractive potential exploration and production opportunities for international petroleum companies, it is important that an appropriate business environment is created to encourage actual investment. To date, Azerbaijan has been successful in building on the interest shown by many foreign companies in the country, although achievement of final agreements and investment has been slow. In order to speed up foreign investment on the most suitable terms, a number of initiatives need to be pursued. Creation of an appropriate legal and contractual framework, development of a Petroleum Law and standard contracts, and resolution of related legal and fiscal issues is a major priority. It is also important that suitable advisors, with the capacity and experience to advise Azerbaijan on all commercial, financial and legal aspects of petroleum negotiation be recruited from the start. Strengthening of local capacity, through training and assignment of the most capable staff to this area is vital. The organization of negotiations is key to making rapid progress: procedures and documentation of negotiations should be clarified and public and confidential communications well organized. In addition, the number of negotiations being undertaken should be limited to what can be handled by SOCAR and the Government effectively; in the case of the offshore projects, unitization of the fields and negotiations on a single set of agreements with all companies could greatly simplify and speed up agreements. The presentation of data in a manner which is useful and accessible to foreign companies is likely to increase interest and reduce delays in reaching agreements. Finally, it must be emphasized that continuity of commercial approach and negotiations is vital: Azerbaijan has persuaded major petroleum companies to make a considerable commitment to plan investments in the country, and fundamental changes of course or of companies at this stage carries the risk of delaying these investments considerably. Such changes will also reduce the confidence of future investors in the stability of commercial agreements reached with Azerbaijan.

Restructuring Existing Oil Infrastructure

xxviii. While dealing with its large undeveloped fields, Azerbaijan must also focus on restructuring production in the mature fields onshore and offshore. The remaining reserve base in the older fields, at around 300 mt, represents a large resource base which should be accessed efficiently. This will require the shutting-in of a large number of uneconomic wells, and abandonment of non-viable infrastructure (for example in the Oil Rocks field). New investment should focus on the most productive areas. Investment in improved production should be a priority to moderate the production decline until the new offshore fields are brought on stream. Initial investment could utilize resources from multilateral financing agencies, while carrying out a thorough survey of field restructuring requirements. Once a structured

contract and technical framework is in place, the fields should be put out to tender for joint ventures with private companies. A reduction in employment in the oil fields (currently 40,000), will also be required, and should be effected through retraining and within the process of social protection during the economic transition. Investment to reduce environmental contamination in the oil fields should be integrated into a restructuring strategy.

xxix. In restructuring its oil industry, Azerbaijan will also have to address the problems of its refineries. In the medium term, it is highly unlikely that large scale imports of crude oil for export processing would be economic. In the longer term, Azerbaijan will almost certainly be better off exporting crude oil to world markets (via an export pipeline), than processing its crude oil and exporting products. Domestic requirements, as well as modest regional export needs, should probably continue to be met from local refineries. Refinery capacity should be restructured on the basis of an optimization study, which will probably show that a substantial part of the older capacity should be closed down, and the remaining capacity upgraded.

The Petroleum Equipment Industry

xxx. In order to prevent a decline of the petroleum equipment industry, and capture emerging opportunities within the FSU, Azerbaijan must move rapidly to elaborate a comprehensive development strategy for the industry. Joint ventures with foreign companies and participation of private capital should be a key part of this strategy, to provide Azneftekhimmash with needed capital, technology and management expertise. To maintain viability Azneftekhimmash needs to focus on its core markets in the FSU, where other suppliers are making inroads and production is commencing from new local factories (especially former defence suppliers). Access to large contracts, some of which will be financed by multilateral organizations (World Bank, EBRD) will be important. Products should be upgraded to American Petroleum Institute (API) standards so as to be able to compete internationally. Improved marketing, and development of maintenance and service centers are also vital. Azneftekhimmash should be able to supply a greater share of the local Azerbaijan market by targeting its specific product requirements, and manufacturing new products for the offshore developments. Finally, cautious moves should be made to strengthen Azneftekhimmash's position in certain countries in the world market, particularly where Soviet products already have some track record.

The Importance of Natural Gas

xxxi. A focus on the efficient development and use of natural gas resources is vital if the domestic energy sector in Azerbaijan is to contribute positively towards economic recovery. Future associated gas production from the new oil fields may only just offset the rapid decline in production from existing large gas fields. Hence Azerbaijan could continue to require substantial gas imports beyond the year 2000, at a cost of around $600 million per year, or some 20 percent of the value of oil exports.

xxxii. An emphasis on economy of gas utilization will thus be the key to containing import costs. A first step in this direction is the implementation of the project to reduce venting of associated natural gas offshore, which could save Azerbaijan around $100 million per year at international gas prices (about 4 percent of total imports). This project has been started by a foreign petroleum company, and is likely to be integrated with the Guneshli field re-development.

xxxiii. The second priority is to reduce the large losses of gas through the transmission and distribution pipelines, which cost Azerbaijan up to $170 million per year at international prices. This will require

major investments in rehabilitation and reconstruction of pipelines, and general improvement to pipeline and storage networks. Gas processing will also require major investments, since at present only 50 percent of the domestically produced gas entering the system is processed to extract liquids and water, causing a loss of valuable liquid petroleum gasses and aggravated pipeline corrosion.

xxxiv. The third priority is to improve the end-use efficiency of gas, through installation of meters and provision of more efficient gas using equipment. Local manufacture of meters and appliances, using Azerbaijan's considerable light engineering resources combined with private investment, should be a priority, provided of course that the output can be sold at competitive prices.

xxxv. A further priority is to ensure effective development of Azerbaijan's gas resources. It may be possible to develop existing fields more effectively, as well as to develop some modest undeveloped free-gas fields. The large new offshore fields contain both associated and non-associated gas and it will be important to integrate gas properly into the field development agreements to ensure its full and efficient exploitation by the foreign oil companies.

Electricity

xxxvi. The power sector is closely integrated with the gas using infrastructure, since gas capacity accounts for almost 90 percent of total generation capacity (although at present fuel oil is being used). Because power demand has been depressed by around 15 percent over the past two years by the economic decline, new generating capacity is unlikely to be needed before the late 1990s. However, improvements in the gas using efficiency of existing steam plants should be explored, as should rehabilitation of the transmission and distribution infrastructure and improvements in the efficiency of end-use. There is also a need to improve maintenance practices, which are currently poor. A proper customer management and billing system needs to be introduced to reduce non-technical losses. In the longer term, combined cycle power plants using natural gas are likely to prove the most economical option for large scale power generation in Azerbaijan. There is also considerable potential for small scale hydro and wind power applications. The forward investment program for the power sector should be developed on the basis of a least-cost planning study. The district heating sub-sector should also be the subject of a rehabilitation study, to assess its future investment needs and viability.

Environmental Issues

xxxvii. The major environmental problems in the energy sector in Azerbaijan result from pollution associated with oil production. This is particularly the case in the onshore oil fields, which are mostly located in heavily populated areas. Onshore oil pollution results from oil spills, inappropriate disposal of formation water and drilling wastes, and ill-conceived production pit construction. This has caused serious contamination of groundwater resources, which presents a danger to the health of the population. Improved production practices are urgently needed to reduce pollution. In addition, repair and replacement of faulty and corroded equipment will help to reduce leakage of oil and other pollutants. Remediation of polluted areas will require considerable investment, and it is recommended that this be undertaken in conjunction with foreign investors where possible. Improvements in the environmental conditions of the onshore fields should be linked to the wider studies of the restructuring of production along economic lines.

xxxviii. In offshore areas, better controls should be established on the disposal of produced water containing toxic metals and oil. Offshore field rehabilitation should emphasize the reduction of oil leaks,

and there should be better control of the disposal of general waste from offshore production sites. Regional initiatives to establish an oil spill response center for the Caspian Sea should be explored. Some of the pollution in the sea around Baku could also be due to poor waste management by sea-going vessels, which should be assessed and controlled. The venting of large quantities of gas offshore is environmentally as well as economically damaging, particularly as methane is a powerful greenhouse gas.

xxxix. Environmental standards at the oil refineries in Baku are also relatively poor. Inadequate treatment and inappropriate disposal of effluent waters results in sea and land pollution. There is also considerable seepage of hydrocarbons around the refinery sites. There is no monitoring of aerial pollution, which is probably excessive. Improvement of the environmental standards at the refineries, and remediation of polluted areas, should be an important part of the recommended refinery restructuring study.

xl. In the power sub-sector, the major environmental problems arise from the burning of fuel oil in place of natural gas, without adequate environmental controls at the power stations. Improved access to natural gas supplies would greatly reduce the environmental impact of power generation. Greater use of renewable resources (particularly small scale hydro and wind power) will also help to lessen the environmental impact of the power sub-sector.

xli. Proper enforcement of Azerbaijan's existing environmental standards would in many cases greatly reduce the problems described above. Unfortunately, enforcement is hampered by a lack of resources within the Government departments concerned. Moreover, fines are often very low, and are not always enforced. A strengthening of institutions dealing with environmental problems in the energy sector (in conjunction with the wider aspects of environmental regulation) is strongly recommended.

Energy Pricing Reform

xlii. Azerbaijan's energy pricing policy has been slow and uncoordinated in making the transition from the extreme distortion of the Soviet system to an economic basis. Pricing changes, as in most other FSU countries, have been ad-hoc responses to external or internal developments, and have not exhibited a structured move towards economic levels.

xliii. Azerbaijan possesses a greater capacity than many other republics to control the rate of transition of internal oil prices to world market levels. As a net oil exporter, Azerbaijan does not have to "take" price changes in other republics (e.g. Russia) into its internal market. In addition, control of oil production, processing and trade in Azerbaijan is highly centralized and flows are relatively easy to monitor, hence there are fewer of the informal market problems that are present in other FSU countries.

xliv. Moves to world price levels can thus be established in a structured manner, with the internal price of crude and oil products progressing to world parities over a suitable time-frame. It is important that this time frame is sufficiently short to play a positive role in economic restructuring through sending more meaningful price signals to producers and consumers. As prices rise towards world levels, the Government will need to regulate SOCAR's profits through petroleum taxation. This will, in turn provide revenue to the Government which can be used to mitigate the adverse social effects of energy price rises.

xlv. For natural gas, Azerbaijan is essentially a price "taker" from Turkmenistan. Attempts to offset the rise in the price of Turkmenistan's gas with low prices for domestic gas are self defeating, since they

reduce the incentives to produce more gas domestically and to use gas efficiently. Producer prices for natural gas should be raised to an economic level, which will in general be set by the cost of Turkmenistan imports. Prices to gas consumers should be set by adding to the producer price the appropriate transmission and distribution tariffs, which should be set by an independent regulator.

xlvi. The gas price will form a key input into the electricity price, which in addition has to allow for the long run marginal cost of system capacity. The electricity price will be set in the same way as the gas price, through addition of transmission and distribution tariffs to the generators' price.

xlvii. An important aspect of price reform is the need for internal price transparency within the integrated energy enterprises. Thus within SOCAR, the production unit should sell to the refineries at a crude price which approaches the world level over time. Within Azerigaz, the cost of gas purchases, transmission, distribution and storage should be separately identified to the business units and to customers. In power generation, sales by generators, transmission and distribution charges should be similarly itemized. This will help to ensure that the commercial performance and viability of each unit within the companies is properly established.

xlviii. Price reform must take place within the context of macroeconomic restructuring. Energy prices should be targeted to reach world or economic levels within a relatively short period (for example, one year), and should be coordinated with a program of economic and monetary reform. Such a program should also help to stabilize the exchange rate for the national currency at an equilibrium level, which will assist in setting realistic energy price objectives. In order to ensure that the full economic costs of pricing policies are made clear, any subsidies to energy prices, which may be required during a transitional period, should be explicitly identified in the Government's budget.

Institutional Reform

xlix. Institutional reform in the energy sector should focus on three areas: strengthening the Government's coordinating and policy-making role, creation of a suitable legal framework, and enterprise restructuring and reform.

l. The government's role in the energy sector in Azerbaijan is unusual in that there is no energy ministry or similar body with a unique and overriding policy role. This can result in a lack of coordination and forward vision in energy sector planning. Oversight of the activities of the large energy enterprises is also weak. It is therefore important that an Energy Ministry (or similar body) be established, to: set overall energy sector priorities, advise the government on energy issues, establish energy pricing and taxation policy, act as an umbrella body for energy regulators, coordinate information and standards in the sector and represent the country internationally. Such a body could be quite small, but should be sufficiently well-staffed to provide leadership on critical issues.

li. Implementation of energy sector legislation is needed to ensure that investment takes place within a structured framework. Regulatory structures for electricity, natural gas and district heating need to be developed, within a legal structure, that define the rights and responsibilities of the energy utilities, as well as of consumers. Regulation is also needed for petroleum licensing, which should also be carried out separately from SOCAR. More broadly, a petroleum law is required which would set out the framework for investment in exploration and production.

lii. Azerbaijan has chosen to establish integrated national companies for oil, gas and electricity. Enterprise restructuring and strengthening should thus focus on internal structures that ensure commercial transparency. Such structures will help to prevent internal inefficiencies and cross subsidization. This will require a system of internal charges and financial controls related to the real costs of supplying goods and services, and to rates established in competition with external agents. Such internal segmentation of activities is essential as an alternative to splitting up the integrated companies into different units. In general, the segmentation of existing companies may be less disruptive than splitting up recently formed entities. Ancillary units of the enterprises which are not part of the core business (eg. construction, housing, transport etc.) should be spun-off or privatized. A general strengthening of capacity will also be needed through large scale training programs, and the installation of modern financial and management systems.

Role of Technical Assistance

liii. As stated above, Azerbaijan has a number of natural advantages, which should allow it make a transition to an efficient, market-based energy system more easily than many other FSU countries. However, the Government and the energy sector enterprises will require substantial technical assistance to make the transition rapidly, and without costly mistakes. This technical assistance should be seen as a short or medium term transitional aid, to ensure that the sector evolves a modern and efficient structure, which is able to sustain its own skill base.

liv. Technical assistance should focus on three main areas:

- Advice to enterprises and the government on negotiations with foreign companies on petroleum and other energy related contracts,
- Investment planning in the petroleum, natural gas and power sub-sectors, to identify priority investments and put in place long-term investment and financing plans,
- Institutional strengthening through training and financial and management systems development.

lv. Such technical assistance should focus on all energy enterprises. Because of the relative cohesion of the Azerbaijani energy sector, it would be best if the technical assistance was handled in a coordinated manner by the Government. This would ensure consistency between enterprises, efficient allocation of resources across the enterprises and effective liaison with international providers of funding and technical assistance services. The funding of technical assistance on the scale required may need to involve borrowing, since sufficient grant funds may not be forthcoming. This is particularly the case for the petroleum sub-sector, where rapid mobilization of advisors for negotiations, together with staff training and investment studies, are needed to implement large-scale foreign investment. Borrowing for such technical assistance can be justified since rapid execution of appropriate energy investments will lead to large foreign exchange benefits. For example, up to $250 million per year of gas import savings can be achieved through improved utilization of domestic gas resources, while accelerating development of the offshore oil fields by one year will generate additional government revenues of some $1.0 bn before the year 2000. In order to assist in mobilizing the required technical assistance, the World Bank has discussed an integrated energy technical assistance project with the Government and enterprises in Azerbaijan.

Energy Policy Matrix

	Policy Action	Steps Already Taken	Next Steps	Indicative Timing/Status
I.	Upstream Petroleum			
A.	Conclude agreements for offshore oil field developments. Give priority to preventing decline of Guneshli.	Preliminary unitization agreement. Financial and legal advisors engaged. Technical studies with foreign companies.	Negotiate final production agreements. Initiate unified development plan for new offshore fields.	By 1Q 94. Financing for advisors possible from TA funds.
B.	Conclude agreement for oil export pipeline construction.	Preliminary studies with oil company partners completed. Outline agreement with Turkey signed. Contacts with World Bank, EBRD.	Develop commercial structure. Finalize agreement on route. Commence detailed engineering. Seek financing. Plan for early export options (eg. via Russia).	Commercial structure by 1Q 94. Final route by 1Q 94. Start engineering by 2Q 94. Financing possible from TA funds.
C.	Conclude agreements for common offshore infrastructure (offshore pipeline, terminal, construction yard, marine fleet, supply base).	Preliminary studies with oil company partners completed. Joint venture with construction company for platforms. Contacts with World Bank, EBRD.	Develop commercial structure. Commence detailed engineering. Seek financing. Study option for local competitive supplies.	Commercial structure by 1Q 94. Start engineering by 2Q 94. Financing for advisors possible from TA funds.
D.	Initiate restructuring of production in the older oil fields (including Oil Rocks)	Initial discussions and contracts with foreign companies. World Bank field restructuring project discussed.	Undertake studies to determine restructuring options and strategy. Prepare project. Initial promotion to foreign companies.	Studies by 2Q 94 (using TA funding). Project by 4Q 94.
E.	Measures to improve environmental situation in oil fields.	Oil sludge clean up contract with foreign company initiated.	Undertake studies of options (with D. above). Incorporate into field investment plans and institutional reform.	Studies by 2Q 94 (using TA funding). Project by 1Q 95.
F.	Licensing of offshore and onshore areas for exploration.	Initial agreement with BP to explore Shach Deniz structure. Discussions with foreign companies on exploration.	Undertake study of licensing and exploration strategy. Develop license plan and data packages, initiate licensing.	Studies and initial packages by 2Q 94 (using TA funding).

	Policy Action	Steps Already Taken	Next Steps	Indicative Timing/Status
II.	**Petroleum Equipment**			
A.	Develop short term marketing to gain share of Russian purchases (incl. under WB Loans).	Advisors engaged with WB funding, promotional visit to US.	Assess bidding strategies for projects. Engage foreign partners. Bid on contracts.	Initial bidding in 3Q & 4Q 93. Use TA funding for follow on work.
B.	Develop business strategy to improve marketing, rationalize production, target local market.	Advisors engaged with WB funding, promotional visit to US.	Recruit advisors to develop business plan. Find partners and agree joint ventures.	By 2Q 94, using TA funding.
III.	**Oil Refining and Marketing**			
A.	Improve refinery efficiency and economics through restructuring and selective investment.	Investment contracts with foreign companies (economic basis not clear).	Undertake studies to assess least cost options. Initiate discussions with potential investors. Plan for likely reduction in capacity.	Studies by 2Q 94 (using EC Technical Assistance and other sources).
B.	Improve refinery environmental standards.		Formulate and enact environmental standards in line with OECD. Improve enforcement.	New standards by 2Q 94 (using EC Technical Assistance and other sources).
IV.	**Natural Gas**			
A.	Capture gas vented offshore.	Project initiated with Pennzoil.	Complete Pennzoil project, integrate with unitized offshore oilfield investments.	By 3Q 94.
B.	Reconstruct transmission and distribution system to reduce losses.	World Bank project proposed. Initial Azerigaz studies done. Japanese PHRD grant available for project preparation.	Initiate PHRD project preparation study. Initiate World Bank project.	PHRD study by 3Q 94. World Bank project proposed for 1995 or 1996.
C.	Install gas meters for large consumers.	Initial discussions with potential meter manufacturers held.	Study within PHRD project preparation. Initiate prioritized meter installation.	PHRD study by 3Q 94.

	Policy Action	Steps Already Taken	Next Steps	Indicative Timing/Status
D.	Improve gas end-use efficiency through replacement of inefficient appliances.		Study within PHRD project preparation. Initiate pilot program.	PHRD study by 3Q 94.
E.	Improve gas processing through plant reconstruction, gas gathering.	Initial discussions with potential foreign partner for minor upgrading of gas plant.	Study options for constructing new gas processing plant. Initiate investment, with foreign partners if possible.	Studies by 2Q 94 (using TA funding). Start investment in 1995.
F.	Increase domestic gas production capacity through rehabilitation and development of gas fields and associated gas.	Terms for natural gas development being discussed with foreign oil companies.	Agree terms for gas (price, contracts) with foreign companies. Study restructuring of existing gas fields, development of new fields. Initiate foreign investment.	Agree terms by 1Q 94.
G.	Regularize price and volumes of gas imports from Turkmenistan and Iran in line with domestic needs.	Negotiations and temporary agreements with Turkmenistan and Iran.	Conclude negotiations for adequate volumes on favourable terms relative to fuel oil exports. Initiate Gas Development Strategy.	By 1Q 94. Possible TA funding for Gas Development Strategy.
H.	Position Azerbaijan to benefit from future gas transit trade.	Preliminary gas transit agreement reached with Iran and Ukraine.	Continue contacts with Iran and Ukraine. Initiate cooperation with Turkmenistan and Turkey. Initiate Gas Development Strategy.	Ongoing (long term objective). Possible TA funding for Gas Development Strategy.
I.	Improve LPG availability to rural areas (possibly in place of natural gas).	Program to substitute LPG for gas in rural areas initiated.	Study within PHRD project preparation and gas plant investment options.	PHRD study by 3Q 94. Possible TA funding for study.

	Policy Action	Steps Already Taken	Next Steps	Indicative Timing/Status
V.	Electricity			
A.	Improve efficiency of existing power plants.	Grant Technical Assistance via EBRD for efficiency study underway.	Initiate further project preparation. Substitute natural gas for fuel oil in power.	Conclude studies by 2Q 94. Project in 1995.
B.	Improve efficiency of transmission and distribution system.	Grant Technical Assistance via EBRD for efficiency study underway.	Initiate further efficiency improvement studies and project preparation.	Conclude studies by 2Q 94. Project in 1995.
C.	Improve efficiency of electricity end-use.		Initiate efficiency improvement study. Initiate pilot program.	Conclude study by 2Q 94. Grant technical assistance available from EC.
D.	Replace obsolete power stations with gas combined cycle.	Discussions held with potential plant suppliers.	Initiate power least cost investment plan to assess timing. Continue contacts with potential investors and suppliers.	Least Cost study by 3Q 94, using TA funding.
E.	Assess potential for increased use of hydro (esp. small hydro) and wind power resources.	Azenergo initial studies done.	Initiate power least cost investment plan to assess costs and options.	Least Cost study by 3Q 94, using TA funding.
F.	Investigate revived regional power trade.		Continue contacts with Georgia to improve links and with Armenia (taking account of regional conflict).	EC technical assistance available by end-93.
G.	Improve power stations environmental performance.		Substitute natural gas for fuel oil, undertake plant improvements.	Least Cost study by 3Q 94, using TA funding.

	Policy Action	Steps Already Taken	Next Steps	Indicative Timing/Status
VI.	**District Heating**			
A.	Improve district heating system efficiency.		Initiate district heating investment and rehabilitation study. Initiate investment project.	Study by 3Q 94, using TA funding.
B.	Assess district heating economics against gas distribution.		Initiate district heating investment and rehabilitation study.	Study by 3Q 94, using TA funding.
VII.	**Energy Sector Institutions**			
A.	Increase central Government energy policy leadership and coordination.	Formation of part-time Energy Commission proposed.	Create small Energy Commission or Ministry with energy policy responsibilities. Develop capacity with foreign advisors.	EC technical assistance available by end-93.
B.	Develop Petroleum Law to govern SOCAR and foreign oil investment.	Work initiated with UK Grant.	Finalize draft law, consult with all involved, propose to Parliament.	Parliament to pass by 2Q 94 (coordinate with offshore oil agreements).
C.	Develop Laws for Natural Gas, Electricity and District Heating utilities, set up regulatory structures.		Initiate drafting of laws, draft laws and propose to Parliament.	By 2Q 94. EC Technical Assistance available for electricity, TA required for natural gas and district heating.
D.	Restructure and corporatize SOCAR as a commercial state company. Privatize retail stations.	SOCAR reorganization initiated.	Prepare plan for second level SOCAR organization, implement plan. Plan for retail privatization.	By 2Q 94. EC Technical Assistance available for advisors.

	Policy Action	Steps Already Taken	Next Steps	Indicative Timing/Status
E.	Improve SOCAR financial and information systems.	Some assistance obtained from foreign oil companies.	Prepare plan for improved financial systems and information management. Initiate implementation.	By 2Q 94 using possible TA funding.
F.	Undertake training for SOCAR staff in commercial areas.	Some assistance obtained from foreign oil companies.	Prepare training plan and initiate in-house program. Continue cooperation with foreign companies.	By 2Q 94 using possible TA funding.
G.	Improve Azerigaz organization, train staff.	Azerigaz reorganization continuing.	Prepare training plan and initiate reorganization.	By 2Q 94 using possible TA funding. Possibly include in World Bank project in 1995/96.
H.	Corporatize Azenergo and improve organization.	Some experiments with worker-ownership.	Prepare institutional restructuring plan. Initiate corporatization.	By 2Q 94. EC Technical Assistance available for advisors.
I.	Improve financial management and information systems.		Prepare plans for improved systems. Initiate investment and training.	By 3Q 94. Use TA funding Possibly include in future WB and EBRD energy sector projects.
VIII.	Energy Pricing			
A.	Develop and implement energy price adjustment framework.	Initial energy price adjustments made (but not within comprehensive framework).	Assess economic and world price targets for energy prices. Formulate adjustment plan. Initiate coordinated adjustment.	Study by 2Q 94 using TA funding. Adjustment possibly within one year of start of economic stabilization plan.
B.	Develop petroleum revenue taxation system for SOCAR.		Assess SOCAR's financial position at world prices. Develop taxation system. Implement system.	Study by 2Q 94, using TA funding.
C.	Design and implement social protection scheme to cushion impact of energy price rises.		Calculate impact of energy prices on consumers. Propose social safety net scheme.	Study by 2Q 94, using TA funding.

CHAPTER 1

ENERGY SECTOR DEVELOPMENTS AND OUTLOOK

1.1 The energy sector has played a key role in the development of Azerbaijan's economy. As one of the largest oil exporters in the first decades of this century, Azerbaijan's initial economic growth was largely driven by oil. However, oil production has fallen sharply since 1970, and the growth of other industries since World War II has greatly reduced the relative importance of this sector.

1.2 Despite its long history of oil production Azerbaijan has large remaining oil resources in newly discovered fields, and the oil sector is poised again to dominate the country's future economic development. The key challenge for Azerbaijan is to develop its resources as rapidly and efficiently as possible, and to restructure its economy to absorb the resulting financial surplus effectively.

Current Situation

Macroeconomic Developments and Background[1]

1.3 Azerbaijan lies on the southeastern flanks of the Caucasus mountains. It is one of the smallest of the Republics of the Former Soviet Union (FSU), covering an area of 86,000 square kilometers, similar to that of Austria. Over half of its 7.2 million population is urbanized; the capital, Baku, has about 2 million inhabitants and is a major harbor on the Caspian Sea. The country is endowed with fertile agricultural land, and ample natural resources. It also has a diversified industrial structure and a relatively well educated labor force.

1.4 Azerbaijan was among the first of the FSU republics to adopt a resolution of sovereignty, in September 1989. The constitution was amended to legitimize the independence of the Azerbaijani Republic, in August 1991. Azerbaijan chose not to become a member of the Commonwealth of Independent States, preferring instead to maintain its relations with the other FSU republics through bilateral agreements. Notwithstanding its political independence, Azerbaijan has continued to be an integral part of the FSU economy, since the deeply entrenched economic interdependence with the other republics has remained in place.

1.5 As in the other countries of the FSU, 1992 was characterized by a drastic fall in economic activity, and a large scale increase in prices. These trends followed moderate output declines in the previous three years, so that by 1993 Gross Domestic Product (GDP) was only 60 percent of that in 1988. Both consumption and investment were severely hit. Although adverse weather conditions and the unsettled situation in Nagorno-Karabakh contributed to the output decline, the main factor was the transformation process that accelerated in late 1991. The collapse of central planning was rapid, while the emergence of a substitute market-based economic order was slow. Despite the large output drop and high inflation, the macroeconomic imbalances in Azerbaijan appeared to be lower than in most other FSU

[1] This sub-section is based upon the Azerbaijan Country Economic Memorandum, May 1993.

countries. In 1992, the Government managed to keep the budget deficit under control, at about 4 percent of GDP. At the same time, the country registered an overall trade surplus, but at lower import and export levels than in 1991. Although trade with FSU countries contracted drastically in 1992, Azerbaijan managed to expand its export markets outside the FSU, primarily for petroleum. As a growing share of exports was diverted to non-FSU markets, the country may have benefitted from an improvement in the terms of trade.

Energy in the Economy

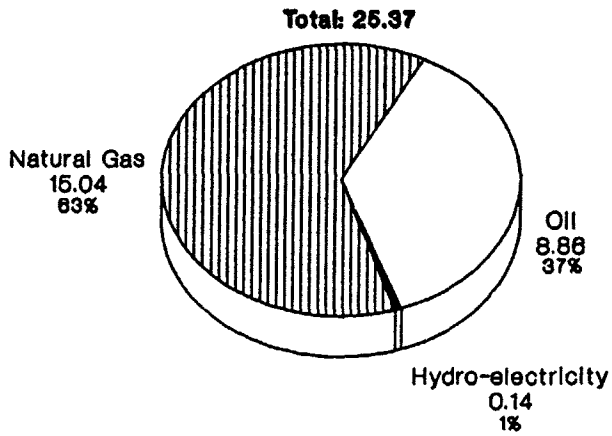
1.6 It is difficult to measure the relative contribution of oil, gas and other energy activities to the economy of Azerbaijan, since Soviet statistics were calculated at highly distorted prices. Thus the energy sector is estimated to have contributed less than 10 percent of GDP in 1991, whereas the actual contribution was probably much higher. In terms of employment, the energy enterprises account for around 120,000 people, or 13 per cent of industrial employment. In terms of investment, the energy sector accounted for 25 percent of all investment in the economy in 1991, of which about 22 percent was attributable to oil and gas production.

1.7 A better measure of the remaining importance of oil to Azerbaijan's economy can be gained from the trade data, which are estimated at "foreign trade" prices as well as domestic prices. At foreign trade prices, oil accounted for 39 percent of total exports in 1990 (compared with 12 percent at domestic prices), and for 26 percent of imports (8 percent at domestic prices). Significantly, the oil and gas trade surplus at foreign prices in 1990 was 605 million Rubles, which almost offset a deficit of 740 million Rubles on industrial products, raw materials and food. Thus the economy continues to depend upon its net oil exports to a significant extent.

Energy Balance

1.8 The structure of Azerbaijan's energy balance is relatively straightforward in comparison with that of many other FSU Countries. Oil and gas account for about 99 percent of primary energy use, with hydropower supplying the remainder. The large coal, nuclear and hydro power supplies which greatly complicate the energy situation in other FSU countries are absent in Azerbaijan. Given the abundance of petroleum, there was no need to develop or import these other fuels. Even in sectoral terms, the structure of fuel consumption is relatively simple, with most non-transport energy supplied from natural gas or fuel oil. Power stations are largely designed to use gas, but have dual fueled boilers and therefore can use fuel oil as well. In 1990, natural gas accounted for 64 percent of power and district heating fuel use. Industrial boilers are nearly all designed to use natural gas, which made up 89 percent of industrial primary fuel supplies in 1990. Households rely on natural gas for a significant proportion of their energy requirements, although district heating also plays an important role in certain regions.

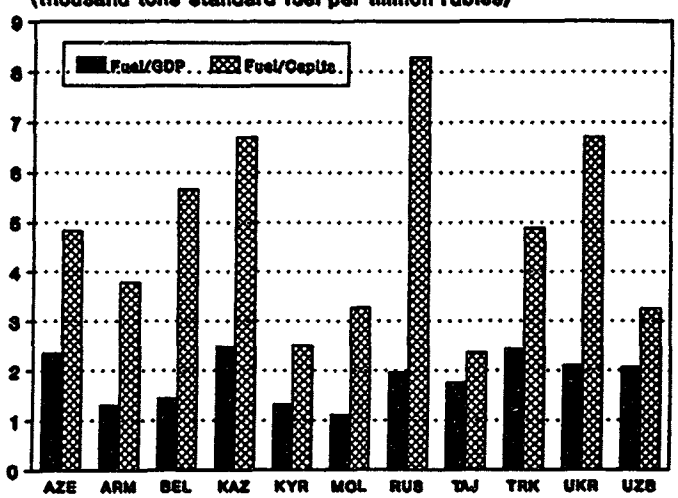
Figure 1.1 Primary Energy Consumption, 1991
(million tons of oil equivalent)



Source: Mission estimates.

1.9 The economy of Azerbaijan is highly energy intensive, even by the standards of the Former Soviet Union. In 1990 its energy intensity was the third highest of the FSU Republics (excluding the Baltic states), in terms of fuel use per unit of GDP. This is probably due to the concentration of inefficient fuel production and processing in the country, as well as the large amount of medium and heavy industry. In terms of fuel use per capita, Azerbaijan stands in the middle of the range of use within the FSU.

Figure 1.2 Energy Intensity of Economy 1990
(thousand tons standard fuel per million rubles)



Source: Mission estimates.

1.10 International comparisons show that Azerbaijan's energy consumption in per capita terms is within the range seen in most central and southern West European countries. In the Northern countries of Scandinavia, consumption is higher due to the colder weather. Consumption in Azerbaijan is below that in such extremely inefficient East European countries as Bulgaria and Czechoslovakia. Comparisons taking account of international GDP relativities are inevitably less reliable, since it is extremely difficult to measure GDP in the FSU countries on a comparable basis. However, using World Bank estimates of GDP shows that energy consumption in Azerbaijan is probably extremely high per unit of output, in comparison with other industrialized countries. Improving energy efficiency, through implementation of economic pricing and replacement of wasteful energy transporting and processing infrastructure is clearly a priority.

Table 1.1: Energy Intensity - International Comparisons 1991/92

	1 GDP/Cap	2 Energy/GDP	3 Energy/Cap
Azerbaijan	870	3770	3356
Poland	1690	2021	3416
Turkey	1630	525	857
Bulgaria	2250	2198	4945
Czechoslovakia	3140	1618	5081
Yugoslavia	3060	787	2409
Portugal	4900	308	1507
Spain	11020	200	2201
Italy	16830	164	2754
France	19490	197	3845
Germany	22320	156	3491
Sweden	26524	239	6347
Finland	27540	206	5650

Source: Mission estimates.

1. US$ GDP per capita.
2. Kg oil equivalent per US$Th GDP.
3. Kg oil equivalent per capita.

1.11 Despite its net oil exports, Azerbaijan was only 88 percent self sufficient in energy overall in 1990. Azerbaijan's energy self sufficiency deteriorated markedly during the 1980's. Combined output of oil and natural gas fell by 22 percent, while energy consumption rose by 19 percent. The deficit in energy in 1990 compares with a large surplus (self sufficiency of 133 percent) in 1980, and a rough balance in 1985.

Table 1.2: Azerbaijan Energy Balance
(Th. tons standard fuel equivalent)

	1980	1985	1990
Total Supply	49665	56107	52462
Oil & Gas Production	37571	35209	29310
Hydro Production	358	427	539
Imports	11589	20471	22613
Other	147	NA	NA
Domestic Consumption	28456	33797	33858
Conversion	9926	11543	10540
Direct Use*	18530	22254	23318
Exports	20887	22926	18276
Stock Change	322	-616	328
Self Sufficiency %	133.3%	105.4%	88.2%

**Note: Includes losses and statistical discrepancies.*
Source: Goskomstat

1.12 The most marked manifestation of Azerbaijan's energy deficit has been the large growth of natural gas imports. In 1980, Azerbaijan was a net exporter of natural gas. By 1991, natural gas imports accounted for about 29 percent of total energy requirements. This shift in the pattern of Azerbaijan's fuel supplies was dictated by the logic of supply within the FSU, where resources from surplus producing republics were transported long distances to consuming areas. The emphasis was on the development of large scale supply and transport systems, rather than on efficiency in end use and development of smaller scale local supplies. In the case of Azerbaijan, gas use was allowed to become extremely wasteful, while a large number of modest but important local resources of gas and other energy sources (mainly hydro) were left undeveloped. The true cost of this policy to Azerbaijan and the other Republics was masked by the extremely low price of gas. Redressing this imbalance in its energy development is one of the key problems confronting Azerbaijan in the coming years.

1.13 The last two years have seen significant changes in the structure of Azerbaijan's energy balance, as a result of the economic decline and changing trade relations within the FSU. The economic contraction has led to an estimated fall of about 18 percent in the combined consumption of oil and natural gas, due to a fall in fuel use for power, industry and transport. This large fall in consumption did not lead to a return to energy self-sufficiency in 1992, due to a fall in production of oil and gas of around 15 percent. At the same time, there has been a significant shift in fuel use from gas to oil, since difficulties in meeting gas import targets have led to a large scale substitution of fuel oil for natural gas in power generation. The share of gas in total primary energy demand fell from about 67 percent in 1990 to 55 percent in 1992 (see table 1.4).

Energy Trade

1.14 The pattern of Azerbaijan's energy trade reflects its strong links with the other FSU countries, as well as its geographical position on the Caspian Sea, but without a seaport with access to world markets. The lack of access to a seaport limited Azerbaijan's ability to export crude oil to world markets, in the absence of a long export pipeline. Azerbaijan's oil exports thus took the form of oil

products, mostly traded within the Caspian and Caucasus region (including Northern Iran).

1.15 Another feature of Azerbaijan's energy trade has been the republic's importance as a transit point and processing center. In the case of oil, Azerbaijan's refining capacity, which became surplus to domestic requirements as oil production fell, served to process imported crude oil from Russia and Kazakhstan (brought respectively by pipeline and Caspian tankers), with the oil products exported. In the case of natural gas, Azerbaijan served as the main transit route for gas from Russia and Turkmenistan to Georgia and Armenia. Azerbaijan was also an important part of the integrated Caucasus electricity grid.

1.16 These trading links have been breaking down over the last two years. The imports of oil from Russia and Kazakhstan virtually ceased by late 1992, as the poor economics of this trade at international prices has become apparent. In the case of natural gas, much of the drastic decline in transit trade has been due to the regional conflict with Armenia. Imports of gas to Azerbaijan, however, have also declined due to disagreements with Turkmenistan over pricing and payments, and difficulty in arranging reliable transit through Russia. Regional electricity trade has also collapsed as a result of the regional conflict and difficulties over payment.

1.17 As it moves towards economic independence from the links established within the FSU, Azerbaijan will have to orient its energy trade according to market forces. This is likely to mean an increased orientation towards the world market, particularly for oil, since Azerbaijan will have to compete with Russia and other suppliers within the FSU. Statistics for 1992 show that an increased proportion of oil exports went outside the FSU, probably because of the higher prices which could be obtained in those markets.

Table 1.3: Azerbaijan Energy Trade (Th. tons)

	1991			1992		
	Imports[1]	Exports		Imports[1]	Exports	
	Total	Total	Non-CIS	Total	Total	Non-CIS
Crude Oil	4301	0	0	1355	1056	1056
Gasoline	0	66	0	0	168	32
Diesel	1	2279	1232	0	2742	2058
Jet Kerosine	1	747	0	12	187	57
Fuel Oil	0	2304	442	0	352	260
Diesel Lubes	4	338	0	2	562	263
Other Oil Prod.	10	11	0	4	144	51
Nat. Gas (MMCM)	14170	5996	0	5263	951	0
LPG	99	0	0	15	0	0
Electr.TKHWH	0	2	0	0	495	0
Coal	101	0	0	11	0	0

[1]*Almost all from CIS republics.*
Source: Mission estimates.

Energy Trade Outlook

1.18 Despite its recent problems, Azerbaijan's long term energy outlook is bright, providing suitable policies are put in place. The key to improving the situation of the energy sector will be to combine the development the new offshore oil fields with suitable restructuring of the domestic energy industry (both the physical infrastructure and the institutional framework).

1.19 Through attracting large investments from international companies to develop its offshore fields, Azerbaijan will be able to increase its oil production, as well as eventually stemming the rapid decline in gas production. Table 1.4 shows the long term supply-demand outlook for energy in Azerbaijan. The energy consumption projections are based upon an economic outlook in which GDP continues to decline slightly until 1995, before rebounding to show fairly strong growth (up to 10 percent per annum) in the late 1990s. Much of this growth will be driven by the expected upsurge in oil investment and production. As the table shows, however, total energy demand is expected to be roughly stable to 2000, and to rise only modestly thereafter, since energy prices are assumed to rise steadily to economic levels over the next few years, while the economy should evolve towards a less energy intensive industrial structure. The higher prices should encourage conservation, with efficiency of use also improving through a reduction in transmission and distribution losses following system reconstruction. It is likely that a marked reduction in energy intensity in industry will occur through rationalization of such heavy energy-using industries as metallurgy and chemicals. Overall, the energy/GDP ratio should decline by about 30 percent between 1992 and 2000, under a Base Case scenario. It can be seen that while Azerbaijan is expected to continue to show a net deficit in energy trade in volume terms until the mid-1990s, by 2000 this will have turned into a large surplus due to the rise in oil production and exports. In a Base Case scenario, total net oil exports could rise from about $173 million in 1992, to $610 million in 1995 and reach $5.3 billion in 2005. The rapid growth in oil exports under the Base Case scenario will allow Azerbaijan to meet its external financing requirements through foreign private investment and borrowing from multi-lateral institutions.

Table 1.4: Energy Supply - Demand Outlook: Base Case
(million tons oil equivalent)

	1990	1992	1995	2000	2005
Production*	21.5	18.2	16.2	30.9	52.4
Oil	12.5	11.1	9.7	25.6	45.2
Natural Gas	8.9	7.1	6.5	5.3	7.3
Imports	16.3	6.1	8.2	9.4	8.3
Oil	4.5	1.4	1.0	0.0	0.0
Natural Gas	11.8	4.7	7.2	9.4	8.3
Exports	13.8	4.9	5.7	20.8	39.7
Oil	9.0	4.0	5.7	20.8	39.7
Natural Gas	4.9	1.0	0.0	0.0	0.0
Domestic Use*	23.9	19.7	18.7	19.5	21.0
Oil	8.1	8.8	5.0	4.8	5.5
Natural Gas	15.9	10.8	13.7	14.7	15.5

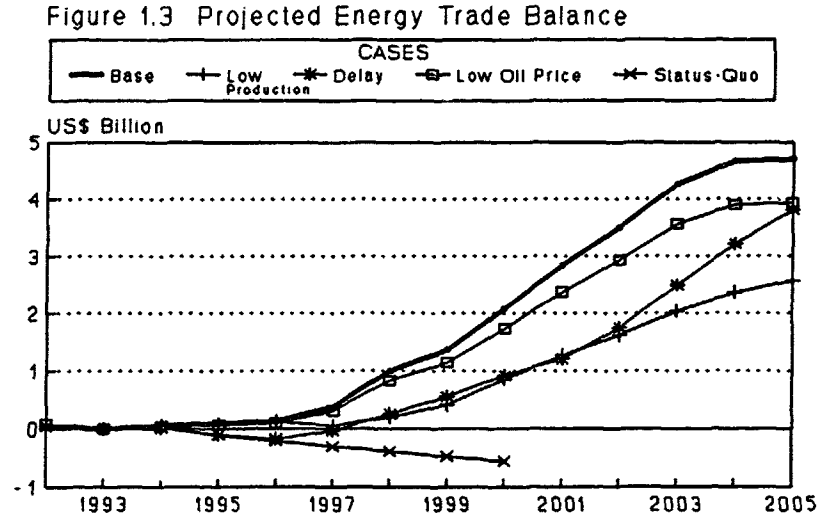
*Note: Includes 0.14 million tons oil equivalent hydro per year. Gas excludes venting.
Source: Mission estimates.

1.20 Azerbaijan will, however, remain a gas importer unless large new gas fields are discovered and developed rapidly. The cost of gas imports is expected to rise rapidly, to about $560 million in 1995 and some $730 million in 2000, as Turkmenistan raises its prices towards world levels. In the medium term this rise in gas import costs would probably limit any increase in Azerbaijan's trade surplus in energy, although in the longer term the rise in oil exports will be the dominant factor.

1.21 Any delay in the development of the new offshore fields will have serious adverse consequences for Azerbaijan's energy trade in the medium term. Thus, if the field developments are delayed two years from the Base Case (the "Delay"case), the energy trade balance in 1996 moves from a surplus of $130 million to a deficit of $170 million. This is due to sharply lower oil exports and higher gas imports as gas production and recovery decline sharply. Even such a modest delay in the development of oil production will cause great difficulties for Azerbaijan in meeting its external financing needs for imports and investments. Debt would grow much more rapidly than under the Base case, and the inability to finance all required imports would reduce economic growth. A further delay in the development of the new fields to beyond 2000 (a "Status-Quo Case") will result in a continued worsening of the trade deficit in energy to US$550 million in 2000.[2] Moreover, Azerbaijan would not benefit from the inflow of US$ 4 to 6 billion of oil related foreign investment. In this case the external financing requirements to maintain economic stability are likely to be wholly unsustainable, and a severe economic decline would be precipitated.

1.22 As a net oil exporter, Azerbaijan's trade surplus in energy would also suffer from lower oil prices. In the medium term, however, the lower revenues from oil exports could be partly offset by reduced gas import costs. This would be the case if gas import prices are linked to oil prices (as is the case in the European gas trade). Thus, at an oil price 15 percent below the Base ($17/barrel versus $20/barrel) the energy trade surplus in 1995 falls only slightly, from $89 million to $72 million, despite a fall in oil export value of $120 million. In the longer term, the energy trade surplus would fall roughly in proportion to the fall in oil prices. Such a scenario, while reducing Government revenues significantly, would not fundamentally alter the positive economic outlook arising from prompt development of the oilfields.

Figure 1.3 Projected Energy Trade Balance



Source: Mission estimates

[2] This scenario has not been extended beyond 2000 as it is likely to be unsustainable and the economic consequences are unclear.

CHAPTER 2

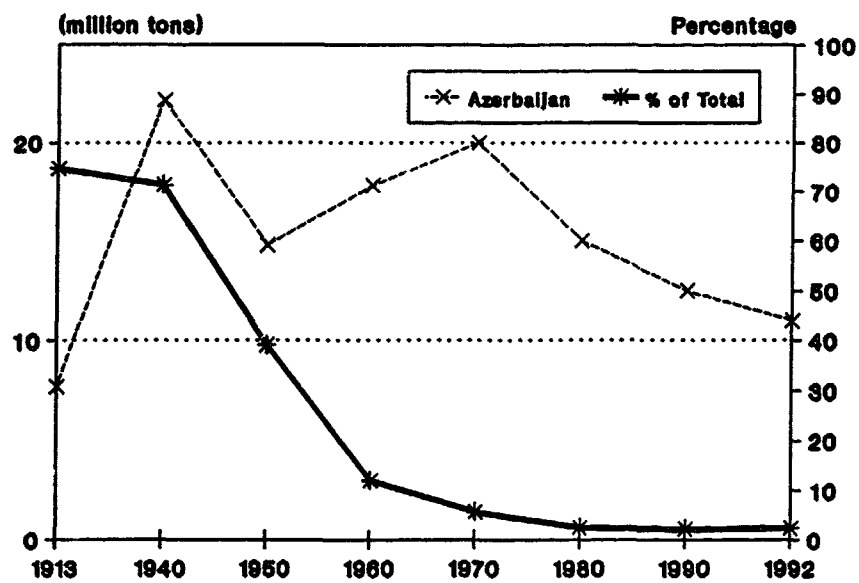
OIL EXPLORATION AND PRODUCTION - CURRENT STATUS

Historical Perspective

2.1 Azerbaijan is one of the oldest oil producing regions in the world, and in order to analyze its present problems, it is necessary to understand some aspects of its history. Many of the current problems of the petroleum industry have their roots in its historical development. Small scale oil production, through wells dug to access oil near the surface, was first practiced in the Baku region several centuries ago[1]. The modern industry, however, started in the late 19th century, when Azerbaijan rapidly became one of the major world oil suppliers. By 1905 the Russian empire, due to the growth of production in Azerbaijan, accounted for 25 percent of world oil production, second only to the United States. Foreign capital, through such firms as Nobel, Rothschilds and Royal Dutch, accounted for a large part of the investment at the time.

2.2 This early development was concentrated in a relatively small region on the Apsheron peninsula around Baku, which owes its modern growth largely to the oil industry. Most of the oil fields developed in the early phase of the industry remain in production. This long history has left a legacy of exceptionally old oil fields and infrastructure in Azerbaijan, as well as considerable environmental damage.

Figure 2.1 Azerbaijan Oil Production (Total and Percentage of FSU Production)



Source: Soviet statistics.

[1] Even in 1991, 1460 tons of oil was produced from oil-pits.

2.3 Azerbaijan remained the main source of supply for the Soviet Union through the Second World War, and rapid development of the fields around Baku was a key part of the Soviet industrialization campaign. Production reached 22.2 mt in 1940, before being disrupted by the War. However, after the War, a larger oil region was discovered in the Volga-Urals area of Russia (centered on the super-giant Romashinko field), and the focus of the Soviet industry shifted away from Baku. The massive development the Volga-Urals in the 1950s and 1960s was followed by that of Western Siberia in the 1970s (centered on the Samotlor field).

2.4 The shift in the focus of the oil industry within the Soviet Union had important implications for Azerbaijan. While it remained an important center of the petroleum industry, including in the areas of exploration and production research and equipment manufacturing, Azerbaijan's industry was probably for a long time deprived of the full investment resources required to maintain output and exploration. This has led to the particularly poor condition of facilities today. Due to the combination of the natural decline of mature fields, and the lack of investment, production has fallen rapidly, from 17.2 mt in 1975 to 11.1mt in 1992. Azerbaijan's share of total production in the FSU, fell from 3.5 percent in 1975, to 2.3 percent in 1991[2].

Recent Trends

2.5 A key factor in the recent history of production of oil in Azerbaijan has been the shift from onshore to offshore production. The initial oil field developments were all onshore, although reserves in very shallow offshore areas were exploited from the early part of the century (mostly through landfill techniques). However, the turning point for Azerbaijan's production came with the development of the giant Oil Rocks (Neft Dashlari) field in 1949. This was followed by the development of further small fields until in 1980 another giant, Guneshli, was brought on stream.

2.6 The development of the large offshore fields helped to arrest the decline in overall output as the old onshore fields faded. From only 33 percent of production in 1959, offshore production rose to 82 percent of the total in 1992. However, Azerbaijan's development probably suffered from the fact that most of its new potential lay offshore. The investments required for exploring and developing oil offshore are far larger that for most onshore areas, and the technology is more complicated. With the bulk of the Soviet industry focussed on onshore areas (offshore production accounted for only 1.5 percent of FSU production in 1985), the few offshore regions such as Azerbaijan on the Caspian and Sakhalin in the Far East, suffered from inadequate research and development in offshore technology and a lack of investment. The lags in developing offshore resources and technology within the FSU condition the requirement for massive infusions of foreign investment and technology today.

2.7 Very large discovered reserves remain undeveloped offshore, due to the limitations of the FSU industry. Around half of the reserves of the Guneshli field lie in deeper waters (over 200 meters) and have not been developed. In addition, drilling during the 1980s identified three further very large fields (Chirag, Azeri and Kapaz). The water depths at which these fields lie (100 m to 300 m) were beyond the reach of Soviet production technology, although the international oil industry has been developing such fields in the Gulf of Mexico and the North Sea since the late-1970s.

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[2] The massive shift in the focus of the industry during the first half of this century is demonstrated by historical statistics showing that the share of Azerbaijan in total Soviet oil investment fell from 45 percent in 1935 to 9 percent in 1955.

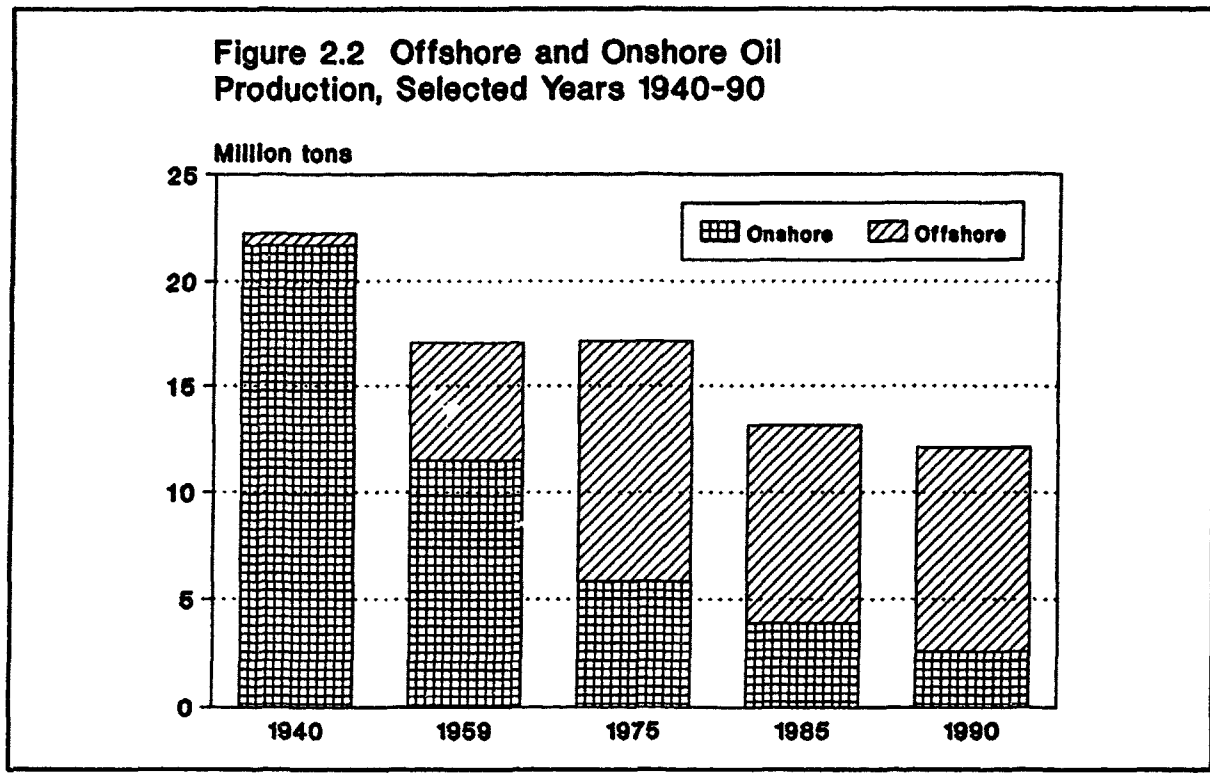


Figure 2.2 Offshore and Onshore Oil Production, Selected Years 1940-90

Source: SOCAR, Soviet statistics.

2.8 As a result of its unusual history, Azerbaijan's upstream oil industry now presents two very contrasting aspects: On the one hand, the older producing fields onshore and offshore are mostly in a state of advanced depletion, with old and dilapidated infrastructure. On the other hand, the large new offshore fields represent some of the major undeveloped petroleum resources in the world, susceptible to development through state-of-the-art offshore technology. This creates a need for a wide range of policies and decisions within the industry, aimed both at exploiting new reserves efficiently, and at restructuring production in the mature areas. In both cases access to foreign capital and technology will be needed, calling for a large scale effort to reach agreements with foreign companies on investment and joint ventures with widely differing technical and investment characteristics.

Current Reserves and Production

2.9 Despite its long production history, Azerbaijan has considerable remaining petroleum reserves and exploration potential. Cumulative oil production from Azerbaijan's fields (to end-1992) can be put at around 1295 Mt, of which 922 Mt has come from the onshore fields, and 373 Mt from offshore. Remaining reserves are subject to considerable uncertainty, although it is clear that at least as much oil remains to be recovered economically as has been recovered in the past century. However, this oil will be considerably more difficult and expensive to produce than that in the easily accessible, shallow onshore and offshore fields exploited to date.

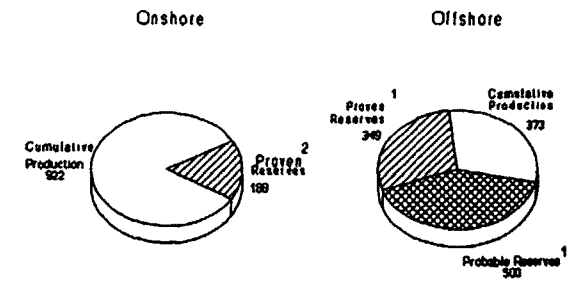
2.10 All of the oil and gas fields, as well as the sole exploration rights in Azerbaijan belong to the State Oil Company of the Azerbaijan Republic (SOCAR), which is the sole licensor. SOCAR was

formed in September 1992 from the two producing associations in Azerbaijan, Kaspormneftegas (offshore) and Azneft (onshore). SOCAR's precise legal status as licensor awaits clarification through a petroleum law.

2.11 For the purposes of policy formulation in exploration and production, Azerbaijan's remaining oil reserves can be classified as follows:

(a) **Mature Fields:** Proven reserves in fields which have a long production history can be assessed with a reasonable degree of certainty. Proven reserves are put at 361 Mt, of which 48 percent lie offshore. As shown in Figure 2.3, most of originally recoverable reserves in the onshore fields have been produced, although significant quantities remain.

Figure 2.3 Cumulative Oil Production and Remaining Reserves (million tons)



1. In producing fields, including Guneshli.
2. In undeveloped fields.

(b) **Guneshli:** The Guneshli field has a much shorter production history than most of the other producing oil fields. With proven reserves of 155 Mt, the field accounts for 43 percent of remaining proven reserves. However, substantial proven and probable reserves in deeper waters, perhaps totalling over 100 Mt, remain undeveloped.

(c) **Newly Discovered Fields:** The three newly discovered fields offshore (Chirag, Azeri, Kapaz) contain reserves estimated at about 500 mt (these are shown as "Probable" in Figure 2.3). However, only about 10 discovery and appraisal wells have been drilled on these fields by Azerbaijan exploration rigs, and proven reserves are substantially less.

2.12 It can be inferred that most of Azerbaijan's offshore reserves are subject to considerable uncertainty, and will require detailed geophysical studies and considerable exploratory drilling to be confirmed. The proportion of reserves in the "probable" category is unusually large for a relatively mature province such as Azerbaijan, reflecting the past under-investment in drilling. However, the substantial producing history of Azerbaijan, which has shown itself to be a very prospective petroleum province, gives considerable confidence in the effectiveness of investment to convert probable into proven reserves. The key issue for Azerbaijan is to attract the investment needed to make its probable reserves available for production, as rapidly and effectively as possible.

Exploration Potential

2.13 In addition to producing and discovered oil fields, Azerbaijan also possesses a large number of undrilled structures which are highly prospective for petroleum. Most of these lie offshore, in water deeper than 200m, and reaching up to 800m in the central part of the Southern Caspian Sea, which represents the limit of current technology. In general these structures represent a continuation of proven hydrocarbon bearing formations onshore and in shallower offshore water, and the probability of

further large discoveries must be considered high. At least 24 significant prospective structures have been mapped by seismic, spread out over most of the southern half of Azerbaijan's sector of the Caspian[3]. Any estimate of the reserves of these structures must be highly speculative, however a very preliminary indication is that they could contain about 2.5 billion tons of recoverable oil. Some of the structures could, however, turn out to be primarily gas-bearing (with oil and condensate), as is the case with some of the existing producing fields.

2.14 Onshore exploration prospects are generally smaller - the largest and most obvious structures having been drilled many years ago. However, a number of significant discoveries have been made outside the Apsheron peninsula, but have not been developed as the structures are deep and at high pressure. New field onshore exploration in recent years has yielded negative results. Nonetheless, although the 13 wells drilled since 1981 resulted in no new field discoveries, this represents a very low level of exploration, which may also not have been targeted at prospects identifiable through high technology search techniques. Several new structures remain untested, which could also have total recoverable reserves of over 150 mt. In addition, there may be significant prospects for additional oil reserves below currently producing fields, at depths of over 3,000m (current average production depth is 1,800m) - until now these horizons have not been properly tested due to a lack of finance.

2.15 The existence of this substantial prospectivity means that Azerbaijan's planning horizons for oil development must be substantially longer than implied by present discoveries. Moreover, the scale of the technical challenge, the large expenditure and long leads times involved in the exploration of the offshore and deep onshore structures, make it essential to initiate a long term coordinated exploration program as soon as possible.

Oil Production in the Mature Fields

2.16 In general, the mature onshore and offshore oil fields of Azerbaijan are in an advanced state of depletion, with old and dilapidated infrastructure and rapidly falling output. Production from these fields has been falling at an annual rate of 10 percent.

Onshore Areas

2.17 In the onshore areas (which includes some very shallow offshore fields), there are around 9,700 wells which are classified as "active" (i.e. capable of producing petroleum), located on some 35 fields. Of these, however, up to 2,000 are inoperative due to a lack of spare parts, sand problems or need for repairs. The producing wells yield on average 0.7 tons/day of oil, with individual well rates varying from 20 tons/day (t/day) to 0.1 t/day. Wells produce on average between 94 percent and 98 percent water.

2.18 The production plans of SOCAR for the onshore areas focus in the short term upon the reactivation of currently idle wells. It is estimated that bringing on stream the 2,000 idle wells could add around 700 t/day to production. In addition, there are proposals to drill a substantial number of new

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[3] The precise territorial waters of the Caspian have not been internationally agreed following the break-up of the Soviet Union. Existing boundaries are based on determinations made before the break-up. It is assumed that any re-determination will not greatly affect Azerbaijan's share of Caspian reserves.

wells so as to maintain production. New wells usually yield at rates of 5 t/day, with a 93-94 percent water cut.

2.19 In this context, the key issues for SOCAR center on the economics of such marginal onshore wells. Estimates presented by SOCAR suggest that the economic cut-off for producing wells is 0.15-0.2 t/day, with a 98-99 percent water cut. Around 1,200 wells produce at or below this level. However, such estimates are based upon the prevailing local costs, and probably do not reflect the full economic cost of resources used for producing the oil. For example, most wells require artificial lift, and the energy for running the pumps is costed at the very low prices prevailing in Azerbaijan. Production in the onshore fields is extremely labor-intensive. The total number of people employed in the onshore fields is 30,500, which is at least two to three times the level which would be used in North America. It is likely that the economic threshold of production is above the limit estimated by SOCAR.

2.20 The problems of the onshore fields can be seen by examining the recent operations of three of the larger fields in the Apsheron (Balachani, Bibi-Eybat and Tagiev -which account for 25 percent of onshore output). The data for these fields, which is shown in Table 2.1, demonstrates that the fields had substantial negative funds flows (i.e. a deficit after allowance for capital investment), even at the artificially low cost of local inputs. This highlights the central problem of very low domestic oil prices, which have for many years been insufficient to cover the real costs of maintaining production (this is discussed further in Chapter 8). If the various inputs are valued at international parities, it can be seen that the cost per ton of oil produced is well above the international value of the oil. The largest cost is for workovers, which greatly inflate the costs if valued at international prices.

Table 2.1: Production Costs in Three Large Apsheron Oil Fields 1/
(Data for January-March 1993)

Operational Data			
Oil Sales (Th. tons)	139.6		
Number of Workers	5,091		
Electricity Consumption (Th. Kwh)	64,232		
Number of Operating Wells	3,500		
		Local Costs (Mn. Rubles)	International Costs (Th. US$)
Financial Data			
Oil Sales Revenues		1691.6	13,960
Labor Costs		430.8	3,818
Electricity Costs		338.5	1,927
Production Materials		300.8	3,008
Workovers and drilling		732.1	21,875
Other Capital Investment		83.1	831
Net Funds Flow		-193.7	-17,499

1. Balachani, Bibi Eibat and Tagiev.
Source: SOCAR, Mission estimates.

2.21 The restructuring of onshore production will clearly require a substantial number of wells to be abandoned. The equipment from such wells would either be sold for scrap, or reapplied to more productive wells, while the land should be reclaimed for housing or agricultural use. Such a process is inevitable as oil fields reach the end of their natural productive life. This process is already underway, but in an erratic fashion.

2.22 In the case of many of Azerbaijan's onshore fields, however, the process of orderly abandonment must be supplemented by assessment of the potential for applying more efficient investment and new techniques to the mature fields. Part of the decline in production is attributable to insufficient suitable production drilling, due to a lack of rigs and a shortage of finance. Field infrastructure, such as pipelines and storage tanks, are also in poor condition, which limits production capacity and increases losses. In many cases application of more modern drilling techniques, including horizontal drilling, multiple completions, and use of more suitable drilling muds and proper tools (including modern logging equipment) could greatly improve drilling and well productivity. A number of fields also utilize air-lift technology, reportedly with good results, but a substantial proportion of the pumps are inoperative due to a lack of spare parts. Modern seismic and other techniques can be used to identify bypassed pools of oil. Selective investment, if combined with improved management practices which focus workovers and repairs on the most productive wells, could result in improved field performance and economics. The resources and technology involved in carrying out such a program call for developing a framework for investment by foreign companies in these fields.

2.23 As far as the onshore fields are concerned, these issues need to be addressed in a comprehensive manner, taking account of the geological characteristics of each field, its production history, remaining reserves and economic cost of production. For each field an outline economic assessment and restructuring strategy should be developed. Based upon this assessment, a comprehensive production restructuring program for the onshore areas needs to be elaborated, involving selective investment by foreign companies in collaboration with SOCAR.

Offshore Fields

2.24 There are some 17 active offshore fields in Azerbaijan. The major producing oil fields are Oil Rocks and Guneshli[4]. Both Oil Rocks and Guneshli present major problems for SOCAR, requiring urgent investment decisions.

2.25 Oil Rocks was the first major field developed in the Caspian Sea. The field is located about 50 kilometers (km) offshore, in relatively shallow waters (6-25 m). Development started in 1949, and at the time Oil Rocks represented one of the most advanced offshore ventures in the world. Development involved using fixed production platforms linked by some 300 km of causeways ("Estacada"), which serve both to support pipelines and to carry supplies with vehicles. In other respects the production systems used were very similar to those in the onshore fields.

2.26 At its peak in 1964-65, the Oil Rocks field produced 21,000 t/day. Production has now fallen to under 2,000 t/day from about 700 wells (a further 400 wells are idle for lack of equipment). In addition to natural depletion, the field has suffered from poor maintenance, with a lack of adequate corrosion protection on the structures, and from the 1.5 m rise in the level of the Caspian Sea over the past 20 years, which has led to major storm damage to the offshore structures. Much of the Estacada has already collapsed, or is in danger of doing so in the near future. There is substantial ancillary infrastructure associated with the field, including a 48 MW gas turbine station, which was built only 10 years ago, but is used at only 15 percent of capacity. Housing and communal buildings for over 1000 people are also built on natural and artificial islands.

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[4] Another major offshore field, Bakhar, is primarily a gas-condensate field and is discussed in the section on Gas Supply.

2.27 Overall, the economics of continuing field production must be seriously in question. Per well productivity is only 3 t/day. Despite the fact that the field is producing only 10 percent of its peak production, field activities continue on a very large scale. Attempts are constantly underway to rebuild damaged sections of the causeway and repair producing structures. The field is also the largest single employing unit within SOCAR, with 5,000 workers directly employed in field operations (2,500 offshore per shift).

2.28 About 88 percent of original reserves have been produced and remaining recoverable reserves are estimated by SOCAR at 32 mt. Although this is a significant amount, it is not clear that these reserves are economically recoverable using the existing infrastructure and production arrangements. At present, production per worker is only 146 tons/year, which is worth about $15,000 at international prices. Although offshore wages (which are about 50 percent higher than those onshore) are at present about $4,000 per year (at an "equilibrium" exchange rate of around R100/$), the margin left for all other costs is low by the standards of the oil industry. An assessment based on international costs and prices suggests that the field had a funds flow deficit of around $1 million in the first quarter of 1993. A major review of the field is required to assess whether remaining reserves would not be best recovered using a redesigned production system, a limited amount of new infrastructure, and with much of the existing infrastructure abandoned. This assessment could serve as a model for the restructuring of the other mature offshore fields, many of which suffer the same problems as Oil Rocks, albeit on a smaller scale.

Attracting Foreign Investment to the Mature Fields

2.29 The restructuring of the mature fields, and enhancement of their production, is best carried out through investment by international companies experienced in this type of work. This type of investment may be suitable for smaller companies used to working mature onshore areas, such as the medium and small independents present in North America. The rewards of such work will in general be modest in relation to development of the large offshore fields, although returns to investment can be extremely high given the lower costs of operating onshore.

2.30 A number of specific issues need to be resolved in reaching such agreements:

- **Sharing of rewards:** If investment is to be rewarded by results, some determination of the incremental production which has been achieved by the investment will usually be required. This needs some agreement on what production would have been in the absence of the investment. Since the technologies which would have been applied by SOCAR differ from those applied by a foreign company, such determination is not always easy. A more straightforward system of sharing rewards on a predetermined basis (for example by sharing total production 50/50) can result in indeterminate returns to the producer, and secondary income or profit taxation may be needed.

- **Definition of incremental reserves:** Within a single field additional production may be obtained both from enhancing the performance of wells in an existing producing horizon (or by drilling new wells in such an horizon), or by locating new horizons (for example by drilling to greater depth). The risk profiles and rewards of the two activities are very different, the former being a low risk and lower cost activity with modest but rapid returns, the latter a much higher risk and cost investment but with larger returns through additional delineation drilling (essentially a form of exploration).

- **Social issues:** The contractor may be unwilling to bear the continuing costs of existing excessive employment and social liabilities. Where it does not interfere with efficient operations, such costs may have to continue to be borne by SOCAR. A major restructuring of the mature oil fields would have a substantial impact on employment. At present SOCAR employs about 58,000 people, of whom 40,000 are employed directly in oil and gas production. Any restructuring plan would have a large impact on employment, reducing it by at least 50 percent in the medium term. In addition, much of the communal and social infrastructure around Baku (eg. hospitals, schools) is associated with the oil fields. A program to mitigate the social impact of employment reductions from restructuring will be needed, including reassignment of staff to the new offshore oil projects and retraining, and the handing over of responsibility for social infrastructure to the appropriate local government authorities.

- **Environmental liability:** Contractors may be reluctant to invest in fields where there is substantial environmental damage, out of concern that they will be held liable for this. Moreover, lack of clarity about the standards which will have to be met for new investment can result in uncertainty over the future costs and production regime to be assumed. Pre-contract agreements on environmental remediation which SOCAR intends to undertake may be needed.

The Problems of the Guneshli Field

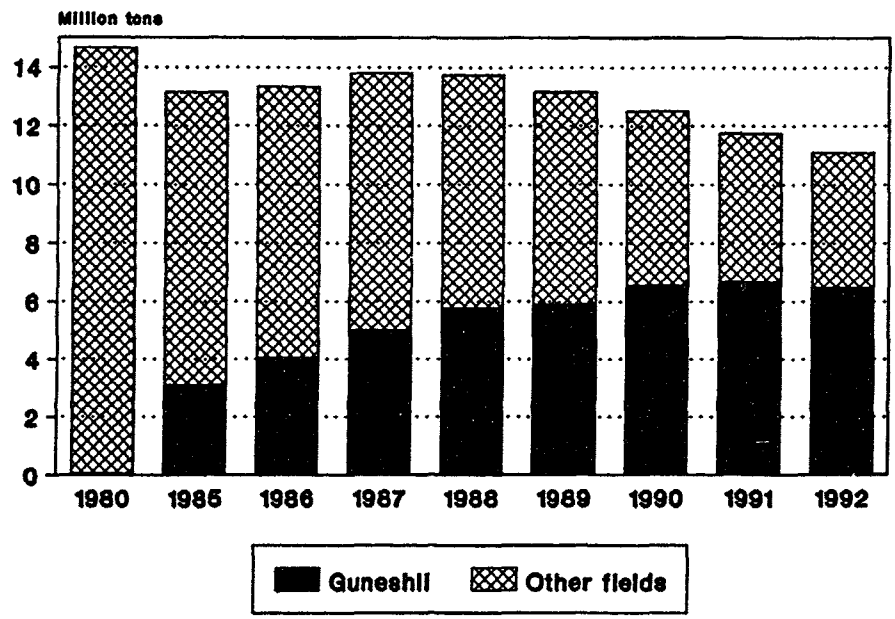
2.31 The Guneshli field accounts for 59 percent of current oil production in Azerbaijan, and it is thus the largest single influence on Azerbaijan's oil output in the near and medium terms. Production from the field started in 1980, and rose rapidly until 1990 to 6.6 mt, as a total of 11 producing platforms were put in place in the shallower part of the field. However, since 1990 production has stopped growing, largely due to the rapid decline in per well productivity, which fell from 115 t/day in 1985 to 59 t/day in 1991.

2.32 The key problem affecting the field has been the failure to implement an adequate water injection program. This has created a dangerous situation, where reservoir pressure has dropped rapidly and there is a significant risk of a substantial loss of recoverable reserves. The problem is compounded by a lack of production separation facilities in the field (to separate oil, gas, water and sand). Redressing this situation is urgent, in view of the possibility of a rapid decline in production, and of a large economic loss to the country.

2.33 A program to address this situation has been proposed by foreign companies (Pennzoil and Ramco), which have been in negotiations with SOCAR. Their plan would involve implementing water injection and an appropriate production regime in the developed part of the field, and producing the undeveloped portion in an optimal manner. The project also involves the capturing of the gas from Guneshli, which is currently vented. Overall investment would be about $650 million in the first stage and $1.0 billion in the second stage.

2.34 The agreement with foreign companies, involving the taking of responsibility for a large offshore producing field, much of which is undeveloped, has few precedents in the international petroleum industry. Key issues which have been addressed in the negotiations include: the definition of "incremental" production from which the foreign investors would be rewarded, the procedure for joint management of the field, the responsibility of the foreign companies for the existing staff and concerns among international companies about liability for safety and environmental shortcomings. A further key issue for Azerbaijan is the need to retain a high share of production in the early years, to avoid a sudden fall in SOCAR's crude availability as the contractor begins to take rewards for investment (this is addressed further in Chapter 3 below).

Figure 2.4 Oil Production - Guneshli and Other Fields



Source: SOCAR.

Oil Field Environmental Issues

2.35 Current environmental problems connected with the oil industry in Azerbaijan are the result of decades of mismanagement under the old USSR system which emphasized oil production at any cost. The scale of oil-related pollution is extremely severe by comparison with similar producing areas in North America and there is a clear potential danger to human health in the affected areas. Immediate action is recommended to reverse the continuing environmental damage. This action should be coordinated with development of management systems and refurbishment of the industry infrastructure. The primary causes of pollution are oil spills and unsound disposal of formation water and oil field wastes.

Offshore Oil Pollution

2.36 Small and large oil sheens can be seen in the Caspian Sea near oil production facilities and natural seeps. About 95,000 cubic meters/day (m3/day) produced water are discharged to the Caspian Sea by SOCAR. Most discharges contain 2 to 4 times the legal content of oil and metals. The shoreline around Baku is black with oil. Although most of the oil pollution there probably results from discharges of oily produced brines as well as natural seepage, some of the pollution in Baku Bay could result from poor waste management by sea-going vessels.

2.37 Air pollution from upstream petroleum production results primarily from the wasteful venting of around 1.4 billion cubic meters (Bcm) of wet gas annually offshore. Venting methane is a powerful contributor to the greenhouse effect, and may also contribute to the formation of ozone and smog. The practice is also extremely dangerous, given the risk of fire and explosion.

2.38 The contribution of Azerbaijan to the general pollution problem in the Caspian Sea is difficult to estimate. Natural oil seeps located in and near the sea result in uncontrolled oil pollution; however, no action is recommended regarding such natural occurrences at this time. Man-made pollution in the sea includes industrial waste from all countries bordering the Caspian Sea. Sound source reduction, waste minimization and pollution prevention policies should be implemented regionally to reduce the contaminant loading on sea life.

Onshore Oil Pollution

2.39 Onshore oil-related pollution results from faulty equipment, inappropriate disposal of formation water and wastes and ill-conceived production pit construction. The problem is greatly aggravated by the location of many of the oldest oil producing facilities in heavily populated areas around Baku. The most serious impact is probably on groundwater resources. Surface and groundwater in Baku are now too polluted with oil and chemical wastes to drink. Local inhabitants rely mostly on bottled mineral water obtained from less polluted mountainous regions. There is also air pollution from the venting of methane and volatile compounds onshore, although the windy conditions around Baku limit the impact of this problem.

2.40 Approximately 7400 hectares are oil- and brine-soaked with severe short- and moderate-term consequences to local plant and animal life. Restoration of 2400 hectares of this total is underway. It is recommended that unlined production pits should be phased out to protect groundwater resources. The rising level of the Caspian Sea has caused flooding of oil and brine pits, leaving large numbers of stagnant oil-filled ponds. Pits vulnerable to flooding should be drained and closed down, while dikes and dams should be constructed to control flood waters. Produced-brine lakes should in general be drained, and the water filtered and re-injected. Alternatively the brine could be treated to remove metals and discharged to the Caspian Sea. The polluted soil should then be restored using chemicals and bio-remediation.

2.41 Most produced brines are re-injected for oil reservoir pressure maintenance; however, improperly plugged boreholes near injection wells may present a significant danger to fresh water resources. Analysis of the mechanical condition of each wellbore located in the immediate area surrounding each injection well is recommended. Currently, used drilling mud is de-watered and landfilled, but controls on seepage of toxic pollutants are inadequate. It is recommended that the landfill

should be constructed with redundant safety features to prevent groundwater contamination by heavy metals. Groundwater monitoring wells and dust control measures should be implemented.

2.42 The impact of oil-related pollution on the health of the population arises mainly from exposure to heavy metals from formation water and drilling muds. Exposure to crude oil itself is less harmful, although some carcinogens can occur in oil which has been exposed to solar heat. Small quantities of ingested heavy metals can have severely detrimental medium-term and long-term effects on human health, including digestive tract and neurological disorders. While immediate comprehensive environmental remediation will prevent further deterioration, the long term adverse health effects resulting from decades of exposure to pollutants will continue to be felt.

2.43 The discharge of oil-related sewage containing excess heavy metals such as chromium, lead and mercury into the Caspian Sea is also dangerous to health, and should cease. There is a risk of exposure to toxic pollutants through the food chain, since seafood represents a significant portion of the average Azerbaijani diet. Steady reductions in sturgeon and caviar production are probably due in part to Caspian Sea pollution, although over-fishing is suspected also. It is recommended that livestock grazing near contaminated areas should be restricted to reduce the accumulation of pollutants in the food chain.

Institutional Issues

2.44 Current environmental codes, laws and institutions in Azerbaijan need continued development. The State committee on Ecology and Use of Natural Resources is responsible for environmental enforcement, but enforcement is limited by the availability of trained specialists and analytical instrumentation. The level of fines set is also very low, for example the fine for discharging liquid wastes (including produced oil brines) to the Caspian Sea was equivalent to only US$1.00 per 100,000 barrels in mid-1992.

2.45 Government plans and policies seem focused on controlling pollution through setting emission limits at source. It is recommended that careful consideration should be given to development of technology- and market-based environmental policies. These policies could stimulate development of pollution control equipment manufacturers and the inclusion of environmental costs in product pricing.

2.46 Efforts and costs to mitigate existing pollution are related to those to upgrade production equipment. New equipment and technologies reduce emissions, leaks and spills. However, an environmentally-conscious attitude in labor and management is required to maintain a clean environment. Such an attitude requires personnel training, and both positive and negative feedback. Workers should be rewarded for increased productivity, including avoidance of costly spills and leaks. Good housekeeping should be emphasized and effective training programs established.

2.47 The costs of onshore remediation could reach several hundred million dollars. Because of this large cost, it is necessary to consider commercial arrangements to encourage remediation. In the case of the onshore areas, SOCAR reached agreement with a foreign private company in 1990 to recover oil from certain polluted areas, which was then exported to pay for the work. This practice could be extended. In addition, there may be commercial interest in recovery of the large amounts of scrap metal which lie in the oilfields, both onshore and offshore.

2.48 As concerns Caspian Sea pollution, regional initiatives are important. In the specific case of oil, it is recommended that consideration be given to establishing a regional oil spill response center, with costs shared among the Caspian Sea countries. Dedicated regional emergency response equipment could cost up to $150 million, including fire fighting ships.

The Petroleum Equipment Industry

2.49 As a result of its early development as an oil producing center, Azerbaijan was the major center for the manufacture of oil field equipment in the Soviet Union. About 65 percent of well service, production and workover equipment for the FSU originated in Azerbaijan. Next to the industry of the United States, which leads the world in oil field equipment, Azerbaijan's industry represents the largest concentration of such manufacturing enterprises in the world. However, only a small part (ca. 3 percent) of Azerbaijan's output of such equipment was exported outside the FSU (chiefly to countries aligned with the Soviet Union). Moreover, the industry was not oriented towards the needs of the Azerbaijan oil industry, since only 6 percent of production went to Azerbaijan, and many important components needed by the local industry, particularly offshore, were not manufactured in Azerbaijan.

2.50 Given the high level of development, and diversification, of industry in the country, the overall economic significance of this industry to Azerbaijan is limited: the industry employs 13,000 people (3 percent of the industrial workforce) and accounts for 4 percent of manufacturing output by value (albeit under the previous distorted pricing scheme). The petroleum equipment industry is nonetheless one of the most important in Azerbaijan for two reasons: firstly, it represents a potential source of substantial hard currency exports as trade in oil equipment shifts to a world price basis, and secondly its continued viability is vital to the maintenance of production in the other Republics (particularly Russia). Although the equipment used in the other Republics could in principle be sourced elsewhere, it will be some time before this can occur for very large volumes, due to the higher cost of equipment from the US, the different standards of non-FSU equipment as well as the sheer volumes of equipment involved. The last point is particularly important: the severe rationalization of capacity in the petroleum equipment industry in the US over the past decade means that there is probably insufficient capacity to replace the production of Azerbaijan, should that be disrupted. The petroleum equipment industry consists of 14 plants, producing hundreds of different products. These plants are all organized within a single holding company, Azneftekhimmash[5], which centralizes key executive functions, while leaving most operational functions entirely a the plant level. Azneftekhimmash also includes three engineering and design institutes, employing over 600 engineers and scientists on research and development.

2.51 The strategic importance of the petroleum equipment industry to the other FSU countries has maintained orders for this branch of Azerbaijan's industry, even as demand for many other industrial products has declined sharply. Nonetheless, the industry faces a number of serious difficulties:

- The system of specialization within the Former Soviet Union made Azneftekhimmash highly dependent on raw materials and finished parts from other Republics. At present 90 percent of the steel used by the industry comes from Russia or the Ukraine. This has led both to

[5] Azneftekhimmash was created in April 1993 through the addition of several plants producing equipment for the chemical and refining industries to the previous company, Azneftemash, which was solely dedicated to oil field equipment.

disruptions in production and to an inability of the industry to negotiate more favorable prices with FSU countries which are also suppliers of raw materials to the industry.

- The design and quality standards of the equipment manufactured in Azerbaijan correspond to the previous Soviet norms. The international petroleum industry, however, generally uses products conforming to the American Petroleum Institute (API) standards, which are different from those used in the FSU. Azneftekhimmash's former clients in the other FSU countries are gradually switching to API standards, under the influence of foreign investors and financiers. In addition, Azerbaijan's non-standard equipment is not readily acceptable on the world market. In general, Azerbaijan's designs are less advanced than those available internationally and in the past the reputation of this equipment has suffered from a lack of adequate quality control.

- The production facilities of Azneftekhimmash are mostly old and in need of replacement: 30 percent of the machinery is over 25 years old and another 30 percent is 10 to 25 years old. There is also a shortage of measuring and testing equipment. This makes it difficult to maintain either a steady volume, or a consistent quality of production. On the labor front, the industry has been weakened by an exodus of skilled non-Azeri workers in recent years.

- Because its previous production was carried out under the centralized ordering and planning system of the Soviet Union, Azneftekhimmash has no marketing capability, and little knowledge of its customer base. Moreover, the company never built up a network of repair and maintenance centers close to its main customers, as is common for such companies in other parts of the world.

- The Azerbaijani industry faces potential competition from new plants in other Republics, especially Russia, where the drive to convert former defense factories to production of petroleum equipment is particularly strong.

- Due to its isolation from the world market and foreign investors, Azneftekhimmash has little experience of how to develop joint ventures with foreign partners.

2.52 Overcoming these difficulties will not be easy. Nonetheless, the maintenance of a substantial and viable petroleum equipment industry in Azerbaijan is in the interests both of Azerbaijan (as a potential source of foreign exchange and equipment for the local industry), and of the other FSU countries (as a competitive source of equipment at affordable prices). Azneftekhimmash needs to follow a number of strategies to maintain viability:

- In its core markets in the FSU (especially Russia): (i) increase production capacity for key products which are currently in excess demand as well as add certain new products so as to fill gaps in its product range, (ii) upgrade the design of products to API standards (where this can be done at acceptable cost), (iii) develop a service, maintenance and repair after-sales service in major customer locations, and (iv) improve marketing and gain access to major competitive contracts, including those financed by multi-lateral institutions (such as the World Bank and EBRD). Maintaining a large share of the FSU markets is critical to the continued viability of a large scale equipment industry in Azerbaijan.

- In the local market in Azerbaijan: (i) Selectively design and produce products which are currently not produced by Azneftekhimmash for the local market, and (ii) focus upon developing products to serve the new offshore developments, to the requirements of the foreign operators.

- In the world market, Azneftekhimmash needs to focus on developing a marketing and representative network, focused on those markets where it previously had a presence.

2.53 In carrying out this strategy, Azneftekhimmash will need to enter into joint ventures with foreign oil field equipment companies, in order to gain access to their expertise in technology, quality control, management and marketing, as well as to their investment capital. It is also probable that in order to ensure its long term survival and viability, Azneftekhimmash will need to be restructured, to eliminate unnecessary ancillary activities and to focus on its most productive units. In the medium or longer term, the successful development of Azneftekhimmash will make it a good candidate for privatization. In order to ensure that this strategy can be identified and pursued efficiently, a full review of the company is recommended, accompanied by a training program for managers in business practices in the OECD.

CHAPTER 3

OIL EXPLORATION AND PRODUCTION - NEW DEVELOPMENTS

3.1 The undeveloped offshore fields of Azerbaijan (Guneshli undeveloped portion, Chirag, Azeri and Kapaz), whose reserves are estimated at about 600 mt, represent one of the major undeveloped accumulations of petroleum in the world. In addition, Azerbaijan's sector of the Caspian is one of the world's most promising exploration areas. The investment and revenue from the development of these resources hold the key to the future of Azerbaijan's economy.

Field Development Issues

3.2 Several fundamental technical issues need to be taken into account in assessing the potential development of these fields and their impact on Azerbaijan's economy. Firstly, the location of the fields, in water depths of 100m to 300m, requires relatively sophisticated production technology, which is widely used in the North Sea and the US Gulf but has not been available to SOCAR or its predecessors. This type of development calls for construction of large offshore platforms, which serve as bases for drilling, production, gathering and processing and staff accommodation. Each finished platform can cost from $250m to $500m and take 1-2 years to construct. There are very considerable economies of scale in this type of development. In addition, in order to position the platforms so as to produce the reservoir optimally, a thorough delineation of the field is required before production starts. There is thus a lead time of 3 to 5 years between the decision to proceed with development and the start of production, during which time delineation drilling, engineering design, platform construction and installation must take place. The optimal field production program thus usually requires very large up-front costs, and a corresponding rapid build up of production to recoup these costs. A gradual or incremental approach to development, which can be implemented with onshore fields, is usually sub-optimal.

3.3 A second issue which applies particularly in the case of the Guneshli, Chirag and Azeri fields, is the needs for common infrastructure and for a coordinated approach to development. The geological and drilling evidence suggests that these fields are probably part of a single structure, and have been separated over time by faulting and volcanic activity. The reservoirs may therefore still be in communication, requiring careful coordination of production drilling at the field boundaries. Crude qualities and other characteristics are also extremely similar, allowing commingling and joint processing configurations. The physical proximity and alignment of the fields makes a common gathering and processing infrastructure optimal. In addition, considerable economies can be achieved through the sharing of construction, marine fleet and supply facilities[1].

3.4 A third issue is the need for a common crude export pipeline, given the landlocked nature of Azerbaijan. This is addressed separately below.

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[1] The Kapaz field appears to be a separate structure, with different crude characteristics, which nonetheless would have to share infrastructure with the other fields for optimal economics.

Role of Foreign Companies

3.5 The estimated investments required for the development of the Guneshli, Chirag, Azeri and Kapaz fields over the next 12 years total US$12 bn. This level of investment can only be obtained by Azerbaijan through the participation of the major international petroleum companies. In addition, these companies bring the necessary technology and project execution experience to these projects.

3.6 SOCAR and the Government have reached preliminary agreements with several groups of companies to participate in the development of the offshore fields. At present, these take the form of exclusive technical study agreements, and a unitization agreement, with negotiations underway for full development agreements.

3.7 A number of issues need to be considered by Azerbaijan in reaching agreement with foreign companies on the development of the offshore fields:

- **Need for unified development:** Although the initial awards of rights to these fields were done separately, there is a need for coordination of development between the fields, and for a unified infrastructure and support system. This is an extremely complex issue, involving a balancing of technical, managerial and financial considerations. Factors to be considered include:

  - **Unitization:** Should the companies retain different shares in the fields, or should the existing field shares be pro-rated across all the fields on some agreed basis (eg. preliminary reserves estimates)? The former case avoids difficulties over the share-out of the fields, and allows the government to vary terms by field; however, it makes rewards for the companies contingent upon the sequence of field development thus creating a divergence between the national interest (optimal overall development) and individual company priorities; the latter case avoids conflicts over field sequencing, but raises the possibility of having to reach a single agreement with all the companies (which increases the negotiating risks to Azerbaijan). SOCAR signed a Declaration of Unitization with the foreign oil companies involved in the country in June 1993, outlining plans to unitize the fields.

  - **Operatorship:** Should the fields be operated separately by different companies, or jointly by a single joint operating company ? The former model maximizes the desirable effects of competition through benchmarking, but can create redundant parallel structures and may make coordinated development more difficult. The latter arrangement may allow better coordination in development, and a sharing of facilities and personnel; however, this may be offset by removal of benchmark competition among operators and by creation of a bureaucratic and unwieldy monopoly.

  - **Ownership/operation of infrastructure:** Should the joint infrastructure form a part of the overall field development package, or should it be a separate project? The former case could create a simpler project structure, since the companies would take joint responsibility for construction and operation, with costs and revenues rolled into the field agreements. The latter case, however, allows a more transparent division of the revenues, creates additional financing possibilities for the infrastructure and, most importantly, facilitates access to the infrastructure by additional oil and gas producers on properly regulated terms.

- **Role of SOCAR:** In general, it is expected that SOCAR would retain a stake in the oil fields, even if these are developed and operated by the foreign companies. SOCAR would thus represent Azerbaijan's interests in the fields, but its involvement should be as a quasi-commercial company. The Government's licensing and fiscal role should be kept separate from SOCAR's role as a participant in the field developments. SOCAR's precise role can be considered on two levels - its technical and operational involvement in the fields, and its involvement in the financing of the developments:

  - **Technical and Operational Role:** Unlike the state companies of many countries with new oil fields, SOCAR has very considerable experience of oil and gas exploration and production. However, SOCAR has little experience of modern offshore project design and execution. Some participation by SOCAR in project design and operation is desirable if transfer of technology and skills is to take place, and the economic benefits of employment of local staff (in place of higher cost expatriates) are to be maximized.

  - **Financial Role:** SOCAR and Azerbaijan are financially constrained, with limited ability to raise funds on commercial terms in international markets, and substantial calls upon state resources for non-oil investment. The alternative to SOCAR funding its own share of costs is to be "carried" by the foreign companies (i.e. have its share of costs paid by the companies). In deciding on the level of SOCAR's participation the relative cost of funding through a "carry" by the companies and through the financial markets needs to be examined. Azerbaijan must also consider the degree of project risk which it wishes to take upon itself, as opposed to putting this risk mainly on the foreign companies. It would probably be inadvisable for SOCAR to assume a large role in financing the first generation of fields, as this would represent a very large financial exposure for the Azerbaijan economy. SOCAR may, however, need to take a larger financial share in the joint infrastructure and export pipeline to inspire confidence among foreign investors. Moreover, SOCAR could take a larger role in "second generation" fields, basing the financing upon the cash flow from the first generation of fields.

- **Type of Agreement to be Reached:** Agreements under which foreign companies take on the development of very large discovered, but only partially delineated oil fields, are somewhat unusual in the international oil industry. It is more common for a single company as operator to take a field through from the exploration phase to development (although it may bring in other partners). Two basic types of agreement are in use by countries with large offshore oil resources - the Production Sharing Contract (PSC) and the Tax and Royalty systems. The issues involved in choosing an appropriate system are complex. However, it is important that the full cash flow and financial implications of the agreement are known to the Azerbaijani authorities and can be tested against different oil production, oil price and macroeconomic assumptions. Azerbaijan has generally opted for the PSC model in its discussions with foreign companies. The nature of the developments in Azerbaijan pose a number of critical issues in negotiating agreements:

  - **Historic Costs:** It is usual in the international oil industry for the discoverer of a field to receive compensation for his costs in discovering the field, as well as some "bonus" in recognition of the risk taken. In the case of Azerbaijan, the use of Soviet pricing in previous exploration work makes calculation of actual costs incurred difficult, and resort to international pricing analogies may be necessary. The bonus payments are a complex

issue for negotiation, although the Government should assess whether high bonuses will be traded off by companies against better terms on subsequent developments.

- **Natural Gas:** The requirement to dispose of associated gas, and Azerbaijan's need for additional gas supplies, makes clarity of terms for natural gas particularly important. (This is addressed further in Chapter 5).

- **Related Provisions:** Many petroleum agreements contain clauses relating to employment and training of local staff, as well as provisions for investment in areas other than the oil development itself. In the case of Azerbaijan, arrangements for training local staff to international standards are particularly important. Azerbaijan may also wish to use oil companies as investors in areas related to the oil industry (petroleum equipment, refining etc.) or in less related areas (eg. housing, social facilities). In addition, Azerbaijan may look to the developers of the new fields to assist in rehabilitation of older fields. However, it is not clear that linking agreements for offshore field development with other investments brings a long term gain to Azerbaijan, since companies will often discount such costs heavily in negotiations, and may not always be best suited to providing the services in question. On the other hand, oil companies will often invest substantial sums in the country in the interest of public relations alone, and such "non price" competition may bring real benefits to Azerbaijan.

- **Choice of International Companies:** Countries which are awarding licenses to companies to explore for and develop oil fields often select these companies with a range of criteria in mind. This is particularly the case for offshore oil fields, where the technical and financial challenges are usually greater. Criteria which can be taken into account include: (i) The experience of the company with similar projects, (ii) The company's financial capacity to undertake investments, (iii) The quality of the company's project proposal, (iv) Ability to work with and to train local staff, (v) Likely long term commitment to Azerbaijan. In addition, countries will often look to the mix of oil companies involved in their offshore developments. Thus, some countries might wish to have a variety of nationalities represented to take account of general international trading and investment relationships. In some cases countries wish to have a mix of major companies represented, with no particular company being dominant, so as to maximize competition and access to capital and technology. Countries may also develop a special relationship with one or more companies, with benefits in terms of long term commitment. In general, when developments reach the scale of those in Azerbaijan, careful attention to having a suitable variety of companies represented is probably preferable to working exclusively with a single company.

Encouraging Foreign Petroleum Investment

3.8 While Azerbaijan's resource base presents attractive potential exploration and production opportunities for international petroleum companies, it is important that an appropriate business environment is created to encourage actual investment. To date, Azerbaijan has been successful in building on the interest shown by many foreign companies in the country, although achievement of final agreements and investment has been slow. In order to speed up foreign investment on the most suitable terms, a number of initiatives need to be pursued:

- **Creation of Legal Framework:** Azerbaijan needs to establish an appropriate legal structure for petroleum resource ownership and investment, both by domestic companies (eg. SOCAR) and foreign companies. To date no such specific framework exists. Work on a Petroleum Law, which should be passed by the legislature and executive at the highest level, is an urgent priority (see also Chapter 7, paragraph 11). Agreement on a Petroleum Law is usually accompanied by development of standard contracts for exploration and development, which clarify the fiscal and practical terms of access to foreign companies and greatly simplify the process of negotiations. Azerbaijan should seek the assistance of international advisors in developing its legal and contractual framework for petroleum. It is important that all associated legal and fiscal provisions which might impinge on petroleum investments are also clarified, to prevent delays due to inappropriate regulations in such areas as company taxation, foreign exchange, customs, labor law etc.

- **Consistency of Commercial Approach:** Negotiation of major petroleum agreements is of necessity a complex and often prolonged process. Continuity of negotiating stance and commercial relations is important. In the case of Azerbaijan, considerable momentum and understanding has already been achieved with a set of major companies, and turning back on the progress to date could delay considerably the start of investments, without a corresponding commercial gain to Azerbaijan.

- **Use of Suitable Advisors:** It is usual in major commercial negotiations, including petroleum negotiations, for Governments to employ financial and legal advisors. In the case of Azerbaijan and the other FSU countries, the lack of previous experience of such negotiations makes this particularly important. The scale and complexity of the projects in Azerbaijan are likely to require the support of advisors with a substantial capacity for such work, as well as relevant experience. Selection of advisors through open competition is to be advised wherever possible, to ensure that the best advice is obtained. Since Azerbaijan's petroleum industry is likely to generate many sub-projects, the use of more than one set of advisors is probably desirable to ensure some diversity of advice and maximum effort. While such advice is relatively high cost, the total costs involved are modest in relation to the revenues which are at stake for the Government.

- **Strengthening of Local Capacity:** While advisors can provide invaluable assistance in reaching agreements, key decisions will remain in the hands of the local officials of the Government and SOCAR. It is thus vital that the commercial skills of Azerbaijani staff are developed as rapidly as possible, and that the most capable local staff are assigned to the petroleum negotiations. Training can be provided through access to foreign financial assistance (grants and technical assistance loans) and also through assistance from the international companies working within the country (who have an interest in speeding up the dialogue with their local counterparts). It is important that local negotiators are organized into effective teams and that there is continuity of staffing to build upon experience and commercial relations.

- **Organization of Negotiations:** It is important that negotiations are well organized, with a clear plan of action and regular meetings. Communications of results of negotiating sessions, and documentation of agreements reached is vital. Senior government officials and management must be kept fully informed. Management of public announcements,

and control of confidentiality where necessary are also critical, to ensure both full public understanding of the process of agreement, and preservation of commercial confidence. Delegation of authority to reach agreements at specific levels of importance should be clear.

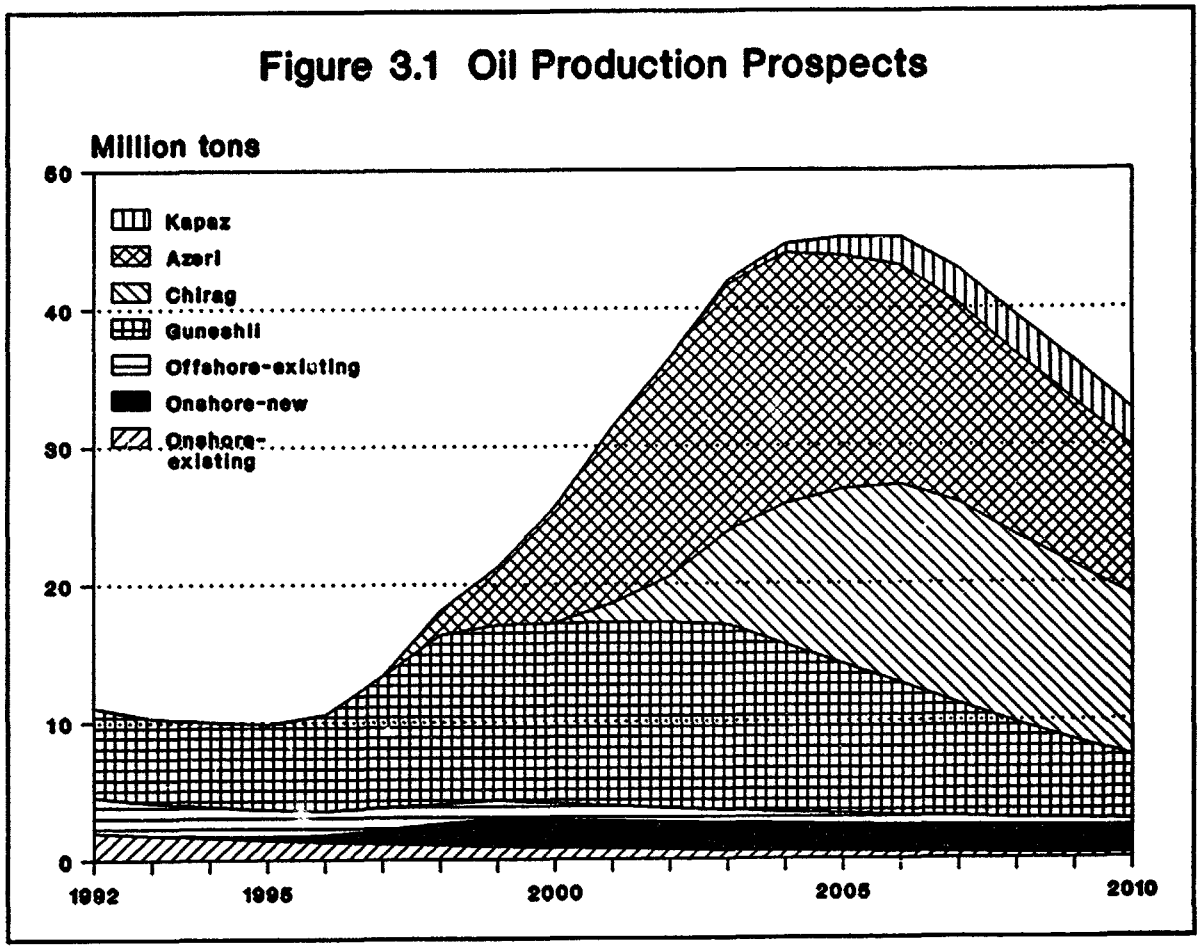
- **Simplification and Prioritization of Negotiations:** It is important that the number of major negotiations being conducted at any one time be limited to what can be handled effectively by local staff and institutions. In Azerbaijan, the project to develop at least three large offshore fields in an integrated manner, as well as large associated infrastructure and an export pipeline, can clearly lead to a large number of complex and related negotiations proceeding at the same time. Additional discussions on other petroleum investments in development of smaller onshore and offshore fields, exploration and other infrastructure and services have also been proceeding. The effective conduct of the large number of discussions involved is probably beyond the present capacity of SOCAR and the government, and simplification and prioritization of the negotiations is critical. In this context, unitization of the three large offshore fields (Guneshli, Azeri, Chirag) would make the negotiation of offshore agreements much more manageable by allowing joint negotiations with all oil companies on a single set of agreements. As indicated above, standardization of the basic contract terms can greatly simplify negotiations, especially on smaller exploration and development contracts.

- **Presentation of Data:** In order to allow for rapid progress in negotiations, and for the attraction of new firms on a competitive basis, it is important that Azerbaijan presents information about its petroleum production and resources in a consistent and accessible manner. Preparation of data through data packages, data rooms and information seminars is a regular part of the petroleum industry, which Azerbaijan would do well to emulate. In the case of all the FSU republics, translation of data into a form accessible to foreign companies can greatly speed up the process of agreement. Azerbaijan should seek the assistance of foreign companies specializing in such work, possibly using international financial assistance.

Future Production Prospects

3.9 An assessment of the likely profile of future oil production is the key ingredient in Azerbaijan's economic and energy outlook. Projections need to be made both for the mature fields, and for the new fields. In both cases there are significant uncertainties, although of different types. The uncertainties on the new fields tend to overwhelm those on the mature fields due to the sheer scale of the new developments.

3.10 An assessment of future production has been made for a Base Case scenario. However, production projections alone are of limited interest without a link to investment flows, and to the sharing of production between the foreign investors (or "contractors") and the host government. An attempt has therefore been made to model the future share of production between the contractors and the Government (including both the central Government and SOCAR). This uses standard production sharing terms to explore the type of profiles which could result from different assumptions about development. In practice, of course, negotiated terms may differ substantially from those used in this exercise, and the aim of this discussion is to raise issues rather than to present precise calculations for planning purposes. In order to assess possible variations in production and revenue profiles, a number of alternative scenarios have been developed.



Source: Mission estimates.

Production Profile - Base Case

3.11 Figure 3.1 shows possible future production profiles for key fields and groups of fields in Azerbaijan. The key factors taken into account are:

- **Existing onshore and offshore fields:** Production from fields currently producing is expected to continue to decline at historic rates (ca. 10 percent per year) due to the maturity of the reservoirs. There could of course be some improvement due to well reactivation, although abandonment of uneconomic producing wells may partly offset this. It is assumed that these fields will continue to be wholly the property of SOCAR.

- **New onshore fields:** This is intended to encompass both development of currently undeveloped structures onshore (and possibly the shallow offshore) as well as of new horizons or pools within existing field boundaries. It is assumed that this exploration and development is undertaken by foreign contractors, who carry SOCAR's costs. Production climbs to 2 mtpy by 2000.

- **Guneshli, Chirag, Azeri, Kapaz:** These fields are assumed to be developed sequentially, with Guneshli the clear priority due to its proximity to shore and critical reservoir condition. The development of the latter fields requires a four year lead time from first investment to production. Azeri thus comes on stream in 1998, followed by Chirag in 2001 and Kapaz in 2003. The lag between the start-up of the fields (Azeri and Chirag in particular) is assumed to be dictated by availability of platform construction facilities, since the construction yard can only produce 1 to 2 platforms per year.[2] The order of field development could vary - a scenario giving priority to Chirag is also plausible. The production profiles of the fields broadly reflect the optimal economic profiles derived from feasibility studies of the fields. Joint production from these fields reaches 21 mt in 2000 and peaks at 42 mt in 2006.

3.12 It should also be noted that these profiles do not take account of potential production from major new discoveries. At present at least one major structure (Shach Deniz) is ready to be drilled, and negotiations are underway with a foreign company for exploration rights. This structure is larger than most existing offshore fields, and holds potential for several hundred million tons of oil, although there is a strong chance of the predominant hydrocarbon phase being gas. Assuming that exploration takes place in 1994 and 1995, production could be on stream by 2002, around the same time frame as is being assumed for Chirag. However, bringing another field on stream at this time would require a major expansion of the fabrication capacity of Caspian Sea yards. Given the high probability of further large discoveries in the Caspian offshore, the fall in production after 2005 shown in Figure 3.1 should be regarded as unlikely. Policy should not therefore be based upon the assumption that the three undeveloped fields represent the sum total of Azerbaijan's future oil resources. Priority should be given to reducing uncertainty for policy planning purposes through a rapid and efficient exploration of key offshore structures [3].

Revenue Generation - Base Case

3.13 In order to assess the likely division of the benefits from oil production between Azerbaijan and the foreign oil companies, it is necessary to reproduce some of the likely features of the production sharing contracts. Key assumptions for the PSC models are shown in Table 3.2.[4] Total oil production is divided into the following categories:

- **Oil consumption:** this is a projection of likely oil consumption in Azerbaijan based upon the trends discussed in Chapter 4. It is assumed that all of this is supplied by SOCAR and the Government (all contractor oil is exported).

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[2] A faster rate of development may be possible, although this could lead to bottlenecks of services and supplies in other areas.

[3] If Shach Deniz is gas bearing, this may make its development a priority to meet gas requirements, see discussion of Shach Deniz in Chapter 5.

[4] It should be noted that the production sharing models used in this study are simplified versions of those in practical use. They capture the major features of this form of agreement, but leave out such complications as sliding scales for cost recovery and profit sharing, based upon such factors as percentage of costs recovered. The model assumes that SOCAR has a 50 percent share of the profits from the fields (after allowing for the share due to the Government itself), although this is only a working assumption and a lower share could emerge from negotiations.

- **Contractor oil exports:** this is the total revenue of the contractors as expressed in terms of oil. Under the PSC models assumed, contractors receive all their revenues as oil for export, in the form of Operating/Capital Cost Recovery and Profit Oil. It is assumed that contractors sell their share of natural gas to the Government/SOCAR (at economic gas prices) and receive in exchange an equivalent value of crude oil. It is assumed that SOCAR is carried by the companies, who therefore recover the full investment cost of the fields (but must share the profit oil and gas with SOCAR on a 50/50 basis after allowing for the Government share).

- **SOCAR+Government exports:** this is the share of SOCAR and the Government in Profit oil, from which is deducted local demand, and the cost of paying the contractors for their gas with oil.

Table 3.1: Production Sharing Model
Key Assumptions (1993 US$)

Oil Price:	$20/barrel (fob Mediterranean)
Natural Gas Price:	$1.90/mcf (ex-gas plant)
Interest Rate:	10% (for unrecovered costs)
SOCAR Investment:	Fields: 0% (SOCAR Carried by Oil Cos.) Infrastructure/Pipeline: 50%
Infrastructure Tariff:	$1.10/barrel
Export Pipeline Tariff:	$2.50/barrel
Max. Cost Recovery:	60% of oil and gas revenues
Gov. Profit Share:	60% to 85% (of Profits)
Foreign Co. Target IRR:	Ca. 20% (rate of return on investment)

Source: Mission estimates.

3.14 Table 3.2 shows the division of oil between the contractors and SOCAR/Government in the Base Case. It can be seen that, due to the impact of high cost recovery in the early years (comprising over 60 percent of oil production), contractor exports exceed SOCAR/Government exports until after 2000. Between 2000 and 2005, the decline in cost recovery oil increases the share of profit oil sharply, and hence the share of SOCAR and the Government, who together take around 75-90 percent of profit oil. Such a regime, which allows companies to recover their investment relatively quickly (within about six years of production start-up) tends to delay the benefits of oil exports to Azerbaijan. However, the nature of offshore field development leaves companies with a large sunk investment, and the companies' unrecovered exposure to Azerbaijan could reach $4 billion in the late 1990s - there may therefore be limits to Azerbaijan's ability to slow down cost recovery.

Table 3.2: Division of Oil Production - Base Case (Million tons)

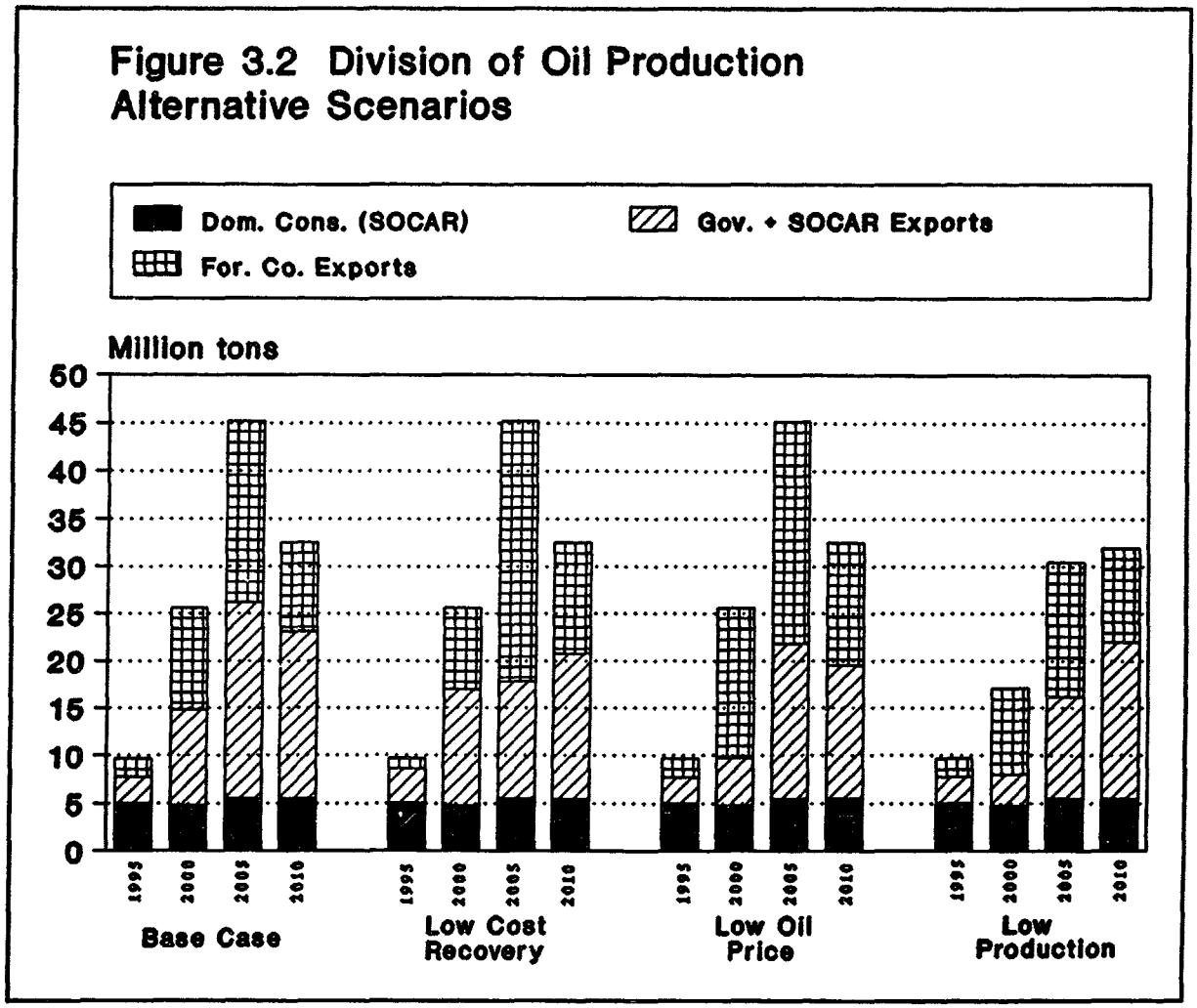
	1992	1995	2000	2005	2010
Domestic Consumption	8.8	5.0	4.8	5.5	5.5
Exports	2.2	4.7	20.8	39.7	27.1
-Gov.+SOCAR	2.2	2.8	9.7	20.7	17.6
-Foreign Cos.	0.0	1.9	11.2	19.1	9.5
Total	11.1	9.7	25.6	45.2	32.5

Source: Mission estimates.

Alternative Scenarios

3.15 Several alternative oil production and revenue sharing profiles can be developed, on the basis of alternative assumptions about the key variables (see Figure 3.2):

(a) **Oil Reserves:** Clearly the volume of future production could vary substantially if reserves in the known fields turn out to be much higher or lower than the Base case. Variations on this have not been tested, since the range of estimates may be too wide to be of interest.



Source: Mission estimates.

(b) **Rate of Development:** The Government may choose to vary the rate of development of the oil fields. A "Low" Production scenario has been developed for the case in which production from the offshore fields is kept at a steady level from the late 1990s, rather than being allowed to peak. This case is based on the assumption that all field developments are reduced in scale. The overall effect will be to reduce the rate of return on the whole venture, due to a loss of economies of scale. It is interesting to note that

one of the possible intentions of such a production policy, to prevent a "peaking" of oil revenues, is not in fact achieved effectively - Government/SOCAR oil exports are more stable from 2000 under the Base Case than the Low Case, due to the effects of the PSC formula. An accelerated development scenario, for example one in which Azeri and Chirag are developed almost simultaneously, is also possible, although uncertainties on the investments required in additional construction capacity mean that this case has not been investigated.

(c) **Cost Recovery and Profit Share Profile:** The profile of cost recovery can be altered through time by placing a lower ceiling on cost recovery, which can then reduce the share of companies in the early years (while giving them more profit oil later). A slower rate of cost recovery on Guneshli would help to increase the Government/SOCAR share of oil before 2000. In the figures shown this is combined with a higher Government profit share in the early years of the field. In this "Low Cost Recovery" case Government/SOCAR exports are generally higher in the years to 2002, but correspondingly lower in the later years. Variations in the cost recovery and profit share elements could be used to increase this shifting of cash flows through time. This would allow the Government to meet early revenue requirements for macro-economic restructuring. The calculations show that a smoothing of Government revenues can probably more effectively be achieved through PSC terms, rather than by a sub-optimal slowing down of oil development. However, there may be a limit to oil company tolerance of deferred returns.

(d) **Oil Price Changes:** Oil price impact could take two forms - unforeseen impacts, which lower the rate of return to both the Government/SOCAR and contractor, and impacts which are taken into account in negotiations (because agreement is reached after a change in the oil price outlook). The effects of the latter case have been evaluated, with the parameters altered to maintain the rate of return to the companies at the lower oil price. A sensitivity test in which world oil prices are 15 percent below the base-case scenario (world fob prices of $17/barrel rather than $20/barrel) shows that the projects would probably still be economic, but that the return to the Government will be seriously eroded, if company returns are to be maintained at a level which still encourages investment. In this case, company exports could rise to 50 percent of total exports in 2005, from the Base case level of 42 percent. The offshore oil projects probably start to become marginal at an oil price of around $15/barrel (fob Mediterranean). Azerbaijan could of course gain even larger revenues from oil development if oil prices are above the Base Case level. However, past experience of the oil market shows that it would be unwise to base planning on an assumption of rising oil prices. Given the uncertainty about future oil price levels, it is important that Azerbaijan adopt cost-efficient development strategies for the offshore fields, as well as reaching agreements with oil companies that allow investment to proceed even under lower oil prices.

Economic Impact of Oil Development

3.16 Policies affecting the development of oil production need to be seen within a macro-economic context. The overall economic impact of the oil developments stretches beyond the generation of revenue for the Government through its share of oil and gas production (including that obtained through SOCAR). Account also needs to be taken of the impact of investment and operating costs on the local economy and balance of payments, of the effect of alternative timing of revenue streams on the economic adjustment process and of the costs of alternative methods of financing oil development.

3.17 The consideration of each of these issues can be summarized as follows:

- **Impact of local investment and operating costs:** Azerbaijani companies have the potential to gain a substantial share of the investment in offshore development, for two reasons. Firstly, the landlocked location of the Caspian makes it difficult to transport heavy equipment to the Azerbaijani offshore fields, greatly favoring local manufacturing. Secondly, Azerbaijan has developed a significant capacity in offshore fabrication and in petroleum equipment (see Chapter 2), as well as having a substantial engineering industry base. As a result it is estimated that between 30 percent and 45 percent of total offshore investments may be made within Azerbaijan. The balance will consist of imported goods. The impact of this, in terms of total investment and imports, is shown in Table 3.3, which demonstrates the vital role which this investment will play in the country's economy. Operating costs will also have a substantial economic impact, with an even larger share of the total likely to stay within Azerbaijan (perhaps 50%). Azerbaijan's large trained workforce, which already services a large offshore industry, is expected to provide most of the service labor, while maintenance and spare parts can also be supplied locally. Critical issues for Azerbaijan to consider in this context include: (i) the need to encourage the maximum local content supply of investment goods and services, on competitive terms, (ii) the need to avoid foreign investment creating inflationary pressures through local bottlenecks, (iii) the potential for a "creaming off" of staff from the state sector to foreign companies.

- **Timing of Revenue Streams:** This issue has been addressed above under Alternative Scenarios. The critical issue for the Government to consider is the integration of this analysis into the overall macro-economic policy framework. Given the difficulty of obtaining finance from commercial sources to bridge any financing gap, the Government may wish to give priority to early revenue generation. Foreign companies, faced with slower recovery of their capital and hence longer exposure to Azerbaijan risk, may demand a somewhat higher rate of return in exchange.

- **Alternative Financing Options:** As discussed above, Azerbaijan must choose between alternative means of financing its oil developments. The above scenario assumes a compromise, whereby SOCAR funds its share of joint infrastructure (including the export pipeline) from various sources (commercial credit, multilateral loans, export credit, internal cashflow), and is "carried" by the foreign companies for the offshore fields. The carry by foreign companies is a relatively expensive form of finance. However, it is improbable that credit on such a large scale would be available to Azerbaijan on commercial terms. Moreover, the impact of borrowing for oil development on access to credit for other purposes must be taken into account.

Table 3.3: Net Oil Financial Flows (US$ million)

		Base Case			Low Oil Prodn.			Low Oil Price		
		1995	2000	2005	1995	2000	2005	1995	2000	2005
Net Oil Trade	(+)	614	2,792	5,327	610	1,628	3,338	530	2,336	4,458
Foreign Invest.	(+)	690	1,078	346	601	821	277	690	1,078	346
Capital Imports	(-)	483	755	242	421	575	194	483	755	242
Operating Costs	(+)	144	461	652	140	294	429	144	461	652
Foreign Operating Costs	(-)	72	231	326	70	147	214	72	231	326
Company Oil Exports	(-)	88	1,138	2,226	88	856	1,596	70	1,060	2,236
Net Foreign Exchange flow	(=)	805	2,207	3,531	772	1,165	2,040	739	1,829	2,652

Source: Mission estimates

Oil Export Pipeline

3.18 In order for exports of crude oil to take place from Azerbaijan on a large scale, a new dedicated pipeline must be constructed from the Caspian coast of Azerbaijan, to a port with access to the world market. Most oil exports from Azerbaijan have in recent decades taken the form of oil products, exported by rail car, Caspian tanker and/or river barge (see Chapter 4). In 1992 Azerbaijan exported crude (ca. 1 million tons) by swapping crude delivered to a Russian Caspian port with Russian oil exported through the Black Sea. However, such swaps, as well as the existing export routes, are inadequate for the volumes of crude exports contemplated in the long term.

3.19 Four potential routes have been examined for Azerbaijani exports (see Map in annex):

(a) **Via Turkey to the Mediterranean:** This route would have to cross either Iran, Armenia or Georgia to reach Turkey. Within Turkey the line would join an existing pipeline which was used for the export of Iraqi crude, with exports going through the existing terminal at Ceyhan. This route has been favoured through bi-lateral agreements between the Governments of Turkey and Azerbaijan.

(b) **Via Russia to the Black Sea:** This route would follow existing pipelines to the port of Novorossyisk (although a new terminal may need to be built nearby). Such exports could be integrated with planned exports from Kazakhstan through Russia to the Black Sea.

(c) **Via Georgia to the Black Sea:** This route is the shortest to a seaport, and could follow the track of a pipeline which existed in the first few decades of this century, to the port of Batumi. A pipeline to a new port at Poti, north of Batumi is probably the preferred alternative.

(d) **Via Iran to the Persian Gulf:** This route is the longest, and although it allows easier access to Far East crude markets via the Gulf, was rejected as probably uneconomic compared with the other options at an early stage.

*Table 3.4: Oil Export Pipeline Options**

	Baku-Novorossiysk (via Russia)	Baku-Poti (via Georgia)	Baku-Ceyhan (via Turkey)
Length (km)	1346	795	1608
Cost-Pipeline (US$m)	2121	1231	1793
Cost-Terminal (US$m)	283	283	0
Total Cost (US$m)	2404	1514	1793

** Note: Assumes all costs are borne by Azerbaijan crude exports only (excludes possible costs attributable to Kazakhstan or other exporters).*
Source: SOCAR

A number of issues need to be taken into account in assessing the choice of route:

- **Construction Cost:** An assessment is required of the cost of various routes. Since the routes pass through different countries, with differing local cost parameters this is more difficult than for pipelines within a single country.

- **Transit Cost:** Different countries may have different expectations for transit fees, and some form of early indication of this would help to generate confidence in a route choice.

- **Financing:** This is closely related to the perception of the political risk of different routes, as well as the financing capacity of the countries through which the pipeline passes.

- **Political Factors:** For a multinational project of this type, political considerations cannot be ignored. They may affect the perception of potential investors in Azerbaijan exploration and production, who must be persuaded that their export route for crude is secure. The risk of disruption will be closely related to that of political friction with a country through which the pipeline may transit.

- **Shipping Issues:** The final ports of loading, in the Black Sea and Mediterranean are not comparable in terms of their crude shipping capacity and costs - Black Sea ports can only load tankers up to 150,000 tons, which is the maximum which can transit through the Bosphorus, while the Mediterranean port of Ceyhan can load super-tankers up to 300,000 tons. The unit cost of shipping varies almost directly with the size of the tanker. In addition, there are serious environmental, safety and logistical questions over the possibility of transiting a large increment of crude oil through the Straits of the Bosphorus[5].

[5] Under a 1936 Treaty, international shipping has free passage through the Bosphorus. However, there are some restrictions on larger vessels. Very few large tankers pass through the Bosphorus each year, and Turkey has expressed serious concern about a substantial growth in tanker traffic through the Straits.

3.20 A further key issue which must be considered is the commercial structure of any pipeline project. The government has indicated its intention of involving the foreign oil companies working offshore in the project. It also intends to cooperate closely with the Governments and state companies of the countries through which the pipeline would pass. In financing a venture such as this, it is clearly important to involve all interested parties so as to ensure maximum access to finance and coordination of the pipeline project with other regional projects. Involvement of multilateral banks, and export credit agencies, may also be required to complete the financing and reassure investors. The Government should seek suitable experienced advisors to arrange financing and the projects' commercial and legal structure.

3.21 The link with the foreign oil companies is particularly important in this respect, since they will be financing the projects which will supply the oil to fill the pipeline. The security of their production revenues depends upon the reliability of the pipeline. Moreover, their guarantee of throughput to the pipeline is necessary for arranging financing. For this reason oil pipelines are often regarded as an integral part of oil production ventures. In this case, however, it is probably best to develop a separate company for the pipeline, given the scale of the project, and the probable need eventually to transport oil from new oil fields.

3.22 A transparent and stable tariff and capacity allocation structure is vital in order to provide confidence to future investors in Azerbaijan's oil fields. In this context, it is important to signal that the pipeline is viewed as a cost-center, not as a profit-center. That is, tariffs should be transparently based upon justifiable costs, with no excessive charges for profit beyond those needed to repay debt and reward equity adequately. This will both ensure that the full benefits of oil development remain with Azerbaijan, and reassure future oil shippers that they will obtain fair revenue for their oil.

3.23 It is also important that the pipeline is planned within an overall regional context. Future oil developments on the Northeastern edge of the Caspian in Kazakhstan also require access to the world market. Production from the Tengiz, Karachaganak and other oil fields in Kazakhstan is expected to reach 25 to 50 mtpy by 2005. Additional production may also come from the Caspian shores of Turkmenistan. The integration of exports from these countries with those from Azerbaijan could provide important economies of scale and scope for regional cooperation.

3.24 The political, financial and commercial difficulties to be overcome in developing the oil export pipeline are considerable. While full development of Azerbaijan's offshore oil fields will doubtless require a new pipeline, lower volumes could probably be exported by developing low cost options to access the Russian oil transport system. This would allow Azerbaijan's oil to be swapped for Russian exports from the Black Sea, or to Europe by pipeline. Such an option could allow early exports of incremental oil from Guneshli. Agreements would need to be reached with Russia on transit fees and especially on compensation for quality differentials between the higher quality Azeri crudes and the lower quality Russian crude. Some investments in reversing and augmenting pipeline flows may also be required. Assistance from multi-lateral institutions could be sought in arranging such ventures.

CHAPTER 4

PETROLEUM REFINING AND PRODUCTS MARKETING

Introduction

4.1 The petroleum refining and products trading industry in Azerbaijan dates back to the start of oil production in late 19th century. As a part of the former Soviet Union (FSU), the industry's development was based on its perceived comparative advantages and role within the overall Union refining and oil transport system. Azerbaijan's importance as a refining center is due to its being the third largest crude producer in the FSU, after Russia and Kazakhstan, and its location on the Caspian Sea with marine transport access to republics around the Sea. Under the Soviet system, prices of crude oil and refined products were regulated at levels far removed from international prices; inter-republican trade, and trade with countries outside the FSU were regulated from Moscow; technology imports were restricted; wage and employment policies did not encourage labor mobility, and there was little or no financial performance accountability. Production and marketing agencies functioned as agents for carrying out centrally-planned objectives and had no autonomy in carrying on business as commercial enterprises.

4.2 The planned-economy management of the industry emphasized the increase of production volumes without taking into account cost and efficiency. While additions to refining capacity and marketing infrastructure took place, there was very little modernization and retirement of old facilities. Current physical facilities are thus a combination of old and obsolete and relatively modern facilities with low average cost efficiencies. The industry's structure and management, as well as most likely its competitiveness, are significantly inferior to those in OECD countries.

4.3 The new oil trading environment which has arisen following the break up of the FSU has put pressures on refineries, as trade patterns and costs adapt to world prices. The key issue for Azerbaijan in the petroleum refining industry is the future role and economic viability of its refineries within this market oriented trading context. While a full assessment of the future of the country's refineries should await a detailed industry study, it is clear that substantial rationalization and restructuring will be needed if the refineries are to operate profitably and provide least cost oil product supplies to Azerbaijan.

Refinery Facilities

4.4 Azerbaijan has two refineries, both located on the outskirts of Baku on the Caspian Sea, with a total refining capacity of about 20 million tons per year (mtpy). The refineries were integrated into SOCAR in September 1992. The Azneftyag Refinery includes refining facilities which commenced operations about 120 years ago and currently has operable capacity of about 11.7 mtpy of crude charge. Facilities consist of several trains of crude and vacuum distillation units, and lube oil manufacturing units. It is essentially a lubricating oil/bitumen plant, with incidental production of straight run kerosene, diesel oil and fuel oils. The refinery's current lube production capacity at 1.0-1.2 mtpy is very large in relation to domestic requirements and produces relatively low quality lubes which it has been exporting to other republics of the former Soviet Union. Without even a reforming unit, the refinery does not produce marketable gasoline, and sells the naphtha to a petrochemicals plant at Sumgait as feedstocks, and to the New Baku refinery which upgrades the naphtha to gasoline. The technology base of all constituent

process units and production control systems is obsolete. Physical facilities are very old, poorly maintained, and generally run-down. Production and offsites facilities have been built over a very large area with poor operational and control integration.

4.5 The New Baku Refinery commenced operations initially in 1965/66 with 2 mtpy crude and vacuum distillation capacity, and with secondary processing units, consisting of a fluidized catalytic cracker (FCC), a coker and light ends polymerization units. Crude oil distillation capacity was increased by 6 mtpy in 1976, and a reformer was added in 1980. Refinery configuration is somewhat complex, but hydroprocessing capacity for distillates treatment is quite limited, thereby constraining its ability to process high (in excess of 1.7-2.0 percent) sulfur crude oils. Except for the new FCC unit under construction, the technology base of process units is obsolete. Maintenance of facilities at the refinery is also poor. Both the refineries purchase electric power from the State grid, steam from nearby thermal plants, and make-up water from Baku municipality. A small part of utilities requirements is generated within the refineries from waste heat. (A brief description of physical facilities of the refineries is in Annex 4.)

Crude Supply and Product Output

4.6 Total refinery throughput was more or less at a constant level of 21 mtpy (range: 20.4-22.1 mtpy) during 1981-88. Throughput has fallen rapidly since 1989, to only 12.1 mtpy in 1992. During the 1970's and 1980's there was an important shift in the pattern of crude supplies. Azerbaijan's refineries had both originally been developed to process domestic production. In the early 1970's their capacity was thus largely devoted to processing almost all local crude output. However, as domestic oil production declined, the resulting refining surplus was allocated to the processing of imported crudes from Russia and Kazakhstan. As table 1 shows, these crudes accounted for about 40 percent of refinery throughput in the mid-1980s. Imports from Russia have been largely of Tyumen type crude from W.Siberia, while those from Kazakhstan have been of poor quality (high sulphur and metals content) Buzachi crude, for which Baku was the only direct outlet. In general both the Russian and Kazakh crudes imported have been of substantially lower quality than domestic crudes, which have very low sulphur contents and relatively good yield characteristics. Because of lack of secondary processing and hydrotreating facilities at the Azneftyag refinery, available domestic crude oil was preferentially allocated to this refinery.

4.7 The rapid decline in throughput since the late 1980s has been due mainly to the rapid fall in imports from other republics, as well as to the continuing decline in domestic production. The fall in imports from other republics is due to the change in trading relationships within the FSU in recent years, with a shift away from central planning towards bilateral trade based upon negotiated prices.

4.8 Because Azerbaijan's products output until the late 1980's was 150 percent in excess of domestic demand, the republic was a substantial exporter of products, mainly diesel oil, fuel oil and lubricants. Products exports in recent years went back to Russia and to local Caucasus or Caspian border republics, with Baku essentially functioning as a regional refining center. A significant proportion of exports also went outside the FSU, with a large diesel trade to Northern Iran. Azerbaijan was one of the most important suppliers of lubricants within the FSU, and was the main supplier of certain specialized lubricants (such as for diesel engines and transformers).

Table 4.1: Refineries Crude Throughput and Production, 1981-92
('000 tons)

	1981	1985	1989	1990	1991	1992
Crude Oil Processed	20499	21135	18435	16331	15820	15639
Crude Oil Supply	20628	21240	18440	16342	15837	15650
- Domestic Crude	(13283)	(12387)	(12646)	(12073)	(11088)	(10549)
- Russian Crude	(5054)	(3203)	(2879)	(2515)	(2514)	(3000)
- Kazakh Crude	(2171)	(5612)	(2909)	(1754)	(2235)	(2100)
Main Products:						
Automotive gasoline	1992	1898	1549	1480	1174	1265
Diesel Oil	3534	4500	4237	3975	3635	3750
Bitumen	188	181	167	145	113	240
Lubricating Oils	1132	1118	934	819	763	1041
Coke	125	103	300	178	161	180
Fuel Oil	8838	9316	9429	6579	6400	6400
Kerosene	N/A	N/A	1539	1304	1350	1400

Source: Azneftchim and Goskomstat

4.9 The key issue now facing Azerbaijan in this sub-sector is whether its role as an exporter of products can continue within a market oriented environment. The lack of upgrading capacity and generally poor facilities of the refineries are clearly a disadvantage in this respect. Due to the relatively poor processing configuration, the production of fuel oil (at 43-46% of crude charged) is very high, resulting in low added-value in refining. Although the Azneftyag refinery produces a high percentage of crude charged (about 8-10%) as potentially high-value lubricating oils, its lack of reforming and secondary processing facilities limit its ability to produce high-value distillates. The low sulphur content of domestic crude oil will favor exports to third countries of diesel oil and fuel oil which are processed from domestic crude. However, there is little market internationally for the higher sulphur products derived by Azerbaijan's refineries from imported crudes. Lube oils would need significant quality improvements to approach international quality standards.

4.10 Domestic marketing is carried out by Goscomtopliva which operates 32 inland storage terminals and about 500 retail stations within the country. As in other FSU republics the overall level of coverage by service stations is inadequate, and quality of service poor. However, given ample local production of products, supplies at the retail level are more readily available in Azerbaijan than in many other FSU countries. The Government should examine the possibilities of privatizing retail pumping stations in the near future, to introduce competition and improve service to consumers.

Domestic Product Consumption

4.11 Domestic consumption of refined products in the country totalled about 7.5 mtpy during 1991. Although complete historical data on consumption are not available, domestic consumption is said

to have remained relatively flat during the 5 years to 1990. In 1991 and 1992, however, demand rose significantly due to higher fuel oil usage. Of the total consumption, road transport fuels account for 33-35% (equally shared between gasoline and diesel oil), fuel oils (nearly all for the power sector) for 53-55%, and the remainder is accounted for by jet fuel, and non-energy products (lubes, bitumen). In the short term a modest decline in transport fuel demand is likely, due to the economic decline and the considerable fall in transit traffic through Azerbaijan. Fuel oil demand, on the other hand, will depend upon structural changes in the user sectors (mainly power generation), and the country's ability to maintain the levels of gas imports from Turkmenistan. As Table 1 shows there was a very sharp rise in fuel use in power during 1991 and 1992, which was caused by a fall in gas availability (net gas imports fell from 7.7 bcm in 1990 to 4.3 bcm in 1992 - see Chapter 5).

Table 4.2: Azerbaijan: Crude Oil and Products Supply-Demand Balance (Base Case, '000 tons)

	1990	1991	1992	1995	2000	2005
Production	12513	11742	11084	9700	25603	45174
Imports	4505	4516	1375	1025	0	0
- Crude	4290	4301	1350	1000	0	0
- Products	215	215	25	25	0	0
Consumption	6708	7576	7998	4292	4358	4974
- Gasoline	1260	1252	1125	1122	1432	1828
- Diesel	1271	1263	945	851	1085	1385
- Fuel Oil	3216	4185	5228	1690	1036	735
- Other	961	875	700	630	804	1026
Exports	7769	6065	3955	5719	20809	39702
- Crude	0	0	1050	500	n.a.	na
- Diesel	2733	2279	2000	n.a.	n.a.	na
- Mazut	3594	2297	320	n.a.	n.a.	na
- Jet Kero	823	747	150	n.a.	n.a.	na
- Diesel Lubes	220	338	90	n.a.	n.a.	na
- Other	399	403	345	n.a.	n.a.	na
Refinery Fuel & Loss	1344	1283	797	714	436	497
Unreported Balance	1196	1334	-290	0	0	0

Source: SOCAR, Mission estimates.

4.12 Once gas imports are restored to the levels required by the power sector (imports in 1993 are expected to remain constrained), Azerbaijan's oil demand is unlikely to be above the level of 1990 at least until the year 2000. This assumes that fuel oil use in power plants is gradually phased out, since domestic and imported gas is likely to be more economical (see Chapter 5 paragraph 27), and fuel oil availability declines as additional cracking capacity is installed. Although the gradual economic recovery from 1995 should lead to a rise in car numbers, and in commercial and public transport, the impact of rising transport activity on oil demand may be offset by improvements in the average fuel efficiency of the fleet (due to the much greater efficiency of new vehicles entering use) and to more cautious fuel use as retail fuel prices approach economic levels.

New Investment Plans

4.13 Despite the considerable uncertainties over the future economics of refining capacity in Baku, both the refineries have commenced implementing physical restructuring investment projects. At Azneftyag refinery, contracts have been entered into with US and South Korean companies, for construction of two 2 mtpy capacity each of atmospheric and associated vacuum distillation units, each with an investment of about $30 million equivalent (including $18-29 million in foreign exchange), and planned to be completed by mid-1995. Upon completion, except for the largest and relatively new (1963 vintage) primary distillation unit of 6 mtpy capacity, the remaining 5 smaller distillation units are to be scrapped. The existing vacuum unit of about 2 mtpy capacity is to be modernized under an Azeri-British joint venture, through changes in the vacuum system internals; the incremental benefits from the modernization are to be shared among the partners to be redeployed for further modernization of plant facilities. Azerneftyag has not yet developed plans for rationalizing and modernizing lube oil production, its main business. Nor does it seem to have concrete plans for producing marketable motor gasoline from naphtha which it currently transfers in part to the New Baku refinery and in part to an olefins production plant at Sumgait as feedstock. Lubes capacity rationalization and modernization should be based on a realistic assessment of future export markets and on achieving international quality standards of high-value lubricating oils in order to derive the maximum benefits from domestic crude oil. Rationalizing the lubes production section will also have an impact on the upstream crude processing sections, and the need for modernizing the primary crude oil distillate capacity should be assessed taking into account the possible option of purchasing a part of the vacuum gas oil feedstocks (for lubes manufacture) or reduced crude from the New Baku refinery.

4.14 At New Baku Refinery, the ongoing and planned future investments include a joint venture agreement between the refinery company, a W. European company and a Russian trading company, to recover hydrocarbon oils from the semi-solid sludge from a waste water treatment plant. The recovery plant, with an investment of about $10-12 million has been in operation for the last 2 years and export sales revenue from recovered oil is being shared between the partners pro-rata and the export and excise taxes accruing to the Government. The refining company is currently evaluating two proposals for future modernization investments. The first involves the purchase of a 6 mtpy refinery meant initially for a W. European buyer who did not proceed with its implementation. This refinery, whose component units were manufactured around 1985, has light ends processing units of modern technology, but lacks heavy ends secondary processing. It is possible to match this refinery with an FCC unit under construction for the last 8 years. With this combination, and with refurbishing and modernization of the existing larger crude (6 mtpy) and vacuum units, the new configuration will be able to process flexibly a wide variety of crude oils with sulphur content of up to about 1.6% and be able to produce products of international specifications. The new 6 mtpy refinery is estimated to cost about $340 million on a turnkey basis. However, it is recommended that a thorough process and engineering study should be carried out to establish the economic and financial viability of the offered refinery in combination with the FCC unit and modernized existing crude and vacuum capacities. The second proposal being considered by New Baku Refinery concerns the offer from a consortium to modernize the existing refinery over a 8-year period in 4 stages. However, major issues concerning leasing/ownership, costs and benefits sharing and management structure are yet to be resolved. While this alternative is likely to be less attractive compared to the proposed purchase of a new refinery mentioned above, the possibilities of quickly implementing a flare gas reduction scheme (likely to have a quick payoff), and modernizing the cooling water system should be evaluated.

4.15 These physical restructuring investments do not appear to have been justified before the investment decisions, taking into account projected changes in policy framework, market shares, prices, and impacts on ability to achieve competitiveness. The refineries should carry out a comprehensive study through external consultants on the continued operation of existing physical assets, costs of operations, and options for achieving competitiveness with identified and prioritized investments, retiring obsolete/uneconomic plant, and modernizing technology and equipment. The study should also examine methods for modernizing management systems. The study findings should then be used as a basis for implementing domestic and foreign private investment.

Crude Oil and Product Transportation

4.16 The main oil pipeline in Azerbaijan is the crude oil line which is used to import oil from Russia, which was commissioned in 1983. This line, which has a diameter of 720 mm and a total length of 600 kms, runs south from Grozny (in the Chechen Autonomous Republic of Russia) to Baku. Its nominal capacity is about 8 mtpy. The line is operated by the Transcaucasian Main Pipeline Association, which is part of SOCAR. There are additional smaller lines for crude from the various oil fields to the tank farms and refineries with a total length of about 370 km. The main Grozny-Baku line and other lines in Azerbaijan have suffered damage from the rise in the level of the Caspian Sea. Product movement within Azerbaijan is all done by road and rail, as there are no significant product pipelines.

4.17 Azerbaijan lacks low cost access to international markets for its crude and products. Exports of crude oil and products have historically been carried out by rail car and by Caspian Sea tanker. The main rail lines lead north to Russia, and west to Georgia. The rail line to the Georgian Black Sea port of Batumi provides access to non-FSU markets. Oil can also be sent via Caspian tanker to the Russian port of Machatscshkala (in Dagestan) where it can enter the Russian pipeline system, and similar tankers can be sent to Turkmenistan and Northern Iran. River tankers can access distant markets in Russia and beyond via the Volga-Don canal. While freight rates were previously held at artificially low levels, at economic prices all of these routes represent high cost transport modes for substantial crude or product quantities.

Refinery Strategic Issues

4.18 Several questions need to be addressed in developing short term and long term strategies for the refining sector. The common objective of the strategies would be to reduce the cost of products supply to the domestic market through a combination of domestic refining at optimum capacity utilization, and imports and exports of crude oil and products. An additional consideration is the profitability of transit refining (i.e. refining imported crude for product exports). In the medium term, the country theoretically has the option of: (i) exporting all of its domestically produced crude and importing all of its products requirements; (ii) processing some domestic crude while exporting the balance and supplying some local demand with products imports (iii) processing all domestic crude and exporting the products surplus to local requirements, (iv) operating the refineries at their full capacity with domestic crude supplemented with imported crude (until local supplies are sufficient to fill local capacity), and exporting surplus products.

4.19 The relative evaluation of the four above-mentioned options would require realistic estimates of the opportunity values of exported crude and products, and costs of imported crude and products at the country border. These values and costs would depend upon the destination market for exports, source markets for imports, and the corresponding freights between the border and the

source/destination markets. At this time, it is difficult to identify such markets and, more importantly, the freight costs, given the lack of direct access to open seas and the unclear economic costs of overland haulage using the current transport infrastructures.

4.20 As concerns the first option (i above), the export of crude oil from Azerbaijan is at present difficult due to the lack of a suitable pipeline. Moreover, transport costs of product imports would also be high, and it is therefore attractive in principle for Azerbaijan to supply most or all of its own product needs by refining its own crude. The precise proportion of local product supply, and of which products, which should be met by local refineries will require careful study, taking into account regional refinery yield patterns, crude and product quality availabilities and transport costs.

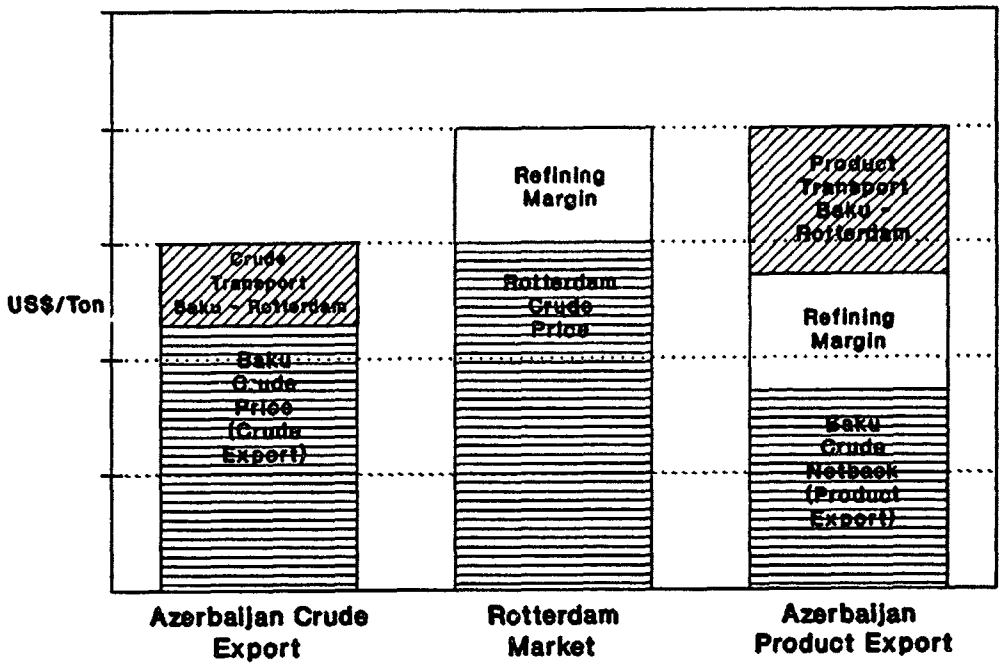
4.21 The most difficult question for Azerbaijan is whether to continue to refine substantial quantities of oil in excess of its domestic requirements, i.e. whether to refine crude for export (options iii and iv above). In the medium term, while production of oil remains below domestic refining capacity, it is highly unlikely that large scale imports of crude for export processing would be economic. Azerbaijan's refinery configuration is generally poor and the refineries are high cost. A large part of the yield is of fuel oil, with a low market value. While there may be some limited justification for meeting regional requirements (eg. in Georgia) until the other Republics can restructure their own facilities, Azerbaijan would seem to have little comparative advantage as an international refining location.

4.22 By the late 1990s, however, Azerbaijan's oil production could approach current refining capacity. Nonetheless, even with crude available domestically, refining for export is unlikely to be preferable to exporting the crude directly by pipeline. In order for product export to the world market to be preferable, the margin from refining would have to cover the operating and capital costs of the refinery and the additional costs of transporting products. In practice, for the major international markets in the Mediterranean and Northern Europe, it is highly unlikely that this would be the case. As figure 4.1 shows, it will usually be preferable to export crude from Baku if the cost of shipping products to a major market (eg. Rotterdam) exceeds the cost of shipping the crude. For the local Caucasus/Caspian market the situation may be less clear cut, although the size of this market is likely to be limited and there will be growing local supplies from other regional refining centers in Kazakhstan, Turkmenistan and Russia. It is therefore important, given the rather narrow gross margins, to assess the freight costs and operating costs with reasonable precision, under the various option scenarios.

4.23 A low-risk short-term strategy for the refinery sector would be to target the level of refining to the level required by the domestic products market (about 5 million tons per year) while seeking to maximize the value of the balance of domestic crude production through both product and crude exports, based upon market conditions. SOCAR should also maximize available crude supplies to the New Baku refinery (which can produce higher proportions of high-value fuel products), while at the same time assuring adequate vacuum gas oil feedstock to the Azneftyag refinery for high-value added lubricating oils. In addition, local trading opportunities for product exports should be evaluated, as should opportunities to import crude on favorable terms (for example Buzachi crude from Kazakhstan which may have no other acceptable outlet).

4.24 The long-term strategy for the refinery sector should be defined based on the results of the proposed consultant study which inter-alia will examine the options discussed above, the optimal levels and nature of investments required for efficiency, and product yield improvements at either one or both refineries.

Figure 4.1 Relative Economics of Crude and Product Exports from Azerbaijan



Management and Training

4.25 Awareness is limited among refinery management about international markets, prices, and factors that influence success as a producer/marketer of petroleum products in a competitive environment, given their historical role as agents to carry out centrally planned directives. Similarly, adequate appreciation of the objectives, expectations, and concerns of potential private sector investors is lacking. Refinery managers are also not familiar with modern enterprise-level systems for production, maintenance, and marketing controls, and information systems necessary for overall general management. Environmental pollution aspects have not received sufficient attention from refinery management. Maintenance of effluent treatment, control, and disposal facilities are poor, even compared to process units maintenance. Production flexibility, product quality, and environmental pollution aspects need to be considered as an integral part of restructuring plans by refinery management. A comprehensive training and technical assistance program will be required to upgrade technical and commercial management skills.

Refinery Environmental Issues

4.26 While the basic framework for environmental pollution policies and regulations exists, these do not appear to be comprehensive, and are outdated, relative to those in Western countries. Regulatory standards exist for fuels quality, permissible pollutants levels in effluents from refineries discharged finally into water bodies, and those in ambient air both at the workplace and in habitable areas

around refineries. Institutional mechanisms for conformance enforcement, as well as penalties for non-conformance appear to be lax. With the maximization of physical production volumes being the main objective of refining operations, environmental pollution control has received less priority and management attention at both the government and at enterprise levels. Refinery companies generally agree with regulatory and enforcement authorities on standards that are less stringent than the so-called national applicable standards. Further, they prefer to pay penalties for non-conformance to these relaxed standards, rather than invest in improvements for pollution monitoring and control systems. As a part of restructuring the economy, the Government should, as a priority, reformulate its environmental pollution control policies (including those for the refinery industry) in tune with those in W. Europe, and strengthen the institutional arrangements for monitoring and enforcement.

4.27 A specific problem at the Azneftyag refinery, concerns the cooling water, which is drawn from the sea and is treated primarily to reduce suspended matter, with the effluent waters gathered in settling ponds. After decantation, most of the water is recirculated back to the cooling water system, with a part of the water discharged into the sea without further treatment. Although detailed analysis of the discharge waters into the sea has not been made available it is likely that pollutants levels would be much higher than the standards. The New Baku Refinery has biological treatment of effluent waters; however, its operation is not dependable because of design and operational deficiencies in the aeration systems. The refineries lack aerial pollution measurement and monitoring systems. There is also a need for establishing appropriate analytical standards and methods. It is estimated that investments in the range of $1.5-2.0 million would be required for modernizing the aerial pollution control systems, including training of selected personnel at each refinery. There is considerable seepage of hydrocarbons into the soil at the Azneftyag refinery. The refinery needs to assess the impact of seepage on the underground water table as well as on the coastal waters nearby. It is recommended that a study should be carried out on the pollution control facilities to identify modernization options for aerial, liquid and oil seepage pollution controls.

CHAPTER 5

NATURAL GAS

5.1 Natural gas is the major fuel for domestic use in Azerbaijan, accounting for 63 percent of primary energy supplies in 1991. While the country has substantial gas resources, and a long history of gas production and use matching its oil production record, production has been declining in recent years, and gas imports have reached a high level. Gas utilization is highly inefficient, with very large amounts wasted through venting at the field, leakage from corroded transmission and distribution pipelines, and inefficient and largely un-metered gas using equipment and appliances. Despite the anticipated growth in oil production, continued gas imports may be required for at least a decade, placing a heavy burden on the economy as prices of imported gas rise to world levels. Improving the efficiency of gas production, capture, transport, and use should thus be one of the key aims of energy sector investment and policy in Azerbaijan.

Current Status

Natural Gas Production

5.2 Azerbaijan's gas production comes as associated gas from its oil fields, and from large offshore gas condensate fields. The latter are by far the most important source of supply, with the large Bakhar field accounting for about 51 percent of production in 1991. The development of the Bakhar field and the Bulla Daniz condensate field in the 1970s allowed production to rise rapidly during the 1980s, reaching 14 billion cubic meters (Bcm) in 1982.[1] Since the mid-1980s production has fallen rapidly as all the large fields, with the exception of Guneshli, entered a rapid decline. In recent years gas production has been falling at a rate of 8-10 percent per year, consistent with the decline of oil production in the mature fields. Production of associated and non-associated gas from the onshore (or near-shore) fields, which still accounted for 20 percent of supplies in 1975, has fallen rapidly and now accounts for only 3 percent of supplies.

5.3 A substantial proportion of gas production is vented offshore, principally from the Guneshli field. Gas production from the Guneshli field, amounting to about 1.8 Bcm per year, is mostly transported to the Oil Rocks field, where some is used in field operations, but about 1.4 Bcm per year is vented. Plans to install compression and build a pipeline from the Oil Rocks field to the Bakhar complex to capture this gas were not fulfilled, and the pipeline has been only partially constructed to date. SOCAR has sufficient processing capacity to process this associated gas; the problem is the lack of field compression and pipelines to bring the "wet" gas onshore. This resource waste results from the low priority given to associated gas recovery under the previous Soviet system, where gas prices to producers were extremely low, and planning authorities emphasized inter-union energy trade over development of local resources.

[1] The precise definition of "production" by SOCAR is unclear. It appears to include gas quantities which are vented or flared, but to exclude quantities which are re-injected for pressure maintenance.

Table 5.1: Natural Gas Production (Bcm)

	1975	1980	1985	1990	1991	1992
Total	9.89	14.00	14.07	9.93	8.62	7.84
of which:						
Onshore	1.57	1.22	0.71	0.41	0.29	0.24
Offshore	8.32	12.78	13.36	9.52	8.33	7.60
Bakhar	n.a.	5.10	6.57	4.85	4.22	3.67
Other	n.a.	7.68	6.79	4.67	4.11	3.93

Note: Production is delivered, net of venting and flaring.
Source: SOCAR

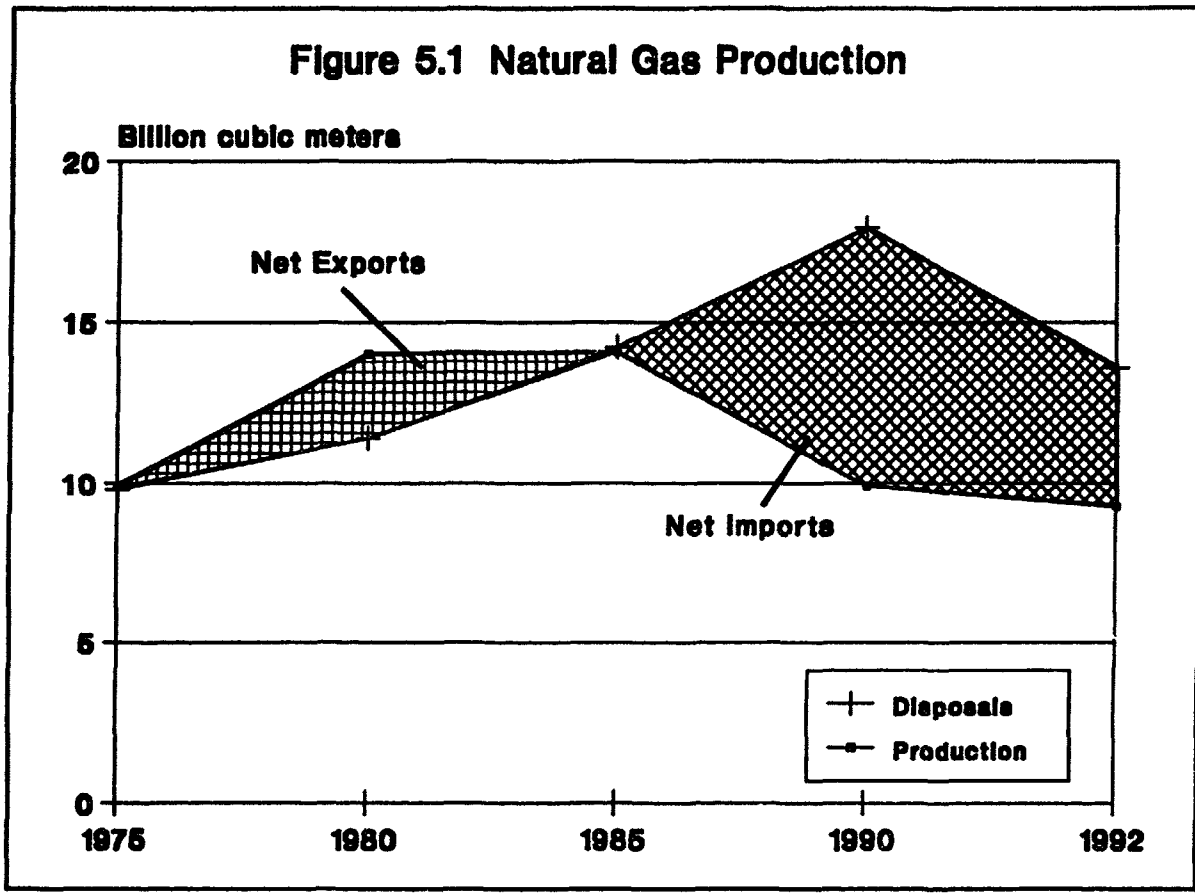
Natural Gas Trade

5.4 In 1980, as a result of a rapid rise in associated gas production, Azerbaijan was a modest net exporter of natural gas to neighboring republics. During the 1980s, as gas consumption grew and production stagnated, Azerbaijan became a growing net importer of natural gas (see Figure 5.1). Most of these imports come from Turkmenistan, the second largest gas producer in the FSU. Gas from Turkmenistan transits Uzbekistan, Kazakhstan and Russia, arriving in Azerbaijan by way of a pipeline following the Northern and Western shores of the Caspian sea. This line was built and reinforced during the 1980s specifically to meet the growing gas requirements of Azerbaijan and the other Caucasus republics.

5.5 Azerbaijan has also imported gas from Iran under an agreement signed between Iran and the former Soviet government. The gas was supplied through the IGAT pipeline, which runs from the main gas system in central Iran to the Azerbaijan-Iran border. This line was built specifically to supply gas to the FSU, under an agreement involving swaps of Iranian gas for Soviet gas exports to Europe. This trade never reached the proportions envisaged: in 1991, FSU imports of gas from Iran reached 3.0 Bcm, still far below the theoretical capacity of the IGAT system.

5.6 Azerbaijan is situated along the main route for gas exports from Turkmenistan and Iran to Armenia and Georgia. Out of total imports of 14.4 Bcm in 1991, re-exports to Georgia and Armenia were 6.0 Bcm. In 1992 the regional conflict resulted in a complete cut-off of supplies to Armenia and a fall in sales to Georgia to 1.0 Bcm, with a corresponding drop in total imports by Azerbaijan.

5.7 A critical problem for Azerbaijan has been the increase in gas prices demanded by Turkmenistan, which has stated its intention of raising prices to "world" levels. Prices of gas from Turkmenistan rose from Rb 1,700 per thousand cubic meters (Mcm) in the first half of 1992, to Rb 2,500 in the second. However, prices in early 1993 were much higher at Rb 15,000 (including transit costs in Kazakhstan, Uzbekistan and Russia). Eventually Turkmenistan is expected to price gas with reference to the European border price. This could lead to prices to Azerbaijan of $70/Mcm to $80/Mcm, if account is taken of the shorter transport cost to Azerbaijan compared with Central Europe (where border prices are $95-100/mcm). The cost of required gas imports in 1994, at $70/Mcm, would be about $600 million/year, which represents 25 percent of the country's estimated total import cost for 1994.



Source: Goskomstat, Azerigas

5.8 Despite the recent moves towards denomination in dollar terms, the gas trade with Turkmenistan is mostly conducted by barter, with Azerbaijan sending manufactured goods (such as refrigerators, oilfield equipment, etc.) to Turkmenistan in exchange for the gas. Dollar values for these products are determined from cash sales for hard currency to other customers. However, in the longer term a move towards cash settlement can be expected.

5.9 Future gas trade policy should focus on Azerbaijan's strong position as a crossroads for regional gas trade. Full use of the existing lines to Georgia and Armenia (assuming a cessation of regional hostilities) could provide $35-50 million per year in transit revenues for Azerbaijan, assuming a return to "normal" transit volumes of about 6 Bcm per year. Azerbaijan signed an agreement with Ukraine and Iran in 1992, providing for a joint venture to construct pipelines to export up to 75 Bcm of gas from Iran through Azerbaijan to Ukraine. While construction of the lines is anticipated to start in 1996, in practice the venture depends upon transit rights through Russia and may not materialize as rapidly as proposed. However, increased availability of gas from Iran will arise with completion of the IGAT 2 line within Iran in the next few years, which will reduce the current bottleneck on supplies from Southern to Northern Iran. In addition, Azerbaijan provides a potential route for a new pipeline from Turkmenistan across the Caspian to Turkey and Europe. Either of these new projects could be very lucrative to Azerbaijan, which could receive up to $5 to $8 million per year in revenue for each Bcm

transported. Given the clear benefit to Azerbaijan of providing gas transit service, national policy should focus upon encouraging such projects, while limiting commitments to new capital expenditure and guarantees (which may be borne by the gas suppliers and end consumers).

Gas Pipeline System

5.10 With its long history of gas use and role in transporting gas to other republics, Azerbaijan has a relatively large natural gas pipeline system. Pipelines total 40,000 km, of which 4,000 km are main transmission lines (up to 1200 mm in diameter). Nearly all the country, including about 100 towns and cities, is connected to the gas grid and some 80 percent of the population have access to piped gas service; this figure is particularly remarkable in view of the fact that much of the population (about 50 percent) lives in rural areas. Azerbaijan must rate as one of the most thoroughly gassified countries in the world.

5.11 Both the transmission and distribution systems are controlled by the State Gas Company, Azerigaz. Azerigaz was formed in 1992 through the merger of the national gas transmission company with the natural gas distribution segment of the State Fuel Committee. Azerigaz also controls gas storage facilities and a small gas processing plant, is responsible for LPG distribution and incorporates gas research institutes.

5.12 A key problem facing Azerbaijan in the natural gas sector is the extremely poor physical condition of large portions of the gas infrastructure. Much of the pipeline system (including compressor stations and pressure reducing stations) is many decades old; some of it dates from the 1920s. Routine maintenance and replacement of older pipes has been neglected, especially in recent years, as economic conditions have worsened. There is insufficient cathodic protection of pipelines, and such systems as exist have been reduced in effectiveness by a shortage of spare parts and of skilled maintenance staff. The "aggressive" soil in Azerbaijan, which is high in corrosive salts and acids, greatly contributes to the corrosion problem. An additional problem is that in the past many large consumers, including collective farms and industries, built their own pipelines to the gas distribution network, often to poor standards and without adequate corrosion protection. In the adverse soil conditions some of these pipelines last for only 5 years, instead of the intended 25 years.

5.13 It is difficult to estimate how much gas is lost through leakage, since most gas use is unmetered (and many of the meters that are in place are of questionable accuracy). Azerigaz estimates that around 1.4 Bcm per year escapes through leaky pipes (equivalent to around 8 percent of consumption). The loss percentage is acknowledged to be much higher in certain regions, ranging up to 20 percent. However, the actual figure could be even higher than these estimates. For example, the specific use attributed by Azerigaz to households appears high, and there is in addition a large balance unaccounted for in the gas balance statistics. On the basis of these estimates, total annual losses could be some 15 to 20 percent of domestic supply, and could be worth US$150-200 million per year in imports at world price levels. These large methane emissions from the pipeline system also pose significant threats to public safety and the environment.

5.14 The pipeline system includes five large compressor stations (including one in the disputed Nagorno-Karabakh region), each with 4 to 6 turbine-compressor sets. All of the equipment is Soviet-made, indicating that the stations are probably highly fuel-inefficient and probably present significant air emission and noise pollution problems. With the dissolution of the Soviet Union, there has been increasing difficulty in obtaining spare parts and necessary refurbishment materials, which could

ultimately lead to disruptions in gas service reliability.

5.15 In many areas there are two gas distribution systems laid side-by-side: one at low pressure to serve households and one at a higher (medium) pressure to serve industrial enterprises. These duplicate facilities reduce the system's operational efficiency, and also increase the level of pipeline leakage. These problems could be reduced by the elimination of the low-pressure system and the introduction of proper pressure regulators for gas delivery to households and other small consumers from the medium pressure system. In addition, inadequate gas flow and pressure control equipment, poor measurement devices and a lack of modern control and communications systems also limit operational efficiency. Safety is also clearly a problem, with many pipelines having been built in unsuitable areas - - there is no concept of a "right of way" that is clear of other activities, there are many buildings situated over main pipelines and there is often no proper separation of pipelines from main roads, railroad crossings, housing, etc.

5.16 Processing of associated gas volumes, to remove water, impurities, and natural gas liquids, is the responsibility of SOCAR, but the present system is inadequate for Azerbaijan's needs. SOCAR controls the only large gas processing plant, at Karadag near Baku (another plant controlled by Azerigaz is very small). The Karadag plant has a design inlet capacity of 6.5 Bcm per year of wet gas and 675,000 tons of gas condensate, and includes six gas processing trains and one condensate processing train. However, most of the plant was built in 1961, and the equipment is old, obsolete, and generally inefficient. Because much of the offshore gas is not delivered to the plant, capacity utilization is low; deliveries are currently only about 2.9 Bcm per year, and annual production of liquefied petroleum gases (LPG) is only 26,100 tons. Hence, up to 60 percent of the associated "wet" gas that is captured offshore, most of which is produced at low pressure, is not processed before it is delivered to the gas transmission/distribution system, primarily due to the absence of compression equipment in the field and pipelines to bring the gas to the Karadag plant. Instead, the gas gathering lines lead directly to the Azerigaz system. These deficiencies in associated gas capture and processing represent a significant waste of valuable LPGs. Azerbaijan is deficient in LPG, and imported 20,000 tons from Russia in 1991 (worth about US$4 million per year at current world prices). The introduction of unprocessed gas into the gas transmission/distribution system also accelerates the pipeline corrosion process and damages compressor stations, meters, and gas-using equipment.

5.17 Azerbaijan's gas storage capacity (working capacity) of about 1 Bcm, located in two depleted oil/gas fields, is not adequate to cope with seasonal demand fluctuations, resulting in additional curtailments of gas service to electric power plants with dual fuel capability. Moreover, the stored gas absorbs water and liquid hydrocarbons from the reservoirs, but there are no gas processing/dehydration facilities at the storage sites; thus, valuable natural gas liquids are not captured, and the introduction of more "wet" gas into the pipeline system exacerbates the corrosion problem.

Gas Consumption

5.18 Natural gas is traditionally the main fuel in all end-use sectors in Azerbaijan (except in transport). Gas consumption rose from 10.0 Bcm in 1980 to 13.0 Bcm in 1985 and 14.2 Bcm in 1990. Trends in use since 1990 have been greatly influenced by the changing prices and availability of imported supplies, and by the general decline in economic activity. In 1990 (the last year of relatively "normal" gas availability under the previous Soviet system) about 40 percent of Azerbaijan's gas was used for power generation, with the remainder split fairly evenly among industry, district heating, the commercial/public sector and household use.

Table 5.2: Azerbaijan Gas Supply - Demand (Million cubic meters/yr)

	1990	1991	1992
Production	11,234.3	10,051.8	9,275.2
Venting	1,308.9	1,430.7	1,430.7
Net Available	9,925.4	8,621.1	7,844.5
Imports	13,114.0	14,170.0	5,263.0
Exports	5,424.0	5,996.0	951.0
Net Imports	7,690.0	8,174.0	4,312.0
Consumption	14,238.0	13,256.4	9,538.4
-Power+Heat	5,474.0	4,238.4	1,621.4
-Industry	3,051.0	3,118.0	2,467.0
-Commercial	3,012.0	2,730.0	2,600.0
-Distribution	2,701.0	3,170.0	2,850.0
Own Use/Losses	3,373.0	3,455.0	2,412.6
Balance	4.4	83.7	205.5

Source: Azerigaz and Mission estimates

5.19 The main change in the pattern of gas consumption since 1990 has been a very sharp fall in gas use in power generation. The availability of gas from Turkmenistan has been curtailed since early 1992, due to price disputes and changes in transit allocations to the Caucasus region by the Russian authorities. Overall, gross imports from Turkmenistan fell from 11.9 Bcm in 1990 to 4.2 Bcm in 1992, with a corresponding fall in re-exports to Georgia and Armenia from 5.4 Bcm in 1990 to under 1.0 Bcm in 1992. In addition, imports from Iran have dropped sharply, from 3.0 Bcm in 1991 to well under 1 Bcm in 1992, as a result of price increases. This supply disruption has forced a switch to fuel oil use in Azerbaijan's dual fueled power plants, with the share of gas in power generation falling from 62 percent in 1990, to only 21 percent in 1992, and gas consumption in power declining to 1.4 Bcm in 1992, from 4.6 Bcm in 1990.

5.20 Gas usage by industry, where gas accounts for 90 percent of fuel supplies, fell by 21 percent in 1992, due to the decline in industrial output. Household and commercial demand has remained relatively stable, the estimated annual fluctuations in use being partly due to the weather. Gas is used for cooking, water heating and space heating, with most houses having some form of gas heating appliance (for water or space). This pattern of use is different from that in most other areas of the FSU, where a larger proportion of heating and hot water is supplied through district heating systems.

5.21 Most gas use in the country is un-metered. As shown in Table 5.3, nearly half of industrial and power enterprises lack meters, and only 10 percent of the larger commercial/municipal enterprises have meters. There are no meters in individual households. This lack of metering (and of gas flow control on most heating appliances) not only causes problems of flow measurement and control, but also prevents the implementation of an effective gas pricing policy based on actual consumption. At present, un-metered household consumers are billed according to formulae based on household area,

persons per dwelling, and assumed usage of various gas appliances.

5.22 Azerigaz is also responsible for LPG distribution throughout the republic. Total supplies of propane/butane in 1992 were 43,700 tons, which was supplied by the Karadag gas processing plant, from the two Baku oil refineries, and from Russia. Azerigaz delivers these supplies by railcars (owned by Azerigaz) to four bulk terminals, and also delivers about 99 percent of these supplies to households, primarily in mountainous regions of the republic without piped gas service.

Table 5.3: Gas consumers and meters in Azerbaijan, 1992

	No. of consumers	No. with meters	Percent
Industry/power/heat	837	465	55.6
Municipal enterprises	2,341	361	15.4
Public institutions	8,325	731	8.8
Residential households	1,098,264	0	0

Source: Azerigaz

Outlook for Natural Gas Supply and Demand

5.23 The outlook for natural gas supply and demand has been examined in the same set of scenarios used for oil supply and demand in Chapter 3. The projections suggest that it may be difficult to increase domestic production substantially within the next decade, since production of associated gas from the new oil fields is only likely to offset the natural decline in production from existing fields. The new offshore fields are predominantly oil fields, with some associated and free gas, and resources are thus not sufficient to offset the output decline from the existing large gas-condensate fields. Some of the gas will also be needed for re-injection to maintain oil production. Continued substantial imports are likely to be required, probably in the range of US$600-700 million per year, imposing a significant burden on the economy. Thus, improvements in the efficiency of the entire gas system hold the best hope of mitigating the high cost of imports.

5.24 Under the Base Case scenario, the rapid fall in oil production from existing fields leads to a further decline in associated gas production until around 2000, when gas from Azeri and the other new offshore oil fields begins to come on stream. By 2005, gas production would still be below the level of 1992. Exploration of the offshore South Caspian basin can reasonably be expected to yield one or more large gas/condensate fields that could be brought into production in the period 2000-2005. However, the most important influence on gas supplies under this scenario is the recovery of vented gas from the Guneshli field from 1995, which would prevent an even more rapid fall in domestic supplies in the mid-1990's.

5.25 The venting reduction project, designed to recover about 1.3 Bcm/year of gas from the Guneshli field that is currently vented, is particularly urgent. The project involves: (i) laying an underwater pipeline from the Guneshli field to the Oil Rocks field; (ii) installing a gas compressor station at the Oil Rocks field; and (iii) completing the partially built pipeline from Oil Rocks to the gas processing plant at Karadag (via the Bakhar field). Because of the use of existing facilities and pipelines,

the total cost of this project is expected to be around $100 million. The annual saving in gas imports (or alternatively, the gain from fuel oil exports) would also be around $100 million, suggesting that the project is very attractive economically. A foreign company (Pennzoil) is undertaking this project, as a preliminary phase to the Guneshli field development project. It is important that the contractual framework with the company set a proper precedent for future gas developments by foreign companies, in terms of gas pricing (and liquids pricing) and contractual obligations.

5.26 Gas demand in 1993 is expected to remain constrained by limited availability of imports from Turkmenistan. Azerbaijan's outlook for gas imports for 1994 and beyond is fraught with difficulty. In addition to continued price increases from Turkmenistan, the transiting republics (Uzbekistan, Kazakhstan, and Russia), joined by Chechenia and Dagestan (two autonomous regions within the Russian Federation, through whose territory the gas pipelines pass) continue to press for higher transit fees. As Azerbaijan has been unwilling to pay these high prices for gas imports, and has also found it difficult to coordinate arrangements between the transit authorities, the gas enterprise has developed, and begun to implement, plans to reduce gas use in the country. These plans include the curtailment of gas service to areas affected by the regional conflict, further reductions in gas deliveries to the power generation sector (leading to higher fuel oil use), and increases in the delivery of LPG to households. In taking these measures, Azerigaz must weigh carefully their real economic costs. For example, it is not clear that restricting gas deliveries to the power sector is justified in terms of the cost of lost fuel oil exports, since the export value of fuel oil in 1992/early 1993 was above the cost of gas imports. Additional efforts to import gas supplies at a cost below the economic opportunity cost of fuel oil should be encouraged.

5.27 From 1994, gas imports, and hence usage in the power generation sector, are expected to return to "normal" levels, accounting for around 70 percent of power sector fuel demand. Usage is assumed to remain constant in the medium term, with some of the modest increase in fuel demand for power met by fuel oil use. The rise in gas import prices to "world levels" from 1994 would still make gas somewhat less expensive than fuel oil in calorific terms. As shown in Table 8.1, at notional "World Prices" imported gas from Turkmenistan would probably be up to 25 percent less expensive than fuel oil valued at export parity. Even if the price margin in favor of gas were low or negligible, the operating and environmental advantages of gas would still lead to its use in preference to fuel oil. Gas demand in power could be expected to climb in 2000 and in 2004, due to the proposed construction of combined cycle power plants (which further reduce fuel oil use).

5.28 Demand in the industrial sector is expected to continue to decline in 1993, as the economy restructures, but henceforth to remain stable. Despite the anticipated modest recovery in industrial output from the mid-1990s no increase in gas demand is projected, due to the possible closure of some heavy energy-intensive industries, and to an improvement in end-use efficiency in response to higher prices and more widespread metering. Similarly in the commercial and residential sectors, demand is expected to be constant, as higher penetration rates and household growth are offset by gradually improving efficiency.

5.29 The net result of the projections is an increase in import demand for gas in the base case, to 10.5 Bcm in 2000, slightly declining thereafter to 9.2 Bcm in 2005. The cost of gas imports at "world prices" will rise from around $300 million in 1993, to $730 million in 2000.

Table 5.4: Azerbaijan Gas Supply - Demand (Base Case) (Bcm)

	1992	1993	1994	1995	2000	2005
Production	9.28	8.44	7.76	7.17	5.84	8.06
Venting	1.43	1.43	1.43	0.00	0.00	0.00
Net Available	7.84	7.00	6.33	7.17	5.84	8.06
Net Imports	4.31	4.15	9.00	8.04	10.46	9.18
Consumption	9.54	9.13	12.67	12.67	14.17	15.67
-Power+Heat	1.62	1.45	5.00	5.00	6.50	8.00
-Industry	2.47	2.22	2.22	2.22	2.22	2.22
-Comm.+Distr.	5.45	5.45	5.45	5.45	5.45	5.45
Own Use/Losses	2.41	2.03	2.66	2.53	2.13	1.57

Source: Mission estimates

5.30 The outlook for gas imports in the other oil development scenarios is even less favorable:

- **Delay Case:** If the new field development, the pipeline system rehabilitation, and the gas venting reduction at Guneshli are delayed by two years, gas imports will rise very rapidly to 10.0 Bcm in 1996, compared with 6.8 Bcm in the Base Case. The resulting increase in the cost of imports by $220 million per year would represent a substantial setback to economic recovery. Imports would remain above 11.0 Bcm from 2000 to 2004 due to the delay in production from new fields.

- **Low Production Case:** The lower production of oil in the Low case leads to a lower production of associated gas, with output in 2000 16 percent below the Base Case. Gas imports are correspondingly much higher than in the Base Case throughout the forecast period: an additional $70 million in the year 2000. Given the shortage of gas in Azerbaijan, there would seem little justification in delaying domestic production of natural gas in favor of imports.

5.31 There may be some prospects for cutting imports through higher domestic production, but it is unlikely that imports can be eliminated before 2005 through higher output alone. Production from the new offshore fields and Guneshli would have to be four times higher than the Base Case forecast in 2000, and two times higher in 2005, in order to eliminate imports.

5.32 However, development of the offshore fields should emphasize gas production, in addition to oil production, since the fields contain free gas horizons that could be independently developed. It is important that these options be incorporated into development plans, and that agreements reached with the oil companies provide for adequate incentives for gas development. In this connection, it should be noted that terms which compensate foreign companies for gas production on the basis of a price related to its economic value, and provide for them to take payment in oil for export, have proved successful in encouraging investment in gas development elsewhere (eg. Egypt where companies have received a price linked to world fuel oil parity). In the case of Azerbaijan, the reference price for gas purchased from foreign companies would be the cost of gas imports, or the value of fuel oil exports. The level at which natural gas is priced will depend upon the relationship between natural gas supply and demand. As

discussed in Annex 5.4, domestic natural gas output displaces either imported natural gas or fuel oil (for export), depending upon the level of domestic production, the demand for gas in power and the relative economic value of gas imports and fuel oil exports. It is important that the gas price offered to foreign companies be based on a relatively transparent formula, allowing them to make realistic assessments of the costs and benefits of investment in gas production and capture. Provision for new gas processing facilities should also be part of any integrated offshore gas investments.

5.33 Many of the undrilled structures lying in the deeper waters of the Caspian may be predominantly gas bearing (though containing substantial quantities of oil and condensate). If this proves to be the case, Azerbaijan could eventually become self sufficient in gas, and may even become an exporter. For example, the Shach Deniz structure, on which exploration drilling by a foreign company could commence in 1994 or 1995, may be a giant gas condensate field, containing over 140 Bcm of gas. However, production, which in this case might reach 7 Bcm/year and thus greatly reduce the need for imports, is unlikely to be significant before 2002. The scale of potential gas resources to be discovered offshore reinforces the importance of establishing clear terms for natural gas development by foreign companies.

5.34 There may also be scope for improved recovery of gas, and a moderation of the rate of production decline, in the existing gas-condensate fields (such as Bakhar), possibly through joint ventures with foreign companies. Development of these fields appears to have been undertaken primarily with a view to recovering liquids rather than gas. There are also a number of discovered and partially developed onshore gas fields that have not been brought into production. This was partly due to the extremely low price of gas offered to the state producing companies, which was only 40 percent of the calorific equivalent of the oil price until 1990. Since then the relative producer price of gas has fallen further to only 8 percent of the oil price (at end 1992 - see Chapter 8). The price paid by Azerigaz to SOCAR should be governed by the same principles as the price offered to foreign companies, in order to provide economic incentives to gas exploitation.

Improvements in Gas System Efficiency

5.35 The best prospects for reducing the requirement for gas imports over the next decade are through substantial improvements in gas system efficiency. This effort would require an investment program on several fronts which should be made a high priority:

- **Replacement and rehabilitation of gas pipelines:** A large-scale program is required to rehabilitate and replace corroded and leaking gas distribution pipelines throughout Azerbaijan. As a prelude to this program a detailed study is needed to identify priority areas for investment and the requirements of each part of the system. Azerigaz already has a reasonable inventory of its own system and of the key problem areas, but this needs to be integrated with economic, financial, and environmental analyses of the problem and alternative solutions, and with consideration of the application of the latest technologies available on the international market. Any program of rehabilitation and replacement would also consider the transmission system (including improvement of compressor station efficiency), gas storage, associated equipment (e.g. pressure reducing stations, SCADA systems) and gas processing facilities.

- **Installation of gas meters:** A pre-requisite to improving end-use efficiency is the installation of gas meters in all industrial, commercial/institutional and residential consumers. Widespread metering, coupled with controls for water and space heating appliances, would allow consumers

to moderate their demand in response to higher prices. Azerigaz estimates that about 1.12 million meters of various sizes are needed for households and small commercial establishments, plus about 7,100 larger meters for commercial/ institutional and industrial users. At international prices for such meters, the cost of this program would be some $100 million. Even with a rapid installation program, it could take up to ten years to install meters for all consumers. While Azerbaijan has the technical capability to manufacture gas meters domestically, the choice of meter procurement method -- imports or local manufacture -- must be the result of appropriate economic and financial analysis, including analysis of potential export markets for meters. If a project to manufacture meters is justified, a joint venture with foreign private investors is likely to be the most appropriate way forward.

- **Improvement in gas appliance efficiency:** The installed base of gas appliances, both industrial boilers and household cookers and heaters, is generally inefficient and obsolete. Allowing imports from other countries should permit replacement of existing equipment by consumers who can afford the new equipment. As with meters, a program to manufacture higher standard appliances for domestic use (as a private joint venture) could well be justified, but final decisions should not precede detailed feasibility and market studies. Depending upon the levels of saving which might be achieved, a system to provide incentives (via rebates from Azerigaz) for consumers to trade in particularly wasteful appliances and boilers could be introduced to accelerate the elimination of older equipment.

- **Increased efficiency in power and heat stations:** Azerbaijan's power and district heating stations are relatively inefficient, reflecting their age (much of the capacity is over 20 years old), the obsolete Soviet boiler designs, and the lack of combined cycle systems. A program to improve the efficiency of these existing steam stations is urgently required. In addition, accelerated replacement of some older steam capacity with combined cycle capacity may be justified. Such options need to be examined within the context of a least-cost power investment plan, taking account of the full economic costs of natural gas systems. Again, plans for replacement of gas-using equipment and appliances must be based on appropriate economic and financial analyses of the potential for gas savings and the costs of the new equipment.

5.36 The aggregate impact of an accelerated investment program to improve end-use efficiency of gas will be significant, although it is difficult to estimate precisely. The Base Case projection shown above incorporates some assumptions about increased efficiency to 2005, including a reduction in total system use and losses to around 10 percent, improvements of about 25 percent in end-use efficiency in the industrial, commercial/institutional and household sectors, and introduction of 800 MW of combined cycle capacity. This projection already assumes a substantial investment program in pipeline replacement/rehabilitation, metering, new appliances and power generation capacity.

5.37 A more optimistic projection of gas savings, based upon an accelerated investment program, could yield an additional 1.9 Bcm per year of savings by 2000, consisting of:

- 0.8 Bcm of reduced system losses through accelerated pipeline replacement (reducing losses to the level of about 10 percent of throughput);

- 0.8 Bcm of consumer efficiency improvements (through accelerated meter and appliance installation); and

- 0.3 Bcm of power generation savings through replacement of an additional 400 MW of steam capacity by combined cycle.

5.38 The annual savings in gas import costs from such an accelerated program of investment would be about $130 million, representing a substantial return to an investment of up to $600 million over the period 1995-2000. Coupled with the gas venting reduction program, these measures could greatly reduce the need for gas imports, thus saving Azerbaijan up to US$250 million per year. However, the precise scope and magnitude of investment in the sector should await the outcome of detailed reviews of gas and power sector investment plans.

CHAPTER 6

ELECTRICITY

6.1 With an installed capacity of nearly 5,000 MW, Azerbaijan is the largest power producer among the Caucasus republics and has played a key role in power exchanges within the region. Azerbaijan has made impressive progress in extending electrification to the whole country and expanding power supply to become a net exporter of electrical energy. However, a large part of its productive assets are obsolete and require major refurbishment. Further, the disruption of trade within the FSU and the war with Armenia are causing major constraints to this sub-sector's development. As it moves to a market economy, Azerbaijan will have to restructure its power industry to make it more efficient. Also energy prices will have to be adjusted to ensure cost recovery and provide incentives for end-use efficiency. The declining demand for power will limit the need for capacity expansion in the medium term, allowing Azerbaijan to carry out a least cost planning study before deciding which plants to return and rehabilitate. Further, introduction of appropriate technologies will help improve energy efficiency and mitigate adverse impacts on the environment.

The System

6.2 Azerbaijan has an installed capacity of 4,908 MW, of which 692 MW is hydro-based and the rest thermal, in 8 conventional steam thermal power stations and 4 hydropower stations. In 1991 the energy generated was 23.3 TWh, of which 21.6 TWh was thermal and 1.7 TWh hydro; energy exports were 3.3 TWh and energy imports 1.6 TWh giving a gross domestic supply of 21.6 TWh.

6.3 Of the total thermal energy generated in 1991, 49 percent was from natural gas, and 51 percent from fuel oil. However, because of constraints in natural gas supply the share of fuel oil in 1992 increased to 78 percent. Natural gas is supplied from local production and from Turkmenistan via Russia through the Caucasian pipeline system which supplies also Georgia and Armenia. Fuel oil is supplied from the refineries in Baku. The largest power plant is the newly constructed Azgres power station near Mingechaur, which consists of 8 units of 300 MW, 7 of which are in operation. The turbine and generator of one unit were completely destroyed in 1990 during an accident caused by a hydrogen explosion and fire. Work is underway to replace the damaged equipment and to put the unit back into service. The units were designed to burn gas as the main fuel and to use heavy fuel oil only as a back up and, in particular, the boilers are not equipped with soot blowers. The use of heavy fuel oil as a main fuel has, therefore, caused major operating problems including a significant drop in maximum capacity and fuel efficiency. All other thermal power stations are also fuel oil and gas-fired since there are severe restrictions in gas availability especially during winter. The units located at Baku, Sumgait and Gandja provide process steam, district heating and hot water in a combined heat and power operation. The supply of adequate quantities of natural gas is critical for the reliable operation of the power system. The list of power plants is given in Annex 6.

6.4 The main hydropower stations are on the Kura river with the main purpose being irrigation. The reservoir has significant storage capacity (16 billion m3 at Mingechaur and 2.7 billion m3 at Shamkor). Some of the equipment at Mingechaur was brought second hand from Manchuria at the end of World War II as war reparation from Japan and has had to be retired. The installed capacity at Mingechaur is now only 260 MW instead of 380 MW.

6.5 A great portion of the thermal power plants are obsolete and all the units are not properly equipped to reduce environmental emissions (SO_2, NOx and fly ash) especially when burning fuel oil. Major investments would be required to refurbish the units in order to improve efficiency and reduce environmental emissions to a level prescribed by Western standards. Most of the units are of Russian design with a unit size varying from 20 to 300 MW. The disruption of trade within the FSU combined with the high ruble inflation is having an adverse impact on plant maintenance. The power company (Azenergo) is having serious difficulties with the procurement of spare parts mainly because of their high cost and lack of financing. In 1991 the thermal plants achieved an average capacity factor of 58 percent but power supply conditions could quickly worsen if the issue of timely supply of spare parts is not addressed urgently. Further, the maintenance practices need to be upgraded and brought up to the standards of a modern power utility.

6.6 High voltage transmission is provided through an extensive network of 694 km of 500 kV lines, 1,026 km of 330 kV lines, 1,331 km of 220 kV lines and 5,881 km of 110 kV lines. There was one substation at 500 kV, 5 at 330 kV, 8 at 220 kV and 163 at 110 kV in operation as of June 1992. The 500 kV network is part of the integrated system of the Transcaucasian interconnected system which is controlled by a regional dispatching center at Tiblisi. Also a 330 kV line connects Azenergo's system to the South Caucasian grid in Russia.

6.7 Subtransmission and distribution is carried out at 35 kV (6,333 km of lines and 636 substations), 6 and 10 kV (38,110 km of lines and 17,064 substations), and 0.4 kV (58,583 km of lines). The number of customers supplied is 703,850, including 2,409 industrial, 6,065 commercial, 2,996 agricultural and 692,361 residential consumers and 3 independent distribution entities which supply the three major cities (Baku, Sumgait and Gandja). The distribution network is generally in poor condition and needs upgrading to reduce losses which are estimated at 20 percent.

Sectoral Organization and Management

6.8 The power sector is under the responsibility of a vertically integrated production Union, Azenergo, which reports to the Cabinet of Ministers. Production units under Azenergo are organized into 53 "autonomous budget entities", whose management from the center is not well defined. Most of the production units are experiencing serious difficulties in meeting target budgets because of the dramatic increase in the cost of inputs (fuel, spare parts etc.), and this has led to inadequate system maintenance. In general, Azenergo has been isolated from modern utility practices and needs to introduce modern management and finance systems and provide extensive training in all its production units.

6.9 A key problem with the current institutional arrangement is that responsibility for policy making and planning in the power sector is not clearly vested in any institution. Further, the Soviet practice of planning only on the supply side persists, and there is no strategy to deal with the demand side and end use efficiency. These key demand-side functions ought to be assumed by an independent entity, probably linked to a Ministry of Energy, or similar institution. A related problem is the lack of proper legislation covering the power sector. An independent regulator needs to be established to mediate in a transparent way between the government, the power supplier and consumers, and to take account of economic, financial, environmental and service issues. There should be a move towards corporatizing and commercializing Azenergo, in line with its management's wishes, although account will have to be taken of the lack of experience of such arrangements in Azerbaijan.

Electricity Supply and Demand

6.10 Electricity consumption in Azerbaijan grew at 3.8 percent on average between 1980 and 1988. Between 1988 and 1990 consumption declined by 7 per cent. In 1991 gross supply was 21.6 TWh at about the same level as in 1990. Total domestic sales of 17.6 TWh were distributed between industry (44%), agriculture (20%), residential (16%), commercial (7%) and distribution retailers (13%). Internal use and losses represent 14 percent of gross supply, respectively, which is too high and reflects the obsolescence of several power stations. However, the loss figure does not include distribution losses below 35 kV in Baku, Gandja and Sumgait, since these networks are not managed by Azenergo, and information is not readily available. While "non technical losses" are difficult to evaluate because there is no customer management, they are expected to become significant as tariffs are increased. There is a need to introduce a customer management system including proper billing and collections procedures.

Table 6.1: Azerbaijan - Electricity Balance
(GWh)

	1985	1989	1990	1991	1992	percent (1992)
Generation	20,702	23,306	23,152	23,450	19,770	
+ Imports	2,345	2,482	1,752	1,576		
- Exports	1,887	2,913	3,356	3,279		
Net Exp./Imp.	458	-431	-1,604	-1,703	-633	
Gross Supply	21,160	22,875	21,548	21,747	19,137	
Losses &	15%	16%	14%	13%	14%	
Internal Use	3,097	3,590	3,102	2,890	2,680	
Net Consumption	18,063	19,285	18,446	18,857	16,457	
-Industry	9,437	9,150	8,482	8,873	6,972	42%
-Construction	659	640	573	558	530	3%
-Transportation	1,495	1,613	1,273	1,277	914	6%
-Agriculture	3,099	3,724	4,210	4,276	4,333	26%
-Residential & Commercial	3,374	4,157	3,901	3,872	3,708	23%

Source: Azernergo.

6.11 The demand figures for 1992 show a significant drop in consumption for the industrial sector, especially the chemical and metallurgical industries (where usage fell by 30 percent). The declining trend in industrial demand is the result of the disruption in trade among the FSU countries and is likely to continue over the next 3 to 5 years with the restructuring of industries. Demand from other sectors is expected to soften in response to large tariff increases which need to be implemented over the near term. From the mid-1990s, demand is expected to recover gradually as economic growth resumes.

6.12 The current per capita consumption of electricity in Azerbaijan is about 3,080 kWh, which is high compared to countries with similar GDP per capita. This is partly due to the large demand from chemical industries, metallurgy and pumping for irrigation, but it also reflects the inefficient use of energy particularly in the industrial sector. As in other FSU countries, the low price of electricity did not provide incentives for the use of energy-efficient appliances nor for the development of energy-efficient industrial processes. There is a substantial potential for energy savings and end-use efficiency is an area where external assistance would be required. As a first step, however, tariffs need to be increased and an entity in charge of energy policy, including demand management, needs to be set up.

6.13 On the supply side, although the existing installed capacity is 4,908 MW, available capacity is only 3,821 MW due to obsolescence and various maintenance problems. About 2,000 MW installed capacity have accumulated between 26 and 39 years of operation and may have to be retired over the medium term. Construction of Unit-9, (300 MW), at Azgres is underway with commissioning expected by end-1993 and Unit-10 is planned subject to availability of funds. A 75 MW hydropower station, (2x37.5 MW), is being constructed at Yeniken on the Kura river, between Shamkor and Mingechaur, with commissioning expected in 1995.

6.14 Power sector planning is carried out by the Energy Institute in Baku taking into account load demand for various sectors (industry, agriculture, services, residential), availability of fuel, energy savings and availability of funds. The hydro resources inventory has been partly completed and there is an estimated capacity of about 1000 MW, of which 550 MW is in small units, under 10 MW unit capacity, which could be developed competitively according to Azenergo. While limited refurbishment of several power stations has been scheduled over the next 5 years, Azenergo is considering the construction of 1,200 to 1,400 MW new capacity by 1998. A feasibility study of a 1,500 MW combined cycle plant was carried out by the Rostov Institute (Moscow) in 1990. The plant would be located close to Ali-Bairamli in a site originally earmarked for a nuclear plant. Azenergo is considering seriously private sector participation in the project development but it has no experience in undertaking such a scheme. While it will be necessary to justify the project with a least cost generation expansion planning study, its implementation would allow the retirement of obsolete and inefficient capacity and would boost power exports. Further, the project could be developed in phases (300 to 600 MW) to match the actual demand.

6.15 The conflict with Armenia has caused major disturbances in the power supply to the Nakhchevan province, normally fed by a 220 kV line through Armenia. A second hand diesel power station, (4 x 16 MW), is being constructed as an emergency measure and a 4 x 35 MW combined cycle plant is planned for the medium term provided that natural gas could be supplied from Iran.

6.16 There is a great potential for wind energy in Azerbaijan and the Baku region is well known for its constant winds. The Energy Institute in Baku has been making wind measurement tests in various sites and has prepared a wind map for coastal areas and rivers. A wind velocity between 4.5 and 10 meters per second is sustained over 3000 hours per year. Although some power generation experiments were carried out with a wind mill of 4 to 6 kW, the generation cost was considered too high compared to the low cost of fossil fuel prevalent at that time. With the increase of fossil fuel costs to international levels the use of wind energy might be competitive. Further, the hinterland of Baku is barren and hilly and would not pose any problems for installing windmills.

6.17 Because of the dramatic equipment cost increases in rubles, the overall medium term investment program would amount to about 120-150 billion rubles which would be clearly beyond Azenergo's financial resources. Therefore, if the combined cycle project were to be implemented it would be necessary to involve the private sector in the financing and operation. However, in view of the uncertainty on load demand, any decision on Unit-10 at Azgres and on the combined cycle should be deferred until a least cost generation expansion planning study has been carried out. The study should take into account the prospects for power exports in the region.

Table 6.2: Load Forecast (GWh)

	1991	1992	1993	1995	2000	2005
Gross supply*	21.7	19.2	17.4	17.7	19.8	22.9
Losses & Internal use	14%	14%	15%	14%	13%	12%
Net Consumption	18.8	16.5	14.8	15.2	17.2	20.2
Load factor	67%	66%	61%	65%	65%	68%
Peak load	3,700	3,310	3,250	3,130	3,480	3,850

** This does not take into account possible exports to Georgia*
Source: Mission estimates.

District Heating

6.18 District heating is generalized in Azerbaijan and is provided by two state-owned entities: (a) Teplokamunenergo all over Azerbaijan, except Baku; and (b) Bakteploset in Baku. Azenergo supplies process steam to industries, heat and hot water to Bakteploset in Baku, and to Teplokamunenergo in Sumgait and Gandja. In 1991 Azenergo supplied 15 million Gcal in process steam and hot water. Teplokamunenergo supplied 1.6 million Gcal, of which 0.5 million were provided by Azenergo and the rest from 850 heat-only boilers. Bakteploset supplied 2 million Gcal, of which about 1 million Gcal were provided by Azenergo and the rest from 100 heat-only boilers. Losses in the system are high (13 to 20 percent), heat pipes are poorly insulated and water losses are significant (30 percent in Baku), mainly because of corrosion and the lack of adequate sanitary cold water supplies in apartments.

6.19 Both Teplokamunenergo and Baktepioset provide heat at the entrance of the apartment buildings. Municipal entities are responsible for the distribution and collection of charges from residential consumers. There is no metering and the rates are based on the areas heated. For Azenergo the current rates cover the current financial costs. For Teplokamunenergo and Bakteploset the current revenues for heat sales do not cover costs and both had losses in 1991 and a greater deficit in 1992. Further, major rehabilitation works are required to reduce water and heat losses. In view of the availability of gas in most of the homes, the economics of district heating under the new set of relative prices will need to be reviewed. A diagnostic study of the district heating systems to define the rehabilitation needs is also recommended.

Regional Trading of Power

6.20 The Azerbaijani power system is interconnected at 500 kV and 330 kV with those of Georgia and Armenia constituting the Trancaucasian system with a regional dispatching center at Tiblisi. There are major economic benefits associated with the combined operation of the Georgia and Armenia systems, largely hydro-based, and the thermal based system in Azerbaijan. In view of the conflict between Azerbaijan and Armenia, however, the regional dispatching center no longer plays its role and acts only as a mediator on bilateral agreements between the countries. During 1991 Azenergo exported 1.7 TWh to Georgia and Armenia at a rate of 4.75 R/kWh. In 1992 there were no exports to Armenia and exports to Georgia amounted to 633 Gwh at a rate of about US$0.04/kwh.

Environmental Aspects

6.21 There are no fly ash or SO_2 emissions associated with gas fired generating plants. However, the increasing use of heavy fuel oil with a high sulfur content in generating plants which are not properly equipped to burn such fuel may result in localized higher harmful emissions. In 1991, however, the figures given for the emissions of SO_2, NO_x and V_2O_5 are within the limits imposed by the FSU standard. As imports of crude oil decline, high sulphur fuel oil based upon imported Russian crude is being replaced by lower sulphur fuel oil derived from higher quality local crudes. Nonetheless, there is a need to increase the quantities of gas available and reduce the burning of fuel oil, since this promotes both better plant performance and reduced environmental emissions.

Table 6.3 Annual Emissions from Existing Power Plants
(tons)

	NO_x	SO_2	Solid
1. Azgres (2,400 MW)	8,802	24,323	830
2. Ali-Bayramli (1,050 MW)	13,286	17,704	73
3. Severnaya (300 MW)	1,840	1,274	
4. Sumgait CHP-1	4,606	4,015	
5. Sumgait CHP-2	4,391	2,043	45
6. Baku CHP-1	2,396	934	
7. Baku CHP-2	403	326	12
8. Gandja CHP	1,270	925	

Source: Azenergo

CHAPTER 7

ENERGY SECTOR INSTITUTIONAL REFORM

7.1 Upon its independence in September 1991, Azerbaijan inherited an institutional structure in the energy sector which had formed a part of the Union-wide system under the FSU. Thus Azerbaijan's institutions were merely branches, usually minor ones, of Union-wide institutions controlled from Moscow. Local capacity for energy policy formulation, handling of commercial matters and international trading and relations was limited. Along with the general Government institutional structure, Azerbaijan's energy sector institutions have been going through a period of rapid transition. In many respects Azerbaijan has made important strides towards rationalizing and reorganizing its energy sector. However this process has been hampered by the lack of experienced local staff, and by the more general instability and lack of organization in the Government. Much therefore remains to be done to create an efficient framework for the transformation of the energy sector within the transition to a market economy.

Energy Sector Governance

7.2 Azerbaijan's central government institutions concerned with energy are weak, even in relation to those of other FSU republics. Under the administration of the Soviet Union, Azerbaijan had no independent policy making and administrative capacity for energy. Such centralization as existed within Azerbaijan was in the hands of the local State Planning Committee (Gosplan), which carried out the republic's share of the overall Union planning effort.

7.3 Since independence, the responsibility for energy policy and coordination has become diffused. Azerbaijan has not set up a centralized Ministry of Energy, nor any other body capable of assuming this role, as has been done in other FSU countries. To some extent this had been due to a general lack of clear separation of power between the legislative (Parliament, Council of Ministers) and executive (Presidential office) branches of Government. Ministerial responsibility for energy lies with a First Deputy Prime Minister, who has a number of other important portfolios. He is supported by a very small staff of specialized civil servants, although in some cases their roles go beyond energy (for example the responsibilities of the office dealing with power also cover all other branches of heavy industry).

7.4 In addition, other Ministries play a role in the energy sector, particularly the Ministry of External Economic Relations, which is responsible for overseeing energy trade. The Ministry of Finance oversees and controls the revenues generated from petroleum products taxation.

7.5 Given its importance to national policy, there is also an important element of energy policy making within the Presidential office. Thus all important decisions are taken both by the Council of Ministers and by the President's office. The President's office also has primary responsibility for drafting new basic legislation, including that covering the energy sector. This situation reflects some of the continuing constitutional uncertainties affecting the Government of Azerbaijan following independence.

7.6 The role of Gosplan has been subsumed by the Ministry of Economy, and has diminished greatly with respect to energy, although some of the traditional reporting and target-setting systems remain in place as formalities. The Ministry of Economy's main role appears to be in assisting with

energy price setting, since it has the capacity to undertake the necessary cost and revenue analysis.

7.7 In the absence of a strong central coordination of energy policy, considerable power has devolved to the heads of the key enterprises, particularly the leadership of the State Oil Company. There is limited ability on the part of government to take action against the wishes of the state enterprises, which largely control the evolution of policy in their areas. There are some advantages to this situation in that bureaucracy is limited and little effort is dissipated in unproductive monitoring and reporting. Recent moves to establish a part-time "Energy Commission", staffed by representatives of Government and energy enterprises, to advise the Deputy Prime Minister and other senior officials on energy policy represent an acknowledgement of the need for stronger central coordination and oversight of policy. However, Azerbaijan will need a more focussed and permanent institution at this level as it evolves its mode of governance towards a more stable system.

7.8 A central body should be established to coordinate energy policy and supervise the activities of the energy enterprises. This body should not be a large bureaucratic entity, but a smaller policy-oriented institution, with a limited number of professional higher level staff. It may take the form of a small Energy Ministry, under a Minister, or could be an "Energy Commission", reporting to a Minister or to the President directly. Creation of multiple institutions (eg. a large Ministry and a Commission) should definitely be avoided. Similarly, it would be inappropriate to set up specialized Ministries for each sub-sector (eg. Petroleum, Power etc), since this would create redundant parallel structures to those in the enterprises. Small independent regulatory and supervisory bodies for the energy enterprises could be situated under the Ministry/Commission.

7.9 The responsibilities of the Ministry/Commission would therefore include:

- Setting overall energy policy priorities on an annual and multi-year basis;
- Advising the Government on particular energy policy problems (eg. energy trade issues, legislative matters, agreements with foreign companies etc.);
- Establishing the framework for energy pricing and supervising implementation of energy pricing by the enterprises;
- Acting as the umbrella body for regulatory agencies covering such areas as power, natural gas, petroleum licensing etc.;
- Acting as a central gathering point for key statistical, operations and financial data on the energy sector;
- Coordinating matters of environment, safety, standardization etc. with other responsible specialized agencies.

Energy Sector Legal Framework

7.10 Azerbaijan did not inherit from the Soviet Union a legal framework for energy suitable for an independent country moving towards a market economy. Laws do not clearly establish such matters as ownership of energy resources and the possibility of foreign participation in their development, the legal status of the energy utilities or the regulatory framework covering energy enterprise operations.

7.11 In the petroleum sub-sector, a Petroleum Law (covering both oil and natural gas) is needed to establish the framework for SOCAR's operations and for investment by foreign companies in petroleum development. Such a Law should cover the ownership of resources, the status of SOCAR, the rights and obligations of private and foreign investors in upstream oil and gas, and arrangements for oil and products trade, processing and marketing. It is important that this law is established separately from that covering other mineral resources and energy sources (eg. electricity), to avoid unnecessary complexity and ambiguity. The law should be accompanied by provisions for establishing standard contract terms for foreign investors in petroleum exploration and production.

7.12 A regulatory framework is needed for the natural monopolies, such as power, natural gas transmission and distribution and district heating, which establishes the duties of the utilities, the system for price and tariff setting, the rights and obligations of consumers and the potential for participation by private or independent operators within the system (eg. through access to the grid for independent generators or to pipelines for gas producers). These laws would set up regulatory institutions which would be charged with implementing the regulations for the various utilities. Such institutions should be independent from political influence, so as to ensure fairness and consistency of application of regulatory principles over time. Thus they should have statutory independence, and budgets which are set independently by parliament or through levies, even if they are situated under the umbrella of an Energy Commission.

Energy Enterprise Reform

Petroleum

7.13 In the petroleum sub-sector, Azerbaijan has initiated a substantial process of restructuring, which puts it among the leaders within the FSU countries in restructuring the oil industry. In September 1992, a Presidential Decree founded the State Oil Company of the Azerbaijan Republic (SOCAR) to encompass all activities connected with exploration and production of oil and gas, refining of oil and bulk transport and storage of crude oil. Control of internal oil product transport, distribution and marketing remained with the State Fuel Committee (Goscomtopleva).

7.14 Prior to independence, Azerbaijan's upstream oil industry consisted of two "Production Associations" (PAs), which were part of the network of such bodies comprising the Soviet oil industry. The Azneft PA controlled all onshore fields and some of the shallowest offshore fields, while the Kaspmorneftegas PA controlled all the remaining offshore fields. Each of these PAs in turn comprised a series of relatively autonomous units, which included the producing operating units (NGDUs), and separate units concerned with construction, transportation, drilling, well workovers, research institutes and administrative units for such areas as safety, marine inspections, communications, training and environment.

7.15 This structure had two fundamental weaknesses: firstly, there was a large scale duplication of functions as each unit had its own technical and administrative staff, secondly, there was little strategic coordination between the units, with each unit performing a narrow function linked to certain (usually physical) targets. The PAs and NGDUs were thus characterized by overmanning and inefficiency in drilling and production operations. In addition all key exploration and production decisions were taken by specialized Institutes, which handed inflexible instructions to the NGDUs. The ability of the NGDUs to adapt these instructions to conditions encountered in the field was highly limited, while the Institutes took too little account of the NGDU's practical experience.

7.16 The first reform of the sector undertaken following independence was to group the PAs together under a "State Concern", Azerineft. This Concern, however, was little more than a holding company, and the two PAs continued to function very much as before. The main function of Azerineft was to replace the PAs as the primary focus for high-level negotiations with foreign oil companies. However, Azerineft had little manpower, and was dependent on the PAs for negotiations back-up.

7.17 The downstream petroleum sector prior to restructuring consisted of the two refineries (operating as separate units), the fuels distribution organization, "Goscomtopleva" and the crude oil pipelines company "Transcaucasian Main Pipelines Association". While nominally under the control of various Government and Planning Committee units, the refineries in practice had some operational latitude. The fact that the refineries accounted for all of Azerbaijan's oil trade gave them a key economic role, which was not matched by the official oversight of their activities. After independence an attempt was made to place the refineries, and some petrochemicals and lubricants plants under a separate holding company, "Azneftechim", although this seems to have had little practical effect.

7.18 At the time of SOCAR's founding, the PAs were officially dissolved, and the refineries and crude pipelines company integrated into SOCAR. The concept behind SOCAR appears to be that of a modern integrated petroleum company, functioning in both the upstream and downstream areas.

7.19 SOCAR's structure has been evolving as the management seeks to adapt organization concepts to the existing reality of the industry. SOCAR is intended to consist of a number of key departments, each fulfilling a specific business function: Exploration and Production, Refining, Machinery and Equipment Supply, Drilling, Planning and Construction, and Offshore Fleet Services. Each of these departments is overseen by a Vice President, reporting to the President of the Company. The President is advised by a Strategic Planning department reporting directly to him. The President in turn reports to a Board, of which he is chairman. The members of this Board include both the key Vice Presidents of SOCAR, and a number of external directors. The President of SOCAR and all members of the Board are appointed by the President of the Republic.

7.20 SOCAR retains a virtual monopoly of petroleum trade. Some activity in petroleum products barter and trade by other organizations has recently been permitted, but all transactions must be physically handled by SOCAR. In circumstances where the substantial revenues generated by petroleum trade in the public sector have been difficult to control, such an emphasis upon physical checks of all flows is understandable. However, the granting of such a monopoly of trade services should be seen as a temporary measure, pending establishment of more reliable customs, fiscal and financial controls.

7.21 While the establishment of SOCAR represents an important step in restructuring the petroleum industry away from the previous Soviet model, a number of issues remain to be clarified:

- The extent to which the second level of organization has been restructured remains unclear. It is quite possible to reshuffle existing units between major departments without affecting the inherent inefficiencies of the units themselves. In this respect, the inefficiencies inherent in the Institutes and NGDU system do not appear to have been fundamentally altered, nor has the internal organization of the refineries been substantially changed by their integration into SOCAR;

- The reporting relationships between the units are undefined. Thus there appears to be little

distinction in the hierarchy between a service unit such as construction (which is a cost center) and an operating unit such as exploration and production (which is a profit center);

- The inter-departmental charges for services have not been clarified, with the basis of internal costing of goods and services not fully established, and transfer pricing therefore does not reflect the true financial cost of goods and services provided.

7.22 At the broader institutional level, the degree of oversight of SOCAR's operations by Government has not been well established. As stated previously, it is desirable that a policy coordinating and regulatory body for the whole energy sector be established at national level. The creation of a large company, such as SOCAR, with a de-facto (and possibly later de-jure) monopoly over all oil and gas production and processing, establishes an extremely powerful economic force, accounting for a large share of Azerbaijan's economic output, investment and trade. While the appointment of outside directors to the board represents some degree of oversight, the ability of these directors to monitor the activity of such a complex organization will necessarily be limited. It is therefore desirable that SOCAR is overseen by a capable regulatory unit within a central Government department. This applies in particular to agreements with foreign companies for exploration and production, where a Government licensing authority is required.

7.23 It is also important to keep the finances of SOCAR separate from those of the Government. This means that SOCAR's role in the agreements with foreign petroleum companies should be to represent the Government, and to participate in exploration and development as a national partner. SOCAR may obtain its own share of production as a partner in oil and gas ventures. However, the Government's share of petroleum production and revenues should be allocated directly to the Government through the agreements. SOCAR should not appropriate to itself all the revenue due to the Government, since this confuses SOCAR's role as the national oil company with the role of the state Treasury in collecting taxes. Commercializing SOCAR means allocating to it only those revenues needed to sustain its business efficiently, with excess profits captured through appropriate taxation. SOCAR can act as an agent of the Government in marketing the Government's share of oil and gas production, but the accounts for such activities should be kept separately from those of SOCAR's main activities.

7.24 In terms of SOCAR's restructuring, the decision to proceed to form a single integrated state oil company, with a highly centralized management, should be seen more as a pragmatic step in the restructuring process, than as an end in itself. Within the post-Soviet disorganization of this fundamental industry, the government's move to centralize control of oil-related activities can be justified as part of the process of restructuring the economy and gaining full control of public finances. However, the further evolution of SOCAR, should stress structural steps which are key to the creation of an efficient petroleum industry:

- The role of the "center", clustered around the President and Board, should be focused on strategic direction and major investment and policy decisions. Other decisions, including some of great importance, should be delegated downwards through the organization on a steadily declining and well defined scale of authority. This will help to prevent the bureaucratic paralysis and gross overmanning at the center which characterizes many large state oil companies. International advisors, highly specialized in specific areas such as negotiating agreements with foreign oil companies, should be used routinely to accelerate SOCAR's operations while its own staff gain experience;

- A system of internal charging for goods and services should be established, based upon true financial costs, so as to provide a clear picture of the profitability and performance of each unit and allow comparison with the local and international marketplace. This is important both in the sales of crude oil by the production department to the refinery department (which should be based upon international parities) and in the provision of such services as drilling and construction by centralized departments;

- As the company is commercialized, ancillary companies unconnected with core petroleum operations (housing, farming etc.) should be spun-off and privatized as a priority. Increased contracting out of services currently provided exclusively by SOCAR's internal units (eg. drilling, maintenance, marine services) needs to be introduced, to establish a sound competitive basis for internal suppliers and to improve efficiency (OECD companies routinely contract out most routine drilling, maintenance and support services);

- Financial and management information systems need to be established across the company, allowing rapid communication and consolidation of key performance data, appropriate short term and medium term planning and budgeting, and comprehensive financial reporting on a transparent and internationally comparable basis;

- Work to establish the need for the restructuring of producing and refining facilities (including the older oil fields and the refineries, see Chapters 2 and 4) should commence immediately, so that the restructuring of these facilities can be undertaken as part of the general reorganization. This will avoid the creation of entrenched non-viable units within the new company which may be difficult to eliminate or reduce in size;

- A large scale training program needs to be established, to familiarize staff with all commercial, managerial and financial aspects of the restructured company. This program should complement the development of a comprehensive personnel system, to improve the quality of staff selection and to create an effective system of staff incentives.

7.25 By following these principles, SOCAR could evolve in the medium term into a holding company for a number of commercial subsidiaries (upstream oil, refining, construction, oil pipelines etc.), or could eventually be split into separate companies. The ability of SOCAR to compete with private companies for business within Azerbaijan and abroad will steadily grow. Privatization, in whole or in part following an early move to joint stock status, should also be an aim.

7.26 In assessing the future of SOCAR, the increase in its scale of operations as Azerbaijan's oil production grows must be borne in mind. With a move to world pricing, SOCAR could by the year 2005 have revenues from crude, oil product and natural sales of $1.0 billion for its own account. Assuming SOCAR acts as the Government's agent for oil and gas sales, the amount of oil its handles would grow from 11.1 million tons in 1992, to 26 million tons in 2005, as well as 8 Bcm of natural gas per year. Although much of the activity and investment in Azerbaijan will be undertaken by foreign companies, SOCAR will nonetheless have to maintain a key role as a partner in the US$12bn integrated offshore development projects. With time, SOCAR's own investment budget will also rise to match the growth in its cash flows and commercial capacity.

7.27 In order to address the restructuring issues raised above and prepare for the growth in its scale of operations and role in the economy, SOCAR will need to seek advice from international

consultants in organization, financial systems, petroleum production and refining operations. In addition, training and human resource development will have to be undertaken on a large scale. This capacity building program should be a priority within the framework of energy sector technical assistance.

7.28 As concerns petroleum product storage, distribution and marketing, this is an area suitable for early privatization and introduction of competition. The first candidates for such privatization could be the retail oil product stations, which could be sold off to individual operators (or in modest lots - but avoiding creation of local monopolies). Provided that construction of new stations was freely permitted (subject to reasonable local planning rules) the retail price of gasoline and diesel could be liberalized at an early stage to provide for both price and service competition among existing stations and new entrants. Petroleum product tankers could be privatized (along with general trucking services), as could petroleum storage services (based upon reasonable regulated charges).

Natural Gas, Power and District Heating

7.29 In all of the energy network sectors (natural gas, power, district heating), the key issues concern the restructuring of sector operations along efficient lines, and the appropriate regulation of the resulting natural monopolies.

7.30 Of these sectors, only natural gas has undergone significant organizational restructuring since independence. Before the dissolution of the Soviet Union, gas transmission and storage was controlled by Aztransgas, a unit of the all-Union Gazprom enterprise. Unlike many of its counterparts in other Republics, however, Aztransgaz was a pure transmission company, without any production operations. Gas production and processing were the responsibility of the petroleum PA's (since the primary purpose of this activity was the recovery of liquids). Gas distribution, along with oil product distribution, was the responsibility of Goskomtopleva, the State Fuel Distribution Committee.

7.31 In September 1992, Aztransgaz and the gas distribution activities of Goskomtopleva were merged into a single company, Azerigaz. The central transmission department is located at company headquarters in Baku; distribution is divided into 5 zones (comprised mostly of small towns and rural areas) plus 6 major cities (where most of the industrial activity is centered). The distribution departments are also responsible for Azerigaz' LPG business. Azerigaz also incorporates two research institutes on technical gas problems (employing 560 people) as well as various construction, transport and ancillary subsidiaries. There are in addition some subsidiaries manufacturing gas equipment and appliances (although not on a scale to meet the country's needs).

7.32 Azerigaz buys gas from SOCAR, and also acts as the Government's agent in negotiating gas purchases from abroad (Turkmenistan and Iran). The President of the company reports to the Council of Ministers, which must clear price changes, gas laws, investment plans and import levels. The Ministry of Economy (formerly Gosplan) approves and oversees Azerigaz's budgets.

7.33 The power sector is under the responsibility of a production Union, Azenergo, which reports to the Cabinet of Ministers. All activities are vertically integrated under the General Director of Azenergo assisted by one Chief Engineer heading generation and associated technical services and four Deputy General Directors. Under Azenergo's supervision the production units are organized into 53 "autonomous budget entities". While the units have autonomous budget, their management and control from the center is not well defined. At the Baku No. 1 power plant an experiment has been undertaken in leasing out the assets to the workers, but this practice is controversial and has not been generalized.

District heating is less centralized, with the system in Baku managed separately from that in the other urban areas. The entities in this sub-sector remain substantially unreformed.

7.34 For natural gas, electricity and district heating, the key issues of restructuring are similar:

- Effective regulation of these entities should be introduced, under a transparent statute setting out clearly the functions of the company and the regulator. There is a need for the establishment of an independent, arm's length, transparent regulatory process between the government, the utilities and consumers as an intervention point for consideration of economic, financial, environmental and service issues. This will help create transparency in the way Government interacts with the sector and would facilitate commercialization and corporatization of the sector entities, as well as facilitating participation by private capital;

- The vertical integration of the utilities, and their national scope, should not provide a cover for inefficiency through cross subsidization, or a lack of transparency in costing. Tariffs should be set for each stage of operation, from generation (in power and heat) through transmission and distribution, so that the full costs of system operation are reflected in charges (although there may be a need for a transitional period, see Chapter 8). This charging structure should be reflected in an organizational structure encouraging autonomy of function (generation/transmission/distribution) and region, within the limits set by efficiency and scale considerations;

- Commercialization should be a goal for all operations in this area, so as to improve efficiency and allow utilities to raise capital from sources other than Government. This will have to include the separation of ancillary activities (such as construction, housing and equipment manufacturing) from the main companies, with spinning-off and privatization the preferred options where viable. There should be a move towards a contracting out of services (eg. maintenance) currently provided solely by in-house departments;

- Supply-side planning needs to be supplemented by demand-side planning, so as to put in place mechanisms to improve energy efficiency and environmental performance. Oversight of demand side planning may need to lie outside the utilities, within the central regulatory and policy making functions of Government. There is scope for an agency to promote energy efficiency and conservation;

- All utilities need to introduce modern financial, management and information technology systems, including systems for handling customer billing. This will have to be accompanied by intensive and large scale training of personnel in such systems and modern utility practices;

- In the longer term, the possibility of participation by independent operators needs to be established, including independent generators of power and heat, independent gas producers and independent owners of power and gas transmission facilities. Although it will be some time before a competitive system of energy supply can be introduced, the potential for participation of independent entities should be set within the regulatory framework from the beginning.

CHAPTER 8

ENERGY PRICING POLICY

8.1 Azerbaijan's energy prices, as in other FSU republics, are substantially below world and economic levels. While the government's policy is in general to bring prices into line with the world market, this process has been retarded both by the rapid devaluation of the ruble, and by a reluctance to impose very sharp price rises on consumers. The result is a system in which producer prices are too low to permit both recovery of current operating and maintenance costs and investment in producing and transport infrastructure, and in which there is massive cross subsidization between industry and residential consumers. As energy prices are now the most significant prices remaining under state control (most other prices have been freed), price policy in the energy area will be a key part of Azerbaijan's economic reform agenda.

Energy Pricing Framework

8.2 Energy pricing policy in Azerbaijan should seek to reflect the general principles of economic pricing. As in other FSU republics, the key issues concern the pace and pattern of the transition towards such a pricing structure. Within the FSU Republics, the transition process has in large part been dictated by trade patterns: Republics which are fuel exporters have tended to set prices for those that are fuel importers. The exporters have been seeking to gain revenues from the importers and to reflect world market realities, under which the option exists to sell at world prices rather than at artificial inter-republican levels. The main constraint on the pace of price rises is the ability of the importers to pay and inter-dependencies in other products, which create the possibility of trade-offs between energy and non-energy products. For importers faced with rapidly rising fuel prices, the choice is between a rising subsidy burden, or a deficit by fuel distributors, or passing on price rises to a population already suffering general economic hardship. An additional important factor, particularly in the case of petroleum, has been the often limited capacity of authorities to control trade by individual enterprises, with a rapidly growing quasi-official and unofficial market setting prices in many regions. Finally, the complexity of the energy sector varies greatly in different republics due to their different geographic scale and fuel mix; fuel pricing in the larger more diverse republics is more problematic than in some of the smaller republics.

8.3 Azerbaijan possesses a number characteristics which could help to define the pace of the transition in prices. In general, these make energy price reform in Azerbaijan more straightforward than in some other republics:

- As a net exporter of oil and oil products, the country is in a position to be a price setter for oil products -in theory it can regulate the pace at which internal prices approach "world" levels at the ruling exchange rate, without explicit domestic subsidies to petroleum enterprises;

- As a large net importer of natural gas, the country is a price taker for this fuel - it can only control the evolution of prices to end-consumers by explicit subsidies, however, as a large producer it can also trade-off lower prices for domestic gas against higher import prices;

- Azerbaijan has a single enterprise controlling all oil production, refining and trade. This allows a much closer policy control over petroleum prices than in many other republics, where the sector remains highly fragmented;

- The natural gas and power sectors are organized within single vertically integrated national companies, which facilitates an orderly process of price adjustment between various consuming sectors and regions;

- Azerbaijan largely depends upon two fuels, oil and natural gas, both of which are internationally traded within the region, providing market reference levels. Prices for other final energy supplies (electricity, heat) are largely set in relation to the cost of gas or oil inputs. In this sense Azerbaijan avoids some of the pricing difficulties experienced by Republics with large untraded energy sources (coal, nuclear, hydro);

- Azerbaijan is a relatively compact country, with good transport links which limits the need for geographical disparities in prices;

- Azerbaijan is a key supplier of certain industrial products (eg. petroleum equipment, air conditioners, refrigerators) and of agricultural products to other republics, which provide some leverage in inter-republican price negotiations.

Recent Pricing Trends

8.4 Table 8.1 shows the structure of energy prices in Azerbaijan, and recent trends of key fuels in relation to international prices. Figure 8.1 shows prices in Azerbaijan in relation to two other major FSU countries which are also large energy producers (Russia and Kazakhstan)[1]. A number of key features stand out:

- Azerbaijan has been relatively slow in raising its fuel prices towards international and economic levels in comparison with other FSU countries, particularly for oil and oil products;

- The producer price for crude oil is low in relation to that in other producing countries and has been falling in real terms;

- Fuel oil remains the oil product whose price is lowest in relation to international levels;

- The price of diesel has been raised far less than that of gasoline, causing diesel prices in Azerbaijan to lag behind prices in other FSU countries;

- The producer price for natural gas has remained exceptionally low, and has fallen as a proportion of the import price from Turkmenistan;

- The price of gas from Turkmenistan increased substantially in real terms in 1993;

- Prices of natural gas to residential consumers remain exceptionally low and have fallen in relation to prices to industry;

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[1] The prices shown in Table 8.1 and discussed in the text are in Rubles. In August 1992 Azerbaijan introduced the Manat, which has circulated in parallel with the Ruble (at an initial rate of 1 Manat=10 Rubles).

- Prices of electricity have been raised substantially, but prices to industry are much higher than those to residential consumers, and the gap between the two has grown in relative terms.

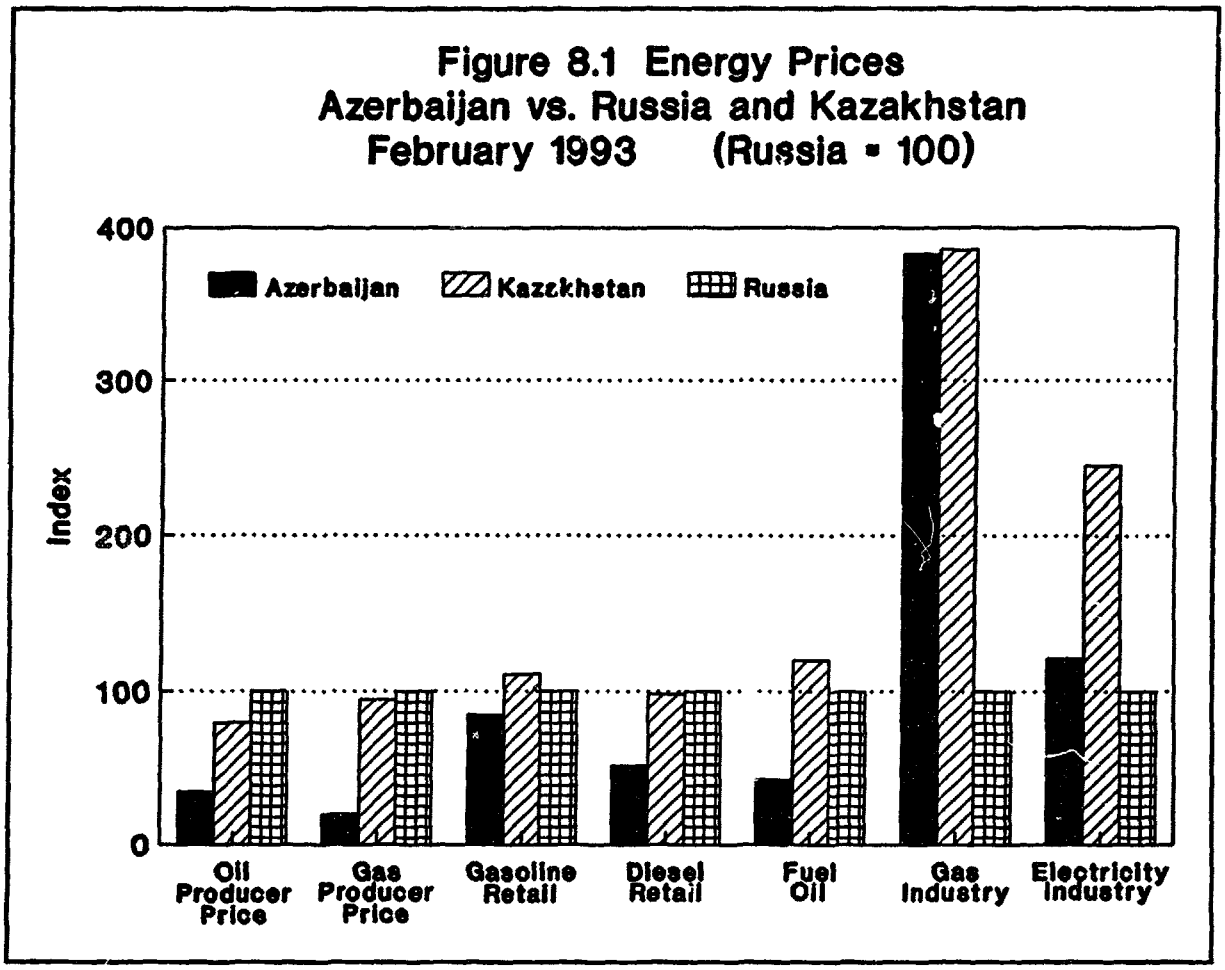
8.5 The Government's stated policy has been to raise energy prices to economic levels as rapidly as social and financial circumstances permit. However, the trends above demonstrate that the process of transition to economic pricing levels in Azerbaijan has not been proceeding in a smooth or coordinated manner. Much of recent pricing policy has reflected expediency or a delay in taking socially contentious decisions, rather than a clear policy of price reform.

Table 8.1 Azerbaijan Energy Prices

	August 1992	February 1993	World Price February 1993	% of World Price August 1992	February 1993
Oil					
Producer Price (Rb/ton)	2197	6500	71400[1]	10.5%	9.1%
Fuel Oil (Rb/ton)	1250	6830	60950[2]	7.0%	11.2%
Gasoline					
Retail (Rb/ton)	4791	35100	124950[3]	13.0%	28.1%
Retail (Rb/liter)	8.00	27.00			
Diesel					
Retail (Rb/ton)	5786	22000	113050[3]	17.4%	19.5%
Retail (Rb/liter)	7.00	20.00			
Natural Gas					
Producer Price (Rb/mcm)	300	600	41650[4]	2.4%	1.4%
Imports(Turkmen)(Rb/mcm)	1700	15000	41650[4]	13.9%	36.0%
Power (Rb/mcm)	305	18377	47600[5]	2.2%	38.6%
Industry (Rb/mcm)	2450	18377	59500[5]	14.0%	30.9%
Commercial (Rb/mcm)	305	3294			
Residential (Rb/mcm)	250	720	190000[5]	0.4%	0.2%
Electricity					
Industry (Rb/kwh)	0.24-0.38	3.85-5.70	45.0[6]	1.8%-2.9%	8.6%-12.7%
Commercial (Rb/kwh)	0.38	7.70			
Residential (Rb/kwh)	0.04-0.06	0.50-0.80	80.0[6]	0.2%-0.3%	0.6%-1.0%
Exchange Rate (Rb/US$)			595	175	595

Source: Government of Azerbaijan and Mission estimates.

1. Arab Light $130/t cif NW Europe, plus $15/t quality differential, less $25/t transport Baku-NW Europe.
2. Low Sulphur Fuel Oil $122/t cif Turkey, less $20/t transport Baku-Turkey.
3. Cif Turkey prices ($240/t gasoline, $220/t diesel, less $30/t transport Baku-Turkey).
4. Turkmen gas price based upon European border price of $95/mcm, less $25 transport differential.
5. Turkmen price plus notional $10/mcm for power, $30/mcm for industry and $200/mcm for commercial/residential customers.
6. OECD Europe averages of $0.08/kwh for industrial and $0.14/kwh for residential.



Source: Governments of Azerbaijan, Russia and Kazakhstan and Mission estimates.

Energy Price Reform

Energy Pricing and Economic Reform

8.6 Energy price reform is an important part of the economic adjustment process. Pricing reform for energy should be coordinated with overall macroeconomic reform. It is particularly important that energy price adjustments be accompanied by appropriate monetary, fiscal and exchange rate policies, so as to ensure that energy price increases are not neutralized by inflation or exchange rate movements. Appropriate fiscal measures must be in place, so that the effects of price changes on enterprise profitability are properly offset, and the effect on the Government budget is in keeping with macroeconomic targets.

8.7 Setting energy price targets, in terms of international parities or economic levels is thus an essential part of an economic adjustment strategy. In Azerbaijan, because of the relatively straightforward nature of the price transitions required, it is recommended that pricing reform to economic levels be aimed to be attained in a short period (for example, one year) after the start of a comprehensive economic stabilization program. Such a program would involve the introduction of a

stable national currency, and of a clear plan to lower inflation and stabilize government revenues and the external balance, probably with the assistance of international financial institutions. The range of target price levels for each fuel is addressed in the sub-sector paragraphs below.

8.8 It is possible that some prices, for example those for natural gas and electricity to residential consumers, may have to be adjusted over a longer time frame, to avoid an intolerable burden on consumers. Gas price changes in particular will have to allow for the installation of meters, while electricity price reform will require improved collection systems. In such cases the subsidies required to maintain low prices should be made an explicit part of the Government budget, so that the full economic costs of pricing policies are made clear. The government should however, limit general subsidies to all consumers as much as possible, and should aim to cushion the effects of price rises on consumers through targeted social payments wherever feasible.

Petroleum

8.9 As concerns oil pricing, Azerbaijan has maintained the producer price for oil at a level which is not sufficient to cover the increases in the cost of production incurred by SOCAR. As a result, SOCAR was running a monthly deficit of Rubles 4 billion by the second quarter of 1993. A substantial proportion of SOCAR's costs are of materials and services which are priced at international levels and hence have risen rapidly in costs in Ruble terms. Wages have also been raised to keep pace with local inflation. In order to provide SOCAR with resources for its operations (especially hard currency), the Government has allowed it to export crude oil and oil products (processed for a fee in the local refineries) for its own account free of taxes. This bypasses the usual channel of sales through the refineries, or at least through the Ministry of Foreign Economic Relations.[2]

8.10 The maintenance of a low producer price for oil has forced SOCAR to limit investment and essential maintenance, increasing the rate of decline of oil production. The diversion of crude and product sales to SOCAR's account amounts to an indirect subsidy to the company, since revenues from such exports might otherwise accrue to the Government.

8.11 In principle, SOCAR should be allowed to sell its crude oil or products directly onto the international market. However, such sales would have to be accompanied by appropriate Government taxation of SOCAR's profits, after allowance for necessary operating and investment expenses. Similarly, prices for crude oil and products sold on the domestic market should be steadily raised towards the international level, with a similar tax regime applied.

8.12 In this context, it is important to note that SOCAR should maintain a transparent internal pricing system for crude oil sales to its refineries, so that the revenues from crude oil production and the margins earned from refining are clearly distinguished. This is essential if the economics of distinct activities (oil production and refining) are to be properly assessed, and the correct economic signals given to producers and consumers.

8.13 For crude oil, the policy should be to raise the internal SOCAR sales price to the refineries to the international parity level. The establishment of such a level is not simple in Azerbaijan,

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[2] SOCAR was allocated part of the 1.05 million tons of crude exported for US$107 million in 1992, and has been allocated about 1 million tons of products in 1993.

since its crude oil is not directly traded internationally. One option, pending completion of the export pipeline, would be to use a crude (possibly Russian crude), which is widely traded in Europe (including the Black Sea) as a reference. Since Azerbaijan is a net exporter of oil, the relevant price is an export parity price. A notional transport differential between Baku and the Black Sea could be established to fix a netback to Baku. Suitable adjustment would, of course, have to be made for the generally higher quality of local crude (in particular its low sulphur level).

8.14 As for petroleum products, these are generally exported from Baku, and reasonable export quotations could be used to set a target for local ex-refinery prices. Both crude and product reference prices could be set monthly. Setting of such prices should commence as soon as mechanisms to do so can be established, so that the gap between local and international prices can be monitored and targets for price reform established.

8.15 An important issue for Azerbaijan is whether to liberalize (i.e. de-control) wholesale prices for crude oil and petroleum products. In practice the transition to liberalized trading could occur only when suitable regional marketing and trading structures are in place. In the near future, for example, free trading of crude will continue to be hampered by the lack of infrastructure, while product markets are unlikely to be entirely transparent. Hence local prices for crude and products could remain controlled, provided these are based upon a reasonable approximation of international parities as described above. SOCAR would of course receive international market prices for its international sales and the government's taxation of its revenues would reflect actual realizations from domestic and international sales. Retail prices for gasoline and diesel could be liberalized once a privatized and competitive service station network has been established. In the meantime, retail prices for petroleum products should be adjusted to a level which provides an adequate return on the costs of distribution. [3]

8.16 Adjustments to taxation systems will be required mainly in the upstream oil and gas sector. At present the Government raises a substantial proportion of its revenue from oil (estimated at about 40 percent of the budget for 1993). Gasoline and diesel sold on the internal market are subject to excise taxes and VAT amounting to 50 percent and 32 percent of the retail price (fuel oil is not taxed). In addition, SOCAR's refineries must surrender 70 percent of their hard currency revenues from oil product exports to the National Bank, receiving in compensation local currency at an exchange rate of about 16 percent of the market rate. The key taxation changes following a move to international prices will be those required to recoup any excessive profits from SOCAR following the raising of domestic oil and gas prices to international levels. This will require a study of SOCAR's finances, operating costs and investment requirements. Under such a system, profit taxes on SOCAR would replace the current high excise taxes on domestic sales, and heavy surrender requirements on exports. Excise taxes on oil products (above the international wholesale parity), will still need to be determined within the overall fiscal strategy for the Government.[4] As concerns foreign companies, taxation mechanisms for "rent"

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[3] It should be noted that the price comparison in Table 8.1 understates the true gap between retail gasoline and diesel prices in Azerbaijan, and their economic costs, since it is based upon international wholesale prices. Comparison with retail prices in other countries shows a much larger gap - for example Azerbaijan's gasoline and diesel prices in early 1993 were respectively only 19 percent and 14 percent of pre-tax prices in Turkey.

[4] Although in principle taxation of energy should reflect only the additional environmental or other costs imposed by energy use (including for example road maintenance costs in the case of transport fuels), in practice energy may be used as one means of indirect taxation, in the case where income tax collection systems are inadequate. This requires a judgement of the relative economic merits of different means of raising revenues in an "imperfect" economic context.

from oil and gas production will be built into the production contracts. In addition, these companies may be subject to the general corporate taxation levels in Azerbaijan on their profits.[5]

Natural Gas

8.17 Despite the fact that natural gas is the most important domestic fuel in Azerbaijan, the Government has not developed a coherent gas pricing policy. In part this reflects the legacy of the previous Soviet regime, in which the price for gas bore no relation to the cost of production or to its economic value as an energy source. In part, however, it reflects the failure to respond promptly to the increasing costs of gas imports.

8.18 Since the beginning of 1992, Azerbaijan has faced a dilemma on gas pricing. On the one hand prices of imports from Turkmenistan have been rising rapidly, from Rb 51/mcm in 1991 to Rb2,500/mcm at end 1992 and Rb 15,000/mcm in the first quarter of 1993. At the same time, however, the government has felt constrained in passing this cost on to consumers, mainly because over 50 percent of gas use is unmetered, and a large rise in prices would amount to imposing a substantial fixed costs on users, based upon somewhat arbitrary assumptions about usage levels. To offset the rise in imported gas costs, the government kept down the producer price of domestic gas, in order to maintain the average cost of gas to Azerigaz at a level which would keep the company solvent. Since local supplies account for about 60 percent of total supplies, the weighted average price to Azerigaz in the final quarter of 1992 was about ruble 1360/mcm, compared with the producer price of ruble 600/mcm and the import price of ruble 2,500/mcm. The result of this policy was an erosion in the producer price of gas relative to oil from even the very low levels of 1990 (before which the prices had been stable for many years). In 1990 gas producer prices had been 40 percent of oil prices in thermal equivalent, while by end-1992 this ratio had fallen to 8 percent.

8.19 As regards consumer prices, these have been maintained at an exceptionally low level to residential users, with the prices for industry taking most of the adjustment. Since 55 percent of industrial users have meters, and since the cost of energy to industry is often a modest proportion of total production costs, this is the sector on which the Government has found it easiest to impose increased charges. In the first quarter of 1993 industrial prices were 30 times the level of residential prices. In the OECD, residential prices are usually 2 to 3 times the level of industrial prices. The Government has also raised prices to power users to the level of industrial users, but this has been partly offset by the substitution of fuel oil for gas in power stations. As noted in Chapter 6 the share of fuel oil in power generation rose from 51 precent in 1991 to 78 percent in 1992. Since domestic fuel oil prices were kept down, at only 40 percent of gas prices (in thermal equivalent), this fuel switching reduced the input costs of Azenergo, thus keeping down pressure on electricity prices. However, as a result of this policy the Government lost potential revenues from fuel oil exports, which would have amounted to an additional US$200 million if gas usage had been maintained at the 1991 level. The corresponding saving in gas import costs was almost certainly below US$200 million.

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[5] Although oil companies are likely to be the most important foreign investors in Azerbaijan, it is not desirable that they receive special treatment in respect of corporate taxation, since this can create distortions and unpredictable conditions for future investors. Any special taxation of these companies should be included as part of the production agreements.

8.20 With prices of gas from Turkmenistan rising rapidly towards world levels and prices from Iran established at world levels for some time.[6] Azerbaijan's policy of attempting to absorb the pressure from rising import prices by keeping down domestic producer prices and raising domestic prices to industry, is clearly unsustainable. The very low price to domestic producers puts further pressure on SOCAR's finances (which are then offset through oil allocations). For domestic consumers, the cost of gas is barely keeping pace with the general rate of inflation (prices in December 1991 were ruble 50/mcm, while prices had risen 600 percent to ruble 300/mcm by December 1992, compared with a rise in the retail price index of 2200 percent). The maintenance of an artificially low price of fuel oil, in part as a subsidy to power users, creates a distorted perception that usage of domestic fuel oil is less costly than imports of natural gas. The rising distortions in Azerbaijan's gas pricing system, which are linked to distortions in fuel oil and electricity pricing, must be corrected urgently, so as to limit the economic disruption from an eventual move to economic pricing levels.

8.21 The calculation of economic gas tariffs should start from the assessment of an economic value for gas at the inlet to the system. The level at which domestic natural gas production should be priced will depend upon the relationship between natural gas supply and total demand. Domestic natural gas output displaces either imported natural gas or fuel oil (for export), depending upon the level of domestic production, the pattern of demand for gas in the country and the relative economic value of gas imports and fuel oil exports. These relationships are somewhat complex, and are assessed in Annex 5.4. The current pattern of supply and demand suggests that it will usually be appropriate to price domestic gas production according to the import price of natural gas into Azerbaijan, at least until the year 2000 (when supply and demand patterns could begin to change substantially). Accordingly it would probably be appropriate to take the economic cost of imported gas from Turkmenistan as the relevant price-guide. As indicated in Chapter 5, this is likely to be about US$70-80/mcm, based upon European border parities for Russian gas (and transport differentials).

8.22 Once the price at the inlet to the system has been determined, appropriate charges for transmission and distribution need to be established based upon cost of service studies, applying a suitable rate of return to the replacement cost of the system. Tariffs should be set within Azerigaz for individual system components (transmission lines, regional distribution systems etc.) so as to allow an assessment of costs and profitability at the business unit level. It should be noted that while some discount from replacement cost may sometimes be permitted to take account of the depreciated life of the system, and its long remaining life, in the case of Azerbaijan the urgent need to replace much of the pipeline system means that tariffs will have to reflect a substantial part of system capital cost if Azerigaz is to be self-financing. In practice, introduction of economic gas tariffs will have to keep pace with meter installation. As noted in Chapter 5, this is likely to take some years as concerns the household sector in particular. A coordinated program of price reform and meter installation must therefore be developed as a priority.

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[6] In late 1992 Azerbaijan reached agreement with Iran to trade 63,000 tons of diesel for 250 million cm of gas, implying a price of around $40/mcm, although Iran has on other occasions demanded $75/mcm.

SHARING THE SURPLUS FROM PETROLEUM

Since Azerbaijan is a major oil and gas producer, the allocation of the economic surplus (or "rent") from petroleum production is critical to the shape of Azerbaijan's economy. At present, the extremely low producer price for oil leaves most of the surplus with either the users (through low consumer prices) or with the government (where exports take place at world prices). It can be calculated that, at December 1992 prices and with 1992 demand patterns, consumers would have appropriated about US$600 million (46 percent of the world value of oil and products output) in the form of surplus (difference between world price and domestic production cost), while the Government would have taken some $230 million from net export receipts and further $55 million from tax receipts from oil products. Some $350 million (27 percent of the total) would have gone to the producers and about $60 million to the refiners (see Figure 8.2).

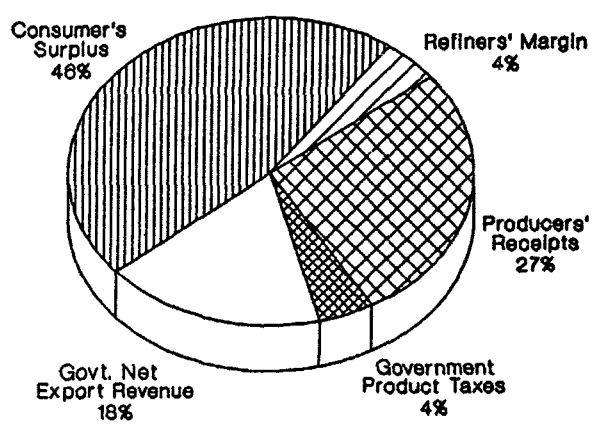
The pattern of distribution of the petroleum surplus (at world price equivalent) in Azerbaijan is highly inefficient, in that neither producers nor consumers are receiving appropriate economic price signals. The low government revenues from petroleum also aggravate the problem of balancing the public sector budget. A shift in pricing policy toward world price levels for producers and consumers is urgently required. This would need to be accompanied by an appropriate taxation system for upstream profits. Targeted subsidies to vulnerable consumers who might suffer particular hardship may also be desirable. Such a realignment of prices would channel a larger share of the petroleum revenues through the producers, and leave a much larger share with the government (via upstream taxation). Taxation of petroleum products should be put on an ex-refinery basis for domestic consumption (i.e. as a special excise tax). Given the large tax revenues which could be received by the government from upstream oil, there may be little justification for the imposition of petroleum product taxes other than implicit road user taxes for transport fuels.

Electricity

8.23 The current electricity tariffs do not reflect the true cost to the consumers and the distortion between households and industrial tariffs has been growing. Despite a significant increase at the end of 1992, the average rates are only a fraction of the long run marginal cost. The relative prices of electricity do not provide the correct signals to consumers which is the main cause for inefficient use and waste of energy. Further, the power sector is accumulating an increasing deficit because of the rise in costs of inputs and the cap put on tariffs.

8.24 The current cross subsidization between industry and agriculture and residential consumers is significant. Residential consumers are paying only a fraction of the cost to industrial users while the true cost to households is typically 1.5 to 2 times that of industrial consumers. As shown in Table 8.1, prices are only a small fraction of those typically prevailing in industrialized OECD countries. Prices to residential consumers need to be increased substantially to correct this distortion. Price adjustment in the short term is less of a problem for electricity than for natural gas, since all consumers have meters.

Figure 8.2 Petroleum Value Shares (million US$)



** Approximate share of world value of petroleum and products output at end-1992 prices and 1992 consumption and export levels.*

Source: World Bank estimates.

However, collection and billing systems need to be greatly improved if higher prices are to be translated effectively into revenues. As in the natural gas sub-sector, price reform in electricity should be based upon cost of service studies. This involves calculation of system long run marginal cost (which could be done within the context of the proposed least cost investment study), complemented by financial analysis of utilities.

CHAPTER 9

ENERGY SECTOR INVESTMENTS AND TECHNICAL ASSISTANCE

Energy Sector Challenges

9.1 The energy sector has played a major role in Azerbaijan's modern economic development. Azerbaijan was one of the earliest centers of the petroleum industry, and oil exports were for many years the motor of the country's economy. Oil has declined in relative importance in recent decades. Yet Azerbaijan still possesses very large petroleum resources, which could once again make oil the key to economic growth. The efficient development of the large resources in the country's offshore oil fields is the best means of generating the foreign exchange to finance economic restructuring and recovery in the medium to long term. In the shorter term, rehabilitation of existing oilfields and a reduction of gas imports can provide important benefits. In addition, the reform of energy institutions and the rationalization of energy use is essential if the transition to a market economy is to be successfully accomplished. In order to fulfill the potential of its energy sector, Azerbaijan's government and energy sector institutions will require technical assistance from the international community, so as to adapt their skills and plans to a market oriented environment as rapidly as possible.

9.2 In assessing the investment and technical assistance requirements of its energy sector, Azerbaijan must take account of the considerable challenges which it must confront:

(a) The Government, through the State Oil Company, needs to conclude detailed agreements with foreign companies on offshore oil field developments and construction of an oil export pipeline, all of which require complex legal, financial and technical arrangements. The Government has made encouraging progress in attracting major international oil companies to Azerbaijan. Investment by these companies is essential to obtain the finance, technology and project management for the development of the offshore fields. Planning this investment and integrating the cash flows with the macroeconomic framework is vital to ensure orderly economic development. In addition, Azerbaijan needs to assess how it can supply the investment and operating requirements of the offshore projects efficiently from domestic industries, so as to maximize the benefits to the local economy and provide least-cost supplies.

(b) The existing energy sector infrastructure is often obsolete and in poor condition. In the older oil fields production has reached levels which are probably economically marginal and a major restructuring of production practices and facilities is needed; there is also serious environmental pollution associated with oil production. The country's oil refineries lack upgrading capacity, and much of their equipment is antiquated. The gas pipeline system is corroded and losses of gas through leakage are very large. Much of the power capacity is near the end of its useful life, and fuel usage is very wasteful. In all of these areas a major restructuring of existing infrastructure will be needed, together with substantial investments in more efficient systems.

(c) The energy sector institutions, and the experience of their staff, need to be adapted to a market economy. There has been significant initial progress towards restructuring some of the energy enterprises, particularly in oil and natural gas. Yet enterprise management systems and operating structures are still geared towards a command economy.

Enterprise structures need to be thoroughly reformed, management and staff require training in market-oriented business practices and modern financial and information systems need to be installed, as enterprises move towards commercialization. In addition, the Government's capacity to formulate and implement national energy policies requires strengthening. Appropriate independent regulation of the energy enterprises and a legal framework for petroleum should be introduced.

(d) Azerbaijan's energy sector is oriented towards interaction with the other FSU countries under the previous central planning system, not with the world market. Moreover, the distinction between the market in the FSU and that in other countries is becoming less relevant. This has a number of implications, including the need to build better transport links with the world market, particularly a crude oil export pipeline. All energy enterprises must interact with foreign investors to find the technical and financial resources for future investment. In the case of the important petroleum equipment industry, urgent action is needed to develop a commercial strategy (emphasizing quality improvements) for retaining a substantial share of the market in other FSU countries, as well as in the domestic market.

(e) Domestic energy pricing and taxation policies are distorted and do not reflect current economic realities. Energy prices are well below international and economic levels. Producer prices are too low to provide resources for investment, while consumer prices are subsidized, and do not provide incentives for efficiency. The problems of moving to world price levels are significant, and reform must take account of exchange rate distortions, the social costs involved and practical problems such as the lack of gas meters. However, a coherent framework for moving to economic pricing for energy is urgently required.

9.3 There is a need to move rapidly to address these problems so as to take advantage of Azerbaijan's petroleum resources, to avoid continuing economic losses due to inefficiency, and to halt the further deterioration of infrastructure.

Investment Plans

9.4 The Government and the energy enterprises have set out the following priority projects in the energy sector (to the year 2000), for which international financial assistance may be required:

(a) **Oil - Rehabilitation of the old oil fields to repair infrastructure and extract remaining reserves:** The dilapidation of the infrastructure, surplus employment and major environmental problems in these fields present obstacles to attracting foreign investment in a comprehensive manner (in contrast to the situation with the new offshore fields). Yet the old producing areas still contain significant resources, despite their long producing history. Short term investment may be required to repair producing equipment. In the medium term, international financial assistance designed to complement private investment, and focussed on removing institutional, environmental and social obstacles to restructuring, will probably be most effective.

(b) **Oil - Construction of a crude oil export pipeline:** The development of the offshore oil fields requires access to world markets through a new export pipeline. Azerbaijan has

been working with the oil companies and neighboring countries to develop this pipeline, which is likely to cost at least US$1.5 billion. In view of the large sums involved, and the political and commercial issues raised by this key project, financial support by multilateral institutions may be required.

(c) **Natural Gas - Rehabilitation of pipelines to reduce losses caused by leakage from corrosion, and investments in improving usage efficiency:** Gas is the key fuel for the domestic economy, and Azerbaijan is a major gas importer, despite also having large resources. Gas losses are high, and use is extremely wasteful due to the lack of gas meters and of efficient appliances. Gas processing is inadequate. The price of imports from other Republics is rising rapidly, causing significant economic strains. A plan to rehabilitate the pipeline system, improve processing, introduce meters and enhance end use efficiency is urgently required.

(d) **Electricity - Construction of combined cycle power stations, and investments to improve the efficiency of the system:** While electricity capacity in Azerbaijan is adequate, fuel usage is extremely wasteful, and many of the power plants are over 25 years old. The transmission and distribution system has also suffered from under-investment and lack of maintenance. The problems of the power sector are the result of the lack of emphasis on efficiency under the previous regime. In the short and medium term, the investment priorities are probably the rehabilitation of the generation, transmission and distribution infrastructure. In the longer term, replacement of obsolete capacity by new combined cycle plant is probably justified. Power sector investment needs to be conducted within the framework of a least cost investment plan.

(e) **Oil Field Equipment - Investment programs in the oil field equipment industry to improve quality, restructure capacity and develop marketing:** Azerbaijan supplied 65 percent of the oil fields equipment in the Former Soviet Union, and remains a vital supplier to the other republics. The survival of this industry is important to maintaining oil production capacity in the other FSU Countries (especially Russia) and to ensuring the future of the industrial sector in Azerbaijan. Yet the industry must learn to compete in the international marketplace. Joint ventures with foreign investors represent the best chance of long term survival.

(f) **Oil Refining - Investments in additional and more modern refining capacity:** Azerbaijan's refining capacity is well in excess of its domestic requirements. Much of the capacity is obsolete, some dating from the beginning of the century. In recent years the refineries processed crude imported from Russia and Kazakhstan and exported the products, but the economics of this trade at world prices are questionable. Older capacity will probably have to be reduced, and the newer capacity should be restructured to incorporate improved upgrading.

9.5 Detailed investment studies for these projects need to be carried out, utilizing methods of economic, financial and environmental analysis widely used in the OECD energy industry. Such studies are essential to decide whether projects are justified and to mobilize external funding, and what should be the project design and timing. These studies would of course make use of the high quality technical data which is available from the energy sector in Azerbaijan. Staff from the energy enterprises and institutes in Azerbaijan should be involved in these studies, and should be trained in the methods used.

9.6 The study and implementation of investment projects should be accompanied by the strengthening of energy institutions and reform of energy policies. Only through the introduction of a full range of appropriate policy measures will the benefits of energy sector investments be fully realized.

9.7 Total investment requirements for the various sub-sectors are summarized below (additional details are in Annex 1). These figures also show investments for projects which will be undertaken wholly or largely by the foreign oil companies, including in particular the new offshore field developments, which are the largest element of total investment. The Guneshli gas capture project is also being funded by foreign oil companies. In most other areas, some funding from international financial institutions may be required. In the case of the older oil fields and refinery rehabilitation, investment is likely to come mostly from the international oil companies, although multilateral assistance may be needed to mobilize funding in rapidly in a risky environment, and to address environmental and social issues. It should be stressed that these figures are very preliminary estimates only, and are likely to be substantially revised in the course of the recommended investment studies.

Table 9.1: Azerbaijan Energy Sector Investment Financing Requirements
(US $ Million)

	TOTAL	"Short Term" 1993-1994	"Medium Term" 1995-1996	"Long Term" 1997-2002
Mature field rehab. (On/Offshore)	690	30	150	510
Offshore field development	6,970	310	1,530	5,130
Crude oil export pipeline	1,800	0	1,150	650
Offshore common infrastructure	1,600	0	650	950
Total Upstream Petroleum	11,060	340	3,480	7,240
Total Refining	135	0	20	115
Guneshli Field Gas Capture Project	100	100		
System rehabilitation/metering	850	0	250	600
Total Natural Gas	950	100	250	600
Generation/System Upgrading and Rehab.	640	40	50	550
District Heating Upgrading and Rehab.	70	5	15	50
Total Electricity/District Heating	710	45	65	600
TOTAL INVESTMENT	12,855	485	3,815	8,555

Source: Mission estimates.

Energy Sector Technical Assistance Strategy

9.8 In order to address the problems of Azerbaijan's energy sector in a comprehensive and practical manner, and to prepare investment projects for international financing, a program of technical assistance to the energy sector should incorporate the following types of work:

- **Energy Policy Studies:** to decide on the general directions of the Government's energy policies;

- **Investment Studies:** to assess the priority projects in each energy sub-sector using appropriate economic, financial and environmental analysis, and to develop a scheme to implement these projects;

- **Institutional Strengthening:** to improve the organization, management, and financial and information systems of the energy enterprises and government institutions;

- **Advisory Services:** to provide the Government and the enterprises with advisors for their dealings with foreign investors in the energy sector;

- **Training:** to train staff of the government and enterprises in economic, financial, managerial, technical and environmental aspects of the energy sector.

9.9 A set of technical assistance components covering all these areas is shown in Annex 1. It would clearly be desirable if the management and programming of technical assistance in this area could take place within an integrated framework. Coordination of technical assistance to the energy sector is one of the areas which should be handled by a strengthened central body for energy (eg. Energy Commission) as is recommended to be established in Chapter 7. The funding of technical assistance on the required scale may involve borrowing, since grant funds may not be forthcoming on the necessary scale. This is particularly the case for the petroleum sub-sector, where rapid mobilization of advisors for negotiations, together with staff training and investment studies, are needed to mobilize large-scale foreign investment. The World Bank has discussed an integrated energy technical assistance project with the Government and enterprises in Azerbaijan which could provide the required financing.

9.10 It should be stressed that in the case of Azerbaijan, technical assistance in energy will lead to concrete financial benefits in terms of foreign exchange revenues, which helps to justify any borrowing which may be required. For example, reduction of gas venting and losses to OECD levels and improvements in gas usage could save about $250 million per year in gas imports, while accelerating the development of the offshore oil fields by one year could bring forward additional Government revenues of over US$ 1.0 billion before the year 2000. The benefits of accelerating investment through a comprehensive technical assistance program in energy will thus be clearly visible in improved economic and financial performance in the years ahead.

AZERBAIJAN

ENERGY SECTOR REVIEW

ANNEXES

Azerbaijan Energy Sector Investment Financing Requirements

Annex 1.1

(US$ MILLION)

	TOTAL COST	"Short Term" 1993-1994	"Med. Term" 1995-1996	"Long Term" 1997-2002
Upstream Petroleum				
Mature field rehabilitation (On/Offshore)	690	30	150	510
Offshore field development	6,970	310	1,530	5,130
Crude oil export pipeline	1,800	0	1,150	650
Offshore common infrastructure	1,600	0	650	950
Subtotal Upstream Petroleum	11,060	340	3,480	7,240
Petroleum Refining & Products Distribution				
Efficiency & Process Control Improvement	20	0	5	15
Pollution Control Systems Improvement	5	0	0	5
Lube Oil Section Modernization (Azneftyag)	40	0	5	35
Other Upgrading & New Units	70	0	10	60
Subtotal Refining	135	0	20	115
Natural Gas and Gas Processing				
Guneshli Field Gas Capture Project	100	100	0	0
Processing System Upgrade/Expansion	300	0	100	200
Pipeline system rehabilitation	450	0	100	350
Gas meter procurement	100	0	50	50
Subtotal Natural Gas	950	100	250	600
Electricity				
Generation/Transmission/Distribution Upgrade	640	40	50	550
District Heating Upgrade and Rehabilitation	70	5	15	50
Subtotal Electricity/District Heating	710	45	65	600
TOTAL INVESTMENT	12,855	485	3,815	8,555

AZERBAIJAN ENERGY SECTOR TECHNICAL ASSISTANCE
Summary Priority Components

1. Energy Policy Development

- Energy Pricing and Taxation Strategy

  To assess the economic level of prices and taxation for energy products, and recommend a policy for price adjustment. (US$450,000)

2. Petroleum

- Contractual and Financial Advisory Services for Petroleum Negotiations

  Hiring of advisors by SOCAR to provide legal, economic and financial advice for negotiations with foreign petroleum companies and other entities for exploration and development and for the export pipeline. (US$9.9 million).

- Oil Export Pipeline and Infrastructure Engineering Studies

  Detailed engineering design of oil export pipeline, including preparation of bid documents (SOCAR share of costs). (US$3.2 million).

- Advice on Organization and Management

  Analysis and recommendations to SOCAR on organizational changes to adapt to the growth of the oil industry, and related advice on management and personnel management policies. (US$300,000).

- Advice on Business Unit Structure, Budgeting and Performance Reporting

  To put in place a business unit structure clarifying management accountability, with an associated system of budgeting and performance measures. (US$600,000).

- Upgrading of Financial Systems

  Development and installation of modern financial systems in SOCAR. (US$2.0 million).

- Management Information System Development

  To design, purchase and install modern computer and management information systems. (US$3.0 million)

- Rehabilitation of the Old Onshore Oil Fields

  Studies of older onshore and offshore oil fields to assess economics, and best methods of extracting remaining oil and attracting private investment for joint ventures (to be done with SOCAR staff). Study of environmental improvements in fields. (US$1.0 million)

- Oil Rocks Offshore Field Rationalization/Rehabilitation Study

  Study of the Oil Rocks field to assess current economics of production and options for future extraction of remaining reserves. (US$700,000).

- Licensing and Investment Promotion

  Development of licensing framework for offshore and onshore fields and preparation of data packages, training and promotion. (US$800,000)

- Petroleum Refining and Products Marketing Study

  Detailed techno-economic study of refineries in Azerbaijan to recommend investment and rationalization options (including training and development of management systems), review of petroleum distribution and marketing. (US$800,000).

- Gas Processing Plant Reconstruction Study

  Detailed assessment of investment requirements for reconstruciton of SOCAR gas processing plant. (US$500,000)

- Training of SOCAR Staff

  Training of SOCAR staff in commercial, legal, technical areas of the petroleum industry, according to international practice. (US$1.0 million).

3. Natural Gas

- Gas Transmission and Distribution System Reconstruction and Metering Study and Project Preparation

  Assessment of investment priorities for rehabilitation of gas networks to reduce losses and preparation of detailed investment plan. (US$800,000).

- Development of Legal and Regulatory Framework for Natural Gas

  Drafting of legal statutes governing natural gas transmission and distribution and assistance in putting in place appropriate gas industry regulation. (US$400,000).

- Azerigaz Business Unit Structure, Budgeting and Performance Reporting

  To put in place a business unit structure clarifying management accountability, with an associated system of budgeting and performance measures. (US$600,000).

- Azerigaz Short Term Management Information System

  Installation of system to improve provision of management information, and of enterprise performance measures. (US$800,000).

- Azerigaz Improvement of Accounting Procedures, Systems and Controls

  Development and installation of modern financial systems. (US$2.0 million).

- Natural Gas Development Strategy

  Development of a long term strategy for gas supply and usage within the country, especially as concerns gas trade and training of staff in gas business planning and practices. (US$500,000).

4. Electricity and District Heating

- Azenergo Least Cost Power Investment Plan, 1993 - 2010

  Detailed assessment of power demand and investment options using economic/technical least cost analysis, preparation of detailed investment plan. (US$600,000).

- Development of Power Sector Regulatory Framework

  Review of power sector organization, drafting of appropriate legal statutes and assistance in putting in place appropriate regulation. (US$400,000).

- Azenergo Business Unit Structure, Budgeting and Performance Reporting

  To put in place a business unit structure clarifying management accountability, with an associated system of budgeting and performance measures. (US$600,000).

- Azenergo Short Term Management Information System

  Installation of system to improve provision of management information, and of enterprise performance measures. (US$800,000).

- Azenergo Improvement of Accounting Procedures, Systems and Controls

  Development and installation of modern financial systems. (US$2.0 million).

- District Heating Investment Strategy

  Investment plan for district heating rehabilitation and restructuring. (US$400,000).

5. Petroleum Equipment

- Petroleum Equipment Industry Strategy

  Development of a business strategy for Azneftekhimmash, including an investment program, implementation of joint ventures, marketing and training. (US$1.0 million).

Azerbaijan Energy Trade

IMPORTS

	1991				1992			
	CIS		NON-CIS		CIS		NON-CIS	
	VOL TONNES	VAL TH RUB	VOL TONNES	VAL TH RUB	VOL TONNES	VAL TH RUB	VOL TONNES	VAL TH RUB
Crude Oil	4301346	317687	0	0	1355101	2664246	0	0
AvGas	0	0	0	0	100	886	0	0
MoGas	194	39	0	0	279	19050	0	0
MoDiesel	504	73	0	0	157	489	0	0
JetKero	457	82	0	0	12188	50483	0	0
Mazut	0	0	0	0	0	0	0	0
Bunker FO	0	0	0	0	0	0	0	0
Diesel Lubes	1594	1626	1950	3023	0	25071	1738	103518
Bitumen	0	0	0	0	0	0	0	0
Additives	9728	8644	0	0	4462	225492	485	271353
Other	0	56799	0	126027	0	0	0	112222
TOTAL OIL PRODS.		67263		129051		321471		487093
Nat. Gas (MCM)	11163	368377	3000	126000	2764	3262261	0	0
LPG	99216	19604	0	0	17667	11049	0	0
Electr. THKWH	0	0	0	0	0	0	0	0
Coal	101437	5065	0	0	10629	6383	0	0
TOTAL ENERGY		3124555		255051		3601164		487093

EXPORTS

	1991				1992			
	CIS		NON-CIS		CIS		NON-CIS	
	VOL TONNES	VAL TH RUB	VOL TONNES	VAL TH RUB	VOL TONNES	VAL TH RUB	VOL TONNES	VAL TH RUB
Crude Oil	0	0	0	0	0	0	1056055	15043692
AvGas	53366	12742	0	0	7848	85393	18109	349588
MoGas	12973	4367	0	0	140320	1428649	13915	257394
MoDiesel	1046806	217207	1232147	148100	703137	8339502	2057502	48873094
JetKero	746909	162959	0	0	137221	1652608	56726	1422309
Mazut	1855071	221458	442263	30156	97096	743782	260232	3886537
Bunker FO	6534	653	0	0	0	0	0	0
Diesel Lubes	338369	221537	0	0	113098	1675284	0	0
Bitumen	7696	1097	0	0	6899	43444	0	0
Additives	3346	3518	0	0	1217	72213	50689	1219977
Other	0	156838	0	21944		626430		714198
TOTAL OIL PRODS.		1002375		200200		14667305		56523096
Nat. Gas (MCM)	4356	156838	0	0	121	24100	0	0
LPG	0	0	0	0	0	0	0	0
Electr. THKWH	1703	115837	0	0	631000	2957412	0	0
Coal	0	0	0	0	0	0	0	0
TOTAL ENERGY		1275050		15243892		17648817		56523096

ENERGY BALANCE FOR AZERBAIJAN, 1990
(Thousand tons of oil equivalent)

	Coal	*Crude Oil**	*Petroleum Products*	*Natural Gas*	*Hydro/ Geo*	*Electricity*	*Heat*	*TOTAL*
Production	...	12,576	...	8,934	143	...	...	21,653
Imports	79	4,559	246	12,098	...	151	...	17,133
Exports	...	...	(7,771)	(4,882)	...	(289)	...	(12,942)
Stock Change	0	(140)	...	(89)	...	...	...	(229)
TPES	79	16,995	(7,525)	16,061	143	(138)	...	25,615
Public Electricity	...	...	(2,813)	(4,095)	(143)	1,991	...	(5,060)
Petroleum Refineries	...	(16,855)	15,526	...	...	...	...	(1,329)
CHP Plants	(4)	...	(68)	(1,061)	...	...	2,140	1,007
Losses	...	(140)	...	(822)	...			(962)
Statistical Differences	(36)	(95)	(1,410)	(1,082)	...	(267)	(61)	(2,951)
FINAL CONSUMPTION	38	...	3,710	9,001	...	1,586	2,079	16,320
INDUSTRY	3	...	414	2,391	...	841	1,541	5,190
Power	...	...	...	11	...	129	...	140
Fuel	...	...	78	1,173	...	203	345	1,799
Iron and Steel	...	...	67	139	...	10	15	231
Non-ferrous Metals	...	...	15	59	...	103	174	351
Chemical	...	...	20	260	...	115	691	1,087
Engineering	...	...	7	66	...	34	82	189
Construction (inc.materials)	1	...	217	559	...	96	52	925
Other	...	...	10	124	...	151	179	464
TRANSPORTATION	...	...	2,139	311	...	69	6	2,525
Rail	...	...	25	...	...	45	6	76
Water	...	...	133	...	...	...	...	133
Motor Vehicles	...	...	1,981	1	...	8	...	1,990
Pipeline transmission	...	...	...	310	...	16	...	326
AGRICULTURE	0	...	559	91	...	184	14	848
COMM. & PUBLIC SERVICES	4	...	323	3,205	...	270	262	4,064
RESIDENTIAL	24	...	192	2,276	...	92	238	2,822
NON-SPECIFIED OTHER	2	...	83	727	...	130	18	960

Source: Fuel-Energy Balance, 1990, Government of Azerbaijan.

TPES = Total Primary Energy Supply.

*Including condensates.

AZERBAIJAN ENERGY TRADE

BASE CASE

		1992		1993		1994		1995		1996		1997		1998		1999		2000		2005	
		ORIG.	'000$ 1)	ORIG.	'000$ 1)	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$
IMPORTS																					
Crude Oil	'000T	1350	91159	1000	67525	1000	135050	1000	135050	0	0	0	0	0	0	0	0	0	0	0	0
Gasoline	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Diesel	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Mazut	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Other Prode	'000T	25	1500	25	1500	25	3000	25	3000	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	MMCM	5263	184205	4250	148750	9003	630224	8037	562618	8228	575939	8831	618170	9143	640024	9216	645120	10461	732235	9179	642495
LPG	'000T	20	1500	20	1500	20	3000	20	3000	20	3000	0	0	0	0	0	0	0	0	0	0
Coal	'000T	15	375	15	375	15	750	15	750	15	750	15	750	15	750	15	750	15	750	15	750
Electricity	MMkwh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL			278739		219650		772024		704418		579689		618920		640774		645870		732985		643245

		1992		1993		1994		1995		1996		1997		1998		1999		2000		2005	
		ORIG.	'000$ 1)	ORIG.	'000$ 1)	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$	ORIG.	'000$
EXPORTS																					
Crude Oil	'000T	1050	70441	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Gasoline	'000T	70	6606	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Diesel	'000T	2000	165500	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Mazut	'000T	320	10720	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Other Prode	'000T	515	30900	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
(Total Oil)	'000T	3955	284168	3061	205347	6016	807231	5719	767341	5094	683523	7229	969971	12050	1616650	14843	1991545	20809	2792040	39702	5326978
Natural Gas	MMCM	951	33285	100	3500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LPG	'000T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	'000T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electricity	MMkwh	660	13200	660	13200	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400
TOTAL			330653		222047		833631		793741		709923		996371		1643250		2017945		2818440		5353378
BALANCE			51914		2397		61607		89323		130234		377451		1002476		1372075		2085455		4710131

1) 1992 AND 1993 TRADE VALUED AT 50% OF WORLD PRICE.

AZERBAIJAN ENERGY TRADE

DELAY CASE

IMPORTS		1992 ORIG.	1992 '000$ 1)	1993 ORIG.	1993 '000$ 1)	1994 ORIG.	1994 '000$	1995 ORIG.	1995 '000$	1996 ORIG.	1996 '000$	1997 ORIG.	1997 '000$	1998 ORIG.	1998 '000$	1999 ORIG.	1999 '000$	2000 ORIG.	2000 '000$	2005 ORIG.	2005 '000$
Crude Oil	'000T	1350	91159	1000	67525	1000	135050	1000	135050	0	0	0	0	0	0	0	0	0	0	0	0
Gasoline	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Diesel	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Mazut	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Other Prods	'000T	25	1500	25	1500	25	3000	25	3000	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	MMCM	5263	184205	4250	148750	9087	636055	9636	674527	10035	702429	8831	618170	9362	655354	9727	680890	11336	793541	10647	745304
LPG	'000T	20	1500	20	1500	20	3000	20	3000	20	3000	0	0	0	0	0	0	0	0	0	0
Coal	'000T	15	375	15	375	15	750	15	750	15	750	15	750	15	750	15	750	15	750	15	750
Electricity	MMkwh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL			278739		219650		777855		816327		706179		618920		656104		681640		794291		746054

EXPORTS		1992 ORIG.	1992 '000$ 1)	1993 ORIG.	1993 '000$ 1)	1994 ORIG.	1994 '000$	1995 ORIG.	1995 '000$	1996 ORIG.	1996 '000$	1997 ORIG.	1997 '000$	1998 ORIG.	1998 '000$	1999 ORIG.	1999 '000$	2000 ORIG.	2000 '000$	2005 ORIG.	2005 '000$
Crude Oil	'000T	1050	70441	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Gasoline	'000T	70	6608	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Diesel	'000T	2000	165500	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Mazut	'000T	320	10720	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Other Prods	'000T	515	30900	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
(Total Oil)	'000T	3955	284168	3060	205253	5728	768495	5140	689628	3797	509512	4168	559251	6604	886139	9048	1213993	12599	1690472	33783	4532827
Natural Gas	MMCM	951	33285	100	3500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LPG	'000T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	'000T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electricity	MMkwh	660	13200	660	13200	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400
TOTAL			330653		221953		794895		716028		535912		585651		912539		1240393		1716872		4559227
BALANCE			51914		2303		17040		-100299		-170267		-33269		256435		5[illegible]3753		922581		3813173

1) 1992 AND 1993 TRADE VALUED AT 50% OF WORLD PRICE.

AZERBAIJAN ENERGY TRADE

LOW CASE

IMPORTS		1992 ORIG.	'000$ 1)	1993 ORIG.	'000$ 1)	1994 ORIG.	'000$	1995 ORIG.	'000$	1996 ORIG.	'000$	1997 ORIG.	'000$	1998 ORIG.	'000$	1999 ORIG.	'000$	2000 ORIG.	'000$	2005 ORIG.	'000$
Crude Oil	'000T	1350	90075	1000	66722	1000	133444	1000	133444	0	0	0	0	0	0	0	0	0	0	0	0
Gasoline	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Diesel	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Mazut	'000T	0	0	na	0	na	0	na	0	na	0	0	0	0	0	0	0	0	0	0	0
Other Prods	'000T	25	1500	25	1500	25	3000	25	3000	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	MMCM	5263	184205	4250	148750	9003	630224	8037	562618	8228	575939	9228	645792	9769	683823	9898	692839	11404	798245	11361	795270
LPG	'000T	20	1500	20	1500	20	3000	20	3000	20	3000	0	0	0	0	0	0	0	0	0	0
Coal	'000T	15	375	15	375	15	750	15	750	15	750	15	750	15	750	15	750	15	750	15	750
Electricity	MMkwh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL			277655		218847		770418		702812		579689		646542		684573		693589		798995		796020

EXPORTS		1992 ORIG.	'000$ 1)	1993 ORIG.	'000$ 1)	1994 ORIG.	'000$	1995 ORIG.	'000$	1996 ORIG.	'000$	1997 ORIG.	'000$	1998 ORIG.	'000$	1999 ORIG.	'000$	2000 ORIG.	'000$	2005 ORIG.	'000$
Crude Oil	'000T	1050	70058	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Gasoline	'000T	70	6606	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Diesel	'000T	2000	165500	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Mazut	'000T	320	10720	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
Other Prods	'000T	515	30900	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0	na	0
(Total Oil)	'000T	3955	283784	3061	204203	6016	802786	5720	763286	5095	679911	5054	674399	6407	854989	8064	1076039	12196	1627710	25015	3338048
Natural Gas	MMCM	951	33285	100	3500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LPG	'000T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	'000T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electricity	MMkwh	660	13200	660	13200	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400	660	26400
TOTAL			330269		220903		829186		789686		706311		700799		881389		1102439		1654110		3364448
BALANCE			52615		2056		58768		86874		126622		54257		196816		408850		855115		2568428

1) 1992 AND 1993 TRADE VALUED AT 50% OF WORLD PRICE.

AZERBAIJAN OIL AND GAS FIELDS

OIL PRODUCTION ('000 tons)	1975	1980	1985	1990	1991	GAS PRODUCTION (million cubic meters) 1975	1980	1985	1990	1991
Balakhany	1140	987	761	464	401					
Kyurovdag	929	726	441	325	280					
Bibi-Eybat	532	416	368	227	208					
Kyursangya	399	297	261	178	160					
Mishovdag	306	359	326	214	177					
Surakhany	405	306	251	174	153					
Other	2130	1962	1501	1000	870					
Onshore Total	5841	5053	3909	2582	2249	1572	1227	714	400	288
Oil Rocks			2078	1076	779			116	63	58
Sangachaly-Bulla			1830	784	771			1908	818	764
Bakhar			736	386	310			6565	4850	4221
Guneshli			3106	6563	6701			239	587	355
Other			1483	1122	932			4525	3207	2935
Offshore Total	11328	9600	9233	9931	9493	8318	12777	13353	9525	8333

Azerbaijan Petroleum Production and Investment Projections

SOCAR CARRIED

(Production in thousand barrels per day)

*** BASE CASE ***

ASSUMPTIONS	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
FOB Oil Price ($/bbl)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Pipeline Tariff ($/bbl)	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Border Oil Price ($/bbl)	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38	18.38
Baku Oil Price ($/bbl)	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50	17.50
Infrast. Tariff ($/bbl)	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
Wlhead Oil Price ($/bbl)	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40	16.40
Natural Gas Price ($/mcf)	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
Interest Rate 10.00%																			

OIL PRODUCTION (Th. bpd)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	40.2	36.2	32.5	29.3	26.4	23.7	21.4	19.2	17.3	15.6	14.0	12.6	11.3	10.2	9.2	8.3	7.4	6.7	6.0
Onshore-New	0.0	0.0	0.0	2.0	5.0	10.0	20.0	30.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Offshore-Existing	51.4	46.8	42.6	38.7	35.2	32.1	29.2	26.6	24.2	22.0	20.0	18.2	16.6	15.1	13.7	12.5	11.4	10.3	9.4
Guneshli	130.1	123.6	123.6	124.0	139.8	192.0	247.2	256.4	263.3	267.7	271.2	271.2	244.4	218.1	192.6	164.1	137.3	113.2	92.1
Chirag	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.0	66.1	133.8	203.3	253.1	287.8	291.8	272.2	255.4	232.4
Azeri	0.0	0.0	0.0	0.0	0.0	0.0	35.0	82.6	167.3	254.1	316.4	359.8	364.7	340.2	319.2	290.5	263.2	238.0	216.3
Kapaz	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6	13.2	26.8	40.7	50.6	57.6	58.4	54.4
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	221.7	206.5	198.7	194.0	206.4	257.8	352.7	414.8	512.1	627.4	727.7	841.3	893.5	903.5	903.2	857.7	789.0	722.0	650.7

OIL PROD. GOV. (Th. bpd)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore-New	0.0	0.0	0.0	0.8	2.0	4.0	8.0	11.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9
Offshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guneshli	130.1	123.6	106.6	101.1	96.7	106.0	117.4	128.3	176.6	191.0	200.6	206.1	184.8	163.1	142.1	118.5	103.4	83.2	65.7
Chirag	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	13.8	28.8	44.6	55.8	71.6	147.9	145.8	137.9	125.5
Azeri	0.0	0.0	0.0	0.0	0.0	0.0	6.0	15.9	33.0	51.1	63.9	82.1	169.5	167.0	158.1	143.8	129.4	116.1	106.1
Kapaz	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.8	5.8	8.9	11.2	14.3	29.6	29.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	130.1	123.6	106.6	101.9	98.6	110.0	131.3	156.1	225.5	263.3	294.3	334.0	417.6	407.6	396.6	437.4	408.8	382.8	342.4

OIL PROD. SOCAR (Th. bpd)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	40.2	36.2	32.5	29.3	26.4	23.7	21.4	19.2	17.3	15.6	14.0	12.6	11.3	10.2	9.2	8.3	7.4	6.7	6.0
Onshore-New	0.0	0.0	0.0	0.7	1.8	3.7	7.3	11.0	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Offshore-Existing	51.4	46.8	42.6	38.7	35.2	32.1	29.2	26.6	24.2	22.0	20.0	18.2	16.6	15.1	13.7	12.5	11.4	10.3	9.4
Guneshli	0.0	0.0	0.1	0.6	1.0	2.6	4.3	5.8	10.6	12.4	13.7	14.6	13.1	11.5	9.9	8.1	7.0	5.4	4.1
Chirag	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	4.6	9.6	14.9	18.6	23.9	49.3	48.6	46.0	41.8
Azeri	0.0	0.0	0.0	0.0	0.0	0.0	2.5	6.5	13.5	20.9	26.2	33.6	69.3	68.3	64.7	58.8	52.9	47.5	43.4
Kapaz	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.9	1.9	3.0	3.7	4.8	9.9	9.7
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	91.6	82.9	75.2	69.3	64.4	62.0	64.5	69.0	80.2	87.2	93.1	103.5	140.7	140.2	138.9	155.3	146.7	140.4	129.1

OIL PROD. CO. (Th. bpd)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore-New	0.0	0.0	0.0	0.9	2.3	4.5	9.0	13.6	15.1	9.8	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Offshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guneshli	0.0	0.0	16.9	22.3	42.2	83.4	125.6	122.3	76.1	64.3	56.9	50.5	46.5	43.5	40.6	37.5	26.9	24.5	22.4
Chirag	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.0	47.6	95.4	143.8	178.7	192.4	94.5	77.8	71.4	65.0
Azeri	0.0	0.0	0.0	0.0	0.0	0.0	26.6	60.3	120.8	182.1	226.3	244.2	125.8	104.8	96.5	87.8	80.9	74.4	68.8
Kapaz	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.2	9.5	19.1	28.8	35.7	38.5	18.9	15.6
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.0	0.0	16.9	23.2	44.4	88.0	161.2	196.1	212.0	277.2	340.1	403.4	334.9	355.3	367.4	264.7	233.2	198.5	178.9

GAS PRODUCTION (mmcfd)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	23.4	21.0	18.9	17.0	15.3	13.8	12.4	11.2	10.1	9.1	8.2	7.3	6.6	5.9	5.3	4.8	4.3	3.9	3.5
Onshore-New	0.0	0.0	0.0	1.2	2.9	5.8	11.6	17.5	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3
Offshore-Existing	703.9	633.6	570.2	513.2	461.9	415.7	374.1	336.7	303.0	272.7	245.5	220.9	198.8	178.9	161.0	144.9	130.4	117.4	105.7
Guneshli	169.7	161.2	161.2	161.8	182.4	156.6	130.1	115.4	122.1	115.0	99.8	82.4	65.9	48.1	31.9	22.8	10.8	1.1	0.0
Chirag	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.9	39.5	84.7	132.7	192.0	234.4	254.2	251.3	234.4	209.0
Azeri	0.0	0.0	0.0	0.0	0.0	0.0	21.2	49.4	105.9	165.9	240.0	293.0	317.7	314.2	293.0	261.2	222.4	180.0	137.7
Kapaz	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.4	7.9	16.9	26.5	38.4	46.9	50.8	50.3
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	897.1	815.8	750.4	693.2	662.5	591.9	549.4	530.2	564.4	602.9	656.3	715.0	752.9	779.4	775.5	749.6	689.5	610.9	529.4

INVESTMENT (US$ mn)		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	$185	5.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Onshore-New	$630	0.0	0.0	10.0	20.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Offshore-Existing	$665	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Guneshli	$2,077	0.0	0.0	215.3	288.5	295.8	283.0	270.8	241.9	165.3	107.6	63.8	26.1	19.4	18.6	17.8	17.0	16.3	15.6	14.9
Chirag	$2,496	0.0	0.0	0.0	0.0	0.0	22.4	269.2	494.1	476.9	219.1	259.1	237.2	154.4	150.1	83.9	58.8	35.6	22.5	14.4
Azeri	$3,158	0.0	0.0	28.0	336.5	617.7	596.1	273.9	323.9	296.5	193.0	187.8	104.9	73.5	44.5	28.2	18.0	18.0	18.0	0.0
Kapaz	$432	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	53.8	98.8	95.4	43.8	51.8	47.4	30.9	30.0	16.8	11.8	7.1
Other	$0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline	$1,764	0.0	0.0	0.0	112.5	1025.9	625.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Infrastructure	$1,606	0.0	0.0	0.0	321.2	321.2	321.2	321.2	321.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL ($bn)	$13.08	40.0	45.0	298.3	1123.7	2345.5	1933.4	1220.1	1470.6	1077.6	703.5	690.6	497.1	384.1	345.6	245.8	208.8	171.7	152.9	121.4
Cum. Inv. Total		40.0	85.0	383.3	1507.0	3852.5	5785.9	7006.0	8476.6	9554.2	10257.8	10948.4	11445.5	11829.6	12175.2	12420.9	12629.7	12801.4	12954.3	13075.7
Cum. Inv. New Offshore		0.0	0.0	243.3	980.8	2920.1	4447.3	5261.2	6325.6	7318.2	7936.8	8542.4	8954.5	9253.6	9514.2	9674.9	9798.7	9885.4	9953.3	9989.7

INV. SOCAR (US$ mn)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	5.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Onshore-New	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Offshore-Existing	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Guneshli	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chirag	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Azeri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kapaz	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline	0.0	0.0	0.0	28.1	256.5	156.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Infrastructure	0.0	0.0	0.0	160.6	160.6	160.6	160.6	160.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	40.0	45.0	45.0	73.1	301.5	201.4	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0

INV. COS. (US$ mn)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore-New	0.0	0.0	10.0	20.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Offshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guneshli	0.0	0.0	285.3	288.5	295.8	283.0	270.8	241.9	165.3	107.6	63.6	26.1	19.4	18.6	17.8	17.0	16.3	15.6	14.9
Chirag	0.0	0.0	0.0	0.0	0.0	22.4	269.2	494.1	476.9	219.1	259.1	237.2	154.4	150.1	83.9	58.8	35.6	22.5	14.4
Azeri	0.0	0.0	28.0	336.5	617.7	596.1	273.9	323.9	296.5	193.0	187.6	104.9	73.5	44.5	28.2	18.0	18.0	18.0	0.0
Kapaz	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	53.8	98.8	95.4	43.8	51.8	47.4	30.9	30.0	16.8	11.8	7.1
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline	0.0	0.0	0.0	84.4	769.4	469.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Infrastructure	0.0	0.0	0.0	160.6	160.6	160.6	160.6	160.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	0.0	0.0	323.3	729.3	1722.9	1410.8	853.9	1104.4	1032.6	658.5	645.6	452.1	339.1	300.6	200.8	163.8	126.7	107.9	76.4

NET REV. SOCAR (US$ mn)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	257.6	225.4	200.8	178.8	158.9	141.0	124.9	110.4	97.4	85.6	75.1	65.6	57.0	49.3	42.4	36.1	30.5	25.5	20.9
Onshore-New	0.0	0.0	0.0	0.2	0.5	1.1	2.1	3.2	4.8	5.8	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Offshore-Existing	760.1	682.4	612.1	548.6	491.2	439.4	392.5	350.1	311.8	277.1	245.8	217.5	191.9	168.8	147.9	129.0	111.9	96.4	82.4
Guneshli	0.0	0.0	5.9	8.6	9.7	18.6	28.1	37.8	68.8	79.6	86.8	91.5	81.5	71.1	60.9	49.6	42.4	32.6	24.4
Chirag	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	29.8	62.1	96.2	121.9	157.3	327.1	324.4	306.8	278.8
Azeri	0.0	0.0	0.0	0.0	0.0	0.0	16.0	41.9	87.4	135.3	171.4	221.3	460.0	456.1	431.5	392.1	350.7	311.6	281.0
Kapaz	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	6.0	12.4	19.2	24.4	31.5	65.4	64.9
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline	0.0	0.0	0.0	-28.1	-256.5	-156.4	32.3	39.8	55.8	70.3	82.6	96.7	106.4	106.5	106.5	100.4	91.2	82.2	72.6
Infrastructure	0.0	0.0	0.0	-160.6	-160.6	-122.8	-110.3	-104.2	70.5	95.2	117.2	141.8	153.6	156.7	157.1	148.0	133.6	119.1	103.6
TOTAL	1017.7	907.7	818.9	708.1	403.9	443.6	595.9	583.2	626.0	665.2	697.5	762.9	1005.0	992.1	971.7	1064.6	988.5	926.5	831.0

NET REV. COS. (US$ mn)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Onshore-New	0.0	0.0	-10.0	-14.7	-26.6	-13.3	13.5	40.2	46.6	10.0	6.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Offshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guneshli	0.0	0.0	-234.8	-215.0	-91.9	107.9	320.3	318.1	96.9	82.4	87.1	91.5	81.5	71.1	60.9	49.6	42.4	32.6	24.4
Chirag	-30.0	0.0	-60.0	0.0	0.0	-22.4	-269.2	-494.1	-476.9	-122.5	-6.0	291.0	663.6	885.8	1033.1	414.7	333.1	307.7	278.9
Azeri	0.0	0.0	-78.0	-336.5	-617.7	-596.1	-151.4	-2.8	373.5	844.6	1126.3	1315.9	569.5	467.1	432.6	392.2	350.7	311.6	281.0
Kapaz	0.0	0.0	0.0	-20.0	0.0	0.0	0.0	-4.5	-53.8	-98.8	-95.4	-24.5	-1.2	58.2	132.7	177.2	206.6	82.9	66.6
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline	0.0	0.0	0.0	-84.4	-769.4	-469.3	97.0	119.5	167.5	210.8	247.9	290.2	319.2	319.5	319.4	301.1	273.5	246.5	217.8
Infrastructure	0.0	0.0	0.0	-160.6	-160.6	-122.8	-110.3	-104.2	70.5	95.2	117.2	141.8	153.6	156.7	157.1	148.0	133.6	119.1	103.6
TOTAL	-30.0	0.0	-382.8	-831.2	-1666.2	-1115.9	-100.2	-127.8	224.1	1021.6	1483.5	2111.9	1792.2	1964.4	2141.9	1488.7	1345.9	1106.4	978.3

NET REV. GOV. (US$ mn)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Onshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	-0.0
Onshore-New	0.0	0.0	0.0	7.3	18.2	36.4	72.8	109.2	165.4	201.0	204.5	204.9	204.9	204.9	204.9	204.9	204.9	204.9	204.9
Offshore-Existing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	0.0	0.0
Guneshli	0.0	20.0	117.3	97.9	110.0	211.0	319.0	428.5	780.3	902.4	984.1	1036.4	923.9	805.8	690.5	562.1	480.5	368.9	276.1
Chirag	30.0	0.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	34.1	89.3	186.4	288.7	365.6	472.0	981.3	973.1	920.5	336.4
Azeri	0.0	0.0	50.0	0.0	0.0	0.0	39.0	102.4	213.6	330.8	418.9	540.9	1124.4	1115.0	1054.8	958.4	857.4	761.7	686.9
Kapaz	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.8	17.9	37.3	57.7	73.1	94.4	196.3	194.6
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pipeline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Infrastructure	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	30.0	20.0	227.3	125.2	128.2	247.4	430.9	640.1	1159.3	1468.2	1696.9	1975.4	2559.8	2528.6	2480.0	2779.8	2610.3	2452.4	2199.0

ITEMS	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Oil Production (Th. bpd)	221.7	206.5	198.7	194.0	206.4	257.8	352.7	414.8	512.1	627.4	727.7	841.3	893.5	903.5	903.2	857.7	789.0	722.0	650.7
Oil Consumption (Th. bpd)	175.9	165.8	98.9	100.1	104.5	113.2	111.7	117.9	95.9	103.6	111.7	120.1	100.4	109.4	109.4	109.4	109.4	109.4	109.4
Oil Exports (Th. bpd)	45.8	40.7	99.8	93.9	101.9	144.6	241.0	296.9	416.2	523.7	616.0	721.2	793.1	794.0	793.8	748.3	679.6	612.5	541.2
Co. Exports (Th. bpd)	0.0	0.0	24.4	30.9	57.8	99.8	173.3	208.9	225.4	294.7	364.5	433.9	358.0	381.8	395.8	283.6	250.0	211.5	189.7
SOCAR+Gov. Exp. (Th. bpd)	45.8	40.7	75.4	63.0	44.1	44.8	67.7	88.0	190.8	229.0	251.5	287.2	435.2	412.2	398.0	464.7	429.6	401.0	351.6
Total Inv. ($mn)	40.0	45.0	298.3	1123.7	2345.5	1933.4	1220.1	1470.6	1077.6	703.5	690.6	497.1	384.1	345.6	245.8	208.8	171.7	152.9	121.4
Domest. Inv.($mn) 40%	16.0	18.0	119.3	449.5	938.2	773.4	488.0	588.2	431.1	281.4	276.3	198.8	153.6	138.2	98.3	83.5	68.7	61.1	48.6
Total Op.Cost ($mn)	25.0	25.0	134.1	143.9	167.0	250.6	360.4	396.9	462.2	520.7	557.9	614.3	640.3	653.1	659.3	645.7	575.6	555.0	532.3
Domest. Op.($mn) 50%	12.5	12.5	67.0	71.9	83.5	125.3	180.2	198.5	231.1	260.3	279.0	307.1	320.1	326.5	329.7	322.8	287.8	277.5	266.1

COS. OIL (W/head Prices)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Cost Oil (Th. bpd)	0.0	0.0	7.4	11.7	34.6	66.5	120.4	146.7	143.3	190.8	245.6	292.2	168.5	187.3	199.0	67.5	51.9	21.1	13.1
o/w Interest Oil (Th. bpd)	0.0	0.0	0.0	3.7	13.9	28.0	40.3	46.7	55.4	64.1	62.4	54.9	38.8	31.5	20.9	6.4	3.1	0.3	0.0
Profit Oil (Th. bpd)	0.0	0.0	1.0	1.5	1.7	3.3	7.7	13.8	26.9	38.8	49.1	64.0	108.5	111.5	112.8	133.5	126.1	120.7	109.4
Operating Cost Oil (Th. bpd)	0.0	0.0	16.0	17.7	21.5	30.0	45.2	48.3	55.2	65.2	69.8	77.8	80.9	83.0	84.1	82.6	72.0	69.7	67.2
Cost Oil ($mn)	0.0	0.0	44.5	69.9	207.0	398.0	720.8	878.4	857.8	1142.0	1470.1	1748.9	1008.8	1121.3	1191.1	404.3	310.6	126.2	78.3
o/w Interest Oil ($mn)	0.0	0.0	0.0	22.2	83.2	167.5	241.2	279.6	331.5	383.5	373.7	328.9	232.1	188.3	125.1	38.6	18.4	1.8	0.2
Profit Oil ($mn)	0.0	0.0	5.9	8.8	10.2	19.7	46.2	82.9	161.1	232.2	293.9	383.1	649.7	667.5	675.0	799.1	754.9	722.4	655.0
Operating Cost Oil ($mn)	0.0	0.0	95.7	106.0	128.9	179.7	270.5	288.9	330.6	390.1	417.6	465.6	484.2	496.9	503.2	494.2	431.1	417.4	402.0
Total Company Oil ($mn)	0.0	0.0	146.2	184.8	346.2	597.4	1037.5	1250.2	1349.4	1764.3	2181.6	2597.6	2142.8	2285.7	2369.3	1697.6	1496.7	1266.1	1135.3

OIL EXP. (Border Prices)	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Cost Oil ($mn)	0.0	0.0	49.9	78.3	232.0	445.9	807.6	984.2	961.1	1279.6	1647.2	1959.5	1130.3	1256.3	1334.5	452.9	348.0	141.4	87.7
o/w Interest Oil ($mn)	0.0	0.0	0.0	24.9	93.2	187.7	270.2	313.3	371.4	429.7	418.7	368.5	260.0	211.0	140.2	43.2	20.6	2.1	0.2
Profit Oil ($mn)	0.0	0.0	6.7	9.9	11.5	22.0	51.8	92.8	180.5	260.1	329.3	429.2	727.9	747.9	756.3	895.3	845.9	809.4	733.9
Operating Cost Oil ($mn)	0.0	0.0	107.2	118.8	144.4	201.4	303.1	323.7	370.4	437.0	467.9	521.7	542.6	556.8	563.8	553.7	483.1	467.7	450.4
Total Company Oil ($mn)	0.0	0.0	163.8	207.1	387.8	669.4	1162.5	1400.8	1511.9	1976.7	2444.4	2910.4	2400.8	2561.0	2654.6	1902.0	1676.9	1418.6	1272.0
SOCAR+Gov ($mn)	307.1	273.0	505.7	422.7	295.6	300.4	454.0	590.3	1279.4	1535.8	1687.0	1926.3	2918.7	2764.6	2669.2	3116.8	2881.1	2689.5	2358.0

AZERBAIJAN - OIL SUPPLY/DEMAND BALANCE

BASE CASE

Thousand Tons

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	12513	11742	11084	10327	9936	9700	10320	12889	17636	20738	25603	31368	36385	42063	44676	45174
- Onshore	2582	2249	2009	1808	1627	1564	1568	1686	2068	2461	2865	2778	2700	2630	2567	2511
- Offshore	9931	9493	9075	8519	8308	8136	8752	11203	15569	18277	22738	28589	33684	39432	42108	42663
Imports	4505	4516	1375	1025	1025	1025	0	0	0	0	0	0	0	0	0	0
- Crude	4290	4301	1350	1000	1000	1000	0	0	0	0	0	0	0	0	0	0
- Products	215	215	25	25	25	25	0	0	0	0	0	0	0	0	0	0
Consumption	6708	7576	7998	7519	4207	4292	4545	4807	5078	5359	4358	4711	5078	5459	4562	4974
- Gasoline	1260	1252	1125	1069	1069	1122	1178	1237	1299	1364	1432	1504	1579	1658	1741	1828
- Diesel	1271	1263	945	851	851	851	893	938	985	1034	1085	1140	1197	1257	1319	1385
- Fuel Oil	3216	4185	5228	4970	1658	1690	1812	1937	2065	2196	1036	1223	1416	1614	525	735
- Kerosene	561	475	380	342	342	342	359	377	396	416	436	458	481	505	531	557
- Other	400	400	320	288	288	288	302	318	333	350	368	386	405	426	447	469
Exports	7769	6065	3955	3061	6016	5719	5094	7229	12050	14843	20809	26185	30799	36058	39657	39702
- Crude	0	0	1050	300	400	500	600	700	na	na	na	na	na	na	na	na
- Mogas	101	13	70	na	na	na	na	na	na	na	na	na	na	na	na	na
- Diesel	2733	2279	2000	na	na	na	na	na	na	na	na	na	na	na	na	na
- Mazut	3594	2297	320	na	na	na	na	na	na	na	na	na	na	na	na	na
- Jet Kero	823	747	150	na	na	na	na	na	na	na	na	na	na	na	na	na
- Diesel Lubes	220	338	90	na	na	na	na	na	na	na	na	na	na	na	na	na
- Other	298	390	275	na	na	na	na	na	na	na	na	na	na	na	na	na
Refinery Fuel & Loss	1344	1283	797	772	737	714	680	853	508	536	436	471	508	546	456	497
Unreported Balance	1198	1334	-290	-0	-0	-0	-0	-0	0	0	-0	0	0	-0	-0	0

AZERBAIJAN - OIL SUPPLY/DEMAND BALANCE ***DELAY CASE***

Thousand Tons

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	12513	11742	11084	10325	9625	9077	8925	9598	12190	14943	17393	19889	24146	29884	34758	39265
- Onshore	2582	2249	2009	1808	1627	1564	1568	1686	2068	2461	2865	2778	2700	2630	2567	2511
- Offshore	9931	9493	9075	8517	7998	7513	7357	7911	10123	12482	14528	17111	21445	27253	32190	36744
Imports	4505	4516	1375	1025	1025	1025	0	0	0	0	0	0	0	0	0	0
- Crude	4290	4301	1350	1000	1000	1000	0	0	0	0	0	0	0	0	0	0
- Products	215	215	25	25	25	25	0	0	0	0	0	0	0	0	0	0
Consumption	6708	7576	7998	7519	4207	4292	4545	4807	5078	5359	4358	4711	5078	5459	4562	4974
- Gasoline	1260	1252	1125	1069	1069	1122	1178	1237	1299	1364	1432	1504	1579	1658	1741	1828
- Diesel	1271	1263	945	851	851	851	893	938	985	1034	1085	1140	1197	1257	1319	1385
- Fuel Oil	3216	4185	5228	4970	1658	1690	1812	1937	2065	2196	1036	1223	1416	1614	525	735
- Kerosene	561	475	380	342	342	342	359	377	396	416	436	458	481	505	531	557
- Other	400	400	320	288	288	288	302	318	333	350	368	386	405	426	447	469
Exports	7769	6065	3955	3059	5728	5140	3797	4168	6604	9048	12599	14707	18560	23878	29739	33783
- Crude	0	0	1050	300	400	500	600	700	na	na	na	na	na	na	na	na
- Mogas	101	13	70	na	na	na	na	na	na	na	na	na	na	na	na	na
- Diesel	2733	2279	2000	na	na	na	na	na	na	na	na	na	na	na	na	na
- Mazut	3594	2297	320	na	na	na	na	na	na	na	na	na	na	na	na	na
- Jet Kero	823	747	150	na	na	na	na	na	na	na	na	na	na	na	na	na
- Diesel Lubes	220	338	90	na	na	na	na	na	na	na	na	na	na	na	na	na
- Other	298	390	275	na	na	na	na	na	na	na	na	na	na	na	na	na
Refinery Fuel & Loss	1344	1283	797	772	716	670	583	623	508	536	436	471	508	546	456	497
Unreported Balance	1196	1334	-290	0	0	0	-0	0	0	0	0	-0	0	0	-0	0

AZERBAIJAN - OIL SUPPLY/DEMAND BALANCE ***LOW CASE***

Thousand Tons

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	12513	11742	11084	10326	9935	9701	10320	10550	11993	13959	16991	20372	23207	26549	28716	30486
- Onshore	2582	2249	2009	1808	1627	1564	1568	1686	2068	2461	2865	2778	2700	2630	2567	2511
- Offshore	9931	9493	9075	8518	8308	8137	8752	8864	9925	11498	14127	17594	20508	23919	26149	27976
Imports	4505	4516	1375	1025	1025	1025	0	0	0	0	0	0	0	0	0	0
- Crude	4290	4301	1350	1000	1000	1000	0	0	0	0	0	0	0	0	0	0
- Products	215	215	25	25	25	25	0	0	0	0	0	0	0	0	0	0
Consumption	6708	7576	7998	7519	4207	4292	4545	4807	5078	5359	4358	4711	5078	5459	4562	4974
- Gasoline	1260	1252	1125	1069	1069	1122	1178	1237	1299	1364	1432	1504	1579	1658	1741	1828
- Diesel	1271	1263	945	851	851	851	893	938	985	1034	1085	1140	1197	1257	1319	1385
- Fuel Oil	3216	4185	5228	4970	1658	1690	1812	1937	2065	2196	1036	1223	1416	1614	525	735
- Kerosene	561	475	380	342	342	342	359	377	396	416	436	458	481	505	531	557
- Other	400	400	320	288	288	288	302	318	333	350	368	386	405	426	447	469
Exports	7769	6065	3955	3061	6016	5720	5095	5054	6407	8064	12198	15190	17621	20544	23697	25015
- Crude	0	0	1050	300	400	500	600	700	na	na	na	na	na	na	na	na
- Mogas	101	13	70	na	na	na	na	na	na	na	na	na	na	na	na	na
- Diesel	2733	2279	2000	na	na	na	na	na	na	na	na	na	na	na	na	na
- Mazut	3594	2297	320	na	na	na	na	na	na	na	na	na	na	na	na	na
- Jet Kero	823	747	150	na	na	na	na	na	na	na	na	na	na	na	na	na
- Diesel Lubes	220	338	90	na	na	na	na	na	na	na	na	na	na	na	na	na
- Other	298	390	275	na	na	na	na	na	na	na	na	na	na	na	na	na
Refinery Fuel & Los	1344	1283	797	772	737	714	680	689	508	536	436	471	508	546	456	497
Unreported Balanc	1196	1334	-290	-0	-0	-0	-0	-0	0	0	0	-0	0	0	-0	0

AZERBAIJAN - Consumption & Export of Refined Products (1990-1991)
('000 tons)

	1990				1991			
	Domestic Sales	Exports to CIS	Exports to Third Countries	Total Sales (1 + 2 + 3)	Domestic Sales	Exports to CIS	Exports to Third Countries	Total Sales (5 + 6 + 7)
Aviation Gasoline	5.8	72.4	12.0	90.2	7.0	132.5	-	139.5
Motor Gasoline	1,278.9	100.4	-	1,379.3	1,252.0	-	-	1,252.0
Jet Fuel	561.0	823.1	-	1,384.1	474.6	877.0	-	1,351.6
Diesel Oil (Auto)	1,309.6	1,538.7	1,174.5	4,022.8	1,250.0	1,400.0	1,360.0	4,010.0
Industrial & Marine Diesel	45.3	277.5	0.6	323.4	53.5	260.9	-	314.4
Stove Oil	(32.0)	(220.3)	(-)	(252.3)	(40.0)	(217.5)	(-)	(257.5)
Solar Oil	(1.0)	(22.6)	(0.6)	(24.2)	(1.0)	(22.0)	(-)	(23.0)
Fleet Fuel Oil	(12.3)	(34.6)	(-)	(46.9)	(12.5)	(21.4)	(-)	(33.9)
Lubricating Oils	135.2	787.5	16.9	939.6	120.1	994.6	-	1114.7
Motor Lubes (M8B1)	(17.0)	(149.9)	(-)	(166.9)	(17.0)	(178.0)	(-)	(195.0)
Motor Lubes (M12B6)	(31.2)	(314.3)	(16.9)	(362.4)	(42.0)	(446.2)	(-)	(488.2)
Indust'l Lubes (I-40A)	(5.5)	(129.9)	(-)	(135.4)	(5.5)	(126.6)	(-)	(132.1)
Indust'l Lubes (I-12A)	(6.0)	(22.6)	(-)	(28.6)	(6.0)	(92.1)	(-)	(98.1)
Transformer Oil (T-1500)	(3.0)	(52.8)	(-)	(55.8)	(3.0)	(67.5)	(-)	(70.5)
Transformer Oil (K-12)	(18.0)	(4.8)	(-)	(22.8)				
Turbine Oil (T-46)	(-)	(2.6)	(-)	(2.6)	(0.1)	(1.7)	(-)	(1.8)
Cylinder Oil (II)	(3.5)	(8.3)	(-)	(11.8)	(2.5)	(10.5)	(-)	(13.0)
Axle Oil (C)	(-)	(1.3)	(-)	(1.3)	(-)	(-)	(-)	(-)
Axle Oil (Z)	(-)	(66.5)	(-)	(66.5)	(-)	(72.0)	(-)	(72.0)
Motor Oil (DT)	(51.0)	(34.5)	(-)	(85.5)	(44.0)	(-)	(-)	(44.0)
Fuel Oil	4,103.3	2,453.0	1,120.0	7,676.3	4,104.0	2,800.0	500.0	7,404.0
Bitumen	177.2	-	0.9	178.1	170.0	-	-	170.0
Total	7,616.3	6,052.6	2,324.9	15,993.8	7,431.2	6,465.0	1,860.0	15,756.2

Source: Goscomtopliva
Notes: (a) Does not include coke, solvents and other specialties.
(b) There are significant differences between Total Sales shown in this table and Total Refinery Production in table elsewhere. May be due to inventory changes, and/or statistical errors.

AZERBAIJAN - Consumption & Export of Refined Products (1992)
('000 tons)

Products	Domestic Sales	Exports to CIS	Exports to Third Countries	Total Sales
Gasolines	1096.4	154.2	-	1250.6
Diesel Oils	1188.8	715.2	2045.3	3949.3
Fuels Oils	4644.4	95.1	260.2	4999.7
Jet Kerosene	4.9	145.3	48.6	198.8
Lubes	n.a.	113.1	-	113.1
Others	201.6	336.4	342.3	862.3
Total	7136.1	1558.3	2678.4	11372.8

Azerbaijan - Novobakinsky Refinery, Physical Facilities

	Capacity '000 tons/yr	Year of Startup	Technology Source	Remarks
Crude & vacuum distillation unit (unit 16)	2,000	1963-66	USSR	
Crude & vacuum distillation unit (unit 15)	6,000	1976	East Germany	
Naphtha pretreat & Reformer (CCR) (unit 17)	1,000	1980	UOP	
FCC-1 (unit 31)	750	1965	Kellogg/UOP/FSU	Will be retired after commissioning of FCC-3
FCC-2 (unit 32)	750	1967	Kellogg/UOP/FSU	Will be retired after commissioning of FCC-3
FCC-3 (under construction)	2,000	Scheduled 1992	UOP/FSU/Rom.	
Coker-1 (unit 41)	530	1966	USSR	
Vacuum distillation of vac. residues (unit 42)	250			
Coker-2 (unit 43)	1,500	1986	USSR	
Polymerisation (C_4) unit (unit 33)	75	1965	USSR	
Alkylation (C_4) unit (unit 35)	120	1953	Stratco, USA	Shut down, lack of acid
Gas fractionation unit	450			C_3-C_4 recovery to Poly unit
Kero Merox	160			
Thermal cracker/Visbreaker	1,700			

Utilities & Offsites

1. All electric power purchased from State Grid
2. All steam purchased from nearby power/district heating plant
3. Cooling water make up purchased from Baku municipality
4. Crude oil storage: 130,000 m^3 (located 15 km for refinery); product storage: 420,000 m^3.

Crude oil from: (i) eleven domestic sources delivered by pipeline to Main Storage, all mixed, transported to refinery through 10" line, preferentially processed through the Unit 15; (ii) imported crude from Kazahkstan transported by Caspian Sea, unloaded into small storage terminal at Baku port and pumped to Main Storage, similarly imported crude from W. Siberia.

Azerbaijan: Azneftyag Refinery, Physical Facilities

1. Atmospheric/Vacuum Distillation: Total 11.7 mtpy, consisting of:

(i) AVU	:	6.0 mtpy
(ii) ADU	:	2.0 "
(iii) ADU	:	1.5 "
(iv) AVU	:	1.0 "
(v) AVU	:	0.6
(vi) ADU	:	0.6

2.	Vacuum Distillate	:	6 units of total 1.8 mtpy capacity
3.	Deasphalting Units	:	(i) 200,000 tpy; (ii) 300,000 tpy
4.	Furfural Extraction Unit	:	700,000 tpy
5.	Dewaxing Units	:	300,000 tpy total capacity
6.	Lubes and wax hydrolicating	:	1 mtpy total capacity
7.	Bitumen Manufacturing	:	160,000 tpy

Azerbaijan - Refineries crude throughput and production of main products, 1981-92

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Crude Oil Processed	20499	20393	20980	20723	21135	22022	22101	21699,6	18435	16331,6	15820	12099.5
Crude Oil Supply	20628	20467	21000	20854	21240	22062	22383,9	21757,8	18440	16342	15837	n.a.
- Domestic Crude	(13283)	(12161)	(11887)	(11855)	(12387)	(12719)	(13320,8)	(13262,6)	(12646,6)	(12073)	(11088)	(10584.0)
- Russian Crude	(5054)	(5249)	(5562)	(4438)	(3203)	(3759,9)	(3562,8)	(3740,0)	(2879)	(2515)	(2514)	(854.5)
- Kazakhi Crude	(2171)	(3043)	(3551)	(4548)	(5612,5)	(5578,2)	(5500,6)	(4755,2)	(2909,7)	(1754)	(2235)	(661.0)
Main Products												
Automotive gasoline	1992,3	2018,7	2079,4	1909,2	1898,3	2149,6	2121,3	1742,6	1549,2	1479,6	1173,7	1250.6
Diesel Oil	3534	3796,6	3902,8	4010,6	4499,8	5004,3	5158,6	5145,1	4236,9	3974,7	3634,9	3949.3
Bitumen	187,7	176,7	198,5	199,2	181,3	185,2	194,4	185,6	167,0	145,2	113,1	862.3 1/
Lubricating Oils	1131,8	1079	1193,0	1193,5	1118,3	1130,7	1103,5	1061,1	933,8	819,0	762,5	113.1
Coke	125,4	132,0	132,7	128,5	102,5	149,6	226,1	244	229,8	178,4	161,3	180
Fuel Oil	8837,9	9058,5	9048,8	9293,6	9316,0				9429.0	6579.0	6400	4999.7
Kerosene	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1539.0	1304.0	1350	198.8

1/ Includes coke and other products

Source: Azneftchim and mission estimates.

Azerbaijan - Typical Characteristics of Crude Oils, and of Mixtures Charged to Refinery Units, 1991

	Shirvani 493 (onshore)	Surakani 482 (onshore)	Karachukur 488 (onshore)	Oil Rocks 479 (offshore)	Buzachy (Khazakhistan)	Tyumen W. Siberia
1. Density @20°C, gm/cc	0.8802 (0.863-0.898)	0.8573 (0.851-0.863)	0.8507 (0.826-0.832)	0.8573 (0.851-0.864)	0.9140 (0.905-0.9221)	0.8374 (0.831-0.843)
2. Distillation, wt % distilled						
IBP, °C	35	52	30	36	35	53
150 'C	8.6	9.0	36.9	4.7	5.0	16.0
250 'C	23.6	28.7	51.5	14.1	13.0	31.5
350 'C	40.0	55.7	67.3	34.5	34.0	53.9
400 'C	52.7	66.5	74.4	46.8	46.5	61.0
3. Kinematic viscosity @40°C mm^2/sec.	43.5	13.0	7.2	13.5	157.4	7.4
4. Water content, % wt.	0.03-1.6	0.03-0.4	0.03-0.2	0.03-0.4	0.12-1.9	0.03-0.4
5. Chlorides, mg/litre	62-482	20-50	15-52	20-100	140-435	17-40
6. Sulfur, % wt.	0.21-0.35	0.2-0.27	0.13-0.28	0.18-0.35	1.17-1.89	0.4-0.6
7. Pour point, °C	-36	-38	-38	-38	-15	-18
8. Acidity, mg KOH	1.2	1.7	1.9	1.3	0.1	0.1
9. Conradson carbon, % wt.	2.9	2.7	2.5	2.9	4.8	0.3
10. Ash, % wt.	0.01	0.008	0.005	0.01	0.06	0.02
11. Paraffins, % wt.	NA	5.1	4.7	5.1	1.8	2.1
12. Asphaltenes, % wt.	NA	1.1	1.0	1.2	2.8	2.7

Azerigaz Gas Acquisition Prices
(Rubles/1000 cm)

	from SOCAR (wet gas)	from SOCAR's Karadoc Gas Processing Plant (dry gas)	from USSR	from Turkmen-istan
Full year 1991	15	35	33	N/A
January 1, 1992	87.50	175	N/A	1,181
January 11, 1992	87.50	175	N/A	2,926
January 1, 1993	600	600	N/A	9,543
January 5, 1993	600	600	N/A	15,129

Azerigaz Retail Prices (rubles/Mcm)

	Industrial	Commercial	Household
Full year 1991	61	61	12
January 1992	1,954	305	250
April 1992	2,450	305	250
December 1992	5,655	1,171	384
January 1993	18,377	3,294	720
May 1993			720

Source: Azerigaz, May 1993

AZERBAIJAN
Household Gas tariffs (Monthly) January 1, 1993

TYPE OF APPLIANCE	UNIT OF MEASUREMENT	GAS USAGE (cub. m. per month)	BASE TARIFF (rubles)	TARIFF PLUS 20% VAT (rubles)
I. FOR HOUSEHOLDS W/O DISTRICT HEATING				
1 Gas stove	per person/per month	21.50	7.20	8.64
2 Continuous flow water heater	"	7.00	4.20	5.04
3 Boiler-type water heater	"	10.00	6.00	7.20
Non-standard water heaters:				
4a Indoor	per device/per month	200	120	144.00
4b Outdoor (summer rate)	"	300	180	216.00
Outdoor (winter rate)	"	600	360	432.00
5 Radiator-type heater	per device/per month	320	192	230.40
6 Comb. brick stove/space heater	during heating season	400	240	288.00
7 Wall-unit space heater	"	270	162	194.40
8 Iron stove	"	1200	720	864.00
Boilers for space heating	cub. m of heated space			
9a Indoor (non-standard)	"	2.80	1.68	2.02
9b Outdoor (non-standard)	"	5.00	3.00	3.60
10 Factory made	"	2.00	1.20	1.44
11 Private commercial greenhouses	cub. m of heated space	20.00	368.00	441.60
II. FOR HOUSEHOLD WITH DISTRICT HEATING				
1 Gas stove	per person/per month	18.50	4.80	5.76
2 Continuous flow water heater	"	7.00	4.20	5.04
3 Boiler-type water heater	"	21.50	7.20	8.64

REFERENCE GAS PRICES (rubles per cubic meter)

Non-standard (hand-made) boilers, radiators, and wall stoves	0.60
Factory-made stoves and boilers	0.26
Private commercial greenhouses	18.40

Source: Azerigaz, May 1993

AZERBAIJAN GAS SUPPLY-DEMAND

BASE CASE

(Million Cubic Meters)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	11234	10052	9275	8435	7759	7167	6850	6120	5681	5482	5835	6234	6785	7393	7785	8059
– Onshore	406	292	242	218	196	188	189	203	249	296	345	334	325	316	309	302
– Offshore	10828	9760	9034	8218	7563	6979	6661	5917	5432	5186	5491	5900	6461	7077	7476	7757
Venting	1309	1431	1431	1431	1431	0	0	0	0	0	0	0	0	0	0	0
Net Available	9925	8621	7844	7005	6328	7167	6850	6120	5681	5482	5835	6234	6785	7393	7785	8059
Imports	13114	14170	5263	4250	9003	8037	8228	8831	9143	9216	10461	9920	9227	8478	9609	9179
– Turkmenistan	11599	11163	4583	4000	na	na	na	na	na	na	na	na	na	na	na	na
– Iran	1515	3007	680	250	na	na	na	na	na	na	na	na	na	na	na	na
Exports	5424	5996	951	100	0	0	0	0	0	0	0	0	0	0	0	0
Net Imports	7690	8174	4312	4150	9003	8037	8228	8831	9143	9216	10461	9920	9227	8478	9609	9179
Consumption	14238	13256	9538	9125	12670	12670	12670	12670	12670	12670	14170	14170	14170	14170	15670	15670
– Power+Heat	5474	4238	1621	1455	5000	5000	5000	5000	5000	5000	6500	6500	6500	6500	8000	8000
– Industry	3051	3118	2467	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220
– Commercial	3012	2730	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600
– Distribution	2701	3170	2850	2250	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850
Own Use/Losses	3373	3455	2413	2030	2661	2534	2407	2281	2154	2027	2126	1984	1842	1700	1724	1587
Balance	4	84	206	–0	0	0	0	0	0	0	0	–0	–0	–0	–0	–0
% Loss		17.9%	23.0%	22.0%	21.0%	20.0%	19.0%	18.0%	17.0%	16.0%	15.0%	14.0%	13.0%	12.0%	11.0%	10.0%

AZERBAIJAN GAS SUPPLY-DEMAND

DELAY CASE

(Million Cubic Meters)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	11234	10052	9275	8435	7675	6999	6474	6120	5462	4971	4960	4854	4990	5343	5937	6590
– Onshore	406	292	242	218	196	188	189	203	249	296	345	334	325	316	309	302
– Offshore	10828	9760	9034	8218	7479	6811	6285	5917	5213	4675	4615	4520	4665	5027	5628	6288
Venting	1309	1431	1431	1431	1431	1431	1431	0	0	0	0	0	0	0	0	0
Net Available	9925	8621	7844	7005	6245	5568	5043	6120	5462	4971	4960	4854	4990	5343	5937	6590
Imports	13114	14170	5263	4250	9087	9636	10035	8831	9362	9727	11336	11300	11023	10527	11457	10647
– Turkmenistan	11599	11163	4583	4000	na	na	na	na	na	na	na	na	na	na	na	na
– Iran	1515	3007	680	250	na	na	na	na	na	na	na	na	na	na	na	na
Exports	5424	5996	951	100	0	0	0	0	0	0	0	0	0	0	0	0
Net Imports	7690	8174	4312	4150	9087	9636	10035	8831	9362	9727	11336	11300	11023	10527	11457	10647
Consumption	14238	13256	9538	9125	12670	12670	12670	12670	12670	12670	14170	14170	14170	14170	15670	15670
– Power+Heat	5474	4238	1621	1455	5000	5000	5000	5000	5000	5000	6500	6500	6500	6500	8000	8000
– Industry	3051	3118	2467	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220
– Commercial	3012	2730	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600
– Distribution	2701	31[illegible]	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850
Own Use/Losses	3373	3455	2413	2030	2661	2534	2407	2281	2154	2027	2126	1984	1842	1700	1724	1567
Balance	4	84	206	–0	0	0	0	0	0	0	0	–0	0	0	–0	0
% Loss		17.9%	23.0%	22.0%	21.0%	20.0%	19.0%	18.0%	17.0%	16.0%	15.0%	14.0%	13.0%	12.0%	11.0%	10.0%

AZERBAIJAN GAS SUPPLY-DEMAND

LOW CASE

(Million Cubic Meters)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Production	11234	10052	9275	8435	7759	7167	6850	5725	5055	4800	4892	5002	5208	5469	5629	5876
– Onshore	406	292	242	218	196	188	189	203	249	296	345	334	325	316	309	302
– Offshore	10828	9760	9034	8218	7563	6979	6661	5522	4807	4504	4548	4668	4884	5153	5320	5574
Venting	1309	1431	1431	1431	1431	0	0	0	0	0	0	0	0	0	0	0
Net Available	9925	8621	7844	7005	6328	7167	6850	5725	5055	4800	4892	5002	5208	5469	5629	5876
Imports	13114	14170	5263	4250	9003	8037	8228	9226	9769	9898	11404	11152	10804	10401	11765	11361
– Turkmenistan	11599	11163	4583	4000	na	na	na	na	na	na	na	na	na	na	na	na
– Iran	1515	3007	680	250	na	na	na	na	na	na	na	na	na	na	na	na
Exports	5424	5996	951	100	0	0	0	0	0	0	0	0	0	0	0	0
Net Imports	7690	8174	4312	4150	9003	8037	8228	9226	9769	9898	11404	11152	10804	10401	11765	11361
Consumption	14238	13256	9538	9125	12670	12670	12670	12670	12670	12670	14170	14170	14170	14170	15670	15670
– Power+Heat	5474	4238	1621	1455	5000	5000	5000	5000	5000	5000	6500	6500	6500	6500	8000	8000
– Industry	3051	3118	2467	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220	2220
– Commercial	3012	2730	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600	2600
– Distribution	2701	3170	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850	2850
Own Use/Losses	3373	3455	2413	2030	2661	2534	2407	2281	2154	2027	2126	1984	1842	1700	1724	1567
Balance	4	84	206	–0	0	0	0	0	–0	0	0	–0	–0	–0	0	0
% Loss		17.9%	23.0%	22.0%	21.0%	20.0%	19.0%	18.0%	17.0%	16.0%	15.0%	14.0%	13.0%	12.0%	11.0%	10.0%

Pricing of Domestic Natural Gas Production

1. Azerbaijan is an unusual gas market, in that domestic production is relatively large, but insufficient to supply all domestic requirements. Imported gas from Turkmenistan, Russia and (potentially) Iran is (in theory at least) readily available in large quantities. A significant part of demand in the power sector (amounting to about 40 percent of total consumption) is directly substitutable for fuel oil in existing dual-fired boilers, while the balance of demand (in the industrial, residential and commercial sectors) is not easily substitutable.

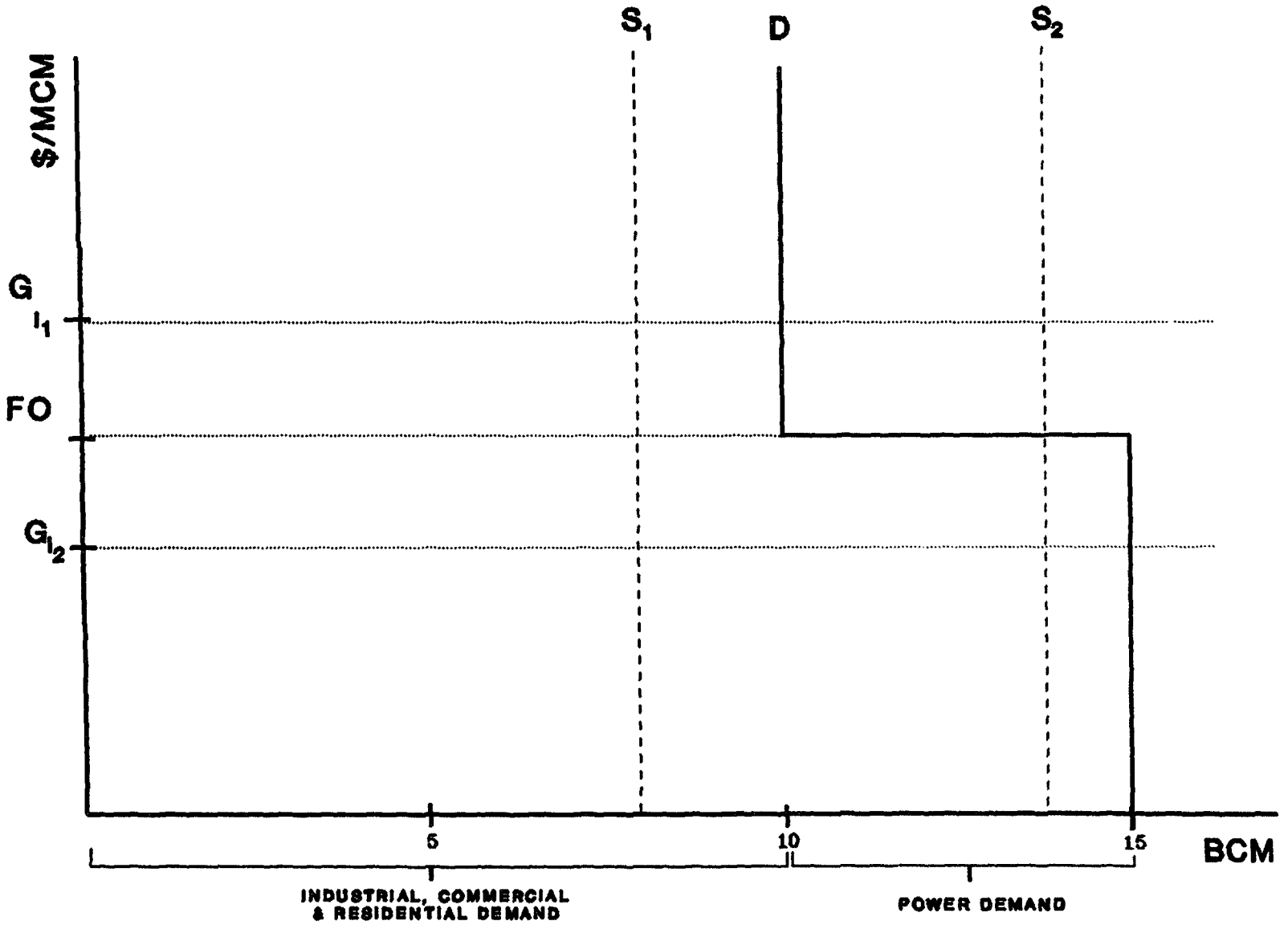
2. The level at which domestic natural gas production should be priced will depend upon the relationship between domestic natural gas supply and total demand. Domestic natural gas output displaces either imported natural gas or fuel oil (for export), depending upon the level of domestic production, the demand for gas in the country and the relative economic value of gas imports and fuel oil exports Where imported natural gas is valued below exported fuel oil, domestic natural gas should be priced to compete with imported gas provided that its cost of supply is competitive, ie. the producer price of gas should be based upon the import price (adjusted for transport costs). However, if imported natural gas is priced above fuel oil export value, then domestic gas will compete with imported gas in the industrial, commercial and residential markets (the "premium" markets where there is no possibility of substitution), and with fuel oil in the power market (where substitution between gas and fuel oil can take place), again provided that its cost of supply is competitive. In this case, the level of pricing will depend upon the relationship between domestic gas output and the requirements of the "premium" markets: if domestic output is below "premium" demand then domestic gas competes with imported gas and the price of domestic gas should be set at the import level; however, if domestic gas output exceeds the requirements of the "premium" market, then domestic gas competes with fuel oil in the power market, and the price should be set at the (lower) fuel oil export parity, plus a premium to reflect the cleanliness and ease of handling of gas.

3. These factors are illustrated in the figure. G_{I1} and G_{I2} are two levels of natural gas import price, with the corresponding (flat) supply curves for imported gas. FO is the world price value of fuel oil exports. S_1 and S_2 are two (vertical) supply curves for domestic natural gas production, reflecting possible alternative levels of supply. D is the demand curve for natural gas. Demand is inelastic in the industrial, commercial and residential sectors, which account for about 10 BCM of demand. Demand in the power sector, of about 5 BCM, is infinitely elastic at the fuel oil export parity price, since at gas prices above this level only fuel oil is used, while at prices below this level only gas is used.

4. With the natural gas import price level at G_{I2}, domestic gas must be priced no higher than this level if it is to gain a market at all, ie. at both S_1 and S_2 the price of domestic gas production should be the imported gas price. However, with imported gas prices at G_{I1} and available domestic supply equal to S_2, the price for domestic gas should be equal to the fuel oil price (FO), since at such high imported gas prices the power sector will be using fuel oil, and domestic gas will be competing with fuel oil. If domestic supply is at S_1, however, domestic gas should be priced at the imported gas price (G_{I1}), since at this level of supply domestic gas is competing only with imported gas.

5. It is probable that pricing according to the import price of natural gas will tend to predominate in Azerbaijan, at least until 2000, since domestic output will probably be below premium demand. However, gas import prices may well be above the export value of fuel oil in the long run. In this case, a large increase in domestic gas production, combined with stagnant or falling premium demand, could lead to pricing of gas at fuel oil parity. If some of the dual-fired power stations are replaced by combined cycle stations, which cannot switch to fuel oil, this will effectively increase the likelihood of prices being set by the gas import parity.

AZERBAIJAN NATURAL GAS SUPPLY - DEMAND & PRICE



AZERBAIJAN
Existing Generating Plants

	No. of Units x Unit Size	Commissioning Dates	Installed Capacity	Available Capacity	Average Fuel Consumption *
A. Thermal Power Stations					
1. Azgres	8 x 300 MW	1981-90	2,400	1,600	360g/kWh
2. Ali-Bayramli Gres	7 x 150 MW	1962-70	1,050	950	386g/kwH
3. Gres "Severnaya" +	1 x 150	1960	150	145	400g/kWh
Subtotal			3,600	2,695	
B. Combined Heat and Power Stations					
4. Baku CHP 1 CHP	2 x 50	1937-75	100	50/30	159g/kWh and 180g/Gcal
5. Baku CHP 2 CHP	4 x 6	1953	24	6	170g/kWh and 168g/Gcal
6. Sumgait CHP-1 CHP	4 x 50	1959	200	200/110	365g/kWh and 179g/Gcal
7. Sumgait CHP-2 CHP	2 x 60 2 x 50	1966 1966	220	210/110	170g/kWh and 168g/Gcal
8. Gandja CHP CHP	3 x 24	1964	72	40/30	256g/kWh and
Subtotal			616	506/286	
C. Hydro Electric Plant					
9. Mingechaur H	4 x 60	1953	240	240/140	
10. Shamkor H	2 x 190	1982	380	380/190	
11. Araks H	2 x 11		22	--	
12. Ter Ter H			50	--	
Subtotal			692	620/330	
Total			4,908	3,821/3,311**	

* Based on a reference fuel of 7,000 kcal/kg heating value.
** Available Capacity Summer/Winter

Source: Azenergo

Azerbaijan
Existing and Projected generating capacity

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2005
(a) Hydro											
-Mingechaur	240	240	240	240	240	310	380	390	400	400	400
-Shamkor	380	380	380	380	380	380	380	380	380	380	380
-Yenikand					75	75	110.5	150	150	150	150
-Araks *				(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
-Ter Ter *				(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
(b) Steam											
-Azgres	1,600	1,600	1,830	2,060	2,060	2,430	2,430	2,430	2,430	2,430	2,430
-Ali Beramli	950	950	950	810	810	810	675	675	540	540	300
-Severnaya	145	145	125	125	125						
(c) CHP											
-Baku 1	50	50	50	50	50	100	100	100	100	100	100
-Baku 2	6	6									55
-Sumgait 1	110	110	110	110	110	55	55	55	55	55	100
-Sumgait 2	210	210	210	210	210	150	150	150	150	150	40
-Gandja	40	40	40	40	40	40	40	40	40	40	
(d) New cap.									200	200	800
(e) Total cap.	3,731	3,731	3,935	4,165	4,165	4,420	4,285	4,370	4,395	4,595	5,155
(f) peak load	3,700	3,370	3,250	3,110	3,130	3,200	3,270	3,340	3,420	3,480	3,850
(g) Reserve (MW)	31	361	685	1055	1035	1220	1015	1030	975	1115	1305
%	1	10	17	25	25	28	24	24	22	24	25

Source: Azenergo

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AZERBAIJAN

Electricity Tariffs

	1990	1991 1st quarter	1991 4th quarter	1992 01/01	1992 05/01	1993 01/01
1. Industrial (>750kVA)						
o Fixed charge R/kW	3.5	5.0	11.1	55.5 25.0	105.5 47.5	6,200
o Energy Kop/kWh	1.7	3.4	5.7 2.3	28.0	54.0 24.0	385
2. Industrial (<750kVA) Kop/kWh	3.0	5.4	8.9 4.0	44.4 20.0	84.4 38.0	570
3. Agricultural Kop/kWh	1.8	1.4	6.3	8.0 5.0	15.2 9.5	308
4. Railway Kop/kWh	3.0	4.1	6.7	33.3	63.3	554
5. Urban Transport Kop/kWh	2.0	5.4	4.0	20.0	38.0	400
6. Commercial Kop/kWh	3.0	5.4	8.9 4.0	44.4 20.0	84.4 38.0	770
7. Residential (urban) Kop/kWh	4.0 2.0	4.0 2.0	4.0 2.0	12.0 6.0	12.0 6.0	80 50
8. Residential (rural) Kop/kWh	1.0 0.5	1.0 0.5	1.0 0.5	8.0 4.0	8.0 4.0	70

- Average Tariff: 4.30 R/kWh

- Export tariff to Georgia: 18 R/kWh (as of February 1993)

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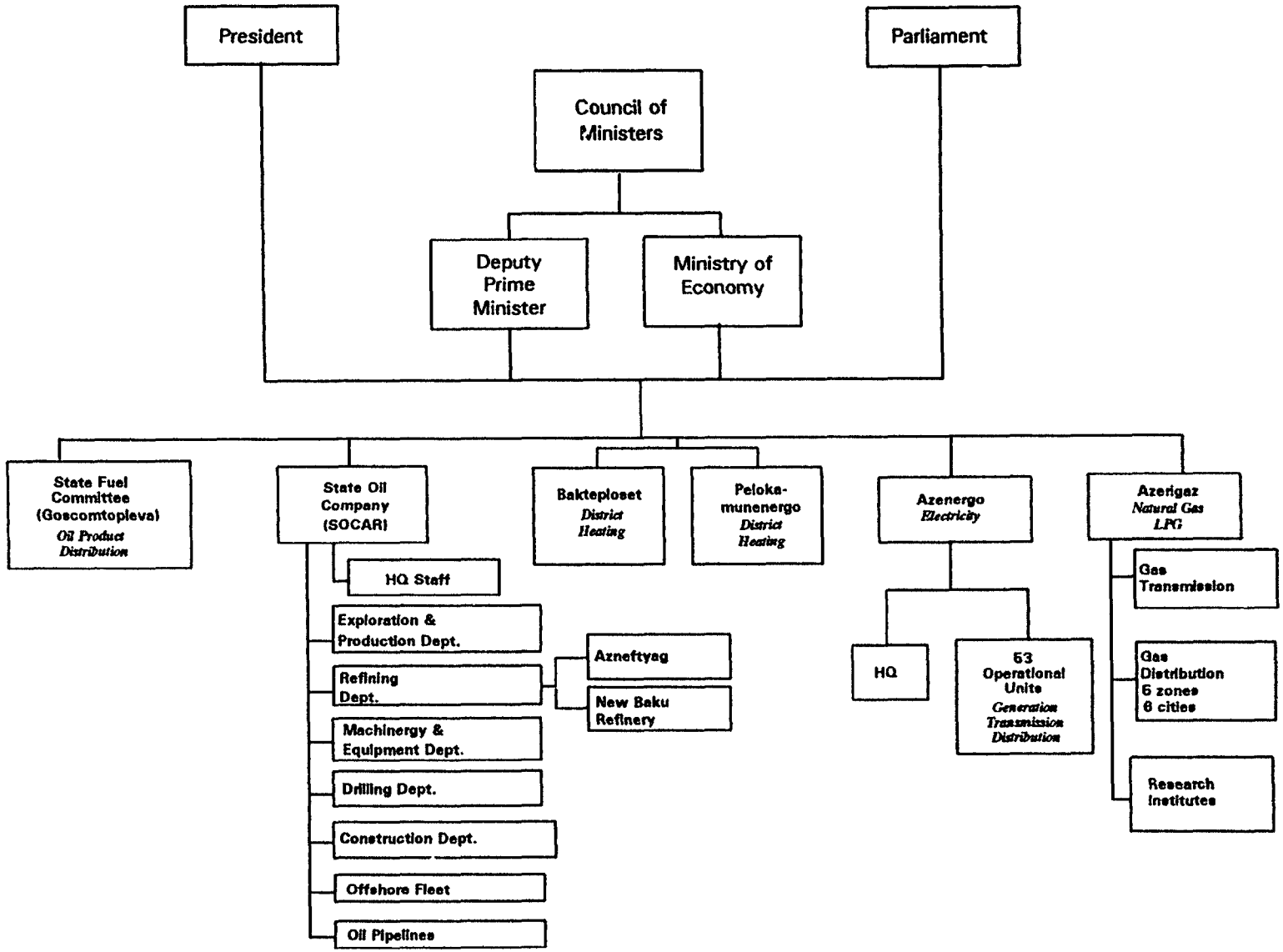
Annex 7.1 Azerbaijan Energy Sector Institutions



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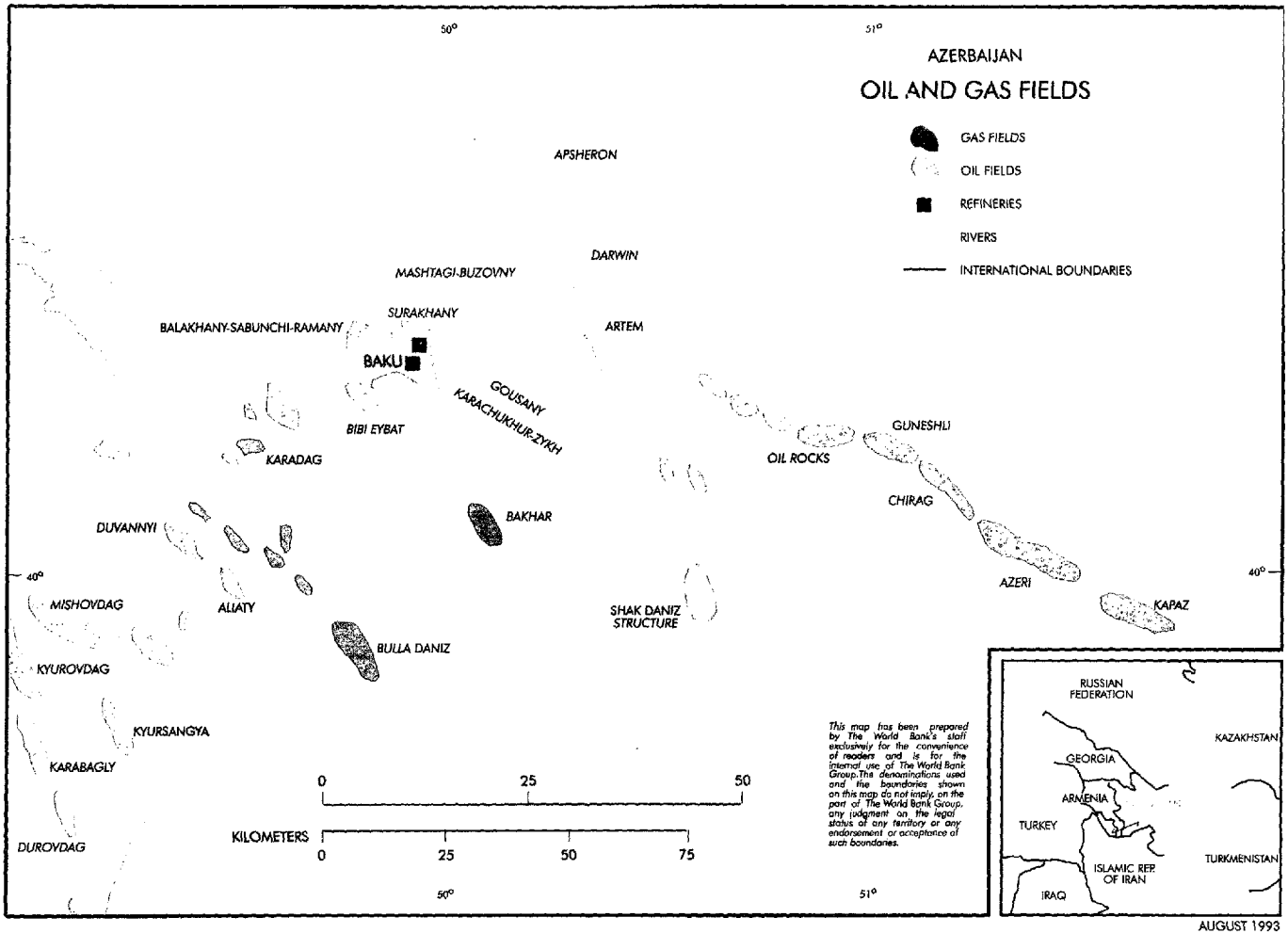
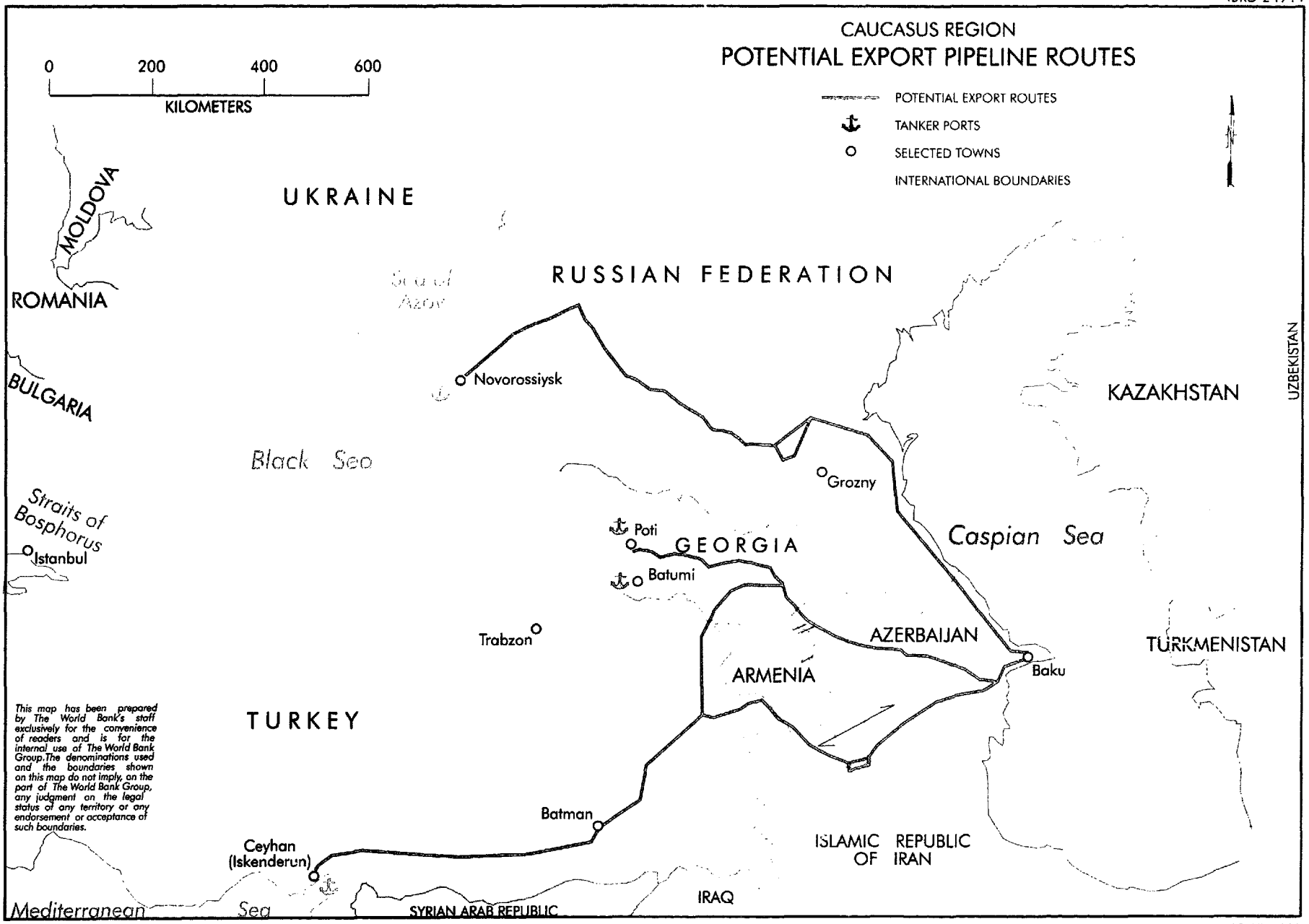


AUGUST 1993

IBRD 24911



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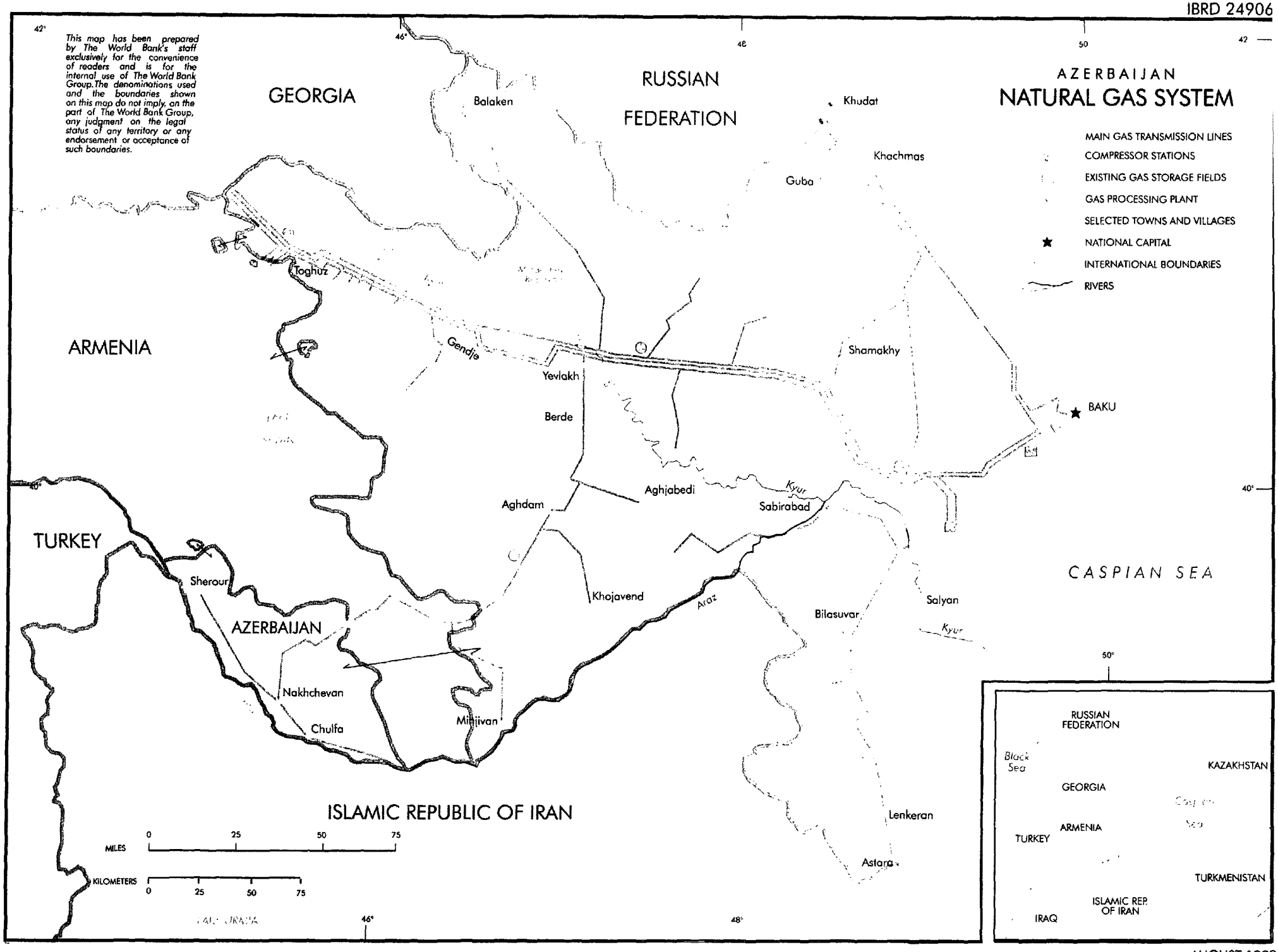
IBRD 24906



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IBRD 24970

AZERBAIJAN ELECTRICITY GRID

EXISTING POWER LINES:
500 kV
330 kV
220 kV
EXISTING POWER SUBSTATIONS
500 kV
330 kV
220 kV
HYDRO POWER PLANTS
THERMAL POWER PLANTS

SELECTED TOWNS AND VILLAGES
NATIONAL CAPITAL
INTERNATIONAL BOUNDARIES
RIVERS

RUSSIAN FEDERATION
GEORGIA
ARMENIA
TURKEY
ISLAMIC REPUBLIC OF IRAN
CASPIAN SEA
AZERBAIJAN

Khudat
Khachmas
Guba
Ismaily
Toghuz
Gendje
Shamakhy
Yevlakh
Myusyushyu
Berde
BAKU
Aghjabedi
Aghdam
Sabirabad
Sherour
Salyan
Bilasuvar
Nakhchevan
Chulfa
Masalli
Lenkeran
Astara

MILES 0 25 50 75
KILOMETERS 0 25 50 75

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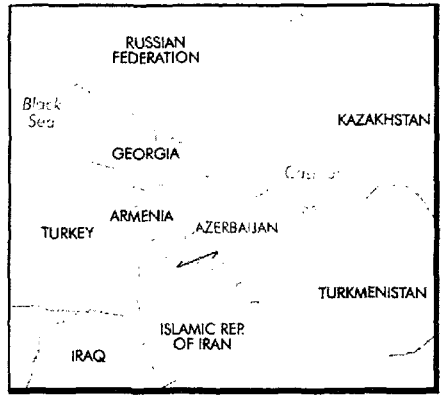

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